RPU-2009-0002

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July 17, 2009
IOWA UTILITIES BOARD

OFFICE OF CONSUMER ADVOCATE

DIRECT TESTIMONY

OF

DR. DAVID S. HABR

IN RE: INTERSTATE POWER & LIGHT COMPANY
Docket No. RPU-2009-0002

July 17, 2009

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Q: Please state your name and business address.

A: David S. Habr, 34333 White Oak Lane, Cumming, Iowa.

Q: By whom are you employed?

A: I am employed by Habr Economics, a consulting firm I founded in January 2009.

Q: Would you describe your education and experience?

A: Yes. I received a Bachelor of Arts (1968) and a Master of Arts (1969) degree in economics from the University of Nebraska – Lincoln. In 1976 I received a Ph.D. degree in economics from Washington State University.

Prior to starting my own business, I was employed by Iowa Office of Consumer Advocate for 21 years, first as head of the technical section and then 19 years as chief of the technical bureau. Before joining the OCA staff, I spent six years as a member of the staff of the Iowa Utilities Board (and its predecessor, the Iowa State Commerce Commission). While a member of the OCA or IUB staff, I testified in more than 50 proceedings before the IUB (or ISCC). Prior to joining the Commission staff, I had a private consulting practice, worked for a small consulting firm, and served six years as member of the economics faculty at Drake

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University. My attached vita contains a more detailed account of my previous professional activities.

Q: What is the purpose of your testimony in this proceeding?

A: I have been asked by the Office of Consumer Advocate to analyze Interstate Power and Light Company's management efficiency pursuant to Iowa Code Section 476.52. My analysis begins with a comparison of the prices paid by the customers of Interstate Power and Light Company (IPL) and those paid by the customers of MidAmerican Energy Company (MEC) and then moves to an examination of the probable causes of those differences.

Q: Have you prepared an exhibit for presentation in this proceeding?

A: Yes, I prepared OCA Ex._____(DSH-1), Schedules A through I.

Q: You referred to Iowa Code Section 476.52 in regard to management efficiency. Would you explain your understanding of the statute?

A: Yes. Section 476.52 states that is the policy of the state of Iowa that a public utility shall operate in an efficient manner. This section also provides that the Board may reduce the level of profit or adjust the revenue requirement for a utility if the Board determines that either (1) the utility is operating in an inefficient manner, or is not exercising ordinary,

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prudent management, or (2) in comparison to other utilities in the state, the utility is performing in a less beneficial manner than other utilities. The idea behind reducing the utility's profit level or revenue requirement is to provide incentives to the utility to correct its inefficient operation.

Q: You stated that your analysis begins with a comparison of the prices paid by the customers of IPL and those paid by the customers of MEC. Why did you choose MEC for comparison purposes?

A: I chose MEC because, like IPL, most of its electric operations are in Iowa and subject to regulation by the IUB. MEC is also owned by a holding company which means MEC's actions are also subject to the holding company's senior management and board of directors. Of course, MEC is also the only other investor owned electric utility operating in Iowa.

Q: Why does your analysis begin by focusing on the prices paid by IPL's customers?

A: Just as profits are thought of as the "bottom line" for a company's shareholders, prices are the "bottom line" for a utility company's customers (ratepayers). The prices paid by a utility company's customers reflect not only the efficiency with which the utility conducts its daily operations but also the impact of strategic decisions made by executive

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management at both the utility company and holding company levels.

Q: Why is it necessary to examine the strategic decisions at both the utility company and holding company levels?

A: IPL and Wisconsin Power and Light (WPL), are both wholly owned subsidiaries of Alliant Energy Corporation (Alliant or AEC). In a holding company arrangement, all strategic decisions, including capital spending decisions, are made at the parent company level, i.e., the AEC level. Executive officers submit their strategic proposals to the Board of Directors for their approval. In AEC's case, this process is facilitated by the fact that the executive officers for AEC, IPL, and WPL are the same eight people; William D. Harvey, Eliot G. Protsch, Barbara J. Swan, Thomas L. Aller, Dundeana K. Doyle, Patricia L. Kampling, Thomas L. Hansen, and Peggy Howard Moore.[1] Likewise, the people who make up the Board of Directors of AEC are the same people who make up the Board of Directors of IPL and WPL.[2]

Q: How do IPL's prices compare with those of MEC?

A: Chart – 1 below provides a comparison of the two companies' prices from 2001 through 2008 for each Company's three major consumer groups;

[1] Alliant Energy Corporation 2008 10-K, pp. 29 – 30.
[2] *Ibid.*, p. 191 and WPL 2009 Proxy Statement, pp. 3 – 5.

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residential, small commercial and industrial, and large commercial and industrial. Chart – 1 shows that IPL's prices started the new century slightly below MEC's but by 2003 IPL's prices exceeded MEC's with the difference increasing through 2006, declining in 2007, and increasing again in 2008.

