COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES CO. FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE No. 2020-00349

-and-

ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC CO. FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE No. 2020-00350

ATTORNEY GENERAL'S RESPONSES TO DATA REQUESTS OF THE KENTUCKY PUBLIC SERVICE COMMISSION STAFF

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits the following responses to data requests of the Kentucky Public Service Commission Staff in the above-styled matters.

Respectfully submitted,

DANIEL CAMERON
ATTORNEY GENERAL

LAWRENCE W. COOK
J. MICHAEL WEST
ANGELA M. GOAD
JOHN G. HORNE II
ASSISTANT ATTORNEYS GENERAL
1024 CAPITAL CENTER DR., STE. 200
FRANKFORT, KY 40601
(502) 696-5453
FAX: (502) 564-2698
Larry.Cook@ky.gov
Michael.West@ky.gov
Angela.Goad@ky.gov
John.Horne@ky.gov

Certificate of Service and Filing

Pursuant to the Commission's Orders in Case No. 2020-00085, and in accord with all other applicable law, Counsel certifies that an electronic copy of the forgoing was served and filed by e-mail to the parties of record. Further, counsel for OAG will submit the paper originals of the foregoing to the Commission within 30 days after the Governor lifts the current state of emergency. Counsel further certifies that the responses set forth herein are true and accurate to the best of his knowledge, information, and belief formed after a reasonable inquiry.

This 1st day of April, 2021

Assistant Attorney General

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES CO. FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE No. 2020-00349

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ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC CO. FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE No. 2020-00350

AFFIDAVIT OF GLENN WATKINS

Commonwealth of Virginia)

Glenn Watkins, being first duly sworn, states the following:
The Data Request Responses are those of the Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Data Request Responses if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief his statements made are true and correct. Further affiant sayeth not.

Glenn Watkins

SUBSCRIBED AND SWORN to before me this 18th day of March, 2021

NOTARY PUBLIC

My Commission Expires: 10/31/2022

JENNIFER R. DOLEN
NOTARY PUBLIC
REG # 7315146
MY COMMISSION EXPIRES 10/31/2022
COMMONWEALTH OF VIRGINIA

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF KENTUCKY UTILITIES CO. FOR AN ADJUSTMENT OF ITS ELECTRIC RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE No. 2020-00349

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ELECTRONIC APPLICATION OF LOUISVILLE GAS & ELECTRIC CO. FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO DEPLOY ADVANCED METERING INFRASTRUCTURE, APPROVAL OF CERTAIN REGULATORY AND ACCOUNTING TREATMENTS, AND ESTABLISHMENT OF A ONE-YEAR SURCREDIT	)	CASE No. 2020-00350

AFFIDAVIT OF PAUL J. ALVAREZ

State of Colorado)

Paul J. Alvarez, being first duly sworn, states the following:
The Data Request Responses are those of the Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Data Request Responses if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, information and belief his statements made are true and correct. Further affiant sayeth not.

____
Paul J. Alvarez

SUBSCRIBED AND SWORN to before me this 18th day of March, 2021

____
NOTARY PUBLIC

My Commission Expires: March 17th, 2024

RAVEN FURLONG
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20204010679
MY COMMISSION EXPIRES MAR 17, 2024

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 1
Page 1 of 1

Refer to the Direct Testimony of Glenn A. Watkins (Watkins Testimony), page 38, lines 19–26. Explain and provide the specific decision criteria used to determine whether generation is considered to be base, intermediate, or peak. For example, if there is an operating cost threshold, unit size threshold, or nameplate capacity threshold, provide the decision matrix.

RESPONSE:

In general, please refer to Mr. Watkins' testimony page 38, lines 10-14. Specifically, please refer to the matrix provided in Mr. Watkins' Schedule GAW-17. KU's and LG&E's base load units were determined by considering those units with the highest generation order of dispatch (Column 6), large number of hours of operation (Column 9) and higher capacity factors (Column 10). Furthermore, Mr. Watkins is well aware that each of the units designated as base load were indeed designed as such in order to minimize the total cost of production due to their relatively low fuel costs as shown in Column 4.

With regard to intermediate units, these units were again determined by using the same criteria as above but with lower orders of dispatch, fewer number of hours of operation, and lower capacity factors than those of base load units, yet, higher than those of peaker units. Furthermore, these intermediate units have higher variable fuel costs than base load units but typically lower than peaker units.

With regard to peaker units, these units operate at very low capacity factors, are dispatched relatively few hours of the year, exhibit higher fuel costs, and are among the last units to be dispatched at any point in time.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 2
Page 1 of 1

Refer to the Watkins Testimony, page 57, lines 1–9. A priori is defined as to be relating to or denoting reasoning or knowledge which proceeds from theoretical deduction rather than from observation or experience. Explain if Mr. Watkins agrees or disagrees whether theoretical deductions are inherent to the analysis associated with cost of service and rate design in general.

RESPONSE:

Class cost allocation studies (cost of service studies) require a myriad of judgmental decisions. These decisions may differ from analyst to analyst depending on the individual's evaluation of cost causation for some accounts, and equity and fairness for other accounts (primarily overhead-related costs). As noted in the quote on page 57, lines 1-9, "in making this determination, supporting data may be more important than theoretical considerations." Indeed, Mr. Watkins is of the opinion that analyses of utility specific data is more important and relevant than simply *a priori* assumptions.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 3
Page 1 of 1

Refer to the Watkins Testimony, page 59, lines 9–12. Provide the case numbers where this Commission did not accept the zero-intercept method as a valid measurement of demand and customer related costs for distribution plant.

RESPONSE:

Commission Staff would have to ask the authors of the NARUC published report entitled Charging For Distribution Services: Issues In Rate Design as Mr. Watkins' statement on page 59, lines 9-12 are the result of the quote provided from this document on page 57, line 22 through page 59, line 4.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 4
Page 1 of 1

Refer to the Watkins Testimony, page 68.

a. For Option 1, provide the rates for all customer classes that would result from the proposed allocations in Table 27, assuming that the entire amount of Kentucky Utilities Company's (KU) proposed electric rate increase were approved by the Commission. Provide this in Excel spreadsheet format with all with all formulas, columns, and rows unprotected and fully accessible.

b. For Option 2, provide the rates for all customer classes that would result from the proposed allocations in Table 27, assuming that the entire amount of KU's proposed electric rate increase were approved by the Commission. Provide this in Excel spreadsheet format with all with all formulas, columns, and rows unprotected and fully accessible.

RESPONSE:

a. Mr. Watkins was not engaged in these proceedings to evaluate or even review the individual rate elements for every KU rate schedule; e.g., customer charges, demand charges, energy charges, KVAR charges, etc., and accordingly has not undertaken such an evaluation or review. Furthermore, Mr. Watkins is not aware of whether other parties propose alternative rate designs for non-residential customers. Therefore, Mr. Watkins offers no opinion as to how specific rate elements should be designed for non-residential customers in that his testimony relates to the distribution of any authorized revenue across classes. With regard to the residential class, please see attachment: Attachment to PSC Question 4.xls.

b. See response to a. above as well Attachment to PSC Question 4.xls.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 5
Page 1 of 1

Refer to the Watkins Testimony, page 72.

a. For Option 1, provide the rates for all customer classes that would result from the proposed allocations in Table 30, assuming that the entire amount of Louisville Gas and Electric Company's (LG&E) proposed electric rate increase were approved by the Commission. Provide this in Excel spreadsheet format with all with all formulas, columns, and rows unprotected and fully accessible.

b. For Option 2, provide the rates for all customer classes that would result from the proposed allocations in Table 30, assuming that the entire amount of LG&E's proposed electric rate increase were approved by the Commission. Provide this in Excel spreadsheet format with all with all formulas, columns, and rows unprotected and fully accessible.

RESPONSE:

a. Mr. Watkins was not engaged in these proceedings to evaluate or even review the individual rate elements for every LG&E rate schedule; e.g., customer charges, demand charges, energy charges, KVAR charges, etc., and accordingly has not undertaken such an evaluation or review. Furthermore, Mr. Watkins is not aware of whether other parties propose alternative rate designs for non-residential customers. Therefore, Mr. Watkins offers no opinion as to how specific rate elements should be designed for non-residential customers in that his testimony relates to the distribution of any authorized revenue across classes. With regard to the residential class, please see attachment: Attachment to PSC Question 5.xls.

b. See response to a. above as well as Attachment to PSC Question 5.xls.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 6
Page 1 of 1

Refer to the Watkins Testimony, page 74, lines 6–11. Provide what, under economic theory, a competitive firm's decision would be if the marginal cost is less than the average total cost of producing a good or service.

RESPONSE:

In the short-run, if the market price is greater than average variable cost and short-run marginal costs is less than average variable costs, the firm will produce additional units. In the long-run, if the market price is greater than the average total cost and the long-run marginal cost is less than average total cost, the firm will produce additional units. Under economic theory in the long-run, a firm will operate where its marginal cost equals its average total cost wherein its average total cost is at the minimum point of its average cost curve. This is a basic principle of micro-economic price theory. See also the attached excerpt from the textbook Microeconomic Theory by James Henderson and Richard Quandt, Attachment to PSC Question 6.pdf.

