STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company d/b/a Ameren Illinois	)	
	)	ICC Docket No. 12-0244
Smart Grid Advanced Metering	)	
Infrastructure Deployment Plan	)	
	)	

NOTICE OF FILING

TO: (Attached Service List)

Please take note that on August 24, 2012, I submitted the ***Public and Confidential Versions of the Direct Testimony of James Richard Hornby with Exhibits 1.1 thru 1.9 on Behalf of the People of the State of Illinois*** for filing in the above-captioned proceeding via e-Docket with the Chief Clerk of the Illinois Commerce Commission at 527 E. Capitol Avenue, Springfield, Illinois 62701.

Dated: August 24, 2012

___/s/________________________
Timothy S. O'Brien
Assistant Attorney General

CERTIFICATE OF SERVICE

I, Timothy S. O'Brien, hereby certify that the foregoing documents, together with this Notice of Filing and Certificate of Service, were sent to all parties of record listed on the attached service list by e-mail on August 24, 2012. Paper copies will be provided upon request.

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BEFORE THE

ILLIINOIS COMMERCE COMMISSION

AMEREN ILLINOIS COMPANY	)	
	)	
Petition for Statutory Approval of a Smart Grid	)	No. 12-0244
Advanced Metering Infrastructure Deployment	)	On Rehearing
Plan pursuant to Section 16-108.6 of the Public	)	
Utilities Act	)	

DIRECT TESTIMONY AND EXHIBITS

OF

J. RICHARD HORNBY

ON BEHALF OF

THE PEOPLE OF THE

STATE OF ILLINOIS

AG Exhibit 1.0 on Rehearing

AUGUST 24, 2012

REDACTED

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EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, EMPLOYER, AND PRESENT POSITION.

A. My name is James Richard Hornby. I am a Senior Consultant at Synapse Energy Economics, Inc., 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?

A. I am testifying on behalf of the People of the State of Illinois, as represented by the Office of the Attorney General, State of Illinois.

Q. PLEASE DESCRIBE SYNAPSE ENERGY ECONOMICS.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including: electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A. I am a consultant specializing in planning and ratemaking in the electric and gas industries. Over the past twenty five years, I have presented expert testimony and provided litigation support on these issues in more than 120 proceedings in over thirty jurisdictions in the United States and Canada. Over this period, my clients have included staff of public utility commissions, state energy offices, consumer advocate offices and marketers.

Prior to joining Synapse in 2006, I was a Principal with CRA International and, prior to that, Tabors Caramanis & Associates. From 1986 to 1998, I worked with the Tellus Institute (formerly Energy Systems Research Group), initially as Manager of the

Natural Gas Program and subsequently as Director of their Energy Group. Prior to 1986, I was Assistant Deputy Minister of Energy for the Province of Nova Scotia.

I have a Master of Science in Energy Technology and Policy from the Massachusetts Institute of Technology ("MIT") and a Bachelor of Industrial Engineering from the Technical University of Nova Scotia, now merged with Dalhousie University. I have attached my resume to this testimony as AG Exhibit 1.1 on Rehearing.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE WITH THE ECONOMICS OF, AND RATEMAKING FOR, ADVANCED METER INFRASTRUCTURE ("AMI") PROJECTS SUCH AS THE AMI PLAN THAT AMEREN ILLINOIS INITIALLY FILED IN THIS PROCEEDING.

A. Since 2008 I have submitted testimony regarding proposed AMI and smart grid projects in Illinois, Arkansas, Maine, Maryland, Pennsylvania and Texas. I have reviewed proposed AMI projects for clients in New Jersey, the District of Columbia and Nevada.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On June 28, 2012 Ameren Illinois Company (Ameren or the Company) filed a petition for rehearing of a revised version of its AMI Plan and supporting Direct Testimony. The Office of Attorney General retained Synapse to assist in its review of that submission. My testimony examines whether the AMI Plan meets the cost-beneficial standard under Section 16-108.6(c) of the Energy Infrastructure and Modernization Act (EIMA).

Q. WHAT DATA SOURCES DID YOU RELY UPON TO PREPARE YOUR TESTIMONY AND EXHIBITS?

A. I relied primarily on the Company's revised AMI Plan, the Direct Testimony and exhibits of the Company's witnesses filed on June 28 as well as the Company's responses to various data requests ("DR"). Certain of those responses are provided in AG Exhibit 1.9

on Rehearing. In addition, I relied upon evidence and reports from AMI and Smart Grid proceedings of other utilities in which I have participated or which I have reviewed.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING THE PROJECTED TOTAL BENEFITS AND COSTS OF THE COMPANY'S AMI PLAN.

A. First, there is considerable uncertainty as to whether the AMI Plan will be cost beneficial to its customers. According to Ameren's projections for its base case, the AMI Plan has a benefit to cost ratio of 1.87 under a Societal Cost Test prepared using a discount rate of 3.62 percent. However, the operational benefits Ameren is projecting only offset approximately 86 percent of the projected cost of the Plan. Thus, the AMI Plan will only have a projected benefit-to-cost ratio if Ameren's projections of customer benefits and of societal benefits are reasonable. Moreover, even if all of the Company's projections for its base case were reasonable, society and Ameren customers would not begin receiving a cumulative net positive impact from the AMI Plan until 2025, twelve years after Ameren begins deployment.

Second, many of Ameren's key projections are unreasonable and lack sufficient support. My analysis, for a case which reflects the currently effective Commission rule regarding notification at the customer premises of residential customers facing disconnection for non-payment (which Ameren refers to as the "Disconnect for Non-Pay Sensitivity Analysis"), indicates that Ameren customers do not have a reasonable expectation of actually receiving the full amount of those projected benefits. My analysis indicates that several Ameren assumptions and projections related to the achievement of key customer benefits are overstated. For example, actual customer benefits are likely to be lower than projected due to lower values for generating capacity costs avoided by peak reductions, lower rates of customer participation than projected by Ameren in the time-varying pricing options enabled by AMI and lower than projected reductions by customers on Power Smart Pricing (PSP). In addition, actual societal benefits will be lower than projected because projected benefits from incremental adoption of Plug-in Electric Vehicles ("PEVs") should be excluded from the AMI cost/benefit analysis since Ameren could achieve those benefits without implementing AMI. After adjusting for those flawed assumptions and projections, the AMI Plan has a benefit to cost ratio of 1.13. As a result, society and Ameren customers do not begin receiving a cumulative net positive impact from the AMI Plan until 2029, 16 years after Ameren begins deployment.

Finally, the Illinois Statewide Smart Grid Collaborative Report recommended that the Commission review up to five different benefit-cost calculations from different perspectives. My analyses show that the AMI Plan is not cost-effective under the Total Resource Cost ("TRC") test, which excludes societal benefits and uses a discount rate of 8.8 percent. Under that test the benefit to cost ratio is 0.87, i.e., the present value of benefits do not offset the projected cost of the AMI Plan.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COST EFFECTIVENESS OF THE AMI PLAN.

A. My major conclusion is that the AMI Plan offers very limited societal benefits, and, under one analytical perspective, is not cost-beneficial. The Plan places a significant financial risk on Ameren Illinois customers, i.e., the risk that actual benefits to customers may prove to be substantially less than the Company's projections, given the results of my cost-benefit analyses.

Based upon that conclusion I recommend that the Commission take those limited societal benefits and the financial risk imposed on customers into consideration when making its decision as to whether to accept or reject the Company's request.

If the Commission decides to accept the AMI Plan, I have three recommendations:

- consider the limited societal benefits and financial risk imposed on customers in all future ratemaking proceedings related to recovery of AMI Plan costs;
- require the Company to work with stakeholders to identify additional initiatives to increase the value of the AMI Plan to the majority of customers; and
- require the Company to adopt the same metrics and stakeholder outreach as the Commission ordered in the Commonwealth Edison AMI proceeding, as well as the same reporting requirements.

III. PROJECTED BENEFITS AND COSTS OF AMEREN AMI PLAN UNDER A SOCIETAL COST TEST

Q. WHY HAS AMEREN FILED A REVISED AMI PLAN?

A. Ameren filed a revised AMI Plan in response to the Commission's May 29, 2012 Order, in which it found that Ameren's original AMI Plan failed to meet the requirement in Section 16-108.6(c) of the Act that the plan be cost beneficial. Ameren witness Abba describes the material changes Ameren made to its base case Cost/Benefit Analysis on pages 3 and 4 of his Direct Testimony on Rehearing, Ameren Exhibit 3.0RH. Among those changes were the development of an updated estimate of demand response benefits and the addition of estimated benefits from energy efficiency, electric vehicles and carbon reduction. Mr. Abba characterizes the latter two sets of benefits as societal benefits. He notes that Ameren needed to add these benefits in order to "…sufficiently prove a 62% electric only AMI deployment within 10 years is cost-beneficial" (Abba, line 105). Thus, in this application the Company has used a Societal Cost Test to compare the costs and benefits of its revised AMI Plan, rather than the Total Resource Cost test it used to compare the costs and benefits of its original AMI Plan.

Q. HOW DOES A SOCIETAL COST TEST DIFFER FROM A TOTAL RESOURCE COST TEST?

A. A Societal Cost Test differs from a Total Resource Cost test in two major respects: 1) the scope of costs and benefits considered and 2) the discount rate. A discussion of these issues can be found in *Best Practices in Energy Efficiency Program Screening.*[1]

In terms of scope, a Societal Cost Test includes the costs and benefits experienced by all members of society whereas a Total Resource Cost test only includes the costs and benefits experienced by utility customers. Thus, if its AMI Plan did in fact cause a reduction in avoided carbon emissions and/or avoided gasoline costs it would be reasonable for Ameren to include those as benefits in its Societal Cost Test but not in its Total Resource Cost Test.

In terms of discount rates, the discount rate used in a Societal Cost test is usually lower than the discount rate used in a Total Resource Cost test. The rationale is that society is willing to wait a longer period to receive its benefits than utility customers. In addition, society, i.e., government, may have access to funds at lower borrowing costs than utility customers. For example a leading reference source on evaluating energy efficiency, *Understanding Cost-Effectiveness of Energy Efficiency Programs,*[2] presents illustrative discount rates for each of the different cost-benefit test, i.e., 10% for the

[1] Woolf, Tim et al. *Best Practices in Energy Efficiency Program Screening.* Synapse Energy Economics. July 2012. Prepared for National Home Performance Council.
[2] National Action Plan for Energy Efficiency (2008). *Understanding Cost-Effectiveness of Energy Efficiency Programs*. Energy and Environmental Economics and Regulatory Assistance Project. www.epa.gov.eeactionplan.

participant test, 8.5% as a utility WACC for the ratepayer impact, program administrator and total resource tests and 5% for the societal test.

Q. DID THE ILLINOIS STATE SMART GRID COLLABORATIVE RECOMMEND THAT AMI PROPOSALS BE EVALUATED UNDER A RANGE OF BENEFIT COST TESTS?

A. Yes. The Illinois State Smart Grid Collaborative recommended up to five different benefit-cost calculations from five different perspectives, i.e., participant, ratepayer impact, program administrator, total resource and societal. At page 236 the ISSGC report recommends:

> *The utility should be required to present multiple views, or perspectives, as part of their cost-benefit analysis to be filed with the regulatory commission. The ICC and others should have the benefit of these different perspectives when weighing the merits of smart grid investments.*

The ISSGC also discusses testing different discount rates on page 237 of its report as follows:

> *For certain tests, the rate of return on utility investments could be a reasonable choice for a discount rate. However, the use of a different discount rate may be appropriate for other tests because customers may have a different assumed cost of capital. (The discount rates used in the analyses are not intended to affect the rate of return that the Commission may set for future cost recovery on the investment.)* ***Discount rates used in the analyses, and the rationale for their use, should be clearly documented. (emphasis added)***

Q. DID AMEREN ILLINOIS EVALUATE ITS REVISED AMI PLAN UNDER A RANGE OF BENEFIT COST TESTS?

A. No. Ameren only evaluated its AMI Plan under the Societal Cost Test.

Q. PLEASE SUMMARIZE AMEREN'S PROJECTION OF THE BENEFITS AND COSTS OF ITS REVISED AMI PLAN UNDER A SOCIETAL COST TEST.

A. Ameren witness Abba presents an overview of the projected benefits and costs of the AMI Plan in his Direct Testimony on Rehearing, Ameren Exhibit 3.0RH. According to his projections, the AMI Plan is cost-effective under a Societal Cost Test prepared using a discount rate of 3.62 percent for the Company's base case. Table 17 and Table 22 of Ameren Exhibit 3.1 present his estimates of the cumulative values of those projections over a 20 year time horizon, 2013 to 2032, on a non-discounted basis and a discounted or present value (PV) basis respectively.

According to Table 22, the present value of the projected benefits of the AMI Plan is $871 million while the present value of the projected costs is $466 million. Dividing the total benefits by the total costs produces a benefit to cost ratio of 1.87. Subtracting the present value of costs from the present value of benefits yields a net present value (NPV) of approximately $405 million. According to Table 20 and Figure 3 of Ameren Exhibit 3.1, if all of the Company's projections for its base case are accurate, society and Ameren customers would begin receiving a cumulative net positive impact from the AMI Plan in 2025.

Q. DID THE COMPANY PROVIDE A PROJECTION OF THE RATE AND BILL IMPACTS OF ITS REVISED AMI PLAN?

A. No.

Q. **PLEASE SUMMARIZE THE COMPANY'S PROJECTION OF BENEFITS FROM THE AMI PLAN.**

A. The Company is projecting three major categories of benefits – operational, customer and societal. The projected operational benefits are savings the Company expects to achieve in its distribution service operations. The present value of the projected operational benefits is $400.9 million, approximately 86 percent of the projected AMI Plan costs. Thus the Company's projected operational benefits, in the absence of any other projected benefits, are not sufficient to justify the AMI Plan.

The projected customer benefits are primarily comprised of savings in projected electricity supply costs from projected reductions in peak and annual load by customers who Ameren projects will take service under the various pricing options to be enabled by the AMI Plan. Those pricing options include the existing Power Smart Pricing program (PSP), a new Critical Peak Pricing (CPP) program, a new Peak Time Rebate (PTR) program, and a Direct Load Control (DLC) program as outlined by Dr. Faruqui in Ameren Exhibit 5.0RH. The Company is projecting the present value of these customer benefits to be $254.8 million, as indicated in AG Exhibit 1.7. The majority of those benefits are generating capacity costs the Company is projecting customers on those pricing programs will be able to avoid due to reductions in their peak load.

The projected societal benefits are savings in gasoline costs and in carbon emission costs. The Company is projecting savings in gasoline costs based on its assumption that time-of-use (TOU) pricing enabled by AMI will cause incremental purchases of plug-in electric vehicles by residential customers. The Company is projecting the majority of reductions in carbon emissions will result from projected reductions in annual load by customers who Ameren projects will take service under the various pricing options to be enabled by the AMI Plan. The Company is projecting the present value of those two categories of societal benefits to be $96.4 mmillion, as indicated in AG Exhibit 1.7

Q. DO THE AMEREN PROJECTIONS PROVIDE A REASONABLE ESTIMATE OF THE BENEFIT TO COST RATIO OF THE REVISED AMI PLAN UNDER A SOCIETAL COST TEST?

A. No. First, Ameren's base case does not reflect the currently effective Commission rule regarding notification at the customer premises of residential customers facing disconnection for non-payment. Second, certain of Ameren's projections of customer benefits and societal benefits are not reasonable. In particular actual customer benefits are likely to be lower than Ameren projects due to lower avoided capacity costs, lower rates of customer participation in the time-varying pricing options enabled by AMI and lower reductions per customer on Power Smart Pricing (PSP). In addition, actual societal benefits will be lower than projected because projected benefits from incremental adoption of PEVs should be excluded since Ameren could achieve those benefits without implementing AMI.

Q. HAVE YOU PREPARED AN ALTERNATIVE OR SENSITIVITY ANALYSIS OF AMEREN 'S REVISED AMI PLAN UNDER A SOCIETAL COST TEST?

A. Yes. My analysis uses the same discount rate and time horizon as Ameren. However, it presents a Societal Cost Test analysis for a case which reflects the currently effective Commission rule regarding customer premises notification of residential customers facing disconnection for non-payment. Ameren refers to this case as the "Disconnect for Non-Pay Sensitivity Analysis". In addition, the analysis uses an alternative estimate of customer benefits which reflects lower avoided generating capacity costs and lower participation in the pricing options Ameren is proposing to enable with AMI. The analysis also uses an alternative estimate of societal benefits which excludes the projected benefits from PEV.