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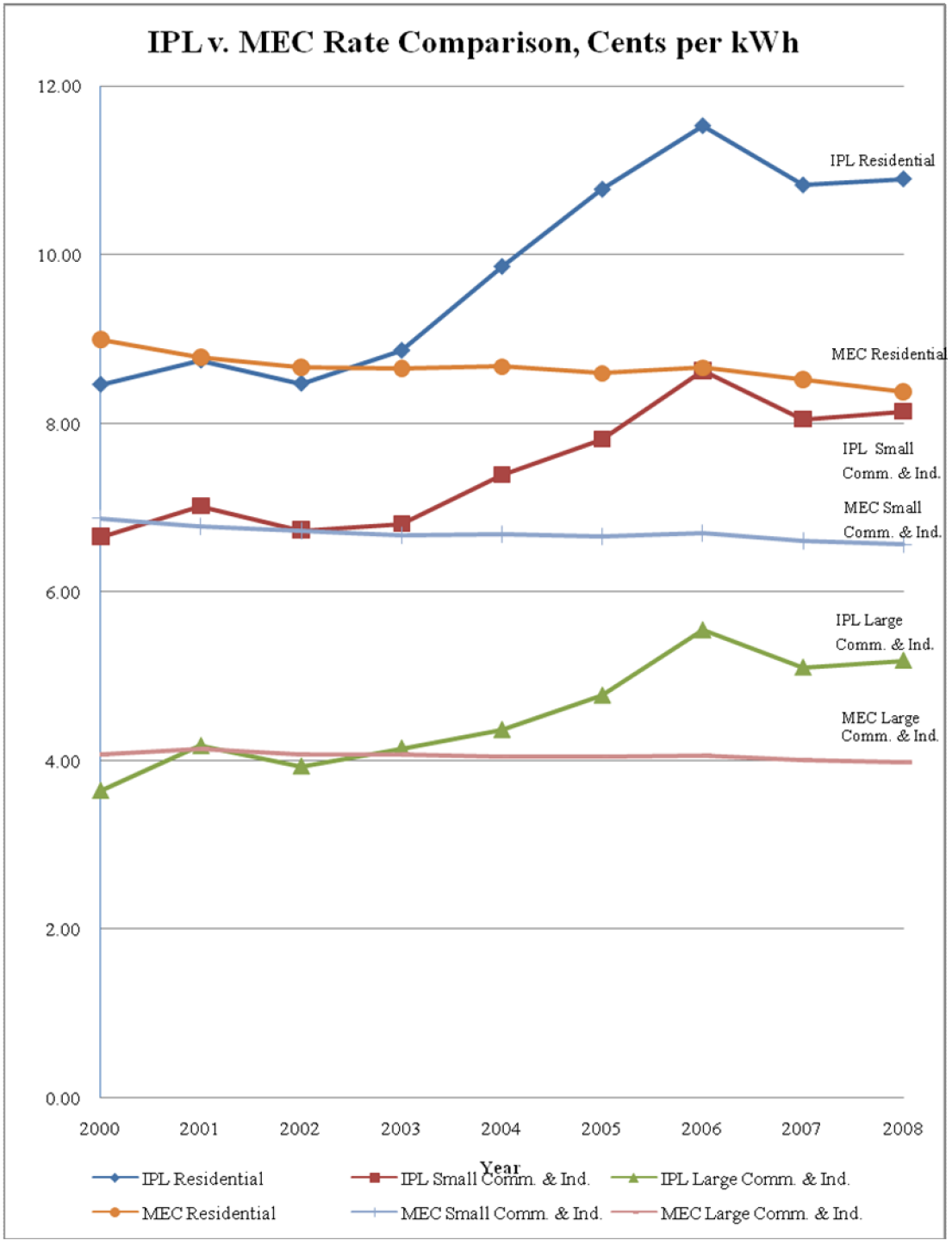
Chart – 1



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The revenue impact on IPL's customers is quite large. As shown on my Schedule A, IPL's customers paid $62 million less for their electricity in 2000 than they would have paid if they had been paying MEC prices. In 2008, IPL's customers paid over $248 million dollars more for their electricity than they would have if they could have bought their electricity at MEC's prices. In the 5-year period from the beginning of 2003 through the end of 2008 IPL's customers paid over $1 billion more for their electricity than they would have paid if they could have bought the electricity at MEC's prices.

Q: How did these price increases affect IPL's customers?

A: The influence of these higher prices can be inferred from observed customer behavior during this time period. As a group, IPL's kWh sales to its three major customer classes (residential, small commercial and industrial, and large commercial and industrial) increased 2.7% from 2000 through 2008. For MEC the growth was 26.6% for these three customer groups.

Schedule B provides more detail on how overall and average usage by customer class varied between IPL and MEC during this time. It is clear from Schedule B that the large commercial and industrial class was

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most impacted by the price differentials. IPL's average usage per large commercial and industrial customer fell by over 14% during this period while MEC's average customer usage in that class increased nearly 12%.[3]

These declining large commercial and industrial sales bode ill for IPL's remaining customers who will be expected to cover any costs "stranded" by these reductions and for economic development in IPL's service territory. As Mr. Vogensen notes at pages 13 – 15 of his direct testimony, two of IPL's existing large customers, Archer Daniels Midland and Roquette, are expanding co-generation in order to be able to remain competitive while operating in IPL's service territory. That quite likely means other firms are choosing to locate elsewhere rather than move into or expand in IPL's service territory. MEC's 21.6% growth in the number of large customers versus IPL's 9.1% in the number of large customers suggests this is happening already. The average large customer usage growth noted above suggests that IPL is adding smaller large customers while MEC is adding bigger large customers.

Q: Did IPL's investment in new generation lead to IPL's prices being higher than MEC's?

[3] MEC's growth in average large customer usage does not indicate MEC's large customer energy efficiency program is not working. Adding customers with larger than average usage will increase the overall average in spite of the effectiveness of an energy efficiency program.

A: IPL's investment in new generation, specifically its 552 MW portion of the Emery Generating Station that cost $402.1 million, was one of the main drivers for the price increase IPL was granted in 2005 (RPU-04-1). However, as MEC has shown, building new generating plants does not have to result in the need to raise prices. Between 2000 and 2008, MEC added 477 MWs ($477.7 million) of coal capacity, 494 MWs ($337.7 million) of combined cycle capacity, and 1,284 MWs ($2.183 billion) of wind capacity.[4,5] (See Schedule C.) Thus, MEC added 2,255 MWs of capacity with a total cost of $3.0 billion without raising prices. In contrast, IPL added 552 MWs of capacity with a total cost of $402 million and needed to raise prices. Clearly, there is a significant difference in the overall operations of these two companies.

Q: What differences in operations have you observed?

A: I have observed a significant difference in the apparent willingness of the two companies to invest in their Iowa operations. For example, after the passage of HF 577 in the spring of 2001, MEC filed a "rate principles" case for its combined cycle combustion turbine (CCCT) in November 2001, a rate principles case for its coal plant in November 2002, and its

[4] MEC also added (through up-rates) 52 MWs to its nuclear capacity during this period.
[5] MEC also had a net additional investment of $238 million in its transmission system during this period.

first wind rate principles case in May 2003.

In contrast, IPL filed the rate principles case for its CCCT in June 2002 and did not file any further rate principles cases until it filed a case for wind development in September 2007 and a case for a coal plant in March 2008. At the end of 2008 none of the wind development was operational and IPL had decided not to go forward with the coal plant. IPL actually substantially disinvested in its Iowa utility operations during this period by completing the sales its nuclear generating station (Duane Arnold Energy Center or DAEC) in 2006 and its transmission system in 2007.

Q: If Alliant was not investing in major utility projects in its Iowa utility operations, was it making major investments anywhere else?

A: Yes. In the late 1990's Alliant began to make significant investments through its affiliate, Alliant Energy Resources (Resources), in utility related assets outside the United States (e.g., Australia, Brazil, China, and New Zealand) and a resort community in Mexico. By the end of 1999 Alliant had $198 million in foreign investments with that amount increasing to over $700 million in later years. (See Schedule D.)