Microeconomic Theory
A MATHEMATICAL APPROACH

Second Edition

JAMES M. HENDERSON
Professor of Economics
University of Minnesota

RICHARD E. QUANDT
Professor of Economics
Princeton University

McGraw-Hill Book Company
New York St. Louis San Francisco
Düsseldorf Johannesburg Kuala Lumpur
London Mexico Montreal
New Delhi Panama Rio de Janeiro
Singapore Sydney Toronto

As prices change the producer will alter his input levels to satisfy his first-order conditions (3-17). Differentiating (3-17) totally and rearranging terms,

$$\begin{aligned} pf_{11}\,dx_1 + pf_{12}\,dx_2 &= -f_1\,dp + dr_1 \\ pf_{21}\,dx_1 + pf_{22}\,dx_2 &= -f_2\,dp + dr_2 \end{aligned} \tag{3-20}$$

Solving (3-20) for dx_1 and dx_2 by Cramer's rule,

$$\begin{aligned} dx_1 &= \frac{p}{\mathbf{H}}[f_{22}\,dr_1 - f_{12}\,dr_2 + (f_{12}f_2 - f_{22}f_1)\,dp] \\ dx_2 &= \frac{p}{\mathbf{H}}[-f_{21}\,dr_1 + f_{11}\,dr_2 + (f_{21}f_1 - f_{11}f_2)\,dp] \end{aligned} \tag{3-21}$$

where $\mathbf{H} = p^2(f_{11}f_{22} - f_{12}^2) > 0$ by (3-19).

Dividing both sides of the first equation of (3-21) by dr_1 and letting $dr_2 = dp = 0$,

$$\frac{\partial x_1}{\partial r_1} = \frac{pf_{22}}{\mathbf{H}} < 0$$

Since $p > 0$ and $f_{22} < 0$ by (3-18), the rate of change of the producer's purchases of X_1 with respect to changes in its price with all other prices constant is always negative, and producer's input demand curves are always downward sloping. This is one of the few cases in economics in which the sign of a derivative is unambiguous. There is only a substitution effect. There is no counterpart for the income effect of the consumer in the theory of the profit-maximizing producer.

Dividing both sides of the first equation of (3-21) by dr_2 and letting $dr_1 = dp = 0$,

$$\frac{\partial x_1}{\partial r_2} = -\frac{pf_{12}}{\mathbf{H}}$$

This derivative will have a sign the opposite of the second cross partial f_{12}. In most cases considered by economists an increase in the quantity of one input will increase the marginal product of the other; that is, $f_{12} > 0$. Therefore, an increase in one input price normally will reduce the usage of the other input.

3-4 COST FUNCTIONS

The economist frequently assumes that the problem of optimum input combinations has been solved and conducts his analysis of the firm in terms of its revenues and costs expressed as functions of output. The problem of the entrepreneur is then to select an output at which his profits are maximized.

SHORT-RUN COST FUNCTIONS

Cost functions can be derived from the information contained in Secs. 3-1 and 3-2.† Consider the system of equations consisting of the production function (3-1), the cost equation (3-11), and the expansion path function (3-16):

$$q = f(x_1,x_2)$$
$$C = r_1x_1 + r_2x_2 + b$$
$$0 = g(x_1,x_2)$$

Assume that this system of three equations in four variables can be reduced to a single equation in which cost is stated as an explicit function of the level of output plus the cost of the fixed inputs:

$$C = \phi(q) + b \tag{3-22}$$

The cost of the fixed inputs, *the fixed cost*, must be paid regardless of how much the firm produces, or whether it produces at all. The cost function gives the minimum cost of producing each output and is derived on the assumption that the entrepreneur acts rationally. A cost-output combination for (3-22) can be obtained as follows: (1) select a point on the expansion path, (2) substitute the corresponding values of the input levels into the production function to obtain the corresponding output level, (3) multiply the input levels by the fixed input prices to obtain the total variable cost for this output level, and (4) add the fixed cost.

A number of special cost relations which are also functions of the level of output can be derived from (3-22). Average total (ATC), average variable (AVC), and average fixed (AFC) costs are defined as the respective total, variable, and fixed costs divided by the level of output:

$$\text{ATC} = \frac{\phi(q) + b}{q} \qquad \text{AVC} = \frac{\phi(q)}{q} \qquad \text{AFC} = \frac{b}{q}$$

ATC is the sum of AVC and AFC. Marginal cost (MC) is the derivative of total cost with respect to output:

$$\text{MC} = \frac{dC}{dq} = \phi'(q)$$

The derivatives of total and total variable cost are identical since the fixed-cost term vanishes upon differentiation.

Specific cost functions may assume many different shapes. One possibility which exhibits properties often assumed by economists is

† The term *cost function* is used to denote cost expressed as a function of output. The term *cost equation* is used to denote cost expressed in terms of input levels and input prices.

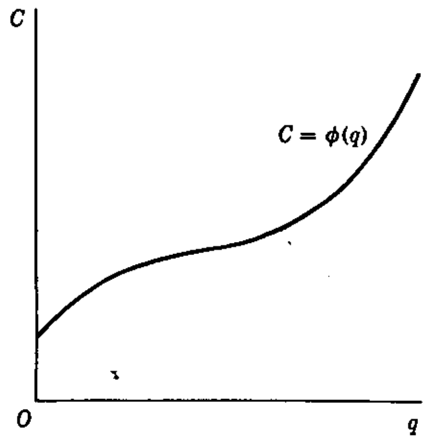

Fig. 3-6

depicted in Figs. 3-6 and 3-7. Total cost is a cubic function of output. ATC, AVC, and MC are all second-degree curves which first decline and then increase as output is expanded. MC reaches its minimum before ATC and AVC, and AVC reaches its minimum before ATC. The reader may verify that the MC curve passes through the minimum points of both the AVC and ATC curves.[1] The AFC curve is a rectangular hyperbola regardless of the shapes of the other cost curves; the fixed cost is spread over a larger number of units as output is expanded, and therefore AFC declines monotonically. The vertical distance between the ATC and AVC curves equals AFC and hence decreases as output is increased.

[1] Set the derivative of ATC (or AVC) equal to zero, and put the equation in a form which states the equality between ATC (or AVC) and MC (see Sec. A-2).

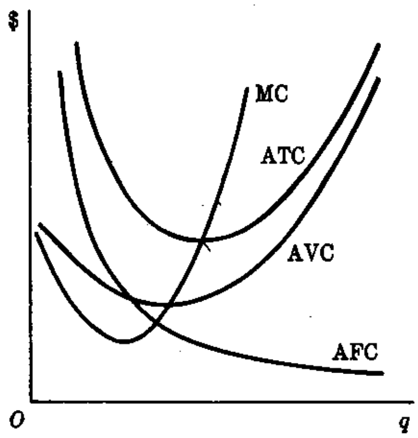

Fig. 3-7

The revenue of an entrepreneur who sells his output at a fixed price is also a function of the level of his output. Therefore, his profit is a function of the level of his output:

$$\pi = pq - \phi(q) - b$$

To maximize profit, set its derivative with respect to q equal to zero:

$$\frac{d\pi}{dq} = p - \phi'(q) = 0$$

Moving the MC to the right,

$$p = \phi'(q) \tag{3-23}$$

The entrepreneur must equate his MC with the constant selling price of his output. He can increase his profit by expanding his output if the addition to his revenue (p) of selling another unit exceeds the addition to his cost (MC).

The second-order condition for profit maximization requires that

$$\frac{d^2\pi}{dq^2} = -\frac{d^2C}{dq^2} < 0$$

or multiplying by -1 and reversing the inequality,

$$\frac{d^2C}{dq^2} > 0$$

MC must be increasing at the profit-maximizing output. If MC were decreasing, the equality of price and MC would give a point of minimum profit.

The level of the entrepreneur's fixed cost (b) generally has no effect upon his optimizing decisions during a short-run period. It must be paid regardless of the level of his output and merely adds a constant term to his profit equation. The fixed-cost term vanishes upon differentiation, and MC is independent of its level. Since the first- and second-order conditions for profit maximization are expressed in terms of MC, the equilibrium output level is unaffected by the level of fixed cost. The mathematical analyses of optimization in the present section and in Sec. 3-2 can generally be carried out on the basis of variable cost alone.

The level of fixed cost has significance for the analysis of short-run profit maximization in one special case. The entrepreneur has an option not recognized by the calculus. He can discontinue production and accept a loss equal to his fixed cost. This option is optimal if his maximum profit from the production of a positive output level is a negative

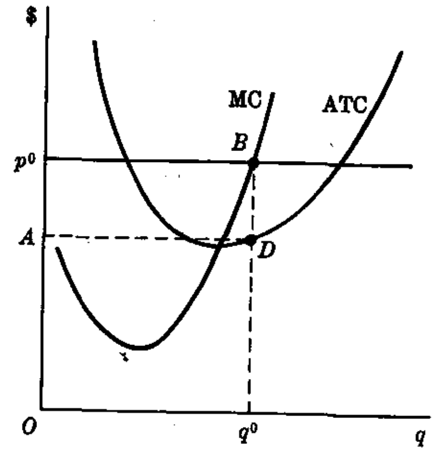

Fig. 3-8

amount (a loss) with a greater absolute value than the level of his fixed cost. The entrepreneur need never lose more than the amount of his fixed cost. He will produce at a loss in the short run if his loss is less than the amount of his fixed cost, i.e., if revenue exceeds total variable cost, and he is able to recover a portion of his outlay on the fixed inputs.