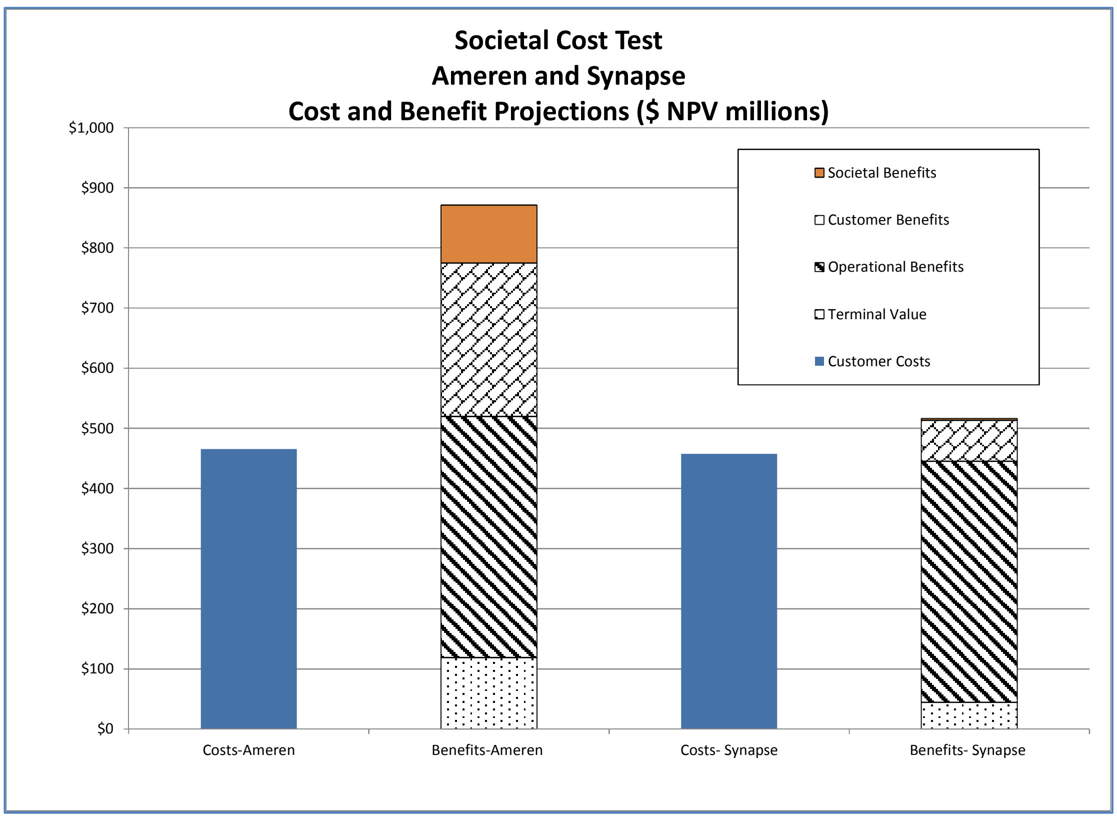
The summary results of my analysis are illustrated in the bar chart below, which is attached as page 1 of AG Exhibit 1.2 on Rehearing.

a. The first bar from the left is the projected total cost of the AMI Plan (solid fill);

b. The second bar from the left is Ameren's projection of terminal value (dots), operational benefits (diagonal), customer benefits (bricks) and societal benefits (solid);

c. The third bar from the left is the projected total cost of the AMI Plan reflecting premise visits(solid fill);

d. The fourth bar is my projection of benefits of the AMI Plan. This bar illustrates that the AMI Plan is much less cost-effective based on reasonable projections of customer and societal benefits.



Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS AND EXPLAIN HOW THEY RELATE TO AMEREN'S PROJECTIONS.

A. The values from my analysis, summarized in the table below, are drawn from page 2 of AG Exhibit 1.2 on Rehearing. The table presents the results from Ameren's base case in column a and from my sensitivity case in column b. As indicated in the last row, my analysis indicates that the AMI Plan has a benefit to cost ratio of 1.13 as compared to the Company's calculation of 1.87.

Ameren AMI Plan - Cost and Benefit Projections ($ NPV million)

Category	Description		Ameren Amended Business Case	Synapse Societal Case
			a	b
Costs	**Customer Costs**		**$465.5**	**$457.5**
Benefits				
AMI	**O&M Benefits**		$334.7	$334.7
DR and EE	**Projected Customer Savings in Reductions**			
	Inactive Meters & Uncollectable Expenses		$48.7	$48.7
	Demand Response	1	$240.6	$61.1
	Energy Efficiency		$14.2	$7.1
	Electric Vehicle Enhancement	2	$90.1	
	Carbon Reduction	3	$6.3	$2.8
	Customer Outage Benefit		$17.6	$17.6
	Terminal Value	4	$119.3	$44.7
Projected Benefits and Savings			**$871.5**	**$516.7**
Net Cost or (Net Benefits i.e. Savings)			**$405.9**	**$59.2**
Benefit to Cost Ratio			**1.87**	**1.13**

A. Benefits of Demand Response versus Energy Efficiency

Q. PLEASE BEGIN BY DISTINGUISHING BETWEEN THE BENEFITS FROM DEMAND RESPONSE AND THE BENEFITS FROM ENERGY EFFICIENCY.

A The Company's AMI Plan, like most deployments of AMI, is projecting to primarily enable customers to reduce their peak load, referred to as demand response (DR), rather than to reduce their annual electricity consumption, referred to as energy efficiency (EE). The benefits of DR are different from the benefits of EE in several important respects.

First, DR typically results in little or no material reduction in annual electricity consumption, and associated carbon emissions, because it occurs in very few hours each year. For example, the CPP and PTR pricing options are typically designed to encourage customers to reduce load in up to 60 hours per year, which represents less than 1 percent of the 8,760 hours in a year. While the reduction in those peak hours tends to have a very high economic value, it still represents a relatively small portion of customer annual usage and annual bills. In contrast, depending on the specific measure, EE will cause reductions in electricity consumption during most, if not all, of the hours when electricity affected by that measure is being used. For example, Ameren Exhibit 5.6RH indicates that the Company is projecting the demand response enabled by the AMI Plan to avoid capacity costs but not to avoid energy costs or carbon costs.

Second, the amount of capacity costs that will be avoided as a result of DR is generally more difficult to estimate than the amount of electric energy costs that will be avoided as a result of EE. For example, a 1 kWh reduction in electricity consumption from energy conservation or EE results in a corresponding immediate reduction in the quantity of electricity generated, after adjustments for system losses. That quantity of electricity generation is clearly avoided. In contrast, a 1 kW reduction in peak load from DR does not automatically produce a corresponding immediate reduction in the quantity of capacity being held to ensure reliable service for that load. Instead, decisions regarding the quantity of generation, transmission and distribution capacity needed for reliable service are made several years before the year in which the actual load occurs. The North American Electric Reliability Corporation (NERC) provides a detailed discussion and categorization of DR and EE from a reliability planning perspective in *Demand Response Availability Data System (DADS): Phase I & II Final Report* dated January 7, 2011.

Thus, in order for DR to avoid capacity costs, the parties responsible for forecasting peak demand, setting reserve margins and qualifying resources as equivalent to firm capacity, need to be convinced that the reduction in peak load from DR can be counted upon over their long-term planning horizon. This is particularly true for avoiding generating capacity costs. The wholesale market in which Ameren is located, which is operated by the Mid-West Independent System Operator (MISO) does not have a separate forward market for capacity. As a result, parties such as retail suppliers, curtailment service providers or even Ameren acting on behalf of its customers, do not have the opportunity to bid forecast demand response reductions for future years into that capacity market and receive a payment for those reductions.[3] As a result those parties do not have an opportunity to explicitly 'monetize' customer peak load reductions and thereby verify the actual capacity costs those reductions actually avoid. Ameren did not describe any existing or proposed formal mechanism for providing advance notification

[3] In contrast, the Commonwealth Edison service territory is located in a wholesale market operated by PJM, which does have a separate wholesale capacity market and thus does provide parties the opportunity to bid demand reductions into that market.

to the parties responsible for forecasting peak demand, setting reserve margins, qualifying resources and/or providing retail supply that customers on PSP, CPP or PTR would have consistently and materially lower peak demand, year after year, than customers on traditional flat rates. In addition, Ameren has not described any existing or proposed method for guaranteeing those anticipated lower peak demands. Thus, Ameren customers on those three pricing options who reduce their peak load can only hope that the relevant decision makers will eventually recognize that customers on those pricing options do have lower peak demand and therefore should be allowed to avoid some amount of generating capacity costs.

Q. HAS THE COMPANY DESCRIBED HOW IT PROPOSES TO FUND THE REBATE THAT CUSTOMERS WOULD RECEIVE UNDER THE PROPOSED PEAK TIME REBATE PRICING OPTION?

A. No. Dr. Faruqui states that customers on the proposed peak time rebate pricing option who reduce their load during defined peak hours would receive a rebate or credit (Ameren Exhibit 5.0, line 179). The Company has not described how it proposes to fund that rebate. In some other jurisdictions utilities that offer a similar peak time rebate pricing fund the rebate with revenues they receive from monetizing the participating customers' peak demand reductions.

Q. DOES THE COMPANY FACE ANY OTHER ISSUES WITH RESPECT TO ACHIEVING CUSTOMER BENEFITS FROM ITS PROPOSED NEW PRICING OPTIONS?

A. Yes. In order for Ameren to offer any of its new pricing options, i.e., Critical Peak Pricing, Peak Time Rebate or Time-of-Use, it would have to obtain Commission approval of a corresponding new tariff governing availability, pricing, and other terms (Response to Response to AG DR 6.15).

B. Value of Avoided Generating Capacity Costs

Q. PLEASE SUMMARIZE THE AVOIDED CAPACITY COST ASSUMPTIONS DR. FARUQUI USED TO EVALUATE THE DEMAND RESPONSE AND OTHER PROPOSALS.

A. Dr. Faruqui used Ameren Illinois projections of avoided generation, distribution and transmission capacity costs. He did not prepare an independent review of those projections.

Ameren Illinois provided its projections of avoided generation, distribution and transmission capacity in Response to AG DR3.18 a. The Company designated those projections confidential. Avoided generation capacity costs are the largest of the three categories of avoided capacity and the projection on which we have focused.

Q. DOES YOUR ANALYSIS INDICATE THAT THE COMPANY'S PROJECTION OF AVOIDED GENERATING CAPACITY COSTS IS REASONABLE?

A. No. My analysis indicates that the Company's projection of avoided generating capacity costs is likely too high.

First, as noted earlier, the mechanism or process through which any reductions in peak demand from customers on these pricing options will ultimately translate into avoided generating capacity costs is not clear. Ameren has not described any existing or proposed formal mechanism for providing advance notification to the parties responsible for forecasting peak demand, setting reserve margins, qualifying resources and/or providing retail supply that customers on PSP, CPP or PTR would have consistently and materially lower peak demand, year after year nor of any existing or proposed method for guaranteeing those anticipated lower peak demands.

Second, the Company assumes that, in the long term, the avoided cost of capacity will be set by the cost of adding a gas fired combustion turbine. However, my analysis indicates that cost of capacity in MISO, as well as in PJM and in New England, is currently being determined by demand and supply fundamentals and those fundamentals will continue to set the avoided cost of capacity in future years. Those fundamentals include the level of peak demand, capacity additions from renewable resources driven by Renewable Portfolio Standards (RPS), demand response from existing large commercial and industrial customers, retirements of older coal-fired units in response to recent and impending changes to air and water emission regulations by the U.S. Environmental Protection Agency ("EPA") and additions of new gas-fired capacity in response to those retirements and to the outlook for natural gas prices..

The difference between current estimates of the cost of adding a new gas fired combustion turbine, or a gas fired combined cycle unit, and the amounts buyers and sellers are actually paying for capacity, energy and ancillary services are illustrated in Figure 6 of the *2011 State of the Market Report for the MISO Electricity Markets.*

Q. PLEASE SUMMARIZE THE COMPANY'S CONFIDENTIAL PROJECTION OF AVOIDED GENERATING CAPACITY COSTS

A. REDACTED

Q. PLEASE SUMMARIZE YOUR REVIEW OF THE COMPANY'S CONFIDENTIAL PROJECTION.

A. REDACTED

Q. PLEASE SUMMARIZE YOUR ALTERNATIVE PROJECTION.

A. My alternative projection is based on an assumption that the avoided cost of capacity will be set by demand and supply over the evaluation period. My projection assumes the avoided cost will be approximately 60 percent of the cost of new entry based upon the actual experience with capacity prices in Eastern MAAC, the most congested zone of PJM, over the last several years.

C. Residential Customer Response to Hourly and Dynamic Pricing Options

Q. PLEASE DESCRIBE THE KEY ASSUMPTIONS DR. FARUQUI USED TO ESTIMATE THE SOCIETAL BENEFITS OF DEMAND RESPONSE BY RESIDENTIAL CUSTOMERS ON THE HOURLY AND DYNAMIC PRICING OPTIONS.

A. In order to estimate the societal benefits from residential customers taking service on the PSP, CPP and PTR pricing options, Dr. Faruqui used two key categories of input assumptions:

- the rate of customer participation in each pricing option, and
- the extent to which customers participating in each pricing option would reduce their peak demand and annual energy consumption in response to the prices under each option.

In terms of customer participation, Dr. Faruqui assumes that by 2032 approximately 36 percent of residential customers will be actively participating in, or taking service under, one of those three pricing options. He further assumes another 3 percent will be participating in DLC or TOU, for a total participation in all of these programs of 40 percent, as shown in Ameren Exhibit 5.3RH. In terms of the extent to which customers participating in each program would reduce their peak demand and annual energy consumption, he assumes the levels of reductions will vary by program as shown in Ameren Exhibit 5.4RH.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSIS OF THESE PROJECTIONS OF PARTICIPATION RATES AND LEVELS OF REDUCTION IN PEAK DEMAND.

A. My analysis indicates that Dr. Faruqui's projections of participation rates in PSP, CPP and PTR by 2032 are too high. In addition, his projection of reductions in peak demand by customers on PSP is too high.

1. Projections of participation rates in hourly and dynamic pricing

Q. PLEASE SUMMARIZE THE BASIS FOR YOUR POSITION THAT DR. FARUQUI'S PROJECTIONS OF RESIDENTIAL CUASTOMER PARTICIPATION RATES IN THESE PRICING OPTIONS IS TOO HIGH.

A. My position that the projections of residential customer participation in these pricing options by 2032 are too high, and therefore not reasonable, is based on several facts. In summary they are as follows:

- very few utilities are offering any of these pricing options to all residential customers, and the actual rates of customer participation in those pricing options to date do not support the Company's projections;
- it is very difficult to motivate residential customers to voluntarily participate, or "opt-in", to these pricing options; and
- the evidence and analyses Dr. Faruqui has provided regarding residential customer participation do not support a capital expenditure of this magnitude.

Q. PLEASE SUMMARIZE YOUR REVIEW OF ACTUAL LEVELS OF RESIDENTIAL PARTICIPATION IN TIME-VARYING RATES.

A. My review examined residential customer participation in a number of dynamic pricing and time-varying rate offerings throughout the U.S. and Canada. These rate offerings include Peak Time Rebates, also referred to as Critical Peak Rebate (CPR), critical peak pricing (CPP) and time-of-use (TOU). Some data is from pilots while other data is from rates that have been offered on a system-wide basis for many years. I have collected the data for a wide range of time-varying rates because the utilities offering each type of rate must motivate their residential customers to engage in that rate.

My review includes high levels of residential participation in time-of-use achieved by two Arizona utilities because some proponents of dynamic pricing have pointed to those levels as an indication of the levels that can be achieved after a long enough number of years. I disagree with that assumption, because the financial incentive residential customers have to participate in time-of-use pricing is much higher than associated with dynamic pricing. Customers on time-of-use pricing can achieve savings during the entire year, while customers on dynamic pricing only achieve savings during a very limited number of critical peak hours each year, typically 60 to 80 hours.

The results of my review are presented in AG Exhibit 1.4 on Rehearing. Those results indicate residential participation levels in time-varying rates such as PTR and CPP are most commonly less than 10 percent. There are a few examples of residential participation levels in the 10 to 25 percent range.

Q. PLEASE EXPLAIN WHY IT IS DIFFICULT TO MOTIVATE RESIDENTIAL CUSTOMERS TO PARTICIPATE IN THESE PRICING OPTIONS.

A. It is difficult to motivate residential customers to voluntarily participate, or "opt-in", to these pricing options because customers' financial incentive to participate is low and, as a result, it is difficult to get customers' attention.

Consider the following simple illustrative example of the financial incentive an average Ameren residential customer would have to participate in the Peak Time Rebate pricing option if it were in effect in 2020.[4] According to Ameren's assumptions, the residential customer has a peak load of 3 kW and is expected to reduce that load by 18 percent during each hour of a critical peak event. That would be a reduction of 0.54 kWh in each hour. Assuming a rebate of $1.25 per kWh and a 4 hour critical peak event, that customer would receive $2.70 for reducing his or her load for the 4 hours ($2.70 = 0.54*$1.25*4). If the year had the maximum 15 critical peak events, and the residential customer participated in all of them, he or she would receive a total of $40.90 in rebates. (Note that not all years will have 15 critical peak events)

In order for that residential customer to achieve those savings, i.e., to participate, he or she would have to be aware of this pricing option, be aware of each critical peak event (typically utilities will notify participants of an upcoming critical event several hours in advance via an automated phone call, e-mail, text message, or combination thereof), have the ability to reduce his or her load during each event, and be sufficiently motivated to "opt-in" during each event by taking one or more actions to reduce load. Some residential customers will participate in peak time rebate pricing, but what percentage will be motivated to participate year after year in exchange for $2.70 per event?

Q. DO LEADING PROPONENTS OF DYNAMIC PRICING ACKNOWLEDGE THE DIFFFICULTY OF DETERMINING HOW TO MOTIVATE CUSTOMERS TO TAKE SERVICE UNDER DYNAMIC PRICING?

A. Yes. Leading proponents of dynamic pricing acknowledge that projecting levels of participation in dynamic rates is difficult. They also acknowledge that the electric industry has not conducted sufficient research into approaches for motivating customers

[4] Ameren Illinois did not provide any illustrative examples of residential customer savings.

to take service under a dynamic pricing tariff, i.e. to engage or participate. Following are several examples.