Q: Were Alliant's foreign investments profitable overall?

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A: No. Column (g) of Schedule D shows that Alliant's international endeavors as a whole were not profitable with Alliant experiencing a net loss of $139 million between 2000 and 2006.

Q: How did these investments impact Alliant's overall profitability?

A: They clearly decreased Alliant's overall profitability. The international investments were held under the Alliant Energy Resources (Resources) umbrella. Schedule E shows Resources with negative earnings from 2002 through 2005. The extremely poor 2005 performance caused the consolidated parent company AEC earnings to turn negative.

Q: Aside from poor earnings, did Resources have any other financial problems?

A: Yes. Resources had a significant investment in the common stock of McLeodUSA, a telecommunications company. The recognition of a $321.3 million non-cash gain (pre-tax) on this stock accounted for the vast majority of Resources' $227.2 million in earnings in 2000. In 2001, the value of this stock collapsed and was responsible for approximately $343.3 million of the $416.7 million decrease in Resources' "accumulated

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comprehensive income" between the end of 2000 and the end of 2001.[6] This caused Resources' common equity ratio to fall from 48% at the end of 2000 to 19% at the end of 2001. Resources' common equity ratio had been as high as 71% at the end of 1999. (See Schedule F.) Resources' capital structure became quite strained for a non-regulated company.

The collapse of the McLeodUSA stock value in 2001 and poor Resources earnings in 2002 led AEC to announce in November 2002 that it would sell certain non-regulated assets including its Australian investments with the anticipation that it could reduce outstanding debt by $800 million to $1 billion. AEC also said it would not make any further foreign investments during 2003. In addition, AEC announced it would reduce its common dividend from $2.00/share to $1.00/share.

Q: Why are AEC's non-regulated activities relevant to your management efficiency analysis?

A: AEC's non-regulated activities are highly relevant because early in this period (1999, 2000, 2001, and at least part of 2002) senior management and the board of directors were focused on expanding AEC's non-

[6] 2001 10-K, pp. 71, 85. This number is from the detail of the AEC consolidated statement of changes in common equity and may not reflect the exact impact of the McLeodUSA stock on Resources' "accumulated other comprehensive income" because it may include unrealized gains associated with the nuclear decommissioning trust funds.

regulated activities as the primary source of earnings growth. As Erroll Davis said in his letter to shareholders, ". . . our non-regulated ventures offer our greatest growth potential."[7]

The 2000 strategic plan was more specific; a growth rate of {[redacted]} was required to be a {[redacted]} company.[8] In the plan, AEC's consolidated earnings per share (EPS) was expected to grow from {[redacted]} in 2000 to {[redacted]} in 2005 with all of the growth ({[redacted]}) coming from {[redacted]}. This growth was to be generated by investments totaling {[redacted]} including utility investments.[9] Given the projected annual growth rate in earnings per share (EPS), it is clear that senior management was expecting {[redacted]} equity returns on the {[redacted]}.

Q: How did AEC expect to finance these investments?

A: The investments were expected to be financed by internal cash flows of {[redacted]}[10] with the remainder from debt and the sale of McLeodUSA stock which was valued at nearly $1 billion at the end of January 2001 and described as "the most powerful engine fueling our

[7] AEC 2000 Annual Report, p. 10.
[8] Response to OCA Data Request 41, Attachment I3, p. 1.
[9] *Ibid.*, p. 7.
[10] *Ibid.*

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growth".[11]

Q: Did this financing plan work out?

A: No. As noted earlier, the market value of McLeodUSA collapsed during the remainder of 2001 with AEC's holdings having a fair value of $21 million at the end of the year, considerably less that the "nearly" $1 billion value projected at the end of January 2001.[12]

Q: What did AEC's senior management propose to do for financing after the McLeodUSA common stock lost nearly all of its value?

A: In July 2001, prior to the McLeodUSA stock losing nearly all of its value, AEC expected to be able to execute its plan by {[redacted]}[13] {[redacted]}, Resources added $63 million to its credit facility (which was classified as long term debt) and issued $300 million of senior notes in November 2001 while AEC issued 9.775 million shares of common stock with net proceeds of $263 million that same month.[14] In

[11] 2000 Annual Report, p. 17.
[12] AEC 2001 10-K, p. 85.
[13] Response to OCA data request 41, Attachment H6, p. 15 and Attachment I5, p. 8.
[14] 2001 AEC 10-K, pp. 70, 82, and 84.

2004, AEC acknowledged that the {[redacted]}[15]

Q: When did AEC's focus move back to its utility operations?

A: AEC's focus returned to its utility operations in November 2002 with the Board of Directors approval of five strategic actions "which signaled a shift to less aggressive growth targets driven primarily by Alliant Energy's utility operations . . .."[16] This point was made even stronger in the 2003 10-K wherein AEC described the utility operations as ". . . the sole growth platform . . .."[17] AEC went on to indicate that the updated strategy reflected utility investment opportunities that had not previously existed due to progressive legislation passed in Iowa and Wisconsin.[18]

Q: What was the "progressive legislation passed in Iowa" that AEC was referring to?

A: House File 577. This is also known as Iowa Code Section 476.53.

Q: Did House File 577 lead to AEC increasing its investments in its Iowa utility?

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[15] Response to OCA data request 41, Attachment E1, p. 12.
[16] AEC 2002 10-K, p. 32.
[17] AEC 2003 10-K, p. 26.
[18] *Ibid.*

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A: Yes. As noted earlier, AEC did build a CCCT (Emery) that went in service in 2004. At this point, Emery is the only additional generation AEC has built in Iowa that is in service. The 200 MW Whispering Willow wind farm is expected to be in service by the end of 2009.

Q: Was there any other impact that HF 577 had on AEC actions in Iowa?

A: In AEC's case, there was an unintended consequence to HF 577. Recall that the reason AEC spent time and money on its non-regulated operations was to achieve earnings growth above what it believed it could achieve on its regulated operations. With the collapse of its non-regulated operations in 2002, AEC returned to its utility origins but still maintained a desire for earnings growth. As explained in a 2004 Strategic Planning Document, {[redacted]}[19] HF 577 provided a means for accelerating and/or stabilizing earnings growth by making it possible for the utility ask for a determination of the return on common equity it would be allowed to earn on a new generation plant for the life of that plant prior to the plant being built. For example, based on the rate principles case for Emery, IPL is being allowed the opportunity to earn

[19] Response to OCA data request 41, Attachment E3, p. 18.