A geometric description of profit maximization is contained in Fig. 3-8. The optimum output (q^0) is given by the intersection of a horizontal line drawn at the level of the going price (p^0) and the rising portion of the MC curve. The entrepreneur's revenue is given by the area of the rectangle Op^0Bq^0, total cost by $OADq^0$, and profit by Ap^0BD.

As an example consider the cubic total cost function

$$C = 0.04q^3 - 0.9q^2 + 10q + 5 \tag{3-24}$$

Assume that the price of q is 4 dollars per unit. Equating MC and price,

$$0.12q^2 - 1.8q + 10 = 4$$

which yields the quadratic equation

$$q^2 - 15q + 50 = 0$$

the roots of which are $q = 5$ and $q = 10$. Two different outputs satisfy the first-order condition for profit maximization, and the rate of change of MC must be calculated for both. The rate of change of MC:

$$\frac{d^2C}{dq^2} = 0.24q - 1.8$$

is negative for $q = 5$ and positive for $q = 10$. An output of 10 units yields a maximum profit, and an output of 5 a minimum. Profit at 10 units, however, is negative:

$$\begin{aligned} \pi &= 4q - (0.04q^3 - 0.9q^2 + 10q + 5) \\ &= 40 - 55 = -15 \end{aligned}$$

The entrepreneur's ATC curve lies above the price line for every output, and his maximum profit is a loss of 15 dollars. He should discontinue production, since his fixed cost (5 dollars) is less than the smallest loss which he can incur from a positive output level.

LONG-RUN COST FUNCTIONS

Let the levels of the entrepreneur's fixed inputs be represented by a parameter k, which gives the "size of his plant"—the greater the value of k, the greater the size of his plant. The entrepreneur's short-run problems concern the optimal utilization of a plant of given size. In the long run he is free to vary k and select a plant of optimum size. The shapes of the entrepreneur's production and cost functions depend upon his plant size. These are uniquely determined in the short run. In the long run he can choose between cost and production functions with different shapes. The number of his alternatives equals the number of different values which k may assume. Once he has selected the shapes of these functions, i.e., selected a value for k, he is faced with the conventional short-run optimization problems.

As an illustration, consider the case of an entrepreneur operating a grocery store. The "size of his plant" is given by the number of square feet of selling space which he possesses. Assume that the only possible alternatives are 5,000, 10,000, and 20,000 square feet and that he currently possesses 10,000. His present plant size is the result of a long-run decision made in the past. When the time comes for the replacement of his store, he will be able to select his plant size anew. If conditions have not changed since his last decision, he will again select 10,000 square feet. If the store has been crowded and he anticipates a long-run increase in sales, he will build 20,000 square feet. Under other conditions he may build a store with 5,000 square feet. Once he has built a new store, his problems concern the optimal utilization of a selling area of given size.

Assume that k is continuously variable and introduce it explicitly into the production function, cost equation, and expansion path function:

$$\begin{aligned} q &= f(x_1,x_2,k) \\ C &= r_1x_1 + r_2x_2 + \psi(k) \\ 0 &= g(x_1,x_2,k) \end{aligned}$$

Fixed cost is an increasing function of plant size: $\psi'(k) > 0$. The shapes of the families of isoquants and isocost lines and the shape of the expansion path depend upon the value assigned to the parameter k. Generally, two of the above relations may be utilized to eliminate x_1 and x_2, and total cost may be expressed as a function of output level and plant size:

$$C = \phi(q,k) + \psi(k) \tag{3-25}$$

which describes a family of total cost curves generated by assigning different values to the parameter k. As soon as plant size is assigned a particular value $k = k^{(0)}$, (3-25) is equivalent to the particular total cost function given by (3-22), and the short-run analysis is applicable.

The entrepreneur's long-run total cost function gives the minimum cost of producing each output level if he is free to vary the size of his plant. For a given output level he computes the total cost for each possible plant size and selects the plant size for which total cost is a minimum. Figure 3-9 contains the total cost curves corresponding to three different plant sizes. The entrepreneur can produce the output OR in any of the plants. His total cost would be RS for plant size $k^{(1)}$, RT for $k^{(2)}$, and RU for $k^{(3)}$. The plant size $k^{(1)}$ gives the minimum production cost for the output OR. Therefore, the point S lies on the long-run total cost curve. This process is repeated for every output level, and the long-run total cost curve is defined as the locus of the minimum-cost points.

The long-run cost curve is the envelope of the short-run curves; it touches each and intersects none. Write the equation for the family of short-run cost functions (3-25) in implicit form:

$$C - \phi(q,k) - \psi(k) = G(C,q,k) = 0 \tag{3-26}$$

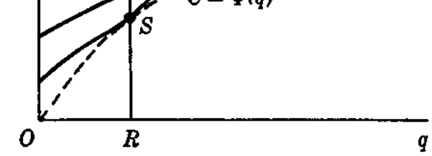

Fig. 3-9

and set the partial derivative of (3-26) with respect to k equal to zero:

$$G_k(C,q,k) = 0 \tag{3-27}$$

The equation of the envelope curve (the long-run cost curve) is obtained by eliminating k from (3-26) and (3-27) and solving for C as a function of q (see Sec. A-3):

$$C = \Phi(q)$$

Long-run total cost is a function of output level, given the condition that each output level is produced in a plant of optimum size. The long-run cost curve is not something apart from the short-run cost curves. It is constructed from points on the short-run curves. Since k is assumed continuously variable, the long-run cost curve (see Fig. 3-9) has one and only one point in common with each of the infinite number of short-run cost curves.

Since AC equals total cost divided by output level, the minimum AC of producing a particular output level is attained at the same plant size as the minimum total cost of producing that output level. The long-run AC curve can be derived by dividing long-run total cost by output level, or by constructing the envelope of the short-run AC curves. The two constructions are equivalent.

The long-run MC curve can be constructed by plotting the derivative of long-run total cost with respect to output level, or can be derived from the short-run MC curves. However, the long-run MC curve is not the envelope of the short-run MC curves. Short-run MC equals the rate of change of short-run variable cost with respect to output level; long-run MC is the rate of change of total cost assuming that all costs are variable. Therefore, portions of short-run MC curves may lie below the long-run MC curve. The long-run MC curve may be defined as the locus of those points on the short-run MC curves which correspond to the optimum plant size for each output.[1] The equivalence of the two methods of deriving the long-run MC curve is obvious in Fig. 3-9. The long-run total cost curve is tangent to each short-run curve at the output for which the short-run curve in question represents optimum plant size. Since the MCs are defined as the slopes of the tangents of these curves, the long-run and short-run MCs are equal at such points.

Assume that the entrepreneur desires to construct a plant for use during a number of short-run periods and that he expects to receive the same price for his product during each of the short-run periods. Since

[1] It *is not correct* to construct the long-run MC curve by selecting the points on the short-run MC curves which correspond to the optimum output (i.e., point of minimum AC) for each plant size.

conditions remain unchanged from one period to the next, he will produce the same level of output in each period. His profit during one of the periods is the difference between his revenue and cost with plant size variable:

$$\pi = pq - \Phi(q)$$

Set the derivative of π equal to zero:

$$\frac{d\pi}{dq} = p - \Phi'(q) = 0$$

or

$$p = \Phi'(q)$$

Profits are maximized by equating long-run MC to price, if long-run MC is increasing (second-order condition). Once the optimum output is determined, the optimum value for k can be determined from (3-26) and (3-27).

Consider the family of short-run cost curves generated by

$$C = 0.04q^3 - 0.9q^2 + (11 - k)q + 5k^2 \tag{3-28}$$

For the plant size $k = 1$, the short-run cost curve is the one given by (3-24). Setting the partial derivative of the implicit form of (3-28) with respect to k equal to zero,

$$G_k(C,q,k) = -q + 10k = 0$$

which has the solution $k = 0.1q$. Substituting into (3-28) gives the long-run cost function:

$$\begin{aligned} C &= 0.04q^3 - 0.9q^2 + (11 - 0.1q)q + 5(0.1q)^2 \\ &= 0.04q^3 - 0.95q^2 + 11q \end{aligned}$$

Long-run fixed cost equals zero.

Let the price of the entrepreneur's product be 4 dollars, as in the example for a short-run cost function. Setting price equal to long-run MC,

$$4 = 0.12q^2 - 1.9q + 11$$

which yields the quadratic equation

$$0.12q^2 - 1.9q + 7 = 0$$

with the roots $q = 5.83$ and $q = 10$. Profit is maximized at an output of 10 units. Utilizing the relation $k = 0.1q$, the optimum-size plant is given by $k = 1$. The entrepreneur's profit per short-run period is

$$\pi = pq - (0.04q^3 - 0.95q^2 + 11q) = 40 - 55 = -15$$

As in the last example, the maximum operating profit is a loss of 15 dollars. In the long run the entrepreneur is unable to earn a positive profit and will not construct a plant of any size.