- A June 2009 report by staff of the Federal Energy Regulatory Commission ("FERC"), which Dr. Faruqui helped prepare, identifies assumptions regarding participation in dynamic pricing as the greatest source of uncertainty, by far, of all the assumptions regarding the potential demand response impacts;[5]
- Dr. Faruqui has testified in Maryland that participation rates are more difficult to forecast than kW-impact per customer.[6] In fact, a review of Dr. Faruqui's published research and testimony indicates that the majority of his research and testimony has not analyzed participation rates but instead analyzed the extent to which customers participating in these pricing options would reduce their peak demand and annual energy consumption;
- In October 2010, in Direct Testimony to support a "test and learn" approach to dynamic rates proposed by PECO Energy Company, Dr. Stephen George stated that despite the 17 dynamic pricing pilots discussed in the Direct Testimony of Dr. Faruqui in the PECO proceeding:

  Without a doubt, the most important issue requiring more investigation is understanding the best way to get customers to sign up for time-varying rates. This is an understudied area that is vitally important to designing good pricing policies and to implementing successful pricing and demand response programs. Predicting the aggregate impact of dynamic tariffs and other demand response programs requires estimates of the average response associated with customers

[5] *A National Assessment of Demand Response Potential*, Federal Energy Regulatory Commission, June 2009, Figure E-1, p. 244.
[6] Case No. 9207, PHI Ex. 6.

who enroll in these programs ***as well as estimates of the number of customers who are likely to enroll. The 17 pilot programs mentioned above have focused almost exclusively on estimating average dynamic rate impacts and hardly at all on understanding customer preferences for such rates and how to effectively enroll consumers in these programs***.[7]

My review indicates that neither the Company nor Dr. Faruqui have provided sufficient support for his projections of residential participation in these pricing options.

Q. IS IT CLEAR THAT THE MAJORITY OF AMEREN RESIDENTIAL CUSTOMERS WILL HAVE BOTH THE FINANICIAL INCENTIVE AND THE ABILITY TO TAKE FULL ADVANTAGE OF THESE PRICING OPTIONS?

A. No. There is considerable variation in the monthly energy use, and peak demand, of residential customers. Some customers have high loads, some have moderate loads and some have very small loads. For example, in July 2011, twenty percent of residential customers in Ameren zone 1 used more than twice the average of residential customers in that zone, while thirty percent used less than 50 percent of the average. That analysis is presented in AG Exhibit 1.5 on Rehearing. All else being equal, it is reasonable to assume that the 20 percent of high use customers would have a higher financial incentive and ability to participate in these pricing options than the 30 percent of low use customers.

Q. PLEASE EXPLAIN YOUR POSITION THAT THE COMPANY HAS NOT PROVIDED SUFFICIENT SUPPORT FOR ITS PROJECTIONS OF RESIDENTIAL PARTICIPATION IN THESE PRICING OPTIONS.

[7] Pennsylvania Public Utility Commission, Docket No. M-2009-2123944, PECO Energy Company Statement No. 2, Direct Testimony of Dr. Stephen S. George, October 28, 2010, p. 6. *(Emphasis added).*

A. Dr. Faruqui states that his projections of participation are based on “expert review” of program participation rates around the country (Response to AG DR 3.17 b and c). The July 2011 IEE report which Dr. Faruqui says these participation rates are documented is limited to four utilities (Response to AG DR 6.16 b). His polling of other experts is not documented (Response to AG DR 6.18).

Neither Dr. Faruqui nor the Company identified the utilities comparable to Ameren who are currently offering PSP, CPP or PTR pricing options to residential customers on a system-wide basis or the actual customer participation levels achieved in the most recent year for which statistics are available (Response to AG DR 3.17 h).

Neither Dr. Faruqui nor the Company provided estimates of the savings a residential customer would receive from participating in the PSP, CPP or PTR pricing option, nor of the prices under each of those options (Response to AG DR3.17 e and f).

Q. PLEASE PROVIDE THE BASIS FOR YOUR POSITION THAT THE PROJECTION OF PEAK REDUCTIONS BY RESIDENTIAL CUSTOMERS ON PSP IS TOO HIGH.

A. The Company is assuming residential customers on PSP will reduce their peak load by 15 percent. That assumption is based on an estimate that customers on PSP have an average peak load of 3 kW and that they would reduce that peak load by 0.45 kw during hours with High Price Alerts. The Company drew those two estimates from a 2010 Navigant report on the operation of the PSP (Response to AG DR 7.04b). However, the estimate of 0.45 kw is a projection based on modeling. The actual maximum peak reductions by PSP customers in years without High Price Alerts have been 0.2184 kW and 0.2594 kw in 2009 and 2010 respectively. Since Ameren does not call High Price Alerts every year, a conservative estimate of the average annual peak reduction per customer on PSP based on actual experience is approximately 0.22 kW from 2009.[8] That reduction is approximately 50 percent of the Company's estimate.

Q. PLEASE DESCRIBE THE PARTICIPATION ASSUMPTIONS FOR THE THREE PRICING OPTIONS USED IN YOUR ANALYSES AND THE BASIS FOR THOSE ASSUMPTIONS.

A. My analyses use the low residential participation rates available in the Company's workbooks. These rates assume an aggregate participation of 20 percent rather than 40 percent, and thus are one-half those the Company uses in its base case. These "low" participation rates are likely still, if anything, optimistic.

D. Exclusion of PEV and DLC Benefits and Costs

Q. PLEASE EXPLAIN WHY YOUR ANALYSIS EXCLUDES BENEFITS AND COSTS FROM PEV AND DLC.

A. My analysis excludes benefits and costs associated with plug-in electric vehicles and direct load control because Ameren can implement the time-of-use pricing underlying the incremental PEV benefits, as well as direct load control, without implementing AMI.

Q. PLEASE SUMMARIZE THE EVIDENCE THAT AMEREN ILLINOIS COULD ACHIEVE ITS PURPORTED BENEFITS FROM PEV WITHOUT AMI.

A. Dr. Faruqui assumes that "… a small set of residential customers will buy electric vehicles in response to the incentives created by a TOU rate and smart charging enabled by a Home Energy Management System" (Faruqui, p.9, line 195). He then estimates the

[8] I did not use the value from 2010 because the report characterized it as unusually hot.

benefits and costs of those incremental purchases of PEVs, and attributes those benefits and costs to implementation of the AMI Plan.

Dr. Faruqui's estimate of those incremental benefits rests upon a number of assumptions which are not reasonable, as outlined in AG Exhibit 1.6 on Rehearing. However, regardless of the validity of his estimates, the bottom line is that Ameren could offer TOU pricing without implementing AMI and therefore it is not reasonable to attribute any benefits or costs of PEVs to the AMI Plan. For example:

- in response to AG Data Request 6.04 a, Dr. Faruqui confirmed that a residential customer could choose a time-of-use (TOU) rate if he or she had an simple interval meter and if Ameren or another third party supplier offered a residential TOU rate;
- in response to AG Data Request 3.17 h, Dr. Faruqui responded that many utilities now offer TOU rates for PEVs. However, in response to AG Data Request 6.04 b he responded that the Brattle Group does not have and has not researched information about the specific technologies that utilities are using to implement their TOU rates; and
- As of July 2011 Union Electric Company d/b/a Ameren Missouri was offering a Time-of-Day rate to its residential customers.

Q. PLEASE SUMMARIZE THE EVIDENCE THAT AMEREN ILLINOIS COULD ACHIEVE BENEFITS FROM DIRECT LOAD CONTROL WITHOUT AMI.

A. Dr. Faruqui assumes that some customers will choose a Direct Load Control program (Ameren Exhibit 5.0RH, line 194). He estimates the benefits and costs of a Direct Load Control program, and attributes those benefits and costs to implementation of the AMI Plan. Again, regardless of the validity of his estimates, Ameren could offer a Direct Load Control program without implementing AMI and therefore it is not reasonable to attribute any benefits or costs of that program to the AMI Plan.

IV. PROJECTED BENEFITS AND COSTS OF AMEREN AMI PLAN UNDER A TOTAL RESOURCE COST TEST

Q. DID YOU PREPARE AN ANALYSIS OF AMEREN'S REVISED AMI PLAN UNDER A TOTAL RESOURCE COST TEST?

A. Yes. I analyzed the costs and benefits of Ameren's revised AMI Plan under the Total Resource Cost test for the same case as under the Societal Cost Test, i.e., a case which reflects the currently effective Commission rule regarding customer premises notification of residential customers facing disconnection for non-payment. The Total Resource Cost analysis excludes societal benefits and uses a discount rate of 8.8 percent.

The results of that analysis are attached as AG Exhibit 1.7 on Rehearing. The benefit to cost ratio of the AMI Plan under this test is 0.87, In other words, the present value of benefits do not offset the projected costs, and as such the AMI Plan is not cost-effective.

Q. PLEASE EXPLAIN THE BASIS FOR USING A DISCOUNT RATE OF 8.8 PERCENT.

A. The discount rate of 8.8 percent assumes a 7 percent real discount rate based upon a U.S. Government Office of Management and Budget (OMB) Circular No. A-94 titled "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs" plus a 1.8% inflation rate based upon an OMB memo dated January 3, 2012. Section 8 b (1) of the OMB circular states that public investments and regulations displace private investment and consumption, and should be analyzed '…using a real discount rate of 7 percent, the marginal pretax rate of return of an average investment in the private sector." The OMB memo dated January 3, 2012 indicates a forecast rate of inflation of approximately 1.8 percent over 20 years. This is the forecast 20-year nominal interest rate of 3.5% minus the forecast 20-year real interest rate of 1.7%.

This discount rate is consistent with the weighted average cost of capital of 8.25% that Ameren uses in its cost-benefit analyses. It is also within the range of discount rates that other utilities have used in AMI filings, as indicated in AG Exhibit 1.8 on Rehearing.

Q. DID THE COMPANY PROVIDE ANY ESTIMATES OF AN APPROPRIATE DISCOUNT RATE FROM A CUSTOMER PERSPECTIVE?

A. No. In response to AG Data request 3.08 the Company did not provide any analyses of the uses to which its ratepayers would put their money if they were not paying for AMI nor did it provide any estimates of its ratepayers "opportunity cost" of money.

V. COST EFFECTIVENESS OF THE REVISED AMI PLAN

Q. PLEASE DISCUSS THE IMPLICATIONS OF YOUR ANALYSES OF THE REVISED AMI PLAN.

A. My analyses under the Societal Cost Test indicate that the revised AMI Plan offers very limited societal benefits and places a significant financial risk on Ameren Illinois customers. If the Commission accepts the AMI plan Ameren will start recovering the costs of the Plan from all customers as soon as the Commission approves rate recovery. In contrast, even if the Company's projections of costs and benefits prove to be accurate, the average customer will not begin receiving a net benefit from the AMI Plan until 2025. Moreover, there is a risk that actual benefits to customers may prove to be substantially less than the Company's projections.

The financial risk to customers from the AMI Plan is due in part to the significant uncertainty associated with the projections of customer and societal benefits that will be achieved from the implementation of AMI. This uncertainty arises from the limited experience with full deployment of AMI utilities in the United States. While a number of utilities have conducted pilot projects testing AMI and dynamic pricing on a limited basis, it is only in the last few years that several United States utilities have received regulatory approval to fully deploy AMI and dynamic pricing tariffs on their systems. Most of those utilities are currently in the process of completing that deployment.

My analysis of the revised AMI Plan under the Total Resource Cost Test indicates that it is not cost-effective.

Q. IS IT IMPORTANT FOR THE COMMISSION TO CONSIDER THESE RESULTS WHEN DECIDING WHETHER TO ACCEPT OR REJECT THE AMI PLAN?

A. Yes. It is important for the Commission to consider these results when deciding whether to accept or reject the AMI Plan because, if accepted, the Company will bear very little of the financial risk associated with the AMI Plan. My understanding is that the Company will make the same AMI investment and earn the same return on that investment regardless of the actual amount of customer and societal benefits that result from implementation of the AMI Plan.

The possibility that future actual benefits may be lower than the Company's projections would be less of a concern if Ameren was proposing to bear that risk or if it was proposing to guarantee customers its projected savings regardless of what the values actually prove to be. However, that is not the case. Ameren is in fact proposing to bear little, if any, of that financial risk the possibility that the future actual benefits from the AMI Plan may prove to be significantly less than those it projected. It is proposing that its ratepayers bear the majority of the financial risk of actual benefits being much lower than projected.

Q. WHAT ARE YOUR RECOMMENDATIONS IF THE COMMISSION DOES DECIDE TO ACCEPT THE AMI PLAN?

A. If the Commission decides to accept the AMI Plan, I have three recommendations:

- consider the limited societal benefits and financial risk imposed on customers in all future ratemaking proceedings related to recovery of AMI Plan costs;
- require the Company to work with stakeholders to identify additional initiatives to increase the value of the AMI Plan to the majority of customers; and
- require the Company to adopt the same metrics and stakeholder outreach as the Commission ordered in the Commonwealth Edison AMI proceeding, as well as the same reporting requirements.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Inc., Cambridge, MA.
Senior Consultant, 2006 to present.
Provides analysis and expert testimony regarding planning, market structure, ratemaking and supply contracting issues in the electricity and natural gas industries. Major projects regarding alignment of financial incentives with aggressive pursuit of energy efficiency by electric and gas utilities include testimony on the "save-a-watt" approach proposed by Duke Energy in North Carolina, Indiana and South Carolina. Major projects regarding proposals for advanced metering infrastructure (smart grid or AMI) and dynamic pricing include testimony in the Baltimore Gas and Electric case. Resource planning cases include the development of long-term projections of avoided costs of electricity and natural gas in New England for a coalition of utility program administrators in 2007, 2009, and 2011.

Charles River Associates (formerly Tabors Caramanis & Associates), Cambridge, MA.
Principal, 2004-2006, *Senior Consultant,* 1998–2004.
Expert testimony and litigation support in energy contract price arbitration proceedings and various ratemaking proceedings. Productivity improvement project for electric distribution companies in Abu Dhabi. Analyzed market structure and contracting issues in wholesale electricity markets.

Tellus Institute, Boston, MA.
Vice President and Director of Energy Group, 1997–1998.
Manager of Natural Gas Program, 1986–1997.
Presented expert testimony on rates for unbundled retail services, analyzed the options for purchasing electricity and gas in deregulated markets, prepared testimony and reports on a range of gas industry issues including market structure, strategic planning, market analyses, and supply planning.

Nova Scotia Department of Mines and Energy, Halifax, Canada.
Member, Canada-Nova Scotia Offshore Oil and Gas Board, 1983–1986.
Assistant Deputy Minister of Energy 1983–1986.
Director of Energy Resources 1982-1983
Assistant to the Deputy Minister 1981-1982

Nova Scotia Research Foundation, Dartmouth, Canada, *Consultant*, 1978–1981.
Canadian Keyes Fibre, Hantsport, Canada, *Project Engineer*, 1975–1977.
Imperial Group Limited, Bristol, England, *Management Consultant*, 1973–1975.