12.23% on the common equity portion of Emery's rate base for the plant's 27.6 year life.[20] That is 108 basis points above the return on common equity ultimately allowed by the Board in IPL's electric case (RPU-02-3) that had been filed prior to the rate principles case.

From AEC's perspective, further investing in generation would lead to a problem, {[redacted]}. This problem was described at AEC's August 2004 Strategic Planning Conference:

{[redacted]}[21]

To successfully invest in Iowa, AEC had to come up with a means to get around this problem.

Q: How did AEC solve this problem?

A: Based on my observations of AEC's actions and a strategic option identified at the August 2004 conference to {[redacted]}[22], AEC decided to sell utility assets beginning with DAEC and followed by IPL's transmission assets.

[20] Order Approving Settlement and Granting Application, Docket No. RPU-02-6, p. 5.
[21] Response to OCA data request 41, Attachment E3, p. 17. See also p. 23.
[22] Response to OCA data request 41, Attachment E4, p. 24.

This not only provides a source of cash but it also gives AEC the opportunity to trade-in assets that earn a "regular" return on common equity for assets that have the opportunity to earn a potentially higher HF 577 "pre-set" return on assets.

Q: How much did AEC expect to earn on its investment in DAEC if it retained ownership of DAEC?

A: In mid-2004 AEC estimated that DAEC was contributing {[redacted]} per share with that contribution declining to {[redacted]} in 2014 if DAEC was not relicensed. If AEC did proceed with relicensing, DAEC was expected to contribute {[redacted]} per share in 2014 with that contribution declining to {[redacted]} in 2034.[23] Clearly these expected earnings were not enough since AEC decided to sell DAEC.

Q: How did the sale of DAEC lead to upward pressure on IPL's costs?

A: There are several ways, each of which is innately tied to AEC/IPL's refusal to retain ownership and extend DEAC's operating license. First, IPL's customers are paying about $13 million per year in the existing purchased power agreement (PPA) to cover decommissioning costs that

[23] Response to OCA data request 109, Strategic Planning Meeting – 07/13/04, Discussion Document – DAEC, page 1 of 1.

NextERA (DAEC's new owner) is not paying out in cash at this time.[24] Had AEC/IPL chosen to retain ownership and relicense the plant, IPL's customers, like MEC's, could now be receiving this benefit.[25]

Second, the DAEC PPA was structured to reflect the costs IPL would incur if it operated the plant until February 2014 and then shut it down. Thus, IPL's customers paid $47.91 per MWh in 2008 for the electricity they received from DAEC. Had IPL been looking for a PPA from any nuclear plant beginning in 2006, they might have been able to find a lower cost alternative. For example, MEC obtained a 5-year contract beginning in 2005 from the Cooper Nuclear station in Nebraska. MEC's 2008 cost for that contract came to $26.33 per MWh.[26]

Third, after February 2014, IPL's customers will lose the protection from CO_2 costs now provided by the DAEC PPA. NextERA, DAEC's owner, will surely take market prices that reflect CO_2 costs into account when negotiations for a new DAEC PPA begin. IPL's customers would automatically have had those benefits if the plant had not been sold.

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[24] 2008 FPL Group 10-K, p. 66.

[25] MEC reduced its annual funding for decommissioning the Quad Cities Station by75% or $6 million in 2007 and passed the Iowa portion of this reduction on to its customers pursuant to an agreement approved by the IUB. 2007 MEC 10-K, p. 45.

[26] 2008 MEC FERC Form 1, p. 327.2.

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Q: Was AEC/IPL aware of the potential impact of CO_2 costs when DAEC was sold?

A: Yes. This issue was raised in that proceeding (SPU-05-15). AEC had been aware of the issue since at least {[redacted]}[27] and had been aware since {[redacted]} that CO_2 remains in the atmosphere for {[redacted]} years.[28]

Q: Turning now to the sale of IPL's transmission assets, what was the expected outcome of that sale on the retail prices paid by IPL's customers?

A: The expected outcome was that retail prices would increase with the increase to be offset to some extent with the use of funds provided by the "Alternative Transaction Adjustment" (ATA). This process is aptly described by Chairman Norris in his dissent:

> More than 20 cost-benefit scenarios were presented by Applicants and other parties, with various terms. Considering all of them, the evidence is not persuasive that this transaction will yield net quantifiable benefits to ratepayers. *The TA [Transaction Adjustment] and ATA,* which IPL used in various scenarios to demonstrate net benefits to the transmission sale, *do not represent benefits in the traditional sense (for example, where there are cost savings as a result of increased efficiencies from a reorganization) but rather are partial offsets to increased costs resulting from the transmission sale*

[27] Response to OCA data request 41, Attachment I3, pp. 40 – 51.
[28] Response to OCA data request 41, Attachment H9, p. 3.

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(due in large part to FERC's higher return on equity). (Decision and Order, RPU-07-11, September 20, 2007, p. 86, emphasis added.)

Chairman Norris went on to say at pages 86 and 87 that "[e]ven with the tax incentives, Applicants could not show a net benefit to this transaction over a 20-year time frame without some questionable assumptions . . . and the use of the ATA which, as I have indicated, *is only a partial mitigation* of increased costs and not a benefit that flows from the transmission sale." (Emphasis added.)

The filing of this case has demonstrated that the ATA is nowhere near sufficient to offset the increased annual costs to retail customers resulting from the sale of IPL's transmission assets. But for senior management's desire to sell the assets, the transaction would not have taken place.

Q: Why would senior management have a desire to sell DAEC and the transmission assets?

A: The sale of these assets puts senior management in a win-win situation with respect to their short and long-term incentive compensation structures. Under AEC's annual Management Incentive Compensation Plan, no annual bonus is paid unless the annual target EPS from utility

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operations is met.[29] The long-term incentives are based on total shareholder return over a three year period.[30] Thus, senior management has every incentive to increase EPS because increasing EPS will also lead to increasing total shareholder returns. (Total shareholder returns are measured as the sum of dividends paid and the net change in the market price of AEC's common stock over a predetermined period of time.)

Q: How can the sale of income earning utility assets actually result in an increase in AEC's earnings per share?