The situation is quite different if price is increased to 6 dollars. Setting long-run MC equal to price yields the quadratic equation

$$0.12q^2 - 1.9q + 5 = 0$$

with the roots $q = 3.3$ and $q = 12.5$. Profit is maximized at an output of 12.5 units. Profit is positive for this plant size:

$$\pi = 75 - 67.1875 = 7.8125$$

and the entrepreneur will construct a plant of the optimum size ($k = 1.25$).

3-5 HOMOGENEOUS PRODUCTION FUNCTIONS

"Returns to scale" describes the output response to a proportionate increase of all inputs. If output increases by the same proportion, returns to scale are constant for the range of input combinations under consideration. They are increasing if output increases by a greater proportion and decreasing if it increases by a smaller proportion. A single production function may exhibit all three types of returns. Some economists assume that production functions exhibit increasing returns for small amounts of the inputs, then pass through a stage of constant returns, and finally exhibit decreasing returns to scale as the quantities of the inputs become greater and greater.

PROPERTIES

Returns to scale are easily defined for homogeneous production functions. A production function is homogeneous of degree k if

$$f(tx_1,tx_2) = t^k f(x_1,x_2) \tag{3-29}$$

where k is a constant and t is any positive real number. If both inputs are increased by the factor t, output is increased by the factor t^k. Returns to scale are increasing if $k > 1$, constant if $k = 1$, and decreasing if $k < 1$. Homogeneity of degree one is most commonly assumed for production functions.[1]

The partial derivatives of a function homogeneous of degree k are homogeneous of degree $k - 1$. Differentiate (3-29) partially with

[1] A function which is homogeneous of degree one is said to be linearly homogeneous. This, of course, does not imply that the production function is linear.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 7
Page 1 of 1

Refer to the Watkins Testimony, page 75, lines 15–22. Provide examples where utilities and regulatory bodies are not increasing fixed monthly fees.

RESPONSE:

Please refer to the following recent examples:

> Avista Utilities – Electric Operations, Washington Utilities & Transportation Commission, Docket No. UE-200900;
>
> Avista Utilities – Natural Gas Operations, Washington Utilities & Transportation Commission, Docket No. UG-200901;
>
> Washington Gas Light Company, Virginia State Corporation Commission, Case No. PUR-2018-00080;
>
> Delmarva Power & Light, Maryland Public Service Commission, Case No. 9630. Note: the Commission authorized a *de minimis* increase to the residential fixed monthly customer charge of $0.21 from $8.30 to $8.51 per month;
>
> Puget Sound Energy – Electric Operations, Washington Utilities & Transportation Commission, Docket No. UE-19-00529; and,
>
> Puget Sound Energy – Gas Operations, Washington Utilities & Transportation Commission, Docket No. UE-19-00530.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 8
Page 1 of 1

Refer to the Watkins Testimony, page 76, lines 11–18. Here, Mr. Watkins provides an analogy of the competitive pricing structure with product pipelines.

a. Explain how reliability is priced within these product pipelines.
b. Explain whether the cost of reliability should be included in the fixed or variable rate components.

RESPONSE:

a. First, it should be noted that products pipeline by the very nature tend to be very reliable. With respect to the competitive pricing of products pipeline services, to the extent a shipper may not be able to move his product through a product pipeline due to an outage, that shipper will pay nothing since the shipper is not moving any products through the pipeline. In other words, the product pipeline is at risk for reliability.

b. Please refer to response to a. above. In this regard, please refer again to Mr. Watkins' testimony, page 76, lines 14 through 18.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 9
Page 1 of 1

Refer to the Watkins Testimony, page 78, lines 10–12. Mr. Watkins states that a rate structure, which is heavily based on a fixed monthly customer charge, sends a price signal to consumers to use more energy.

a. Explain whether Mr. Watkins agrees or disagrees that elasticity measures the amount of the response to a price change.
b. Provide the short-run and long-run price elasticities of demand for electricity.
c. Explain what Mr. Watkins defines as "heavily based."

RESPONSE:

a. Agree.
b. There have been numerous studies concerning the short-run and long-run price elasticity of demand for electricity. These elasticities vary considerably across customer classes and types of usage. However, with respect to the residential price elasticity of demand, both the short-run and long-run elasticities tend to be less than 1; i.e., relatively inelastic.
c. A residential rate structure that collects, for example, 10% of its base rate revenue requirement from fixed customer charges would not be considered "heavily based" on fixed charges. A residential class rate structure that collects, for example, 50% or more of its base rate revenue requirement from fixed charges would be considered "heavily based" on fixed charges. Mr. Watkins has not established a bright line rule in this regard.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 10
Page 1 of 1

Refer to the Watkins Testimony, page 83, lines 13–16. Explain how corporate overhead and other indirect business costs are correlated with usage.

RESPONSE:

Mr. Watkins does not claim that corporate overhead and other indirect business costs are correlated with usage. Rather, and as is clear from Mr. Watkins' direct testimony, overhead is a cost of doing business and because customers do not subscribe to KU's service to simply be connected, they are most appropriately reflected in volumetric energy charges. In this way, customers who use more of the Company's services (energy), and receive more benefits, pay more than customers that do not. This is consistent with economic theory and practice within competitive markets.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 11
Page 1 of 1

Refer to the Watkins Testimony, page 83, lines 27–29. Explain how uncollectible expenses are correlated to usage.

RESPONSE:

Uncollectible expenses are a function of revenue which is correlated to usage.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS, STEPHEN J. BARON and COUNSEL as to Objection

QUESTION No. 12
Page 1 of

State whether Mr. Watkins believes that net metering customers pay their full share of customer costs and whether Mr. Watkins believes that customers with distribution generation benefit from intra-class subsidies.

RESPONSE:

Objection. Mr. Watkins did not proffer any testimony in the above-referenced matters regarding the subject matter of this question. However, the Attorney General has co-sponsored with KIUC that portion of the testimony of Mr. Stephen J. Baron that addresses this subject matter. Accordingly, Mr. Baron will respond to this question below:

Mr. Baron has not performed any specific analysis of whether net metering customers are paying their full share of customer costs. Notwithstanding this, Mr. Baron believes that, to the extent that net metering residential customers are able to offset a portion of their own usage with self-generation, and that some customer costs may be recovered in the volumetric energy charge of the residential rate, it is likely that net metering customers would not be paying their full share of customer costs. If 100% of customer costs are recovered in the basic service charge, then it is likely that the self-generation would not impact the recovery of a net metering customer's customer costs."

With respect to the second part of the question regarding intra-class subsidies, again, Mr. Baron has not performed an analysis to determine whether net metering customers are receiving any subsidies from other customers in their rate class. Notwithstanding this, Mr. Baron does believe that it is likely that net metering customers are receiving intra-class subsidies.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 13
Page 1 of 1

Refer to the Watkins Testimony, page 101. Provide the rates for all customer classes that would result from the proposed allocations in Table 38, assuming that the entire amount of LG&E's proposed gas rate increase were approved by the Commission. Provide this in Excel spreadsheet format with all with all formulas, columns, and rows unprotected and fully accessible.

RESPONSE:

Mr. Watkins has not evaluated or even reviewed the individual rate elements for every LG&E natural gas rate schedule; e.g., customer charges, volumetric charges, minimum bill obligations, balancing charges, etc. Furthermore, Mr. Watkins is not aware of whether other parties propose alternative rate designs for non-residential customers. Therefore, Mr. Watkins offers no opinion as to how specific rate elements should be designed for non-residential customers in that his testimony relates to the distribution of any authorized revenue across classes. With regard to the residential class, please see attachment: Attachment to PSC Question 13.xls.

WITNESS / RESPONDENT RESPONSIBLE:
GLENN WATKINS

QUESTION No. 14
Page 1 of 1

Explain whether Mr. Watkins agrees or disagrees whether the 6 CP COSS approach is a more reasonable approach to measuring cost of service as compared to the LOLP COSS.

RESPONSE:

Disagree. Please refer to Mr. Watkins' testimony, page 13, lines 7 through 22 regarding the reasonableness of the 6-CP method wherein Mr. Watkins is of the opinion that the 6-CP method is exceptionally inappropriate for KU and LG&E for the reasons set forth throughout his testimony on pages 5 through 42. Furthermore, and as explained at length in Mr. Watkins' testimony, the LOLP method for allocating KU's and LG&E's generation plant is extremely inappropriate, and further, Mr. Seelye's LOLP analysis is so flawed that it cannot be relied upon in evaluating class revenue responsibility.

WITNESS / RESPONDENT RESPONSIBLE:
PAUL ALVAREZ

QUESTION No. 15
Page 1 of 1

Refer to the Direct Testimony of Paul J. Alvarez (Alvarez Testimony), page 13, lines 2–4. Mr. Alvarez states that that the projected budget for Volt Var Optimization (VVO) is inadequate. Provide what Mr. Alvarez believes to be an adequate budget as well as support for these estimates.