EDUCATION

M.S., Technology and Policy (Energy), Massachusetts Institute of Technology, 1979.
B.Eng., Industrial Engineering (with Distinction), Dalhousie University, Canada, 1973

TESTIMONY

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Kentucky	Kentucky Power Company	2011-00401	March 2012	CPCN for Big Sandy Unit 2
Nova Scotia	Heritage Gas	NG-HG-R-11	September 2011 and May 2012	Cost allocation and rate design
Arkansas	Oklahoma Gas & Electric	10-109-U	May 2011 and June 2011	Advanced metering infrastructure (AMI)
Texas	Texas-New Mexico Power	PUC 38306	April 2011	Advanced metering infrastructure (AMI)
Arkansas	Oklahoma Gas & Electric	10-067-U	March 2011	Windspeed transmission line
Pennsylvania	PECO Energy	M-2009-2123944	December 2010 and January 2011	Dynamic Pricing
Arkansas	Oklahoma Gas & Electric	10-073-U	November 2010	Wind power purchase agreement
Indiana	Vectren Energy Delivery of Indiana	Cause No. 43839	July 2010	Sales Reconciliation Adjustment
Alaska	Enstar Natural Gas	U-09-069 and U-09-	March 2010	Rate Design

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
		070		
Pennsylvania	Allegheny Power	M-2009-2123951	March 2010 and October 2009.	Smart meters / advanced metering infrastructure (AMI)
Massachusetts	All Massachusetts regulated electric and gas utilities	D.P.U. 09-125 et al.	December 2009	Avoided Energy Supply Costs in New England
Pennsylvania	Metropolitan Edison Company	M-2009-2123950	October 2009.	Smart meters / AMI
Maryland	Potomac Electric Power	No. 9207	October 2009 and July 2011.	Smart meters / AMI
Maryland	Baltimore Gas and Electric	No. 9208	October 2009 and July 2010.	Smart meters / AMI
New Jersey	Jersey Central Power & Light	EO08050326 and EO08080542	July 2009	Demand response programs
Minnesota	CenterPoint Energy	G-008/GR-08-1075	June 2009.	Conservation Enabling Rider
South Carolina	Progress Energy Carolinas	2008-251-E	January 2009.	Compensation for efficiency programs
North Carolina	Progress Energy Carolinas	No. E-2 sub 931	December 2008.	Compensation for efficiency programs

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Maine	Central Maine Power	2007 – 215	October 2008.	Smart meters / AMI
North Carolina	Duke Energy Carolinas	E-7 Sub 831	June 2008	Compensation for efficiency programs (save-a-watt)
Indiana	Duke Energy Indiana	No. 43374	May 2008.	Compensation for efficiency programs (save-a-watt)
Pennsylvania	PECO Energy Company	P-2008-2032333	June 2008.	Residential Real Time Pricing pilot
Arkansas	Entergy Arkansas	06-152-U Phase II A	October 2007	Interim tolling agreement and proposed allocation of Ouachita Power capacity
Washington	Avista Utilities	UE-070804 and UG-070805	September 2007.	Cost allocation, rate design
Arkansas	Entergy Arkansas	06-152-U	January 2007.	Need for load-following capacity
Michigan	Consumers Energy Company	U-14992	December 2006.	Proposed sale of Palisades nuclear plant and associated power purchase
Connecticut	Connecticut Natural Gas Corporation	06-03-04PH01	November 2006.	Gas supply strategy and proposed rate recovery
Michigan	Consumers Energy Company	U-14274-R	October 2006.	Purchases from Midland Cogeneration Venture Limited Partnership

Jurisdiction	**Company**	**Docket**	**Date**	**Issue**
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Illinois	WPS Resources and Peoples Energy Corporation	Docket No. 06-0540	October and December 2006.	Service quality metrics and benchmarks
Arizona	Arizona Public Service	E-01345A-05-0816	August 2006 and September 2006.	Hedging strategy and base fuel recovery amount
Ontario	Transalta Energy Corporation versus Bayer Inc.	Private arbitration	January 2006.	Price for steam under a 20-year contract
Nova Scotia	Nova Scotia Power vs Shell	Private arbitration	October 2005.	New natural gas price under a 10-year supply contract
New York	Consolidated Edison of New York, New York State Electric and Gas	Case 00-M-0504	September and October 2002.	Rates for unbundled supply, distribution, metering and billing services
New Jersey	Public Service Electric and Gas	BPU Docket GM00080564	April 2001.	Proposed transfer of gas contracts to an unregulated affiliate and supply contract associated with that transfer.
Nova Scotia	Sempra	NSUARB-NG-SEMPRA-SEM-00-08	February 2001.	Proposed distribution service tariff rates including market-based rates

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
New Jersey	Generic proceeding	BPU Docket EX99009676	March 2000.	Design and pricing of unbundled customer account services
United States of America	Bonneville Power Administration	BPA Docket WP-02	November 1999.	Functionalization of communication plant
South Carolina	South Carolina Electric and Gas	99-006-G	October 1999.	Purchased gas costs
New Jersey	Public Service Electric & Gas, South Jersey Gas, New Jersey Natural Gas and Elizabethtown Gas	GO99030122–GO99030125	July and September 1999.	Service unbundling policies and rates
Maine	Northern Utilities Inc.	Docket 97-393	September and December 1998.	Rate redesign and partial unbundling
Pennsylvania	Peoples Natural Gas	R-00984281; A-12250F0008	May 1998.	Purchased gas costs and proposal to transfer production assets to affiliate
New Jersey	Rockland Electric Company	BPU E09707 0465 OAL PUC-7309-97 BPU E09707 0464 OAL PUC-7310-97	January and March 1998.	Rate unbundling

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
New Jersey	Jersey Central Power & Light d/b/a GPU Energy.	BPU EO9707 0459 OAL PUC- 7308-97 BPU E09707 0458 OAL PUC-7307-97	November 1997.	Rate unbundling
Pennsylvania	Equitable Gas Company	R-00963858	June and July 1997.	Rate structure proposals
Pennsylvania	Peoples Natural Gas Company	R-00973896 and A-0012250F-0007	May 1997.	Purchased gas costs, proposal to transfer producing assets to CNG Producing Company and proposed Migration Rider
South Carolina	South Carolina Pipeline Corporation	97-009-G	April 1997.	Reasonableness of proposal to acquire additional pipeline capacity
FERC	Transcontinental Gas Pipeline	RP95-197-001; RP97-71-000	March 1997.	Review of proposed rolled-in ratemaking for Leidy Line incremental facilities
Arkansas	Arkla	95-401-U	September 1996.	Gas purchasing and transportation plan
Maine	Northern Utilities Inc. and Granite State Gas Transmission	95-480; 95-481	April 1996	Precedent Agreement for LNG Storage Service and PNGTS Transportation Service
Rhode Island	ProvGas	2025	November 1995	Settlement Agreement

Jurisdiction	**Company**	**Docket**	**Date**	**Issue**
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Pennsylvania	T.W. Phillips Gas and Oil	R-953406	October 1995	Cost allocation, rate design
Illinois	Northern Illinois Gas	95-0219	August1995	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-953316	May 1995	Purchased gas costs
Pennsylvania	Peoples Natural Gas	R-943252	May 1995	Cost allocation, rate design
South Carolina	South Carolina Pipeline Corporation.	94-007-G	April 1995	1994 purchased gas costs
Pennsylvania	National Fuel Gas Distribution Corp	R-943207	March 1995	1995 Purchased Gas Adjustment filing
Pennsylvania	UGI Utilities	R-00943063	December 1994	FERC Order 636 transition cost tariff
South Carolina	South Carolina Electric and Gas Co.	94-008-G	October 1994	1994 Purchased Gas Adjustment
Oklahoma	Public Service of Oklahoma	PUD 920 001342	September and November 1994	Gas supply strategy, transportation and agency services and rate mechanism

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Pennsylvania	Pennsylvania Gas and Water	R-943078	September 1994	Market Sensitive Sales Service
Massachusetts	Generic proceeding	D.P.U. 93-141-A	September 1994	Policies on interruptible transportation and capacity release
Hawaii	HELCO	7259	August 1994	DSM programs for competitive energy end-use markets, multi-attribute analysis
Pennsylvania	Pennsylvania Gas and Water	R-00943066	July 1994	1994 Purchased Gas Adjustment
Pennsylvania	Pennsylvania Gas and Water	R-942993; R-942993 C0001-C0004	May 1994	Take-or-Pay Cost Recovery
Pennsylvania	Columbia Gas of Pennsylvania	R-943001	May 1994	Cost allocation, rate design
Pennsylvania	Columbia Gas of Pennsylvania	R-943029	May 1994	1994 Purchased Gas Adjustment; Negotiated Sales Service
Pennsylvania	Peoples Natural Gas	R-932866; R-932915	March 1994	Cost allocation, rate design
Kansas	Generic proceeding	180; 056-U	February 1994	IRP rules for gas utilities
Arizona	Citizens Utility Company Arizona Gas Division	E-1032-93-111	December 1993	Cost allocation, rate design

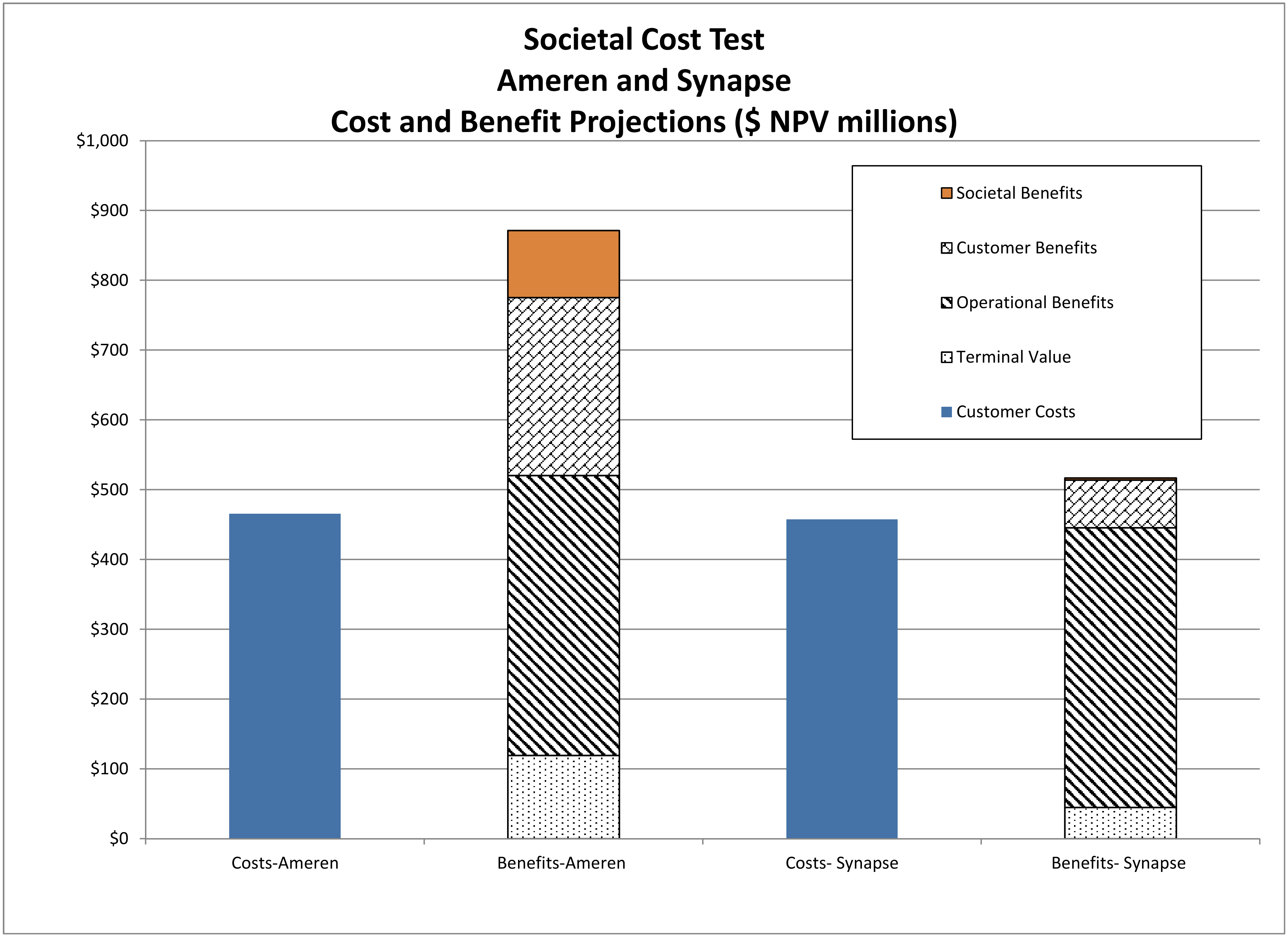
Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Hawaii	HECO	7257	December 1993	Residential sector water heating program
Hawaii	GASCO	7261	September 1993	IRP
Pennsylvania	Pennsylvania Gas and Water	R-932655; R-932655 C001; R-932655 C002	September 1993	Balancing service
Pennsylvania	Pennsylvania Gas and Water	R-932676	July 1993	1993 Purchased Gas Adjustment filing
Rhode Island	Providence Gas Company	2025	April 1993	IRP
Pennsylvania	Equitable	I-900009; C-913669	March 1993	Charges for transportation service and cost allocation methods in general
Arkansas	Arkla Energy Resources, Arkansas Louisiana Gas	92-178-U	August 1992	Gas cost and purchasing practices
Colorado	Generic proceeding	91R-642EG	August 1992	Gas integrated resource planning rule
Pennsylvania	Pennsylvania Gas and Water	R-00922324	July 1992	1992 Purchased Gas Adjustment filing
Pennsylvania	Peoples Natural Gas Company	R-922180	May 1992	Cost allocation, rate design
Michigan	Consumers Power Company	U-10030	April 1992	Gas Cost Recovery Plan, role of demand-side management as a resource in five-year forecast

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
				and supply plan
Pennsylvania	T.W. Phillips	R-912140	March 1992	1992 Purchased Gas Adjustment
FERC	Columbia Gas Transmission and Columbia Gulf Transmission	RP91-161-000 et al RP91-160-000 et al.	February 1992	Cost allocation, rate design
Arkansas	Arkla Energy Resources	91-093-U	February 1992	Base cost of gas
New Hampshire	Energy North Natural Gas	DR90-183	January 1992	Cost allocation, rate design
Arizona	Southwest Gas Corporation	U-1551-89-102 & U-1551-89-103; U-1551-91-069	September 1991	Gas Procurement Practices and Purchased Gas Costs
Maryland	Baltimore Gas and Electric	8339	July 1991	Cost allocation, rate design
Rhode Island	Bristol and Warren Gas	1727	June 1991	Gas procurement
New Mexico	Gas Company of New Mexico	2367	June 1991	Gas transportation policies
Pennsylvania	T.W. Phillips	R-911889	March 1991	Gas supply

Jurisdiction	**Company**	**Docket**	**Date**	**Issue**
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Michigan	Michigan Gas Company	U-9752	March 1991	Gas Cost Recovery Plan
Arkansas	Arkla	90-036-U	August and September 1990	Gas supply contracts, including Arkla-Arkoma transactions
Arizona	Southern Union Gas	U-1240-90-051	August 1990	Cost Allocation and Rate Design
Utah	Mountain Fuel Supply	89-057-15	July1990	Cost Allocation and Rate Design
Pennsylvania	Equitable Gas Company	R-901595	June 1990	Cost Allocation and Rate Design
West Virginia	APS	90-196-E-GI ; 90-197-E-GI	May 1990	Coal supply strategy
Pennsylvania	T.W. Phillips Gas and Oil Co.	R-891572	March 1990	Purchased Gas Costs
Colorado	Generic proceeding	89R-702G	January 1990	Policies and rules for gas transportation service
Arizona	Generic proceeding	U-1551-89-102 and U-1551-89-103	October 1989	Regulatory Oversight of Purchased Gas Costs
Rhode Island	Narragansett Electric Company	1938	October 1989	Sales Forecast, Cost Allocation, rate design

Jurisdiction	Company	Docket	Date	Issue
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Pennsylvania	Pennsylvania Gas and Water	R891293	July 1989	Purchased Gas Costs
Pennsylvania	Columbia Gas of Pennsylvania	R891236	May 1989	Take-or-Pay Cost Recovery
New Jersey	Elizabethtown Gas Company	GR 88081-019	December 1988and February 1989	Take-or-Pay Cost Recovery
Montana	Montana-Dakota Utilities	87.7.33; 88.2.4; 88.5.10; 88.8.23	December1988	Gas Procurement, Transportation Service Gas Adjustment Clause
New Jersey	South Jersey Gas Company	GR 88081-019 and GR 88080-913-	November 1988 and February 1989	Take-or-Pay Cost Recovery
New Jersey	Public Service Electric and Gas	GR 88070-877	October 1988 and February 1989	Take-or-Pay Cost Recovery
District of Columbia	District of Columbia Natural Gas	Formal Case 874	September 1988	Gas Acquisition, Gas Cost Allocation, take or pay-costs; Regulatory Oversight
Illinois	Generic proceeding	88-0103	July 1988	Take-or-Pay Cost Recovery
West Virginia	Generic proceeding	240-G	June 1988	Gas Transportation Rate Design

Jurisdiction	**Company**	**Docket**	**Date**	**Issue**
Nova Scotia	Nova Scotia Power	NSPI –P-203/M04862	June 2012	Load retention rate
Illinois	Commonwealth Edison	12-0298	May 2012	Advanced metering infrastructure (AMI)
Pennsylvania	Pennsylvania Gas & Water	R-880958	June 1988	Purchased Gas Adjustment
Utah	Mountain Fuel Supply	86-057-07	March 1988	Gas Transportation Rate Design
South Carolina	South Carolina Electric and Gas	87-227-G	September 1987	Gas Supply and Rate Design
Arizona		U-1345-87-069	September 1987	Fuel Adjustment Clause


Societal Cost Test
Ameren and Synapse
Cost and Benefit Projections ($ NPV millions)
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$0
Societal Benefits
Customer Benefits
Operational Benefits
Terminal Value
Customer Costs
Costs-Ameren
Benefits-Ameren
Costs- Synapse
Benefits- Synapse

Ameren AMI Plan - Cost and Benefit Projections ($ NPV million)				
Category	**Description**		**Ameren Amended Business Case**	**Synapse Societal Case**
			a	**b**
Costs	**Customer Costs**		**$465.5**	**$457.5**
Benefits				
AMI	**O&M Benefits**		$334.7	$334.7
DR and EE	**Projected Customer Savings in Reductions**			
	Inactive Meters & Uncollectable Expenses		$48.7	$48.7
	Demand Response	1	$240.6	$61.1
	Energy Efficiency		$14.2	$7.1
	Electric Vehicle Enhancement	2	$90.1	
	Carbon Reduction	3	$6.3	$2.8
	Customer Outage Benefit		$17.6	$17.6
	Terminal Value	4	$119.3	$44.7
Projected Benefits and Savings			**$871.5**	**$516.7**
Net Cost or (Net Benefits i.e. Savings)			**$405.9**	**$59.2**
Benefit to Cost Ratio			**1.87**	**1.13**

Sources / Notes

a	AG3.05 Abba DRH-WP_Ameren Illinois - AMI Cost Benefit Analysis (CP).xlsm
b	Ameren: Low Participation, premise visit scenario, Synapse adjustments to PSP, DLC, DR, PEV partiticipation
1	Synapse adjustment to PSP, DLC, and annual DR benefits
2	Synapse adjustment to PEV benefits
3	Synapse adjustment of carbon reduction attributable to EE only
4	Terminal value adjusts based on Ameren low participation scenario