A: There are two ways this can happen. The first I noted earlier in my testimony. If AEC expected to be allowed to earn a higher common equity return on investments made under House File 577 than it was allowed to earn on its existing utility investments, then it would make sense to shareholders to sell the "low" earning assets and replace them with higher earning assets. It would be like trading in a $100 certificate of deposit with a 10% interest rate and replacing it with a $100 certificate of deposit with a 12% interest rate. This gain can be increased more if the utility assets are sold for more than net book value. In this case it would be like being able to trade in a $100 certificate of deposit with a 10%

[29] AEC 2009 Definitive Proxy Statement, p. 15.
[30] *Ibid.*, p. 17.

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interest rate and receiving $150 for it which could then be used to buy a $150 certificate of deposit with a 12% interest rate.

The second way the sale of utility assets can be used to increase earnings per share is to use some or all of the proceeds to repurchase shares of AEC's outstanding common stock. Reducing the number of shares outstanding while maintaining aggregate earnings leads to an automatic increase in EPS. For example, Schedule E shows that AEC's 117 million shares of common outstanding at the end of 2005 had declined to 110 million at the end of 2008. Schedule E, column (f) shows utility earning contributing $2.15 to EPS in 2005 and $2.18 to EPS in 2008. However, if the shares outstanding in 2008 had remained at 117 million, utility earnings would only have contributed $2.06 (= $241.3/117) to EPS in 2008.

Q: How did AEC use the proceeds from the sale of its utility assets?

A: AEC provided the following description of its use of these proceeds in its 2007 10-K at page 33:

> Alliant Energy completed the divestiture of numerous utility and non-regulated businesses during the last five years in order to strengthen its financial profile and narrow its strategic and risk profile. Proceeds from these divestitures have been used primarily for debt reduction, common share

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repurchases, funding capital expenditures and general corporate purposes.

Q: Have any of the funds from the sale of DAEC or the transmission been used for capital expenditures by IPL?

A: It appears that few of the funds have been left at IPL. The DAEC sale closed in January 2006 and the transmission asset sale closed in December 2007. IPL paid AEC dividends in 2006 and 2007 which combined totaled $829.7 million. (See Schedule G.) Prior to this, IPL's annual dividend payment to AEC had been less than $110 million for a number of years. AEC did return $251 million to IPL during the 2006 to 2008 time period but significant funds were still left with AEC. It does appear that a large amount funds from the DAEC and transmission asset sales were used to either repurchase common shares or to make investments in AEC's other activities.

Q: Are there any areas other than the sale of DAEC and the IPL transmission assets wherein management actions have led to higher costs and thus higher prices or potentially higher prices for IPL's retail customers?

A: Yes, there are two that deserve comment; fuel cost differences, and IPL's speed of deployment of its wind generation. Schedule H shows IPL's fuel

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cost per kWh produced versus that of MEC. IPL's overall fuel cost, 2.31¢/kWh is 1.04¢/kWh higher than MEC's overall fuel cost, 1.27¢/kWh. Although 1.04¢/kWh does not seem that large, when the differential is applied to IPL's net generation of 10.5 billion kWhs, the result is substantial, $109 million. That is, if IPL's average fuel costs in 2008 would have been the same as MEC's, IPL's customers would have paid $109 million less for their electricity.

Q: What accounts for the difference between IPL's and MEC's average fuel costs?

A: Part of the difference comes from the Quad Cities generating station's low nuclear fuel cost. Without the Quad Cities station, MEC's average fossil fuel cost is 1.40¢/kWh, which is 0.91¢/kWh less than IPL's average fuel cost. The remainder of the difference appears to be a combination of different fossil fuel generation mixes, the innate potential efficiencies of the existing fossil plants, and the incentives accepted by MEC when it gave up its automatic fuel adjustment clause. All of these differences are the result of AEC/IPL management decisions related to these factors.

Q: How are IPL's customers harmed by the speed at which IPL has deployed its wind generation?

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A: IPL's customers have been harmed in two ways. First, the cost of turbines increased over time. This is clearly shown by the near doubling of MEC's capacity costs for its wind farms, from $1,143 per kW in 2004 to $2,216 per kW for the last farm installed in 2008. The overall average capacity cost for MEC's wind farms is $1,721 per kW. (See Schedule I.)

In its late April 2009 first quarter earnings conference call, IPL indicated it expected its 200 MW Whispering Willows wind farm would cost $425 million or $2,125 per kW.[31] Thus, IPL's first wind farm will have an installed cost that is 86% higher than that of MEC's first wind farm and 23% higher than the average cost of MEC installed wind capacity.

The second harm to customers comes from the purchased power costs that could have been avoided if IPL had also started installing wind farms in 2004. The wind farms MEC installed from 2004 through 2007 generated 2.049 million MWhs in 2008. If IPL had installed like wind farms during that period, it could have saved $94 million in purchased power costs in 2008 based on its $45.91 per MWh average purchased

[31] Alliant Energy 2009 First Quarter Earnings Conference Call, April 30, 2009, p. 4.

power cost.[32]

Q: Based on your analysis of the actions of AEC/IPL's senior management, what actions do you recommend be taken?

A: I recommend that IPL's revenue requirement in this proceeding be reduced by $50 million. This amount is conservative in that it only represents approximately 20% of the $248 million IPL's customers paid over and above what they would paid based on MEC prices for the electricity they used in 2008 and only 5% of the $1 billion they have paid over and above MEC's prices since 2003. My testimony has shown how senior managements actions surrounding the sale of DAEC and IPL's transmission assets caused upward pressure on costs, how management choices with respect to generation and fuel mixes have led to 2008 fuel costs that were $109 million greater than MEC's, and how IPL's delay in building wind generation also put upward pressure on IPL's cost.

Q: Why is the revenue adjustment you recommend necessary?

A: The adjustment is necessary because IPL is a regulated monopolist, not a competitive company. For a competitive firm, profits are grown by finding better and lower cost methods for producing and delivering its

[32] IPL' total purchased power cost in 2008 was $346,051, 950 for the 7,538,157 MWhs purchased. IPL 2008 FERC Form 1, p. 327.

products. If a competitive firm took actions that required price increases which its customers saw as excessive, the customers would leave and the firm's profits would decline or disappear completely. In other words, the market would penalize the firm for its actions even if the management of the firm thought the actions were justified. The majority of IPL's customers have no place else to go without incurring excessive costs. Therefore it is necessary for the Board to step in and act for the market by adopting the revenue requirement adjustment I have recommended.

Q: Does this conclude your direct testimony?