RESPONSE:

Mr. Alvarez believes a budget of approximately $100,000 per circuit is appropriate to maximize the conservation voltage reduction potential of VVO. Some circuits will cost more, some less. The approximate budget includes as follows:

- 1 voltage regulator per circuit at a capital cost of approximately $50,000-$60,000 each;
- 2-4 capacitors per circuit at a capital cost of approximately $10,000-$20,000 each

WITNESS / RESPONDENT RESPONSIBLE:
PAUL ALVAREZ

QUESTION No. 16
Page 1 of 2

Regarding the Universal Peak Time Rebate Program, provide support that the costs associated with maintaining such a program such as labor, record keeping, and billing will be less than the benefits of such a program.

RESPONSE:

As with most utility programs, a universal Peak-Time Rebate program will require both start-up costs and ongoing costs. Based on his experience developing, launching, and promoting other types of rate programs for Xcel Energy, Mr. Alvarez believes the following up-front and ongoing cost estimates represent reasonable costs for a universal Peak-Time Rebate program:

Cost	Amount	Description
Up-Front Costs		
AMI data interface (IT)	$0.025	Develop an application to retrieve the customer-specific AMI usage data needed to create baselines and supply the PTR algorithm with customer-specific usage data from each event as called.
Algorithm development (Economist)	0.050	Develop an algorithm which establishes customer-specific baselines, and which identifies and quantifies statistically significant usage reductions during events when called
Billing system enhancements (IT)	0.100	Develop a way to take algorithm outputs (customer-specific usage reductions during events), multiply them by the agreed upon rebate, and place a credit on appropriate customers' accounts/bills.
Launch promotion & training (Marketing)	0.500	Social/Mass/Outdoor media creative and purchases; web page; bill stuffers; call center training
Feedback algorithm development	0.025	Develop an algorithm which notifies customers who have earned a rebate via e-mail or text.
Total Up-Front Costs	**$0.800**	**Million**
Ongoing Costs (annual)		
Rebates Awarded	$15.320	383 MW x 5 hrs x $1/kWh x 8 summer events
Program Mgr (with benefits)	0.180	$120,000 salary + 50% benefits
Algorithm enhancements	0.010	$10,000 for econometric work
Billing system enhancements	0.010	$10,000 for IT work
Program Promotions	0.500	Social/Mass/Outdoor media creative and purchases; web page; bill stuffers; call center training
Total Annual Costs	**$16.020**	**Million**

Regarding benefits, research indicates that customers with an available peak-time rebate reduced their peak demand by 17.8% at a minimum.[1] Applying a 25% reduction to be conservative, and assuming that residential customers make up 44.1% of KU/LG&E peak demand,[2] Mr. Alvarez believes a utility with a coincident summer peak of KU/LG&E's size (about 6,500 MW), assuming competent and consistent promotion, could eventually reduce the peak by 5.9%[3] with a universal peak-time rebate program, or by 383 MW. If KU/LG&E were to sell this capacity in the PJM market, or to avoid purchases from the PJM market, the value of this capacity at $130 per MW Day[4] ($47,450 per MW Year) would be $18.173 million (383 MW x $47,450 per MW Year). The $18.173 million figure includes only the generation capacity avoided cost benefit. Other benefits, including avoided transmission and distribution costs, though more difficult to quantify, would also be available. Avoided energy costs would also be available.

A summary of benefits and costs for an average year (5.9%, or 383 MW, reduced from peak) might therefore look something like this ($ in millions):

Benefits (not including avoided T&D capacity costs or avoided energy costs)	$18.173
Program Costs (not including $800,000 in up-front costs)	16.020
Benefits available to non-participants annually*	**$2.153**

*Avoided cost benefits in excess of program costs, if any, could be addressed in a number of ways. One idea is to credit any excess benefit against fuel costs, thereby providing benefits to all customers. Alternatively, excess benefits could be added to a reserve as protection against overpayments in future years, or it could be added to a fund to help low-income consumers pay electric bills. Increases in rebate amounts are another potential course of action if avoided cost benefits prove to be consistently higher than program costs.

[1] See attachment, "Dynamic Pricing of Electricity in the mid-Atlantic Region: Econometric Results From the Baltimore Gas and Electric Company Experiment," © Journal of Regulatory Economics, 22 June 2011 40:82–109, Ahmad Faruqui, Sanem Sergici. Page 103. The Attorney General has obtained permission from the Journal of Regulatory Economics to include this article as an attachment to this response.
[2] Companies' response to OAG DR 1-115 (residential demand 2,763 of 6,271 MW on 8-19-2019).
[3] Utilizing the 17.8% figure identified in the article referenced in footnote 1, above, when multiplied by 75% conservatism adjustment then multiplied by 44.1% residential contribution to peak = 5.88735%.
[4] The clearing price for Duke Energy Ohio/Kentucky capacity in the 2020-2021 auction was $130 per MW Day.

J Regul Econ (2011) 40:82–109
DOI 10.1007/s11149-011-9152-5

ORIGINAL ARTICLE

Dynamic pricing of electricity in the mid-Atlantic region: econometric results from the Baltimore gas and electric company experiment

Ahmad Faruqui · **Sanem Sergici**

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Abstract The Baltimore Gas and Electric Company (BGE) undertook a dynamic pricing experiment to test customer price responsiveness to different dynamic pricing options. The pilot ran during the summers of 2008 and 2009 and was called the *Smart Energy Pricing* (SEP) *Pilot*. In 2008, it tested two types of dynamic pricing tariffs: critical peak pricing (CPP) and peak time rebate (PTR) tariffs. About a thousand customers were randomly placed on these tariffs and some of them were paired with one of two enabling technologies, a device known as the Energy Orb and a switch for cycling central air conditioners. The usage of a randomly chosen control group of customers was also monitored during the same time period. In 2009, BGE repeated the pilot program with the same customers who participated in the 2008 pilot, but this time it only tested the PTR tariff. In this paper, we estimate a constant elasticity of substitution (CES) model on the SEP pilot's hourly consumption, pricing and weather data. We derive substitution and daily price elasticities and predictive equations for estimating the magnitude of demand response under a variety of dynamic prices. We also test for the persistence of impacts across the two summers. In addition, we report average peak demand reduction for each of the treatment cells in the SEP pilot and compare the findings with those reported from earlier pilots. These results show conclusively that it is possible to incentivize customers to reduce their peak period loads using price signals. More importantly, these reductions do not wear off when the pricing plans are implemented over two consecutive summers. Our analyses reveal that SEP participants reduced their peak usages in the range of 18 to 33% in the first summer of the SEP pilot and continued these reductions in the second summer.

A. Faruqui (✉)
San Francisco, CA, USA
e-mail: ahmad.faruqui@brattle.com

S. Sergici
Cambridge, MA, USA

Keywords Dynamic Pricing · Experiment · Elasticity of substitution · CPP · Demand model · Rate design

JEL Classification L94 · D04 · D12

1 Introduction

Over the past decade, a variety of pilots featuring several different dynamic pricing rate designs have been carried out in a variety of geographical settings that straddle three continents—North America, Europe and Australia. This paper addresses the findings from a new pilot that was carried out in the Mid-Atlantic region of the United States.

Although there has been a considerable amount of research on quantifying the load impacts of dynamic pricing, most of this research did not make its way into the academic literature and was generally published as company reports or white papers. Here we will review a few studies (mostly involving time-of-use rates) that are indicative of the formal research on the topic.

Caves and Christensen (1984) used the data from five residential Time-of-Use (TOU) pricing experiments in the U.S. and estimated a consumer demand model for each of the experiments. They tested the hypothesis that the substitution elasticities are identical across experiments and they found them to be identical. Aubin et al. (1995) examined the impacts of Electricite de France's (EdF) Tempo tariff which divided the year into three types of days and each day into two periods. Each day type had a different TOU tariff and customers learnt the day types at the end of the preceding day. By using Frisch demand functions and applying Kalman filters to compute the log-likelihood function with each customer's history of electricity consumption, they found that the Tempo tariff improved the welfare of a majority of consumers participating in the experiment. Braithwait (2000) investigated the customer price responsiveness to an innovative residential time-of-use rate program.[1] The study found that the customers facing the TOU rates shifted substantial load from both peak and shoulder periods to the low priced off-peak periods. Elasticities of substitution were estimated using the constant elasticity of substitution (CES) and Generalized Leontief models and ranged between 0.06 and 0.41. Tom et al. (2005) estimated hourly own and cross price elasticities for industrial customers on Duke Power optional real-time rates. Using the Generalized McFadden model, they find that as customers gain experience with hourly pricing, they show larger load reductions during higher priced hours.