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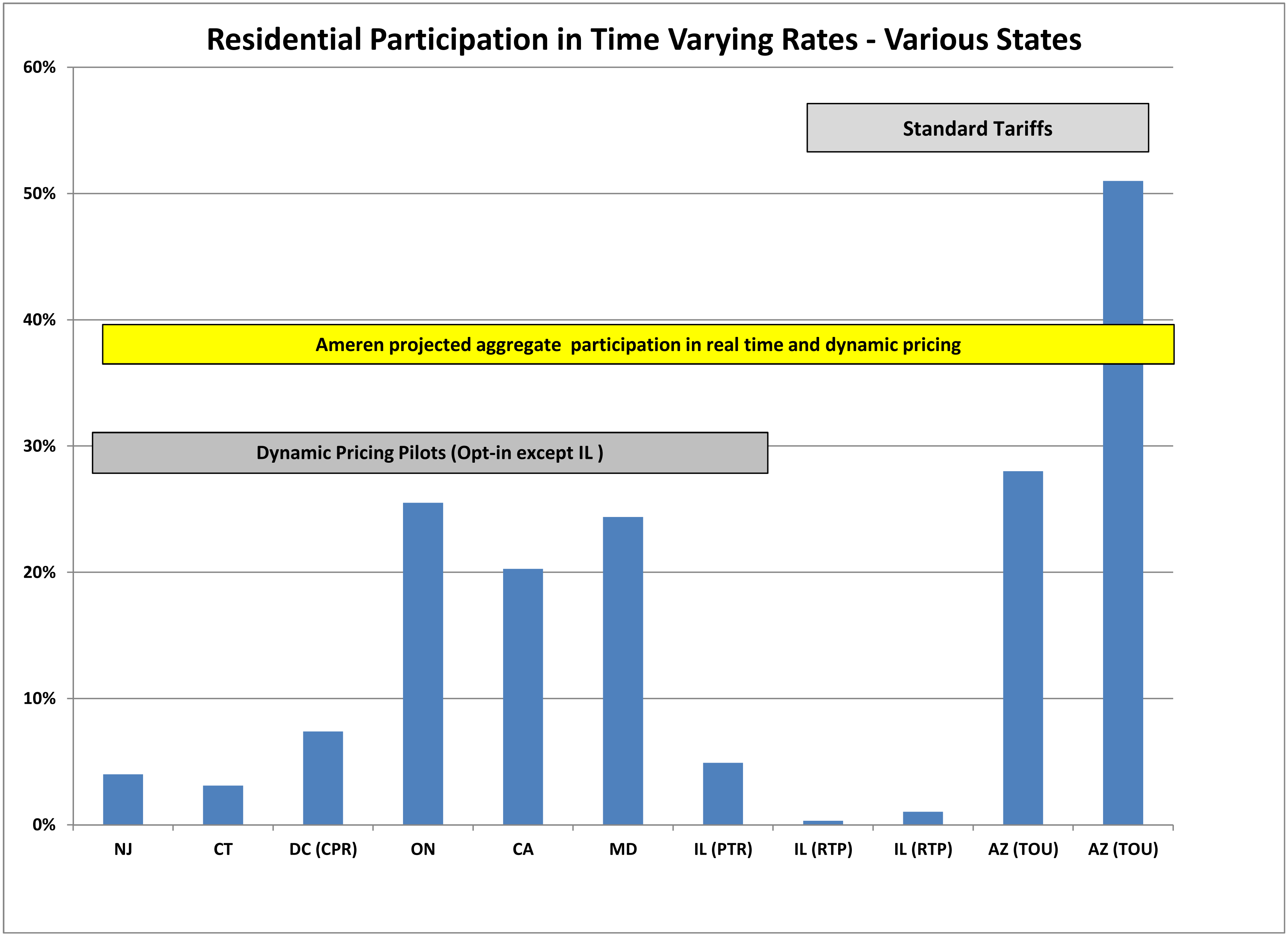
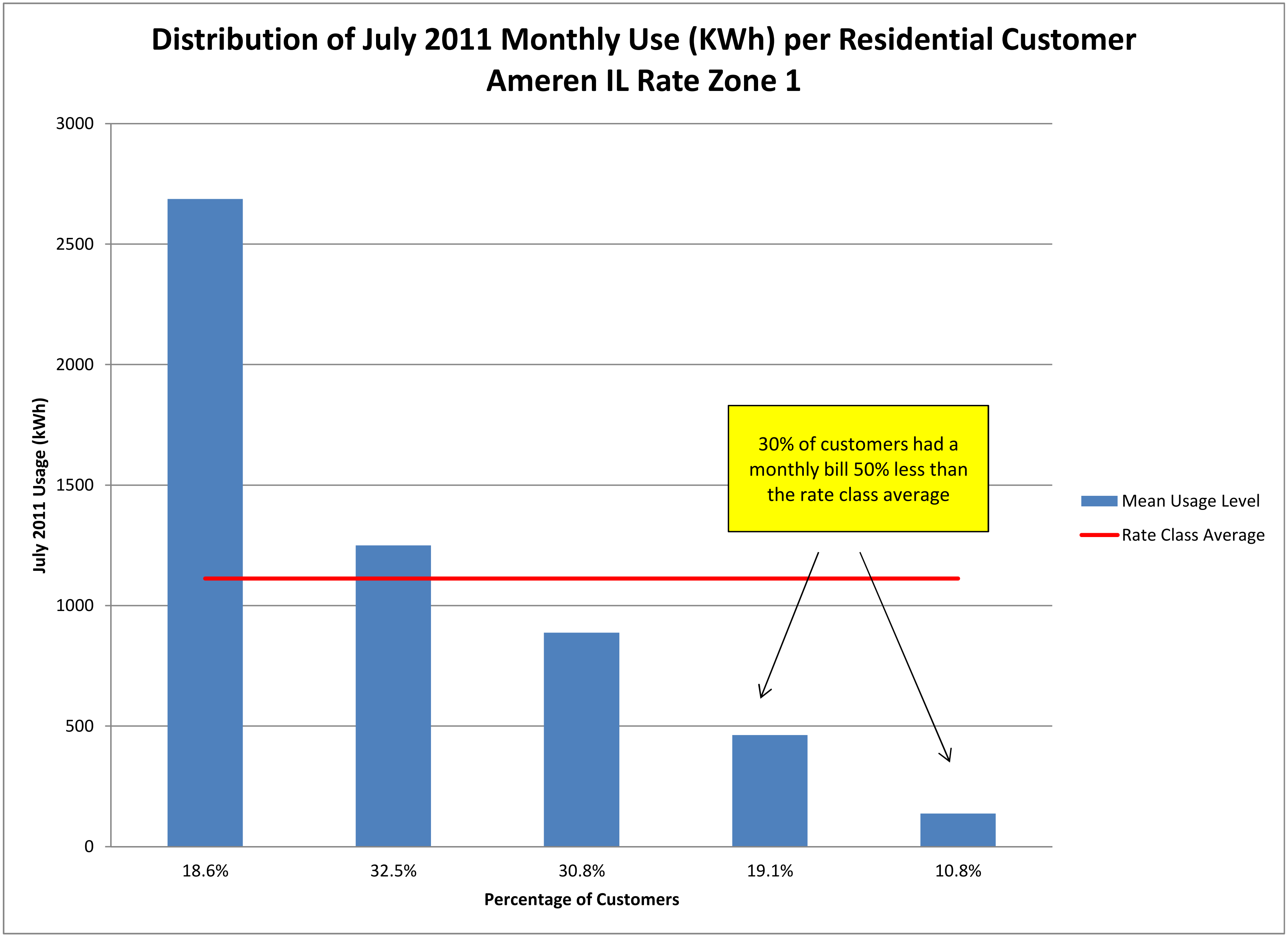

Residential Participation in Time Varying Rates - Various States
60%
50%
40%
30%
20%
10%
0%
Standard Tariffs
Ameren projected aggregate participation in real time and dynamic pricing
Dynamic Pricing Pilots (Opt-in except IL)
NJ
CT
DC (CPR)
ON
CA
MD
IL (PTR)
IL (RTP)
IL (RTP)
AZ (TOU)
AZ (TOU)

Residential customer participation in time-varying rates

Deployment	Number	Source	Location	Legend	Residential Participation
Pilots	1	Public Service Electric & Gas (PSE&G) Residential Pilot Program	page 10	NJ	4%
	2	CL&P Plan-It Wise Energy Pilot	pages 4 and 7	CT	3.1%
	3	PowerCentsDC Program	page 16, Exhibit 13	DC (CPR)	7.4%
	4	Ontario Energy Board Smart Price Program	page 3	ON	25.5%
	5	California Statewide Pricing Pilot (SPP)	page 32 (Synapse calculation)	CA	20.3%
	6	BG&E Smart Energy Pricing Pilot	page 6 (Synapse calculation)	MD	24.4%
	7	Commonwealth Edison Customer Application Plan	page 5-8, Table 5-2	IL (PTR)	4.9%
Full deployments (Standard tariffs)	1	IL Commonwealth Edison Residential RTP	slide 6	IL (RTP)	0.31%
	2	IL Ameren Residential Power Smart Pricing	slide 6	IL (RTP)	1.03%
	3	AZ Salt River Project TOU (Dr. George rebuttal)	page 6	AZ (TOU)	28%
	4	AZ Arizona Public Service TOU (Dr. George rebuttal)	page 6	AZ (TOU)	51%


Distribution of July 2011 Monthly Use (KWh) per Residential Customer
Ameren IL Rate Zone 1
3000
2500
2000
1500
1000
500
0
July 2011 Usage (kWh)
30% of customers had a monthly bill 50% less than the rate class average
Mean Usage Level
Rate Class Average
18.6%
32.5%
30.8%
19.1%
10.8%
Percentage of Customers

REVIEW OF KEY ASSUMPTIONS UNDERLYING DR. FARUQUI ESTIMATE OF INCREMENTAL IMPACT OF AMI ON SALES OF PLUG-IN ELECTRIC VEHICLES (PEV)

Dr. Faruqui presents his quantification of societal benefits and costs associated with PEV's in his Direct Testimony on Rehearing, Ameren Exhibit 5.6RH. His quantification rests upon a number of assumptions. This exhibit reviews those assumptions.

There are two categories of plug-in electric vehicles (PEVs), Plug-in Hybrid Electric Vehicles (PHEV) and Battery Electric Vehicle (BEV). Dr. Faruqui limits his analyses to Plug-in Hybrid Electric Vehicles.

Dr. Faruqui asserts that implementation of the AMI Plan will cause incremental sales of plug-in electric vehicles to residential customers of Ameren Illinois, and are therefore a source of societal benefits and costs. His position is that implementation of AMI will allow Ameren to offer time-of-use (TOU) pricing, which in turn will cause incremental purchases/sales of PEV because a residential customer could charge a PEV at less cost using that pricing as opposed to charging under typical flat pricing.

Dr. Faruqui's estimate rests upon a number of assumptions including:

1. Ameren must implement AMI in order to enable or support TOU pricing for residential customers;
2. The availability of TOU pricing enabled by AMI will cause incremental annual sales of PEVs to residential customers;
3. Annual sales of PEVs to residential customers in the absence of TOU pricing;
4. Societal costs of incremental annual sales of PEVs to residential customers
5. Societal benefits of incremental annual sales of PEVs to residential customers, including reduction in gasoline consumption and carbon emissions

Following is our review of these assumptions.

Assumption 1. Ameren must implement AMI in order to enable or support time-of-use rates for residential customers

Dr. Faruqui assumes that "… a small set of residential customers will buy electric vehicles in response to the incentives created by a TOU rate and smart charging enabled by a Home Energy Management System" (Faruqui, p.9, line 195). He then estimates the benefits and costs of those incremental purchases of PEVs, and attributes those benefits and costs to implementation of the AMI Plan.

It is not reasonable to attribute any benefits or costs of PEVs to the AMI Plan because Ameren could offer TOU pricing without implementing AMI. For example:

- in response to AG Data Request 6.04 a Dr. Faruqui confirmed that a residential customer could choose a time-of-use (TOU) rate if he or she had an interval meter and if Ameren or other third party supplier offered a residential TOU rate;
- in response to AG Data Request 3.17 h Dr. Faruqui responded that many utilities now offer TOU rates for PEVs, however in response to AG Data Request 6.04 b he responded that the Brattle Group does not have and has not researched information about the specific technologies that utilities are using to implement their TOU rates;
- As of July 2011 Union Electric Company d/b/a Ameren Missouri was offering a Time-of-Day rate to its residential customers.

Assumption 2. The availability of TOU pricing enabled by AMI will cause incremental annual sales of PEVs to residential customers

Dr. Faruqui begins by estimating the rate at which residential customers would make incremental purchases of PEVs. His position is that those incremental purchases would be solely a function of the cost savings a residential customer would realize by charging a PEV under TOU pricing relative to charging it under typical flat pricing. Economists refer to the sensitivity of demand for one good due to the price of another as the "cross-price elasticity of demand." This elasticity represents the percentage change in demand for every 1% change in the price of another good (e.g. an elasticity of 0.5 would mean demand for Good 1 would increase by 0.5% for every 1% increase in price of Good 2). As discussed below, Dr. Faruqui's estimate of the extent to which the availability of TOU pricing will cause incremental annual sales of PEV to residential customers is developed in the following steps:

- He assumes that TOU pricing will save PEV owners 23% when compared to typical flat rates over the twenty year time horizon Ameren uses to evaluate its AMI Plan. In his testimony and in Data Response AG 6.08, Dr. Faruqui cites his own article on estimating electricity cost savings from dynamic pricing for PEV owners as his justification for this methodology.
- He assumes the price elasticity for PEV adoption by Ameren residential customers will be equal to the price elasticity of hybrid electric vehicle (HEV) sales with respect to gasoline prices over the period 2000 to 2006 identified in one academic research paper published in 2009. That one paper found that "as the price of gasoline increased by 1%, the quantity of fuel efficient hybrid vehicles increased by 0.86%" (Dr. Faruqui, p.13, lines 290-291). He then applies this price elasticity (0.86) to his estimated 23% electricity cost savings from dynamic pricing to arrive at a 20% increase in PEV sales (.86 * 23%) (Dr. Faruqui, p.13-14, lines 292-294).

The inconsistencies and pproblems with these assumptions are discussed below:

- Ameren compares the costs of charging to gasoline on their website entitled "Charging Time & Fuel Cost Comparison" (attached) but this is based on flat rates and makes no mention of TOU rates.[1]
- The price of electricity is not the only determinant of a PEV purchase. In their analysis in the 2012 Connecticut IRP, the Brattle Group listed several barriers to increased PEV adoption including: "initial cost of the vehicle," "unfamiliarity and range anxiety" and "availability of charging infrastructure."[2]
- Customers may resist switching from flat rates to TOU rates. In their 2010 PEV assessment, Ameren Illinois stated that, "customers may perceive a small benefit under TOU, but find such benefits do not outweigh the convenience of a standard rate." A

[1] http://www.ameren.com/Environment/ElectricVehicles/Pages/ChargingTimesEstimatedCost.aspx. Downloaded on August 24, 2012.

[2] Brattle Group. 2012. 2012 Integrated Resource Plan for Connecticut. Connecticut Department of Energy and Environmental Protection.

recent EPRI report discusses the different effects of TOU pricing on both BEV's and PHEV's, claiming that "if a flat rate comparable to current prices is available, PHEV drivers will be much more likely to choose the flat rate, even if they have to forgo the benefit of the nighttime rate."[3]

- Dr. Faruqui provides no evidence for applying the price elasticity of hybrids with respect to gasoline in order to predict PEV sales. When asked to provide "all the research on the major drivers of residential PEV sales and residential hybrid vehicles sales that Dr. Faruqui reviewed" his response was "we are unaware of any existing data showing how sensitive PEV sales are to electricity prices" (Data Response AG 6.07 b).
- When asked to provide "all analyses of actual residential electricity prices and actual annual residential PEV sales" that he reviewed, Dr. Faruqui responds by saying that "it is premature to undertake this type of analysis due to the nascent nature of the implementation of PEV and AMI technology" (Data Response AG 6.08 c).
- There are several issues with Dr. Faruqui's previous research that he used to justify the savings from dynamic pricing for PEV owners:
    - The article cited claimed that "if the price elasticity is consistent with what has been observed in whole-house applications of time-of-use (TOU) pricing, then the outcome might be disappointing." In fact, the article refers to another previous study that "suggested that wholesale electricity prices could even increase with TOU rates for PEVs."[4]
    - The article also measured the cost savings of a Nissan Leaf which is a Battery Electric Vehicle (BEV) whereas Brattle only modeled Plug-in Hybrid Electric Vehicles in this filing (PHEV) (Data Response AG6.05 a and 6.05 b). PHEV's rely on both electricity and gas, however, Dr. Faruqui applies the effect of electricity cost savings on BEV adoption to that of a PHEV.
    - The article estimated savings from TOU for PEV 's assuming Level 2 charging for the Nissan Leaf whereas Dr. Faruqui is assuming that Ameren's PEV owners will all have Level 1 charging which is much cheaper to install but requires longer charging times (Data Response AG 6.21 i). Therefore, due to the differences in

[3] EPRI. 2011. Transportation Electrification: A Technology Overview. July 2011.

[4] Faruqui, Ahmad, Ryan Hledik, Armando Levy and Alan Madian. 2011. Smart Pricing, Can time-of-use rates drive the behavior of electric vehicle owners? Public Utilities Fortnightly, October 2011, 38-45.

costs and electricity usage between charging types, it is not reasonable to include the lower costs of Level 1 charging with the higher benefits of Level 2 charging.