A: Yes.

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PERSONAL CHARACTERISTICS

A Ph.D. economist with over twenty seven years of applied economic and financial experience in utility regulation with special expertise in rate of return, mergers, and asset transactions. Instrumental in determining the Iowa Office of Consumer Advocate's overall methodology for class cost of service and rate design. Solid technical background with testimony that is very clear and defendable under cross examination. Formally recognized by the Governor of Iowa for his knowledge and understanding of public utilities' operations and his fair and balanced judgment.

PROFESSIONAL EXPERIENCE

Habr Economics . . . . . January 2009 – Present

Established Habr Economics in January 2009 after a long and successful career in public utility regulation. The firm specializes in rate of return, mergers, asset transactions, and general policy issues.

Consumer Advocate Division,
Iowa Department of Justice . . . . . November 1987 – December 2008

Chief, Technical Bureau . . . . . July 1989 – December 2008
Leadership responsibility for the Consumer Advocate Division's technical staff. Staff's expertise includes accounting, economics, finance, and electrical engineering. Members testify on matters ranging from the cost of capital, rate design, and transmission line location to optimal programs for demand side management. Disputed amounts have ranged from $1 million to over $100 million.

- Testified as an expert witness in over 45 cases on the cost of common equity, the overall cost of capital, and other economic and financial matters including utility mergers, asset acquisitions, and competitive market analysis. Testimony successfully defended under strenuous cross examination.

- Initiated studies on electric restructuring which demonstrated that electric deregulation could cost Iowa customers a minimum of $200 million per year. These un-refuted results helped in the efforts which lead to restructuring being rejected in Iowa.

- Achieved consensus in settlement negotiations, represented the Office in public forums, Public Consumer Advocate Sector representative on Midwest Independent System Operator Advisory Committee, drafted legislation, and prepared and managed the OCA's $3 million annual budget.

- Identified and hired the professional staff needed to expand from a six to a 17 person technical staff in 1989. Staff educational level ranges from B.A.'s to Ph.D.'s. At December 31, 2008 staff's average time with the Office was 19 years.

Head, Technical Section . . . . . November 1987 – July 1989
Hired to establish the Consumer Advocate's initial six person technical staff and advise the Consumer Advocate and legal staff on economic matters. Staff's main goal was to provide the attorneys with technical assistance in accounting, economics, engineering, financial, and rate design matters.

- Testified as an expert witness on the cost of common equity, the overall cost of capital, and other economic or financial matters.

- Integrated the use of bond betas to develop a "risk premium" method of estimating common equity cost rates based on the Capital Asset Pricing Model.

Utilities Division,
Iowa Department of Commerce . . . . . September 1981 – November 1987

Utility Specialist . . . . . September 1981 – November 1987

- Determined cost of common equity and overall cost of capital for various utility companies. Presented the analysis as written testimony and was subject to cross-examination on the testimony. By 1987, I had generated annual savings to Iowa customers in excess of $50 million.

- Completed article integrating brokerage fees and flotation cost in the discounted cash flow model which was accepted for publication in the January 1988 issue of the National Regulatory Research Institute Quarterly Bulletin. Presented a paper on the role of double leverage in determining the cost of capital for the utility subsidiary of a holding company at the 1987 winter meeting of the National Association of Regulatory Utility Commissioners' Economics and Finance Subcommittee.

- Refined and improved the accuracy of the computer program used to calculate the weighted cost of capital for rate case presentation.

Private Consulting Practice . . . . . September 1980 – September 1981

- Estimated damages in two antitrust cases; helped develop a brief in a third antitrust case. Testified on a rate design issue for an independent telephone equipment supplier. Testified on alternative benefit payment methods before the Iowa Industrial Commission.

Mitchell & Mitchell Economists, Ltd. . . . . October 1979 – August 1980

- Organized and developed the economics group. Secured and completed contract with Northwestern Bell to develop a revenue forecasting model. Secured and completed contract with City of Des Moines to conduct a feasibility study for the Neighborhood Business Revitalization Program.

Drake University . . . . . September 1973 – June 1979

- Taught graduate and undergraduate courses in the economics program. Courses included Managerial Economics (M.B.A. Program), Government Regulation of Business, Public Utilities, and Transportation.

- Served on University Business Affairs Committee for four years; committee chair 1978-79. Faculty advisor to local chapter of Omicron Delta Epsilon (economics honor society) 1973-79.

EDUCATION

Ph.D. (Economics) . . . . . Washington State University

Dissertation: "The Returns to Advertising: An Analysis of the Relationship Between Advertising and Liquor Sales in the State of Washington"

M.A. (Economics) . . . . . University of Nebraska – Lincoln

B.A. (Economics) . . . . . University of Nebraska – Lincoln

PROFESSIONAL ACTIVITIES

Activities and Memberships: Developed and taught an antitrust economics class at the Drake Law School Fall 1981 and taught the macroeconomics class in the Drake M.B.A. program Spring and Fall 1987. Member of the National Association of State Utility Consumer Advocates' Economics and Finance Committee 1990 – 2008 and the NARUC Ad Hoc Committee on Diversification (1986 – 1987).

Regulatory Proceedings in Which Dr. Habr Has Filed Testimony

1. Northwestern Bell Telephone Company (Iowa State Commerce Commission Docket No. RPU-81-40, Direct January 1982), Cost of equity issues.

2. Northwestern Bell Telephone Company (Iowa State Commerce Commission Docket No. RPU-82-49, Direct March 1983), Rate of Return.

3. MCI Telecommunications Corporation (Iowa State Commerce Commission Docket No. RPU-84-2, Direct 1984), Competitiveness of Long Distance Markets.

4. Northwestern Bell Telephone Company (Iowa State Commerce Commission Docket No. RPU-84-7, Direct June 1984), Rate of Return.

5. Investigation into Competition in Communications Services and Facilities (Iowa State Commerce Commission Docket No. INU-84-6, October 1984), Workable Competition and Cost Allocation.

6. Peoples Natural Gas Company (Iowa State Commerce Commission Docket No. RPU-84-42, Direct December 1984), Capital Structure.

7. Union Electric Company (Iowa State Commerce Commission Docket No. RPU-85-9, Direct August 1985), Flotation Costs.

8. Iowa Public Service Company -- Gas (Iowa State Commerce Commission Docket No. RPU-85-14, Direct September 1985), Rate of Return.