One of the most comprehensive pricing pilots of the last decade was California Statewide Pricing Pilot (SPP) implemented between 2003 and 2005 (Charles River Associates 2005). The SPP involved about 2,500 participants including residential and small-to-medium commercial and industrial (C&I) customers. It tested two rate structures. The first one was a TOU-only rate where the peak price was twice the value of the off-peak price. The second one was a critical peak pricing (CPP) rate where the

[1] In general TOU programs are not classified as dynamic and dispatchable programs. However, the program examined by Braithwait involved a dispatchable critical price component for a limited number of high-priced hours in the summer, in addition to the TOU rates that applied during the remaining hours.

peak price during 15 “critical” days was roughly five times greater than the off-peak price; on non-critical days, a TOU rate applied. The results showed that the customers responded to both rates, more so to the CPP rates than to the TOU rates (Faruqui and George 2002). The results of the SPP pilot and 14 other pricing pilots that were carried out in the U.S. and elsewhere are reviewed in Faruqui and Sergici (2010).

1.1 A new experiment in the mid-Atlantic region

Baltimore Gas and Electric Company (BGE) carried out a dynamic pricing pilot program, the Smart Energy Pricing (SEP) Pilot, with a thousand customers in the summer of 2008. The goal of the pilot was to gather territory-specific evidence on price-induced demand response. Several other dynamic pricing pilots had published their findings prior to the execution of the SEP pilot (Faruqui and Sergici 2010). However, they had been carried out in different geographies and there was a concern that differences in socio-demographic and climatic conditions would impair the transferability of findings (Faruqui et al. 2009). BGE wanted to have precise results on customer behavior that could be used carry out a cost-benefit analysis of a proposal to deploy advanced metering infrastructure in its service territory.

In 2008, the SEP Pilot featured over a thousand residential treatment customers and 350 control customers. It ran from June 1, 2008 through September 30, 2008. Over a thousand customers were placed on one of two types of dynamic pricing rates and some of these customers were paired with one of two technologies, a glass lamp known as the Energy Orb and a switch for cycling central air conditioners. Hourly usage was recorded for customers in both groups during the pilot to determine if the treatment group used less during the more expensive periods. In addition, to assess for any pre-existing difference in the groups, hourly usage was also recorded during a pre-pilot phase. Econometrically, a difference-in-differences estimation procedure was applied to an unbalanced panel for estimating the treatment effects.

The SEP 2008 Pilot tested two types of dynamic pricing tariffs: a dynamic peak pricing (DPP) tariff, where the price during the peak period on a small number of critical peak days was raised by a factor of about nine compared to the standard rate and a peak time rebate (PTR) rider where customers were given an opportunity to earn a rebate during the peak period on critical peak days by lowering usage. Two variations of the PTR were tested: one featured a relatively low rebate amount and was termed PTRL and other featured a relatively high rebate amount and was termed PTRH. During critical days, the PTRL rate provided a rebate that was about nine times higher than the standard rate and the PTRH rate provided a rebate that was about 12.5 times greater than the standard rate. BGE’s standard rate is a flat, seasonal, volumetric rate that includes a fixed customer charge.

To address the issue of persistence of impacts, BGE extended the SEP Pilot program to the summer of 2009 but only with the PTR rate (for reasons that are explained later in the paper). The SEP 2009 ran from June 1, 2009 through September 30, 2009 and featured 912 residential customers, 734 of which were placed on the PTR rates. The remaining customers stayed on the standard rates and constituted the control group. All of the residential treatment customers in the SEP 2009 had also participated in the 2008 pilot but some of them had received the DPP rate treatment. The PTR rate tested in 2009 provided a rebate that was almost 10 times greater than the all-in standard rate.

BGE also recruited a group of small C&I customers in 2009 to find out whether small C&I customers respond to the dynamic prices and if so, how their responses compared to that of the residential customers. Although this is an interesting question, the results of the C&I group will not be discussed in this paper.

The SEP pilot was designed to test several empirical hypotheses that are crucial to the formation of pricing and metering policy not just in Maryland but throughout North America. The SEP pilot asked the following questions: (i) did customers exhibit similar price responsiveness to the DPP and PTR tariffs?; (ii) were the enabling technologies employed in the pilot effective in increasing customers' price responsiveness?; (iii) did customer price responsiveness (or price elasticity) vary with weather conditions?; (iv) did price responsiveness persist across the two summers?

Section 2 of this paper describes the experimental design of the SEP pilot during the summers of 2008 and 2009. Section 3 summarizes the data generated during the pilot that allowed the econometric work to be carried out; presents the demand model used in the study; and discusses the econometric approach to estimating the demand model. Section 4 summarizes the impact evaluation results and Sect. 5 concludes the paper.

2 SEP experimental design

2.1 Rate design

BGE tested three dynamic pricing structures in the SEP 2008 Pilot: a dynamic peak pricing (DPP) tariff, which is essentially a critical peak price (CPP) tariff that is combined with a TOU rate, and two peak time rebate (PTR) riders, one testing a low rebate level (PTRL) and the other testing a high rebate level (PTRH).

BGE's standard rate is a flat, seasonal, volumetric rate that includes a fixed customer charge. The average all-in rate for the residential BGE customers who were on the standard tariff was \$0.15/kW h during the SEP Pilot period and that is the rate that all customers in the control group paid during the pilot period regardless of their load profile.

In 2008, the SEP pilot's treatment group customers were subject to one of the three following dynamic rate designs:

1. *Dynamic Peak Pricing (DPP)*: Under the DPP rate design, the hours between 2 pm through 7 pm on non-holiday weekdays were designated as the peak period and all the remaining hours were designated as the off-peak period. On 12 critical peak days that were called on a day-ahead basis by BGE, the peak hours would become the critical peak hours where the price was raised *by a factor of about nine* compared to the standard rate. At the same time, to preserve revenue neutrality, the off-peak price was lowered by six cents per kW h. On non-critical weekdays, these treatment customers faced a standard two-period time-of-use (TOU) rate. On these days, the price during the peak hours was roughly equal to the standard rate but the off-peak price was lower, as noted above.
2. *Peak Time Rebate-Low (PTRL)*: Under the PTRL rate design, the SEP pilot participants were still subject to the standard BGE rates. However, on the 12 critical

peak days, between the hours of 2 pm and 7 pm, they had the opportunity to receive a rebate if they reduced their consumption below their typical usage during these hours. Participants received \$1.16/kWh of load reduction below their baseline usage, an amount which was almost nine times greater than the all-in standard rate.

3. *Peak Time Rebate-High (PTRH)*: Participants in this cell were provided a rebate of \$1.75/kWh of load reduction below their baseline usage, an amount which is almost 12.5 times greater than the all-in standard rate.

In 2009, the SEP only tested a PTR rate design. The PTR rate design provided a rebate of \$1.50, which is almost ten times greater than the all-in standard rate, for every kWh of load reduction below the customer's baseline usage.

2.2 Technology

The SEP Pilot program also tested the effectiveness of enabling technologies in facilitating the demand response when offered in conjunction with dynamic pricing rates. In order to be able to tell apart the impacts of the enabling technologies from that of the prices alone, each rate design was tested with and without the technology options.

In 2008, the SEP pilot tested the implications of two enabling technologies. One was the Energy Orb, a spherical glass lamp that changes color with changing electricity prices (the device was adopted from the Stock Orb). The other technology was a switch that was placed on the compressor of the central air conditioner (A/C) and which was intended to reduce peak demand.[2] Through the A/C switch, BGE cycled the air conditioners during the critical peak hours so that they were turned off half the time. In the SEP pilot, BGE did not test the A/C switch as a standalone technology since that test had been carried out in 2007 with another group of customers who were enrolled in the Peak Rewards program. In addition, BGE provided a subset of the SEP treatment customers with both with the Energy Orb and the A/C switch. The SEP 2008 Pilot involved three different pricing structures and two technologies that yielded eight program combinations (DPP with the Energy Orb technology was not tested in the pilot).

The SEP 2009 Pilot also tested two enabling technologies: an Energy Orb but the A/C switch was replaced with a smart thermostat that raised the set-point during the critical hours. This yielded four program cells for the residential customers in the SEP 2009 Pilot program. Table 1 presents the rate and technology combinations tested in the SEP 2008 and 2009 Pilots.

2.3 Sample design

The SEP 2008 Pilot featured 1,375 customers of which 1,021 customers were the program participants and constituted the treatment group while 354 customers constituted

[2] If the customers wanted to override an event day, they called the program operators to stop the control. They could either call before or midway through the control period. They could override up to two events each summer.

Table 1 Rate and technology combinations tested in the SEP 2008 and 2009 pilots

SEP	Rate design	Enabling technology	Abbreviation
2008	DPP	None	DPP
	DPP	Energy Orb and A/C switch	DPP_ET_ORB
	PTRL	None	PTRL
	PTRL	Energy Orb only	PTRL_ORB
	PTRL	Energy Orb and A/C switch	PTRL_ET_ORB
	PTRH	None	PTRH
	PTRH	Energy Orb only	PTRH_ORB
	PTRH	Energy Orb and A/C switch	PTRH_ET_ORB
2009	PTR	None	PTR
	PTR	Energy Orb Only	PTR_ORB
	PTR	Smart thermostat	PTR_ET
	PTR	Energy Orb and smart thermostat	PTR_ET_ORB

the control group. BGE identified a random sample of customers that represent the residential customer population and recruited the SEP Pilot participants through direct mailing and follow-up phone calls from this sample.