Assumption 3. Annual sales of PEV to residential customers in the absence of TOU pricing

Dr. Faruqui applies the previous assumption to estimate new PEV sales due to AMI in the following way:

- He starts with the assumption of PEV adoption based on a "Becker, Sindu & Tendrich estimate that PEV's will constitute 24% of the light vehicle fleet in 2030" (Dr. Faruqui, p. 14, lines 298-299).
- He then halves this number to "better reflect PEV penetration predictions filed with the ICC in 2010 in Ameren Illinois" to get 12% adoption (Dr. Faruqui, p. 14, lines 299-300).
- Then, applying the portion of vehicle miles traveled by light vehicles (90%) to this he arrives at an estimate of 11% adoption.
- He then applies the 20% increase in PEV sales due to electricity cost savings and more reductions ("we halve this number again, and then reduce it by one-third to get to the baseline case") to match Ameren's assumption of 0.8% of TOU, HEMS and PEV participation (Dr. Faruqui, p. 14, lines 303-306; Exhibit 5.3RH, page 1). If, as Faruqui claims, 20% of PEV sales are due to AMI then this means that effectively the PEV fleet would be 4% of all vehicles (0.8% / 20%).

Problems with these assumptions are discussed below:

- The study that Dr. Faruqui refers to estimates PEV market share is based on Energy Information Administration (EIA) gas prices applied to a technology adoption model from 1969.[5] When asked he did not simply use the EIA's forecasts for electric vehicle adoption, Faruqui responded that "Becker et al. provide cumulative market shares. The AEO reports only offer the market share in terms of new vehicle sales for a given reference year" (Data Response AG 6.10 b). In fact, the EIA does provide sales and stock of electric vehicles for every future year so this response is incorrect. The EIA's Annual

[5] Becker, Thomas, Ikhlaq Sidhu and Burghardt Tenderich. 2009. Electric Vehicles in the United States: A New Model with Forecasts to 2030. Center for Entrepreneurship & Technology (CET) Technical Brief. See Exhibit 5.

Energy Outlook forecasts that PEV's will comprise 1.3% of the light vehicle fleet in 2030 (3.4 million PEV's of the 264 million in the fleet).[6]

- When asked "how does the assumption that PEV's will represent 11% of the total fleet compare with more recent projections of PEV adoption?" Dr. Faruqui responded that "the Brattle Group is unaware of any more recent studies" (Data Response AG 6.11 c). This claim is unfortunate since the Becker et al study is from 2009 and much research (in addition to the AEO forecasts discussed above) has been made available since including a study by MIT and National Research Council (which includes a "probable" scenario that PEV's will make up 4.5% of the fleet in 2030).[7,8]

Assumption 4. Societal costs of incremental annual sales of PEV to residential customers

Dr. Faruqui assumes that the premium for PEV's (i.e. the cost over and above conventional vehicles) is $9,500 in 2012 but declines over time (Dr. Faruqui p.12, line 271). To arrive at this assumption, he cited several sources including "informal conversations with experts as well as a review of automotive literature" and "prices of the Chevy Volt electric vehicle and the Toyota Prius PHEV were compared to similar models of vehicles made by their respective manufacturers" (Data Response AG 6.21 b).

Problems with this assumption are discussed below:

- The 2013 Chevy Volt currently costs $39,145 and even adjusting for the eligible $7,500 tax credit, this is nearly $15,000 more than the Chevy Malibu.
- The Toyota Prius Plug-in Hybrid costs $32,000 at minimum and even adjusting for the eligible $2,500 tax credit, this is over $13,000 more than the Toyota Corolla.

[6] EIA AEO 2012. Table 58: Light-Duty Vehicle Stock by Technology Type, Reference case. Available here: http://www.eia.gov/forecasts/aeo/tables_ref.cfm

[7] MIT. 2011. The Future of the Electric Grid. An MIT Interdisciplinary Study.

[8] National Research Council. 2010. Transitions to Alternative Transportation Technologies-Plug-in Hybrid Electric Vehicles. See: http://www.nap.edu/catalog.php?record_id=12826

- While Dr. Faruqui assumes that Level 1 charging will be included, if customers require Level 2 charging (i.e. higher voltage for charging in less time) then the installation costs would increase the premium by an additional $2,000 or more.[9]
- Currently, the tax credits are partly making up for the cost differences between PEV's and conventional vehicles yet these incentives are likely to decrease or vanish in the future.

Assumption 5. Societal benefits of incremental annual sales of PEV to residential customers, including reduction in gasoline consumption and carbon emissions

Dr. Faruqui estimates fuel savings from PEV adoption based on gas mileage from a July 2007 EPRI report documented in Data Response DAB 3.02 and Data Response AG 7.10 Attachment 1. This study assumes that conventional (i.e. gas-powered) vehicles get 30 miles per gallon in 2050 from Table 5.1 and 5.2 of the EPRI report.

The problem with this assumption is that the EPRI report is five years old and, therefore, does not account for more stringent CAFE (Corporate Average Fuel Economy) Standards that have been implemented or proposed. The current CAFE Standards for 2011 are 30.2 miles per gallon for passenger cars. However, President Obama has proposed increases in fuel economy up to 49.6 miles per gallon by 2025 for light vehicles.[10] A more realistic gas mileage assumption would decrease the estimated gasoline savings to PEV owners in Dr. Faruqui's analysis. Also, a more recent EPRI report also points out that "owners of plug-in hybrid vehicles that choose to delay charging may end up consuming more gasoline, possibly increasing their energy costs."[11]

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[9] See: http://www.autobytel.com/chevrolet/volt/2011/car-buying-guides/gm-sets-pricing-for-2011-chevrolet-volt-home-charging-station-106968/

[10] Environmental Protection Agency and National Highway Traffic Safety Administration (EPA and NHTSA). 2011. Proposed Rule: 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards. Federal Register, Volume 76, No. 231. December 1, 2011.

[11] EPRI. 2011. Transportation Electrification: A Technology Overview. July 2011.

Environment

Clean Environment
Community
Electric Vehicles
- Know the Basics
- Discover the Benefits
- Compare Fueling Costs
- Get Plug-in Ready
- FAQs
- Free Service Assessment
- Learn More
Managing Waste
Renewable Energy
Solar Energy
Sustainability
Wildlife Protection

Charging Time & Fuel Cost Comparison

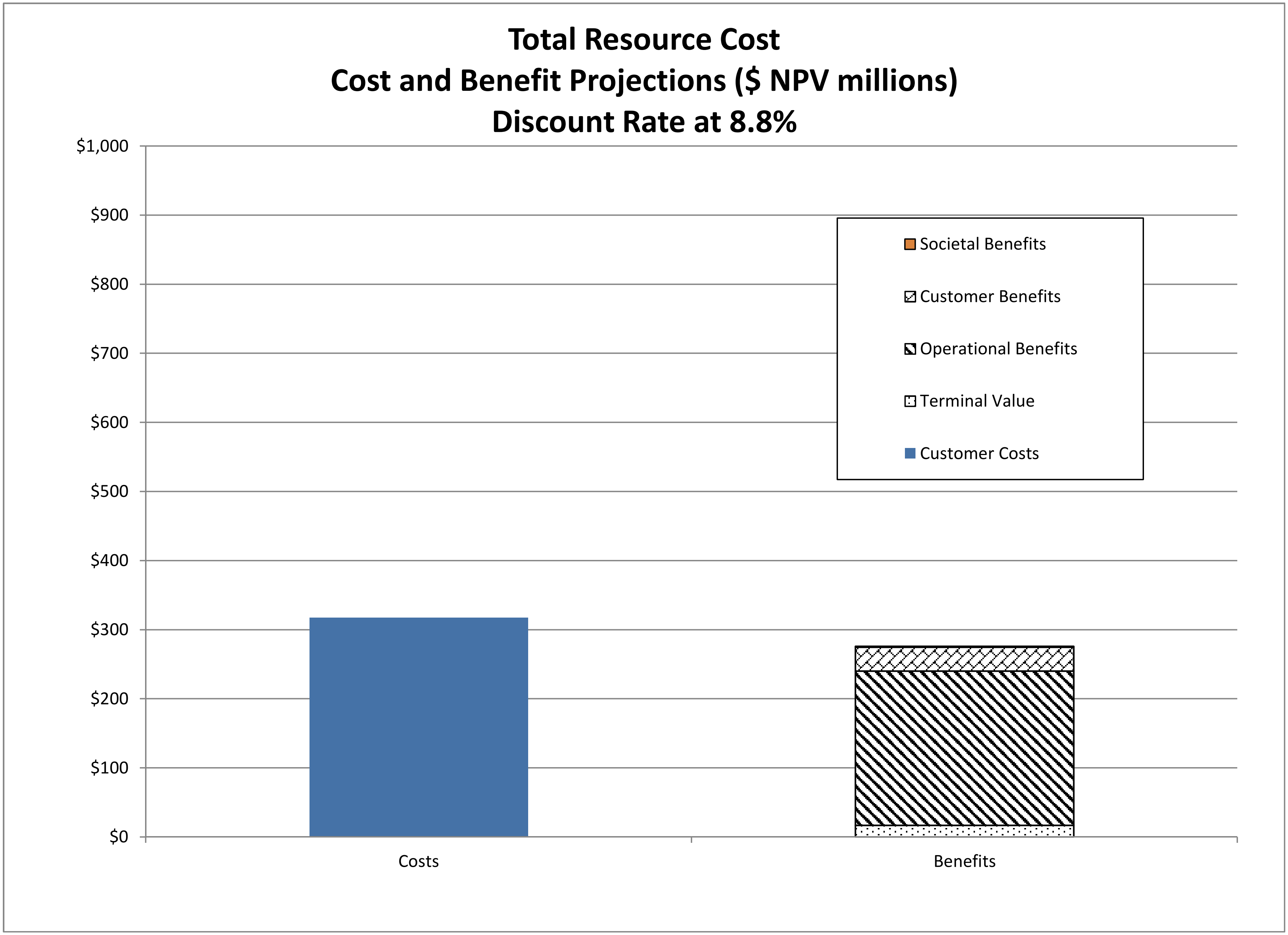
Charging times and costs have more to do with your daily commute and personal driving habits than with the electric vehicle you own. For this reason, it's best to talk about these in terms of the commute miles you are looking to recover with each recharge.

The following table summarizes average charging times and costs per day based on various daily commute miles. Actual daily charging costs may differ based on customer classification, the time of year, and rate structure differences between Ameren Illinois and Ameren Missouri.

Charging Times and Costs

	Charging Times				Equivalent Gasoline Costs[3]		
Miles Driven Daily	Level 1 (120V)	Level 2 (240V)	Level 3 (480V)	Daily Charging Cost[2]	$3 per gallon	$4 per gallon	$5 per gallon
20	4-5 hours	1-2 hours	10 minutes	$0.50	$2.00	$2.65	$3.35
30	6-8 hours	2-3 hours	15 minutes	$0.75	$3.00	$4.00	$5.00
40	8-10 hours	4-5 hours	20 minutes	$1.00	$4.00	$5.35	$6.65
50[1]	10-13 hours	5-6 hours	25 minutes	$1.25	$5.00	$6.65	$8.35
75[1]	15-19 hours	7-8 hours	30 minutes	$1.90	$7.50	$10.00	$12.50

1 Data only applies to an electric vehicle that can provide this many "electric only" miles.
2 Based on Ameren's blended residential rate of 8¢ per kilowatt-hour.
3 Based on a conventional vehicle rated at 30 MPG.


Total Resource Cost
Cost and Benefit Projections ($ NPV millions)
Discount Rate at 8.8%
$1,000
$900
$800
$700
$600
$500
$400
$300
$200
$100
$0
Societal Benefits
Customer Benefits
Operational Benefits
Terminal Value
Customer Costs
Costs
Benefits

Ameren AMI Plan - Cost and Benefit Projections ($ NPV million)					
Category	**Description**		**Ameren Amended Business Case**	**Synapse Societal Case**	**Synapse Total Resource Cost at 8.8%**
			a	**b**	**c**
Costs	**Customer Costs**		**$465.5**	**$457.5**	**$317.5**
Benefits					
AMI	**O&M Benefits**		$334.7	$334.7	$185.9
DR and EE	**Projected Customer Savings in Reductions**				
	Inactive Meters & Uncollectable Expenses		$48.7	$48.7	$27.9
	Demand Response	1	$240.6	$61.1	$30.7
	Energy Efficiency		$14.2	$7.1	$3.6
	Electric Vehicle Enhancement	2	$90.1		
	Carbon Reduction	3	$6.3	$2.8	$1.3
	Customer Outage Benefit		$17.6	$17.6	$9.7
	Terminal Value	4	$119.3	$44.7	$16.8
Projected Benefits and Savings			**$871.5**	**$516.7**	**$276.0**
Net Cost or (Net Benefits i.e. Savings)			**$405.9**	**$59.2**	**-$41.5**
Benefit to Cost Ratio			**1.87**	**1.13**	**0.87**

Sources / Notes

a	AG3.05 Abba DRH-WP_Ameren Illinois - AMI Cost Benefit Analysis (CP).xlsm
b	Ameren: Low Participation, premise visit scenario, Synapse adjustments to PSP, DLC, DR, PEV partiticipation
c	Ameren: Low Participation, premise visit scenario, discount rate at 8.8%, PSP, DLC, DR, PEV partiticipation
1	Synapse adjustment to PSP, DLC, and annual DR benefits
2	Synapse adjustment to PEV benefits
3	Synapse adjustment of carbon reduction attributable to EE only
4	Terminal value adjusts based on Ameren low participation scenario

Utility AMI / Smart Grid projects - Assumptions used in Calculation of Net Present Value & /or Benefit / Cost Analysis (with Note 1)

State & Utility	Docket	Input assumptions		Citations	
		Discount Rate (%)	Time Horizon (Years)	Discount Rate	Time Horizon
Arkansas					
Oklahoma Gas & Electric	10-109-U	8.124	15	Scott, Direct, page 13, line 21	Response APSC 001-08 Att
California					
Pacific Gas and Electric	A.05-06-028	7.6	20	PUC Decision 06-07-027; page 49	PUC Decision 06-07-027; page 28
San Diego Gas And Electric	A.05-03-015	8.23	17	PUC Decision 07-04-043, page 25	PUC Decision 07-04-043, page 32
District of Columbia					
Potomac Electric Power (1)	NJ EO07110881	7.09	15	Exhibit C, page 55	Exhibit B, page 6
Maryland					
BG&E	Case No. 9208	8.49	10	Exhibit DMV-1, page 8	Order No. 83410, page 46
Potomac Electric Power (1)	NJ EO07110881	7.17	15	Exhibit C, page 55	Exhibit B, page 6
New Jersey					
Atlantic City Electric (1)	NJ EO07110881	6.69	15	Exhibit C, page 55	Exhibit B, page 6
Nevada					
Nevada Power	10 - 02009	8.75	20	Response to Staff 463	Response to Staff 463
Sierra Pacific	10 - 03023				
Pennsylvania					
West Penn Power	M-2009-2123951	8.954	15	Hornby, Direct, Exhibit___(JRH-4)	
Note 1.	**"Blueprint for the Future" that ACE filed in New Jersey contains analyses for PEPCO DC and PEPCO MD**				

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

THE DIRECTOR

January 3, 2012

M-12-06

MEMORANDUM FOR THE HEADS OF DEPARTMENTS AND AGENCIES

FROM: Jacob J. Lew
Director

SUBJECT: 2012 Discount Rates for OMB Circular No. A-94

On October 29, 1992, OMB issued a revision to OMB Circular No. A-94, "Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs." The revision established new discount rate guidelines for use in benefit-cost and other types of economic analysis.

The revised Circular specifies certain discount rates that will be updated annually when the interest rate and inflation assumptions in the budget are changed. These discount rates are found in Appendix C of the revised Circular. The attachment to this memorandum is an update of Appendix C. It provides discount rates that will be in effect for the calendar year 2012.

The rates presented in Appendix C do not apply to regulatory analysis or benefit-cost analysis of public investment. They are to be used for lease-purchase and cost-effectiveness analysis, as specified in the Circular.

Attachment

APPENDIX C
(Revised December 2011)

DISCOUNT RATES FOR COST-EFFECTIVENESS, LEASE PURCHASE, AND RELATED ANALYSES

Effective Dates. This appendix is updated annually. This version of the appendix is valid for calendar year 2012. A copy of the updated appendix can be obtained in electronic form through the OMB home page at http://www.whitehouse.gov/omb/circulars_a094/a94_appx-c/. The text of the Circular is found at http://www.whitehouse.gov/omb/circulars_a094/, and a table of past years' rates is located at http://www.whitehouse.gov/sites/default/files/omb/assets/a94/dischist.pdf. Updates of the appendix are also available upon request from OMB's Office of Economic Policy (202-395-3381).

Nominal Discount Rates. A forecast of nominal or market interest rates for calendar year 2012 based on the economic assumptions for the 2013 Budget are presented below. These nominal rates are to be used for discounting nominal flows, which are often encountered in lease-purchase analysis.

Nominal Interest Rates on Treasury Notes and Bonds of Specified Maturities (in percent)

3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
1.6	2.1	2.5	2.8	3.5	3.8

Real Discount Rates. A forecast of real interest rates from which the inflation premium has been removed and based on the economic assumptions from the 2013 Budget is presented below. These real rates are to be used for discounting constant-dollar flows, as is often required in cost-effectiveness analysis.