9. Investigation into Competition in MTS, WATS, and PL Services (Iowa State Commerce Commission Docket No. INU-83-3, October 1985), Workable Competition.

10. Iowa Electric Light and Power Company – Gas (Iowa State Commerce Commission Docket No. RPU-85-31, Direct February 1986), Rate of Return.

11. Iowa Electric Light and Power Company – Electric (Iowa Utilities Board Docket No. RPU-86-7, Direct July 1986), Capital Structure.

12. Peoples Natural Gas Company, A Division of Utilicorp United, Inc. (Iowa Utilities Board Docket No. RPU-86-11, Direct September 1986), Rate of Return.

13. Great River Gas Company (Iowa Utilities Board Docket No. RPU-86-12, Direct September 1986), Rate of Return.

14. Iowa Power and Light Company – Electric (Iowa Utilities Board Docket No. RPU-87-2, Direct, June 1987, Rebuttal, October 1987), Capital Structure.

15. Iowa Public Service Company – Gas (Iowa Utilities Board Docket No. RPU-87-3, Direct December 1987), Rate of Return.

16. Iowa Public Service Company – Electric (Iowa Utilities Board Docket No. RPU-87-6, Direct April 1988, Rebuttal August 1988), Rate of Return, Weather Normalization.

17. Iowa Southern Utilities Company and Ottumwa Water Works (Iowa Utilities Board Docket No. AEP-88-1, Direct May 1989, Rebuttal May 1989), Capacity and Energy Rates for a Small Hydro.

18. Deregulation of Interlata Interexchange Message Telecommunications Services (MTS), Wide Area Telecommunications Service (WATS), Channel Service (Private Line), and Custom Network Service (Iowa Utilities Board Docket No. INU-88-2, September 1988), Strength of Competitive Market Forces.

19. Iowa Southern Utilities Company (Iowa Utilities Board Docket No. RPU-89-7, Direct February 1990, Rebuttal April 1990), Rate of Return.

20. Iowa Electric Light and Power Company – Electric (Iowa Utilities Board Docket No. RPU-89-9, Direct April 1990, Rebuttal May 1990), Cost of Common equity, Double Leverage.

21. Iowa Resources, Inc. and Midwest Energy Company (Iowa Utilities Board Docket No. SPU-90-5, Direct June 1990, Rebuttal June 1990), Utility Holding Company Merger.

22. Iowa Electric Light and Power Company – Gas (Iowa Utilities Board Docket No. RPU-90-7, November 1990), Cost of Common Equity, Double Leverage.

23. Iowa Southern Utilities Company – Electric (Iowa Utilities Board Docket No. RPU-90-8, Direct August 1990, Rebuttal January 1991), Rate of Return.

24. Rochester Telephone Co. et al (Iowa Utilities Board Docket No. SPU-91-3, Direct June 1991, Rebuttal June 1991), Merger Analysis.

25. Midwest Gas, a Division of Iowa Public Service Company (Iowa Utilities Board Docket No. RPU-91-5, Direct October 1995, Rebuttal of Intervenor November 1991, Rebuttal December 1991), Cost of Common Equity, Acquisition Adjustment.

26. Iowa Public Service Company – Electric (Iowa Utilities Board Docket No. RPU-91-6, Direct August 1991, Rebuttal January 1992), Cost of Common Equity.

27. Iowa Southern Utilities Company – Electric (Iowa Utilities Board Docket No. RPU-91-8, Direct September 1991, Rebuttal February 1992, Additional Rebuttal April 1992), Cost of Common Equity.

28. Iowa Electric Light and Power Company – Electric (Iowa Utilities Board Docket No. RPU-91-9, Direct January 1992, Rebuttal of Intervenor February 1992, Rebuttal March 1992), Cost of Common Equity.

29. Iowa Electric Light and Power Company and Union Electric Company (Iowa Utilities Board Docket No. SPU-92-7, Direct April 1992), Asset Purchase Analysis.

30. Iowa Power, Inc. – Electric (Iowa Utilities Board Docket No. RPU-92-2, Direct June 1992, Direct June 1992, Rebuttal of Intervenor July 1992), Cost of Common Equity.

31. Peoples Natural Gas Company, A Division of UtiliCorp United, Inc. (Iowa Utilities Board Docket No. RPU-92-6, Direct August 1992), Cost of Common Equity.

32. Iowa Southern Utilities Company – Gas (Iowa Utilities Board Docket No. RPU-92-8, Direct October 1992), Cost of Common Equity.

33. Iowa Electric Light and Power Company – Gas (Iowa Utilities Board Docket No. RPU-92-9, Direct October 1992, Rebuttal of Intervenor November 1992), Cost of Common Equity.

34. Energy Policy Act of 1992 (Iowa Utilities Board Docket No. INU-93-1, Rebuttal July 1993, Surrebuttal, July 1993), Purchase Power and the Cost of Capital, Financial Leverage Used by EWGs.

35. Interstate Power Company (Iowa Utilities Board Docket No. ECR-93-1, Direct September 1993, Rebuttal October 1993), Rate of Return for Unrecovered Energy Efficiency Expenditures, Cost of Capital for Avoided Cost Calculations.

36. Midwest Power Systems (Iowa Utilities Board Docket No. ECT-93-2, Direct November 1993, Rebuttal January 1994), Rate of Return for Unrecovered Energy Efficiency Expenditures, Appropriate Method for Determining the Annualized Recovery of the Expenditures.

37. Interstate Power Company – Electric (Iowa Utilities Board Docket No. RPU-93-6, Direct November 1993, Rebuttal January 1994), Cost of Common Equity.

38. U S West Communications, Inc. (Iowa Utilities Board Docket No. RPU-93-9, Direct August 1993, Rebuttal February 1994), Rate of Return.

39. IES Utilities, Inc. – Electric and Gas (Iowa Utilities Board Docket No. ECR-94-2, Direct October 1994), Rate of Return to Apply to Deferred Unamortized Energy Efficiency Balances.

40. IES Utilities, Inc. – Electric (Iowa Utilities Board Docket No. RPU-94-2, Direct October 1994, Rebuttal of Intervenor, November 1994, Rebuttal December 1994, Rebuttal Related to Duane Arnold Depreciation, January 1995, Supplemental January 1995), Cost of Common Equity, Acquisition Adjustment, Economic Depreciation for Duane Arnold, Decommissioning Expenditures for Duane Arnold.