In the recruitment process, BGE first mailed information to the customers to notify them about the SEP and to invite them to join the pilot. Customers who received the mailings could contact BGE's hot line by email or telephone. BGE also used outbound calls to contact customers who did not respond. Ample information was provided in the mailing to clearly describe the pilot. It described the type of rate design and/or enabling technology to each customer who was invited to participate. The letter only discussed one specific rate group (*e.g.* PTR or DPP) and did not mention the other available group. BGE sequentially recruited treatment customers for different treatment groups. Customers were offered a one time appreciation payment of $150 (for DPP) or $100 (for PTR) upon their completion of all requirements of the programs.

BGE recruited the control group customers from the load research sample. It is important to note that the control group customers were not aware of their involvement in the SEP Pilot. These customers were intended to serve as a proxy for the behavior of the treatment group customers and to help define conditions in the "but-for" world.

The SEP 2009 pilot featured 912 residential customers. As of August 2009, 734 customers were on the PTR rates, while 178 remained on the standard rates and constituted the control group. All of the residential treatment customers in the 2009 pilot had also been included in the 2008 pilot but some of them were on DPP rates and some on PTR rates that year.

Table 2 shows the distribution of treatment and control customers into different program cells as of August of each year.

2.4 Customer communication

BGE called 12 critical peak days during each of the two summers. The pilot participants were notified of the critical peak days on a day-ahead basis through one or

Table 2 The SEP pilot sample design: number of customers by program cell

SEP	Group	Treatment group	Control group	Total
2008	DPP	148	–	148
	DPP_ET_ORB	111	–	111
	PTRL	126	–	126
	PTRL_ORB	141	–	141
	PTRL_ET_ORB	113	–	113
	PTRH	127	–	127
	PTRH_ORB	137	–	137
	PTRH_ET_ORB	118	–	118
	Total- SEP 2008	1,021	354	1,375
2009	PTR	268	–	268
	PTR_ORB	107	–	107
	PTR_ET_ORB	282	–	282
	PTR_ET	77	–	77
	Total-SEP 2009	734	178	912

more of the following 15 channels: telephone messages (up to five different numbers), e-mail communication (up to five different addresses), and SMS text messages (up to five different numbers). In addition, customers with the Energy Orb also received information through that channel.

3 Data and methodology

3.1 Data

BGE metered the *hourly usage* of the treatment and control group customers both before and during the pilot period. This data compilation yielded two datasets: SEP 2008 dataset that comprise 1,375 residential customers for the April–September 2008 period and SEP 2009 dataset that comprises of 912 residential customers for the April–August 2009 period[3]. Price series that enter into the estimation process are first converted to all-in prices so that they reflect transmission, distribution, generation, and other customer charges. There are four sets of prices that enter into estimation process in the SEP 2008:

1. *Standard all-in rates*: these rates are matched to the control group customers in the pre-treatment as well as in the treatment periods. They are also matched to the treatment customers in the pre-treatment period since the pilot rates are not yet in effect.

[3] SEP 2009 pilot continued through September 30, 2009, however as BGE did not call any critical days in September, the last month of our SEP 2009 dataset is August 2009.

2. *DPP all-in rates*: DPP rates are converted into all in rates and then matched to the DPP customers making sure that off-peak, peak, and critical peak prices correspond to the hours in the definition of the DPP program.
3. *PTRL all-in rates*: PTRL rates are converted into all-in rates and matched to the PTRL customers for the appropriate hours. It is important to note that we sum up the rebate component with the all-in standard rate to obtain the all-in PTRL rate. We conjecture that an additional kW h of consumption means foregoing the rebate amount, and therefore constitutes an opportunity cost for the customer.
4. *PTRH all-in rates*: PTRH rates are converted into all-in rates and matched to the PTRH customers for the appropriate hours. Just like the PTRL rates, we sum up the rebate component with the all-in standard rate to obtain the all-in PTRH rate.

Similar to the SEP 2008, we convert the SEP 2009 rates into all-in rates before we merge them into the load data. As there was only one rate tested in the SEP 2009 pilot program, there are two price series: standard all-in rates, and the PTR all-in rates. We also have two hourly weather variables in our 2008 and 2009 dataset: dry bulb temperature and dew point. These two variables are used to create a temperature-humidity index (THI) variable, which will be described later, that enter into our estimations.

Hourly load, price, and weather data for each of the customers in the sample formed an unbalanced panel and the basis for estimating the demand models.

3.2 Demand model

Our analytical methodology to evaluating the load impacts of the SEP Pilot is based on the application of econometrics and microeconomic theory to data collected in the SEP. We first specify electricity demand models that represent the electricity consumption behavior of the BGE customers. Second, we estimate and parameterize these models. Finally, we calculate the impact of the treatments that were deployed in the pilot as well as intermediate treatments that could be deployed in the post-pilot phase. We use demand models to estimate the demand response impacts, as opposed to alternative methods such as analysis of variance and covariance, in part because they allow for estimation of the price elasticities. This capability is vital to being able to estimate the impact of prices other than those used in the pilot.

We used the constant elasticity of substitution (CES) model to estimate customer demand curves for electricity by time period and also used the CES model to derive peak/off-peak substitution and daily price elasticities. This model merits some discussion. Data in electricity pricing studies that involve individual customers, whether experimental or otherwise, is limited to repeated observations of electricity consumption and prices by period. Thus, if the analyst wishes to estimate demand functions that are consistent with the theory of utility maximization, he or she is forced to assume a two-stage budgeting process on the consumer's part. Often, this means invoking the assumption of homothetic separability in consumer preferences which posits inter alia that the ratio of peak to off-peak consumption does not depend on the amount being spent on electricity. The CES model allows the elasticity of substitution to take on any value and it has been found to be well-suited to TOU pricing studies involving electricity since there is strong prior evidence suggesting that these elasticities are going to be small.

The CES model is superior to the Cobb-Douglas model which imposes a unitary elasticity of substitution. The Cobb-Douglas model is estimated by regressing the log of peak-period consumption on the log of peak and off-peak prices. To be consistent with the theory of utility maximization, cross-equation restrictions have to be imposed on the cross-price terms. In addition, the model forces the underlying elasticity of substitution to be one, which substantially exceeds the values that have been estimated in time-of-use pricing studies. As a practical matter, many analysts do not impose the cross-equations and estimate the demand equations by ordinary least squares (OLS), yielding ad hoc estimates of own-price and cross-price elasticities. One also has the choice of estimating flexible functional forms such as the Almost Ideal Demand System, the Trans-log, Generalized Leontief (Diewert), and Generalized McFadden (Fuss and McFadden 1978). However, this flexibility comes at the expense of ease of interpretation and computation. In addition, there is no guarantee that the flexible functional forms will globally satisfy the concavity conditions of utility maximization. The nature of the problem at hand and the policy making context generally determines the choice of functional form.

For a two-period rate structure, the CES model consists of two equations. The first equation models the ratio of the log of peak to off-peak quantities as a function of the ratio of the log of peak to off-peak prices and the second equation models average daily electricity consumption as a function of the daily price of electricity. The two equations constitute a system for predicting electricity consumption by time period where the first equation essentially predicts the changes in the load shape caused by changing peak to off-peak price ratios and the second equation predicts the changes in the level of daily electricity consumption caused by changing average daily electricity price. The necessary algebra is provided in the appendix to this paper.

3.3 Econometric estimation

We use a “fixed-effects” estimation routine to estimate this demand system. Fixed effects estimation uses a data transformation method that removes any unobserved time-invariant effect that has a potential impact on the dependent variable. By estimating a fixed effects model, we effectively control for all customer specific characteristics that don’t vary over time and isolate their impact on the dependent variable. Fixed-effects estimation routine controls for the unobserved time-invariant variables that are likely to impact the dependent variable. However, there are also several observed variables that may affect the level of the dependent variable and therefore need to be explicitly controlled for in the model. We discuss these variables and more generally the econometric specifications of the substitution and daily demand equations below.

To improve the efficiency of the estimators, the substitution and daily equations are estimated jointly using Zellner’s seemingly unrelated estimation procedure.