Real Interest Rates on Treasury Notes and Bonds of Specified Maturities (in percent)

3-Year	5-Year	7-Year	10-Year	20-Year	30-Year
0.0	0.4	0.7	1.1	1.7	2.0

Analyses of programs with terms different from those presented above may use a linear interpolation. For example, a four-year project can be evaluated with a rate equal to the average of the three-year and five-year rates. Programs with durations longer than 30 years may use the 30-year interest rate.

CIRCULAR A-94

GUIDELINES AND DISCOUNT RATES

FOR BENEFIT-COST ANALYSIS OF FEDERAL PROGRAMS

CIRCULAR NO. A-94
(Transmittal Memo No.64)

MEMORANDUM FOR HEADS OF EXECUTIVE DEPARTMENTS AND ESTABLISHMENTS

SUBJECT: Guidelines and Discount Rates for Benefit-Cost Analysis of Federal Programs

Table of Contents — Page

1. **Purpose**. The goal of this Circular is to promote efficient resource allocation through well-informed decision-making by the Federal Government. It

value. Transfers that arise as a result of the program or project being analyzed should be identified as such, however, and their distributional effects discussed. It should also be recognized that a transfer program may have benefits that are less than the program's real economic costs due to inefficiencies that can arise in the program's delivery of benefits and financing.

b. Measuring Benefits and Costs. The principle of *willingness-to-pay* provides an aggregate measure of what individuals are willing to forego to obtain a given benefit. Market prices provide an invaluable starting point for measuring willingness-to-pay, but prices sometimes do not adequately reflect the true value of a good to society. Externalities, monopoly power, and taxes or subsidies can distort market prices.

Taxes, for example, usually create an *excess burden* that represents a net loss to society. (The appropriate method for recognizing this excess burden in public investment analyses is discussed in Section 11.) In other cases, market prices do not exist for a relevant benefit or cost. When market prices are distorted or unavailable, other methods of valuing benefits may have to be employed. Measures derived from actual market behavior are preferred when they are available.

(1) Inframarginal Benefits and Costs. Consumers would generally be willing to pay more than the market price rather than go entirely without a good they consume. The economist's concept of *consumer surplus* measures the extra value consumers derive from their consumption compared with the value measured at market prices. When it can be determined, consumer surplus provides the best measure of the total benefit to society from a government program or project. Consumer surplus can sometimes be calculated by using econometric methods to estimate consumer demand.

(2) Indirect Measures of Benefits and Costs. Willingness-to-pay can sometimes be estimated indirectly through changes in land values, variations in wage rates, or other methods. Such methods are most reliable when they are based on actual market transactions. Measures should be consistent with basic economic principles and should be replicable.

(3) Multiplier Effects. Generally, analyses should treat resources as if they were likely to be fully employed. Employment or output multipliers that purport to measure the secondary effects of government expenditures on employment and output should not be included in measured social benefits or costs.

7. **Treatment of Inflation**. Future inflation is highly uncertain. Analysts should avoid having to make an assumption about the general rate of inflation whenever possible.

a. Real or Nominal Values. Economic analyses are often most readily accomplished using *real* or *constant-dollar* values, i.e., by measuring benefits and costs in units of stable purchasing power. (Such estimates may reflect expected future changes in relative prices, however, where there is a reasonable basis for estimating such changes.) Where future benefits and costs are given in *nominal* terms, i.e., in terms of the future purchasing power of the dollar, the analysis should use these values rather than convert them to constant dollars as, for example, in the case of lease-purchase analysis.

Nominal and real values must not be combined in the same analysis. Logical consistency requires that analysis be conducted either in constant dollars or in terms of nominal values. This may require converting some nominal values to real values, or vice versa.

b. Recommended Inflation Assumption. When a general inflation assumption is needed, the rate of increase in the Gross Domestic Product deflator from the Administration's economic assumptions for the period of the analysis is recommended. For projects or programs that extend beyond the six-year budget horizon, the inflation assumption can be extended by using the inflation rate for the sixth year of the budget forecast. The Administration's economic forecast is updated twice annually, at the time the budget is published in January or February and at the time of the Mid-Session Review of the Budget in July. Alternative inflation estimates, based on credible private sector forecasts, may be used for sensitivity analysis.

8. **Discount Rate Policy**. In order to compute net present value, it is necessary to discount future benefits and costs. This discounting reflects the time value of money. Benefits and costs are worth more if they are experienced sooner. All future benefits and costs, including nonmonetized benefits and costs, should be discounted. The higher the discount rate, the lower is the present value of future cash flows. For typical investments, with costs concentrated in early periods and benefits following in later periods, raising the discount rate tends to reduce the net present value. (Technical guidance on discounting and a table of *discount factors* are provided in Appendix B.)

a. Real versus Nominal Discount Rates. The proper discount rate to use depends on whether the benefits and costs are measured in real or nominal terms.

(1) A real discount rate that has been adjusted to eliminate the effect of expected inflation should be used to discount constant-dollar or real benefits and costs. A real discount rate can be approximated by subtracting expected inflation from a nominal interest rate.

(2) A nominal discount rate that reflects expected inflation should be used to discount nominal benefits and costs. Market interest rates are nominal interest rates in this sense.

b. Public Investment and Regulatory Analyses. The guidance in this section applies to benefit-cost analyses of public investments and regulatory programs that provide benefits and costs to the general public. Guidance related to cost-effectiveness analysis of internal planning decisions of the Federal Government is provided in Section 8.c.

In general, public investments and regulations displace both private investment and consumption. To account for this displacement and to promote efficient investment and regulatory policies, the following guidance should be observed.

(1) Base-Case Analysis. Constant-dollar benefit-cost analyses of proposed investments and regulations should report net present value and other outcomes determined using a real discount rate of 7 percent. This rate approximates the marginal pretax rate of return on an average investment in the private sector in recent years. Significant changes in this rate will be reflected in future updates of this Circular.

(2) Other Discount Rates. Analyses should show the sensitivity of the discounted net present value and other outcomes to variations in the discount rate. The importance of these alternative calculations will depend on the specific economic characteristics of the program under analysis. For example, in analyzing a regulatory proposal whose main cost is to reduce business investment, net present value should also be calculated using a higher discount rate than 7 percent.

Analyses may include among the reported outcomes the *internal rate of return* implied by the stream of benefits and costs. The internal rate of return is the discount rate that sets the net present value of the program or project to zero. While the internal rate of return does not generally provide an acceptable decision criterion, it does provide useful information, particularly when budgets are constrained or there is uncertainty about the appropriate discount rate.

(3) Using the *shadow price of capital* to value benefits and costs is the analytically preferred means of capturing the effects of government projects on resource allocation in the private sector. To use this method accurately, the analyst must be able to compute how the benefits and costs of a program or project affect the allocation of private consumption and investment. OMB concurrence is required if this method is used in place of the base case discount rate.

c. Cost-Effectiveness, Lease-Purchase, Internal Government Investment, and Asset Sales Analyses. The Treasury's borrowing rates should be used as discount rates in the following cases:

(1) Cost-Effectiveness Analysis. Analyses that involve constant-dollar costs should use the real Treasury borrowing rate on marketable securities of comparable maturity to the period of analysis. This rate is computed using the Administration's economic assumptions for the budget, which are published in January of each year. A table of discount rates based on the expected interest rates for the first year of the budget forecast is presented in Appendix C of this Circular. Appendix C is updated annually and is available upon request from OMB. Real Treasury rates are obtained by removing expected inflation over the period of analysis from nominal Treasury interest rates. (Analyses that involve nominal costs should use

nominal Treasury rates for discounting, as described in the following paragraph.)

(2) Lease-Purchase Analysis. Analyses of nominal lease payments should use the nominal Treasury borrowing rate on marketable securities of comparable maturity to the period of analysis. Nominal Treasury borrowing rates should be taken from the economic assumptions for the budget. A table of discount rates based on these assumptions is presented in Appendix C of this Circular, which is updated annually. (Constant dollar lease-purchase analyses should use the real Treasury borrowing rate, described in the preceding paragraph.)

(3) Internal Government Investments. Some Federal investments provide "internal" benefits which take the form of increased Federal revenues or decreased Federal costs. An example would be an investment in an energy-efficient building system that reduces Federal operating costs. Unlike the case of a Federally funded highway (which provides "external" benefits to society as a whole), it is appropriate to calculate such a project's net present value using a comparable-maturity Treasury rate as a discount rate. The rate used may be either nominal or real, depending on how benefits and costs are measured.

Some Federal activities provide a mix of both Federal cost savings and external social benefits. For example, Federal investments in information technology can produce Federal savings in the form of lower administrative costs and external social benefits in the form of faster claims processing. The net present value of such investments should be evaluated with the 7 percent real discount rate discussed in Section 8.b. unless the analysis is able to allocate the investment's costs between provision of Federal cost savings and external social benefits. Where such an allocation is possible, Federal cost savings and their associated investment costs may be discounted at the Treasury rate, while the external social benefits and their associated investment costs should be discounted at the 7 percent real rate.

(4) Asset Sale Analysis. Analysis of possible asset sales should reflect the following:

(a) The net present value to the Federal Government of holding an asset is best measured by discounting its future earnings stream using a Treasury rate. The rate used may be either nominal or real, depending on how earnings are measured.

(b) Analyses of government asset values should explicitly deduct the cost of expected defaults or delays in payment from projected cash flows, along with government administrative costs. Such analyses should also consider explicitly the probabilities of events that would cause the asset to become nonfunctional, impaired or obsolete, as well as probabilities of events that would increase asset value.

(c) Analyses of possible asset sales should assess the gain in social efficiency that can result when a government asset is subject to market discipline and private incentives. Even

Ameren Illinois Company's
Response to AG Data Requests on Rehearing
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 7/30/2012

AG 3.02

Reference the Direct Testimony on Rehearing of Mr. Nelson, Ameren Exhibit 1.0RH page 8. The California Public Utilities Commission, in rulemaking 08-12-009, has identified 19 metrics to measure various aspects of the grid modernization underway by California's three investor owned utilities.

a. Is the Company proposing to, or willing to, adopt metrics comparable to the metrics adopted in California?
b. For each of the California metrics the Company is not proposing or not willing to adopt, please explain why not

RESPONSE

AIC objects to this data request as beyond the scope of rehearing. Subject to this objection:

a. No.
b. See objection. The Company refers the AG to its testimony in the underlying proceeding and the Commission's final order on this subject. In addition, this subpart is irrelevant because the metrics adopted in this proceeded are subject to specific requirements of Illinois law. Whether AIC is "willing to adopt" any "California metrics" is therefore irrelevant.

Ameren Illinois Company's
Response to AG Data Requests on Rehearing
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 7/30/2012

AG 3.08

Reference the Direct Testimony on Rehearing of Mr. Nelson, Ameren Exhibit 1.0RH page 13 line 271.

a. Please provide the Company's analysis of the uses to which its ratepayers would put their money if they were not paying for AMI. Please include all supporting research and analysis. If the Company has not prepared such an estimate please explain why not.
b. Please provide the Company's estimate of its ratepayers "opportunity cost" of money based upon the comparable uses identified in part a. Please include all supporting research and analysis. If the Company has not prepared such an estimate please explain why not.

RESPONSE

a. Objection. The data request is vague, uncertain, and calls for speculation. It is also immaterial, irrelevant and not likely to lead to the discovery of admissible evidence.
b. See response to subpart a) above.

Ameren Illinois Company's
Response to AG Data Requests on Rehearing
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 7/30/2012

AG 3.17

Reference the Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 9 line 204 to page 10 line 215 and Ameren Exhibit 5.3RH

a. Are the participation rates in 5.3RH expressed as a percent of the 62% of customers who will have smart meters under the Company filing in this proceeding, or as a percent of all customers, i.e. those with smart meters and those without, or does it assume that 100% of customers will have smart meters by 2032?
b. Please provide all inputs and calculations used to prepare Exhibit 5.3RH in an operational electronic format
c. For each program to be offered to Residential customers, please provide all assumptions underlying the 2032 projected participation rate and the support for those assumptions
d. Please provide the Company's estimate of the percentage of its residential customers who have central air conditioning
e. Please indicate the annual dollar amount a residential customer with central air conditioning would receive from participating in each program, assuming currently effective rates, if he or she reduced usage by the average quantities listed in Exhibit 5.4RH. Please provide all supporting calculations.
f. Please indicate the annual dollar amount a residential customer without central air conditioning would receive from participating in each program, assuming currently effective rates, if he or she reduced usage by the average quantities listed in Exhibit 5.4RH. Please provide all supporting calculations.
g. For each program to be offered to Residential customers that Ameren currently offers, please identify the actual participation Ameren achieved in the most recent year for which statistics are available.
h. For each program to be offered to Residential customers, please identify the utilities comparable to Ameren who are currently offering that program on a system-wide basis and the actual participation achieved in the most recent year for which statistics are available. If Dr. Faruqui has not compiled this actual data please explain why not.

RESPONSE

Response to subparts a), b), c), and h) only:
Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

Ameren Illinois Company's
Response to AG Data Requests
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 8/15/2012

AG 6.04

Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 12 line 263 to 265.

a. Please confirm that a residential customer could take advantage of a time-of-use (TOU) rate if he or she had an interval meter and if Ameren offered a residential TOU rate. If not please explain why not
b. Ameren response to AG Data Request 3.17 h states "…many utilities who now offer TOU rates for PEVs". Please identify utilities without AMI who currently offer TOU rates to residential customers for PEVs and describe the meters they use to enable those residential TOU rates.
c. Please provide the installed cost of an interval meter for an Ameren residential customer
d. Please describe the "automated smart charging equipment" referenced on line 264 and the installed cost of that equipment for a residential vehicle owner.
e. Has Dr. Faruqui included the installed cost of automated smart charging equipment in his calculation of the societal costs and benefits of PEVs enabled by AMI? If not, why not.

RESPONSE

Response to Subparts a), b), d), e) only:
Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

Response to Subpart c) only:
Prepared By: Michael S. Abba
Title: Manager, Smart Grid Integration & System Improvement
Phone Number: 618-993-4633

a. Yes, a residential customer could choose a time-of-use (TOU) rate if he or she had an interval meter and if Ameren or other third party supplier offered a residential TOU rate. However, there is an incremental cost to installing and reading an interval meter, and maintaining the interval data. Also, without AMI, a residential customer with an interval meter would not have the additional AMI benefits of near real time usage data, net metering, remote disconnect / reconnect, outage detection and reporting, in-premise device interface, voltage and other power quality sensing, and remote programming.
b. The Brattle Group does not have and has not researched information about the specific technologies that utilities are using to implement their TOU rates.
c. The installed cost of a typical residential meter capable of recording interval data is approximately $140. This is the installed cost only, and does not include the on-going costs of meter reading, storing the interval data, and any post-installation meter

programming that may be required. The functionalities of this meter do not include the additional AMI meter functionalities of net metering, remote disconnect / reconnect, outage detection and reporting, in-premise device interface, voltage and other power quality sensing, and remote programming.

d. The "automated smart charging equipment" referenced on line 264 is a generic term for AMI interconnected charging equipment that would allow charging to only occur in off-peak hours and can verify the time of charging with the utility. The cost of equipment is included in the cost of the Home Energy Management system.

e. Yes.

Ameren Illinois Company's
Response to AG Data Requests
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 8/15/2012

AG 6.05

Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 13 line 269 to 273.

a. Do the PEVS analyzed by Dr. Faruqui include plug-in electric / gasoline hybrids (PHEVs) in addition to one hundred percent battery electric vehicles (BEVs)?
b. If the response to a. is yes, what mix of PHEVs and BEVs did Dr. Faruqui assume to calculate the $9500 cost premium?
c. If the response to a. is yes, did Dr. Faruqui forecast customer adoption rates for PHEVs separately from BEVs? If not, then why? If so, please provide the separate modeling in electronic format.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. Due to the difficulty in forecasting future technological adoption, The Brattle Group did not distinguish between PHEVs and BEVs in forecasting the share of AMI enabled electric vehicles in the vehicle fleet. However, in calculating the future benefits from AMI enabled electric vehicles, we only utilized PHEVs, which run on 66% electricity and 34% gasoline. This was in order to be conservative, since PHEV's yield a lower societal benefit than BEVs.
b. Only PHEVs were analyzed.
c. See the response to AG 6.05(a).

Ameren Illinois Company's
Response to AG Data Requests
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 8/15/2012

AG 6.07

Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 13 line 286 to 292.

a. Is Dr. Faruqui aware of any estimates of the sensitivity of residential PEV sales to residential electricity prices published by electric industry analysts, automobile industry analysts, or scholarly researchers? If yes, please provide these estimates. If no, could the absence of such estimates indicate that other analysts have not found residential electricity prices to be a major driver of residential PEV sales?
b. Please provide all research on the major drivers of residential PEV sales and residential hybrid vehicle sales that Dr. Faruqui reviewed in order to prepare this testimony.
c. Please provide all research on the relationship between gasoline prices and hybrid vehicle sales that Dr. Faruqui reviewed in order to prepare this testimony.
d. Has the actual relationship between gasoline prices and hybrid vehicle sales from 2007 to 2011 been consistent with the price elasticity estimated by Gallagher and Muehlegger? Please provide all analyses supporting your response.
e. Please provide all analyses and reports Dr. Faruqui reviewed to develop his assumption that residential PEV sales will exhibit the same relationship to residential electricity prices as hybrid vehicle sales exhibit to gasoline prices. If none, please explain why this is a reasonable assumption.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. The Brattle Group is not. This reflects the nascent stage of the implementation of PEV and AMI technology; sufficient data does not yet exist for this type of analysis to be carried out.
b. Since we are unaware of any existing data showing how sensitive PEV sales are to electricity prices, The Brattle Group has derived this estimate by analogy, by examining the relationship between the sales of hybrid electric vehicles and gasoline prices. Like PEVs, these vehicles sell at a premium, but have lower costs per mile driven. Recent scholarly research using hybrid vehicle sales in the period 2000 to 2006 showed that as

the price of gasoline increased by 1%, the quantity of fuel efficient hybrid vehicles sold increased by 0.86%.[1]

c. See response to subpart b) above.
d. The Brattle Group does not have this information.
e. No such reports exist as far as The Brattle Group is aware. Both PEVs and hybrid vehicles are new automotive technologies that offer fuel economy improvements and sell at a premium relative to regular combustion engines.