41. Midwest Gas (Iowa Utilities Board Docket No. RPU-94-3, Direct November 1994, Rebuttal of Intervenor, December 1994, Rebuttal January 1995), Cost of Common Equity.

42. Midwest Power (Iowa Utilities Board Docket No. RPU-94-4, Direct January 1995, Rebuttal of Intervenor January 1995, Rebuttal March 1995), Cost of Common Equity.

43. Iowa-Illinois Gas & Electric –Gas (Iowa Utilities Board Docket No. TF-94-640, Direct February 1995), Proper Policy for Rates That are Less Than Full Cost.

44. MidAmerican Energy Company (Iowa Utilities Board Docket No. P-831, Direct July 1995), Cost/Benefit Analysis of Proposed Pipeline.

45. Midwest Wind Developers v. Iowa Electric Light and Power Company et al; and Windustries, Inc. v. Iowa Electric Light and Power Company et. al (Iowa Utilities Board Docket No. AEP-95-1 thru 4, Direct September 1995, Rebuttal December 1995), Develop Appropriate kW and kWh rates.

46. Windustries, Inc. v. MidAmerican Energy Company (Iowa Utilities Board Docket No. AEP-95-5, Direct November 1995, Rebuttal December 1995), Develop Appropriate kW and kWh rates.

47. McLeod Telemanagement v. U S WEST Communications, Inc. (Iowa Utilities Board Docket No. FCU-96-1/FCU-96-3, Direct April 1996), Competitive Impact of Not Offering Centrex Plus to New Customers.

48. MidAmerican Energy Company – Electric (Iowa Utilities Board Docket No. RPU-96-8, Direct August 1996, Rebuttal November 1996), Cost of Common Equity.

49. Lost Nation-Elwood Telephone Company (Iowa Utilities Board Docket No. TCU-96-9, Direct August 1996), Facilities Based Competition.

50. GTE Midwest Incorporated (Iowa Utilities Board Docket No. RPU-96-6, Direct September 1996), Proper Cost Recovery for intraLATA Equal Access.

51. MidAmerican Energy Company (Iowa Utilities Board Docket No. APP-96-1, Direct September 1996, Rebuttal November 1996), Causes of High Payout Ratio and Stranded Costs.

52. South Slope Cooperative Telephone Company (Iowa Utilities Board Docket No. TCU-96-12, Direct September 1996), Facilities Based Competition.

53. IES Utilities (Iowa Utilities Board Docket No. ECR-96-3, Direct February 1997), Pretax Return for Levelized Recovery of Deferred Energy Efficiency Expenditures.

54. U S WEST Communications, Inc. (Iowa Utilities Board Docket No. RPU-96-9, Direct April 1997, Rebuttal July 1997), Rate of Return.

55. MidAmerican Energy Company – Electric (Iowa Utilities Board Docket No. TF-97-229, Direct October 1997), Can Other Utility Companies be Forced to Join a Pilot Project.

56. CalEnergy Company and MidAmerican Energy Holdings Company (Iowa Utilities Board Docket No. SPU-98-8, Direct November 1998, Rebuttal December 1998), Merger Analysis.

57. MidAmerican Energy Holdings Company, MidAmerican Energy Company, Teton Formation L.L.C., and Teton Acquisition Corporation (Iowa Utilities Board Docket No. SPU-99-32, Direct January 2000), Merger Analysis.

58. Qwest Corporation (Iowa Utilities Board Docket No. TF-00-250, Direct February 2001), Price Plan Review.

59. MidAmerican Energy Company – Electric (Iowa Utilities Board Docket No. RPU-01-9, Direct February 2002), Implicit Excess Return on Common Equity.

60. Interstate Power Company – Electric (Iowa Utilities Board Docket No. RPU-02-3, Direct July 2002, Rebuttal of Intervenor August 2002, Rebuttal November 2002), Cost of Common Equity, Duane Arnold Decommissioning Cost, Nature and Purpose of Test Year.

61. Iowa Telecommunications Services, Inc. d/b/a Iowa Telecom (Iowa Utilities Board Docket No. RPU-02-4, Direct August 2002), Appropriateness of Using Forward Looking Cost Models to Establish Retail Rates.

62. Aquila, Inc. d/b/a Aquila Networks (Iowa Utilities Board Docket No. RPU-02-5, Direct September 2002, Rebuttal November 2002), Cost of Common Equity.

63. Interstate Power and Light Company – Gas (Iowa Utilities Board Docket No. RPU-02-7, Direct October 2002, Rebuttal of Intervenor November 2002, Rebuttal January 2003), Cost of Common Equity.

64. MidAmerican Energy Company – Electric (Iowa Utilities Board Docket No. RPU-02-10, Direct March 2003), Cost of Common Equity Issues.

65. Iowa Telecommunications Services, Inc. d/b/a Iowa Telecom (Iowa Utilities Board Docket No. SPU-04-10, Direct May 2006), Analysis of Proposed Initial Public Offering.

66. Qwest Communications Corporation (Iowa Utilities Board Docket No. TCU-03-13, Rebuttal August 2004), Appropriateness of a Telecommunications Company Competing with an Affiliate.

67. Interstate Power and Light Company and FPL Energy Duane Arnold, LLC (Iowa Utilities Board Docket No. SPU-05-15, Direct September 2005, Rebuttal October 2005), Analysis of Proposed Sale of Nuclear Power Plant.

68. Interstate Power and Light Company and ITC Midwest, LLC (Iowa Utilities Board Docket No. SPU-07-11, Direct June 2007, Rebuttal July 2007), Analysis of Proposed Sale of Electric Transmission System.

69. Interstate Power and Light Company (Iowa Utilities Board Docket No. RPU-08-1, Rebuttal October 2008, Additional Supplemental October 2008), Energy Forecast Analysis.

STATE OF IOWA)
) SS: AFFIDAVIT OF DR. DAVID S. HABR
COUNTY OF POLK)

I, Dr. David S. Habr, being first duly sworn on oath, depose and state that I am the same Dr. David S. Habr identified in the foregoing Direct Testimony; that I have caused the foregoing Direct Testimony to be prepared and am familiar with the contents thereof, and that the foregoing Direct Testimony as identified therein is true and correct to the best of my knowledge, information and belief as of the date of this Affidavit.

/s/ Dr. David S. Habr
Dr. David S. Habr

Subscribed and sworn to before me, A Notary Public, in and for said County and State, this 14th day of July, 2009.

/s/ Karen K. George
Notary Public

My Commission expires: July 27, 2011