[1] Gallagher, Kelly S. & Erich Muehlegger (2011): "Giving green to get green? Incentives and consumer adoption of hybrid vehicle technology", *Journal of Environmental Economics and Management,* Vol. 61, Issue 1, pp 1–15.

Ameren Illinois Company's
Response to AG Data Requests
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 8/15/2012

AG 6.08

Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 13 line 292 to page 14 line 297.

a. Is it Dr. Faruqui's assumption that a 1% reduction in average annual residential electricity prices will result in a 0.86% increase in annual residential PEV sales. If no, please clarify Dr. Faruqui's assumption regarding the relationship between changes in residential electricity prices in a year and changes in residential PEV sales in that year
b. If the response to a. is yes, please compare and contrast Dr. Faruqui's assumption to the assumption regarding the relationship between residential electricity prices and residential PEV sales underlying the 2010 Ameren PEV Assessment Report projections.
c. If the response to a. is yes, please provide all the analyses of actual annual residential electricity prices and actual annual residential PEV sales that Dr. Faruqui reviewed to develop his position. If none, please explain why the assumption is reasonable.
d. If the response to a. is yes, please provide all the analyses of projected residential electricity prices and projected residential PEV sales that Dr. Faruqui reviewed to develop his position. If none, please explain why the assumption is reasonable.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. Yes.
b. The 2010 Ameren PEV Assessment Report projections make no explicit assumption over the sensitivity of residential PEV sales to electricity prices.
c. None. It is premature to undertake this type of analysis due to the nascent nature of the implementation of PEV and AMI technology. To be conservative in our analysis, we scaled the 0.86% down to 0.286%.
d. Please see The Brattle Group's paper entitled, "Smart charging, smart pricing"[2] for electricity savings. Projected residential PEV sales are based on Becker, Sindhu & Tenderich's paper entitled, "Electric Vehicles in the United States: A New Model with Forecasts to 2030"[3] and Ameren Illinois' ICC filing in 2010.[4]

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[2] "Smart Pricing, Smart Charging," by Ahmad Faruqui, Ryan Hledik, Armando Levy, and Alan L. Madian, *Public Utilities Fortnightly*, October 2011.

[3] Becker, Thomas, Ikhlaq Sidhu & Burghardt Tenderich (2009): "Electric Vehicles in the United States: A

Ameren Illinois Company's
Response to AG Data Requests
Docket No. 12-0244
AIC's Advanced Metering Infrastructure Plan
Data Request Response Date: 8/15/2012

AG 6.10

Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 14 line 299 to line 307.

a. Lines 297 to 300. Please identify the major differences in assumptions which explain why the Becker, Sindhu & Tenderich market share projection is approximately double the 2010 Ameren PEV Assessment Report projection
b. Please explain why Dr. Faruqui chose to use the Becker, Sindhu & Tenderich market share projection rather than the EIA projection of market shares in AEO 2009 (Table 57) or in AEO 2012 (Table 57).
c. Please provide all analyses or research on future PEV market share other than the Becker, Sindhu & Tenderich estimate upon which Dr. Faruqui relied to develop his assumption. If none, please explain why a review of one estimate is reasonable.
d. Lines 303 to 305. Please provide all analyses underlying the assumption that Ameren customers will effectively exhibit a price elasticity approximately one-third (0.5* 0.67) of the general price elasticity estimated by Dr. Faruqui, i.e. a 1% reduction in Ameren residential electricity prices will result in a 0.286% increase in Ameren residential PEV sales, rather than a 0.86% increase.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. *Objection. The data request misstates the testimony and as such, is improper. Without waiving this objection, the following response is provided by Dr. Faruqui:*
It was never stated that the Becker, Sindhu & Tenderich market share projection was approximately double the 2010 Ameren PEV Assessment Report projection. The 2010 Ameren PEV Assessment Report projection only extends to 2020. At this stage they assumed that 25% of all new vehicle sales would be electric vehicles. Becker et al. use the widely used and accepted Bass model of technology adoption to project electric vehicle adoption rates by year. In 2020 they forecast that electric vehicles will constitute 18 percent of new vehicle sales. This is lower than the Ameren projection. However The Brattle Group analysis extends 10 further years into the future, to 2030, where Becker et al. have forecast that 64% of new vehicle sales will be PEVs. This adoption path leads to a 24% cumulative electric vehicle penetration rate by 2030. Even though Ameren's projections only extend to 2020 and are lower than Becker et al.'s 2020 forecasts, we halve the *cumulative* electric vehicle rate to be conservative in our estimates.

b. Becker et al. provide cumulative market shares. The AEO reports only offer the market share in terms of new vehicle sales for a given reference year.
c. Becker, Sindhu & Tenderich develop estimates based on their review of a variety of papers, models, and industry reports. A full list of resources they relied upon can be found in the report. In the study, electric vehicle sales are forecasted using the Bass new technology diffusion methodology. The Brattle Group also used Ameren Illinois' ICC filing in 2010 to estimate the future PEV market share.[5]
d. These assumptions were made simply in order to be conservative in the estimates of benefits.

[5] Ameren Illinois (2010): "Ameren PEV Assessment Report", available online at http://www.icc.illinois.gov/electricity/pev.aspx

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AG 6.11

Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 14 line 300 to line 302.

a. Please provide the share of the Illinois fleet that is composed of light vehicles.
b. Please explain why the share of vehicle miles traveled by light vehicles can be applied to the total vehicle fleet to estimate the fleet of light vehicles.
c. How does the assumption that PEV's will represent 11% of the total fleet compare with more recent projections of PEV adoption?
d. Line 302. Is Dr. Faruqui aware of any studies or research that shows a positive, causal impact of AMI on PEV adoption?

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. As stated in line 301, The Brattle Group uses the share of Illinois vehicle miles traveled by light vehicles (90%) as a proxy for the share of the Illinois fleet composed of light vehicles.
b. In the absence of other data, it is intuitive that the share of miles driven would be a good proxy for the share of vehicles
c. The Brattle Group is unaware of any more recent studies.
d. No, The Brattle Group is not aware of any such studies and the absence of such studies is to be expected, given the nascent nature of the implementation of PEV and AMI technology.

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AG 6.15

Follow-up to Ameren response to Attorney General data request 3.17 and Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 9 line 204 to page 10 line 215 and Ameren Exhibit 5.3RH.

a. At what level of participation would Ameren have to have a separate supply tariff for customers on its CPP rate? please explain.

b. At what level of participation would Ameren have to have a separate supply tariff for customers on its PTR rate? please explain.

c. at what level of participation would Ameren have to have a separate supply tariff for customers on its PSP rate? please explain.

d. At what level of participation would Ameren have to have a separate supply tariff for customers on its TOU rate? please explain.

RESPONSE

Prepared By: Leonard M. Jones
Title: Manager, Rates & Analysis
Phone Number: 314-206-1878

Objection. The data request is speculative and also seeks information that is not relevant, material or likely to lead to the discovery of admissible evidence. Further, the phrase “separate supply tariff” is vague and uncertain. Without waiving these objections, AIC provides the following response sponsored by Mr. Jones:

a. A Critical Peak Pricing (CPP) rate option offered by 3rd party suppliers does not require a tariff. Any CPP program offered by Ameren Illinois would require a Commission approved tariff. Any such CPP rate offered by Ameren Illinois would likely be incorporated within Rider PER – Purchased Electricity Recovery, in addition to new CPP tariff provisions governing availability, pricing, and other terms and conditions.

b. A Peak Tim Rebate (PTR) rate option offered by 3rd party suppliers does not require a tariff. The PTR program offered by Ameren Illinois to residential customers pursuant to 220 ILCS 5/16-108.6(g) will be through a tariff approved by the Commission. Any PTR program offered by Ameren Illinois to non-residential customers would require a Commission approved tariff.

c. An hourly supply service rate option offered by 3rd party suppliers does not require a tariff. The Power Smart Pricing (PSP) service offered by Ameren Illinois is done so through a Commission approved tariff, Rider PSP. Rider PSP is offered to residential customers pursuant to 220 ILCS 5/16-107(b-5) of the Act. The service works in conjunction with Rider RTP – Real Time Pricing and Rider PER – Purchased Electricity Recovery.

d. A Time of Use (TOU) rate option offered by 3rd party suppliers would not require a tariff. Any TOU program offered by Ameren Illinois would require a Commission approved tariff. Any such TOU rate offered by Ameren Illinois would likely be incorporated within Rider PER – Purchased Electricity Recovery, in addition to new TOU tariff provisions governing availability, pricing, and other terms and conditions.

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AG 6.16

Follow-up to Ameren response to Attorney General data request 3.17 and Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 9 line 204 to page 10 line 215 and Ameren Exhibit 5.3RH

a. Response 3.17 b. Please provide Dr. Faruqui's documentation of the program participation rates around the country and of the expert review of those participation rates.
b. Response 3.17 b. Please describe the steps Dr. Faruqui took to ensure that the expert review of participation rates were for utilities whose key relevant characteristics are comparable to Ameren.
c. Response 3.17 c. Please explain why Dr. Faruqui did not estimate the projected participation rates using PRISM or a similar price elasticity based model,
d. Response 3.17 c. Does Dr. Faruqui agree that residential customer voluntary participation in pricing programs or rate designs such as those listed in Exhibit 5.3RH is a function of numerous independent variables including electricity rates, income, annual cooling degree-days and penetration of central air conditioning? If not, please explain why not.
e. Response 3.17 e and f. Does Dr. Faruqui have, or can he provide, these analyses. If so please provide them with all inputs in an operational electronic format.
f. Response 3.17 e and f. If neither AIC nor Dr. Faruqui have, or can provide, these illustrative analyses, please explain how AIC plans to market these pricing options to its residential customers.
g. Response 3.17 h. The request refers to Dr. Faruqui's testimony and specifically asks "If Dr. Faruqui has not compiled this actual data please explain why not." Is the response the extent of Dr. Faruqui's actual data on participation in each type of pricing program around the United States? If no, please provide that data.

RESPONSE

Response to Subparts a) thru e) and g) only:
Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

Response to Subpart f) only:
Prepared By: Leonard M. Jones (part f)
Title: Manager, Rates & Analysis
Phone Number: 314-206-1878

a. Documentation of the program participation rates can be found in the AMI Cost/Benefit Analysis based on prior work conducted by the Brattle Group for the Institute for Electric Efficiency.[6]
b. Dr. Faruqui conferred with Ameren Illinois to get a sense of what would be realistic estimates for the portion of Illinois served by Ameren.
c. It would be very difficult to do so, since PRISM or a similar price elasticity model does not predict participation rates. These models focus on predicting the change in load shape for the typical participating customer and do not forecast the participation rate.
d. Yes.
e. No. Quantitative models for predicting participation rates would require the existence of data that currently does not exist.
f. The analysis assumes that pricing options for residential customers may be provided by third party suppliers, the utility, or both. Ameren Illinois has not developed detailed plans in this area at this time. However, through the Smart Grid Advisory Council and other stakeholder forums, Ameren Illinois plans to discuss with stakeholders and Staff ways to inform and educate customers on available beneficial rate options as appropriate.
g. As noted earlier, sufficient quantitative data do not exist to model program participation rates.

[6] "The Costs and Benefits of Smart Meters for Residential Customers," by Ahmad Faruqui, Douglas C. Mitarotonda, Lisa Wood, Adam Cooper, and Judith Schwartz, IEE Whitepaper, The Edison Foundation, July 2011

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AG 6.18

Follow-up to Ameren response to Attorney General data request 3.18 and Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 11 line 249 to page 12 line 261 and Ameren Exhibit 5.5RH.

a. Response 3.18 b. Please provide all documentation of the polling of experts.
b. Response 3.18 c. Please explain how technological innovation and economies of scale in production will cause installation costs to decrease at the pace at which Dr. Faruqui is projecting.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. The conversations were not documented. They were informal in nature and intended to simply provide background information that would allow us to update the iGrid model which had been last used in the project we had done for the IEE.
b. The precise rate of decrease reflects our judgment and conversations with experts.

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AG 6.21

Follow-up to Ameren response to Attorney General data request 4.02 and Direct Testimony on Rehearing of Dr. Faruqui, Ameren Exhibit 5.0RH page 12 line 268 to page 13 line 273.

a. Response 4.02 a. Please indicate the page in the Deutsche Bank 2008 study that refers to a $9,500 premium or to a decline in that premium over time.
b. Response 4.02 a. Please provide Dr. Faruqui's documentation of his consultation with technical experts on PHEV premiums.
c. Response 4.02 a. Please provide Dr. Faruqui's documentation of his review of automotive literature on PHEV premiums.
d. Response 4.02 b. Please provide Dr. Faruqui's documentation of his consultation with technical experts on the decline in the premium
e. Response 4.02 b. Please provide Dr. Faruqui's documentation of his review of automotive literature on the decline of the premium
f. Response 4.02 e. Please provide the nominal sum and present value sum of home energy management system (HEMS) costs associated with the PEV analysis. Are those costs included in Dr. Faruqui's estimate of costs shown in Exhibit 5.6RH? If not, please explain why not.
g. Response 4.02 e. Does Dr. Faruqui assert that all customers with a HEMS will also receive a standard level one charger (120V)? If so, please explain why and provide the basis for this assumption. If not, please explain why standard level one charger costs are included as part of the cost of every HEMS.
h. Response 4.02 e. Please provide supporting documentation that standard level one chargers cost $400.
i. Response 4.02 e. Please provide supporting documentation and analyses for Dr. Faruqui's assumption regarding the continued use of standard level one chargers in 2032, when Level 2 and 3 chargers will be available in the market.

RESPONSE

Prepared By: Ahmad Faruqui, Ph.D.
Title: Principal, The Brattle Group
Phone Number: 415-217-1000

a. The Brattle Group chose the $9,500 premium based on the range suggested in the study, as well as our own review of market prices. To this end, The Brattle Group examined existing market price data from a number of industry publications. Examples include the Auto Trader, Edmunds.com, and the websites of various automobile manufactures. The Brattle Group considered comparisons of current prices of PEVs and CVs of similar qualities when determining the price premium. For example, the prices of the Chevy Volt electric vehicle and the Toyota Prius PHEV were compared to similar models of vehicles made by their respective manufacturers. Deutsche Bank's projections can be found on page 10 of the study.

b. This is based on informal conversations with experts as well as a review of automotive literature. An example of this literature is the Deutsche Bank's 2008 study entitled "Electric Cars: Plugged In-Batteries must be included," which can be found at http://www.inrets.fr/fileadmin/recherche/transversal/pfi/PFI_VE/pdf/deutch_bank_electric_cars.pdf.
Other examples include market price data in industry publications such as Auto Trader, Edmunds.com, and the websites of various automobile manufactures. The Brattle Group considered comparisons of current prices of PEVs and CVs of similar qualities when determining the price premium. For example, the prices of the Chevy Volt electric vehicle and the Toyota Prius PHEV were compared to similar models of vehicles made by their respective manufacturers.

c. This value was based on review of the automotive literature and consultations with technical experts. For example, one of the main factors affecting the price premium is the cost of batteries. Literature suggests that the cost of batteries will significantly decline in the coming years. An example of such sources is Deutsche Bank's 2009 study entitled, "Electric Cars: Plugged In 2-Batteries must be included," which can be found at http://www.fullermoney.com/content/2009-11-03/ElectricCarsPluggedIn2.pdf.
Another source is a Green Car Reports article entitled, "Electric-Car Battery Costs To Decline To $200/kWh In 2020, McKinsey Says," which can be found at http://www.greencarreports.com/news/1077804_electric-car-battery-costs-to-decline-to-200-kwh-in-2020-mckinsey-says.

d. In its ordinary course of business, The Brattle Group, as do other analysts, relies on information provided to and from subject matter experts. This is based on informal conversations with experts.

e. Brattle did an online search for articles on items such as future battery costs related to the expected future costs of PEVs. We read a variety of articles similar in nature to Deutsche Bank's 2009 study entitled, "Electric Cars: Plugged In 2-Batteries must be included," and the Green Car Reports article entitled, "Electric-Car Battery Costs To Decline To $200/kWh In 2020, McKinsey Says" . We did not document this process or the exact sources that we consulted. We relied on our expert opinion and informal conversations with other experts to verify that these numbers were realistic.

f. Yes, they are included in Dr. Faruqui's estimate of costs shown in Exhibit 5.6RH. The total nominal sum of HEMs costs associated with PEV is $513,015. The present value sum of these costs is $378,344.

g. Yes. A standard level one charger (120V) is currently provided as a standard offering with all new PEV vehicle purchases. It was assumed this would continue throughout the analysis.

h. Objection. The data request misstates The Brattle Group's testimony as the premise for the data request was never our position.

i. The installed cost of Level 2 or Level 3 chargers comes with a cost premium over standard Level 1 chargers provided with the PEV, therefore The Brattle Group made no assumptions about Level 2 and Level 3 chargers.