3.3.1 Substitution demand equation

As stated earlier, the substitution equation captures the ability of customers to substitute relatively inexpensive off-peak consumption for relative expensive peak consumption. It is true that the decision to substitute between peak and off-peak periods is mainly affected by the relative prices between these two periods. However, the relative weather conditions should also be factored in the analysis because the weather conditions drive the load as much as the prices do. Keeping everything else constant, the average peak load is greater than the average off-peak load on a hot summer day, because the average peak temperature is higher than the average off-peak temperature which leads to more cooling during the peak period. In the mid-Atlantic region, humidity augments the effect of temperature. In order to capture the impact of temperature and humidity on the electricity load, we create a variable called the "temperature-humidity index" (sometimes called the discomfort index). This variable is a weighted average of dry bulb temperature (air temperature shielded from moisture) and dew point temperature (a measure of relative humidity) and computed as follows:

$$\mathrm{THI} = 0.55 \times \text{Drybulb temperature} + 0.20 \times \text{Dewpoint temperature} + 17.5$$

The substitution equation takes the following functional form:

$$\begin{aligned}
\ln\left(\frac{Peak_kWh}{OffPeak_kWh}\right)_{it} &= \alpha_0 + \alpha_1 THI_DIFF_t \\
&+ \alpha_2 \ln\left(\frac{Peak_Price}{OffPeak_Price}\right)_{it} + \alpha_3 \ln\left(\frac{Peak_Price}{OffPeak_Price}\right)_{it} xTHI_DIFF_t \\
&+ \alpha_4 \ln\left(\frac{Peak_Price}{OffPeak_Price}\right)_{it} xORB_i + \alpha_5 \ln\left(\frac{Peak_Price}{OffPeak_Price}\right)_{it} xET_ORB_i \\
&+ \sum_{k=1}^{6} \delta_k (THI_DIFF_t x D_Month_k) + \alpha_6 D_TreatPeriod_t \\
&+ \alpha_7 D_TreatPeriod_t xTreatCustomer_i + \sum_{k=1}^{6} \beta_k D_Month_k + \sum_{k=1}^{12} \gamma_k D_CPP_k \\
&+ \alpha_8 D_WEEKEND_t + v_i + u_{it}
\end{aligned}$$

where:

$\ln\left(\frac{Peak\_kWh}{OffPeak\_kWh}\right)_{it}$: Logarithm of the ratio of peak to off-peak load for a given day

THI_DIFF_t : The difference between average peak and average off-peak THI.

$\ln\left(\frac{Peak\_Price}{OffPeak\_Price}\right)_{it}$: Logarithm of the ratio of peak to off-peak prices for a given day

$\ln\left(\frac{Peak\_Price}{OffPeak\_Price}\right)_{it} xTHI\_DIFF_t$: Interaction of ratio of peak to off-peak prices and THI_DIFF for a given day

$\ln\left(\frac{Peak\_Price}{OffPeak\_Price}\right)_{it} xORB_i$: Interaction of ratio of peak to off-peak prices and *ORB* for a given day.

ORB : is equal to 1 if the customer has an Energy Orb but no A/C Switch.

$\ln\left(\frac{Peak\_Price}{OffPeak\_Price}\right)_{it} xET\_ORB_i$: Interaction of ratio of peak to off-peak prices and ET_*ORB*

ET_*ORB*: is equal to 1 if the customer has an Energy Orb and A/C Switch.

$THI\_DIFF_t xD\_Month_k$: Interaction of *THI_DIFF* variable with monthly dummies.

$D\_TreatPeriod_t$: Dummy variable is equal to 1 when the period is June 2008 through September 30, 2008.

$D\_TreatPeriod_t xTreatCustomer_i$: Interaction of $D\_TreatPeriod_t$ with treatment customer dummy

$TreatCustomer_i$

$TreatCustomer_i$: is equal to 1 for the treatment customers.

D_Month_k : Dummy variable that is equal to 1 when the month is k.

D_CPP_k : Dummy variable that is equal to 1 on the kth *CPP* day.

$D\_WEEKEND_t$: Dummy variable that is equal to 1 on weekends.

v_i : Time invariant fixed effects for customers.

u_{it} : Normally distributed error term.

It is important to note that this equation is estimated using data on both treatment and control customers before and during the pilot period. This type of database allows one to isolate the true impact of the experiment by controlling for any potential biases due to (i) differences between control and treatment customers in the pre-treatment period (ii) any changes in the consumption behavior of the treatment customers between the pre-treatment and treatment periods that are not related to the treatment per se. These potential confounding factors are controlled for by introducing dummy variables pertaining to the customer type and the analysis period.

This equation is estimated to determine the substitution elasticity of the pilot customers. The *Substitution elasticity* indicates the percent change in the ratio of peak to off-peak consumption due to a one percent change in the ratio of peak to off-peak prices.[4] To test for the weather dependency of the substitution elasticity, we have included an interaction term between the price ratio and the weather term in the model specification. And to test for the differential effect of enabling technologies, we have introduced an interaction term between the price ratios and dummy variables for the enabling technologies. The estimation results for the substitution demand model are provided in Table 3.

[4] Sometimes the substation elasticity is presented as a positive number, since the consumption ratios are related to the inverse of the price ratios.

Table 3 Substitution and daily demand equations—SEP 2008

Substitution equation Dependent variable: ln(peak_kWh/offpeak_kWh)		Daily equation Dependent variable: ln(kWh)	
thi_diff	−0.012**	ln_thi	−0.816**
	(0.001)		(0.034)
thi_diff_may	0.008**	ln_thi_may	0.806**
	(0.001)		(0.033)
thi_diff_june	0.037**	ln_thi_june	4.077**
	(0.002)		(0.050)
thi_diff_july	0.047**	ln_thi_july	4.306**
	(0.002)		(0.070)
thi_diff_august	0.051**	ln_thi_august	3.708**
	(0.002)		(0.056)
thi_diff_september	0.029**	ln_thi_september	3.160**
	(0.001)		(0.043)
TreatPeriod	0.051**	TreatPeriod	−12.061**
	(0.016)		(0.235)
TreatCustomerxTreatPeriod	−0.042**	TreatCustomerxTreatPeriod	−0.025**
	(0.015)		(0.007)
ln_price_ratio	−0.056**	ln_price	0.577**
	(0.014)		(0.055)
ln_price_ratio_thi_diff	−0.006**	ln_price_ln_thi	−0.143**
	(0.002)		(0.013)
ln_price_ratio_orb	−0.040**	Weekend	0.046**
	(0.012)		(0.001)
ln_price_ratio_et_orb	−0.084**	April	3.259**
	(0.012)		(0.132)
Weekend	0.096**	June	−1.563**
	(0.005)		(0.287)
May	0.004	July	−2.518**
	(0.007)		(0.348)
June	0.078**	August	0.000
	(0.012)		(0.000)
July	0.084**	September	2.293**
	(0.012)		(0.264)
August	0.000	cpp_day_1	0.014
	(0.000)		(0.008)
September	0.029**	cpp_day_2	0.029**
	(0.010)		(0.008)
cpp_day_1	0.067**	cpp_day_3	0.036**
	(0.015)		(0.009)
cpp_day_2	0.027	cpp_day_4	0.019

Table 3 continued

Substitution equation Dependent variable: ln(peak_kWh/offpeak_kWh)		Daily equation Dependent variable: ln(kWh)	
	(0.016)		(0.010)
cpp_day_3	−0.032*	cpp_day_5	0.020*
	(0.014)		(0.009)
cpp_day_4	−0.051**	cpp_day_6	0.021*
	(0.015)		(0.008)
cpp_day_5	−0.019	cpp_day_7	0.017*
	(0.015)		(0.008)
cpp_day_6	−0.032*	cpp_day_8	−0.002
	(0.015)		(0.009)
cpp_day_7	−0.003	cpp_day_9	0.014
	(0.014)		(0.009)
cpp_day_8	0.011	cpp_day_10	0.039**
	(0.015)		(0.009)
cpp_day_9	0.166**	cpp_day_11	−0.021**
	(0.017)		(0.008)
cpp_day_10	0.157**	cpp_day_12	0.015
	(0.016)		(0.009)
cpp_day_11	0.076**	Constant	−0.031
	(0.019)		(0.019)
cpp_day_12	0.047**	Observations	231236
	(0.016)	Number of customerid	1,375
Constant	−0.007	R-squared	0.136
	(0.008)		
Observations	2,32,169		
R-squared	0.099		
Number of customerid	1375		

Robust standard errors in *parentheses* ** $p < 0.01$, * $p < 0.05$
Standard errors in *parentheses* ** $p < 0.01$, * $p < 0.05$

3.3.2 Daily demand equation

The daily demand equation captures the change in the level of overall consumption due to the changes in the average daily price. Similar to the substitution equation, the daily equation also relies on the pre-treatment and the treatment period data on both treatment and control group customers. This practice allows the elasticity estimates to be free from biases concerning any pre-existing differences between the control and treatment group customers as well as the changes in the consumption patterns of the treatment customers between the pre-treatment and treatment periods due to factors other than the treatment. As in the case of substitution equations, we also control for other independent variables that can affect the average daily consumption and use the fixed effects routine to estimate the model. The specification of the daily demand model is provided below:

$$\begin{aligned}
\ln(kWh)_{it} &= \alpha_0 + \alpha_1 \ln(THI)_t + \alpha_2 \ln(Price)_{it} + \alpha_3 \ln(Price)_{it} x \ln(THI)_t \\
&\quad + \sum_{k=1}^{6} \delta_k (\ln(THI)_t x D_Month_k) + \alpha_4 D_TreatPeriod_t \\
&\quad + \alpha_5 D_TreatPeriod_t x TreatCustomer_i + \sum_{k=1}^{6} \beta_k D_Month_k \\
&\quad + \sum_{k=1}^{12} \gamma_k D_CPP_k + \alpha_6 D_WEEKEND_t + v_i + u_{it}
\end{aligned}$$

where:

$\ln(kWh)_{it}$	: Logarithm of the daily average of the hourly load.
$\ln(THI)_{it}$	: Logarithm of the daily average of the hourly THI.
$\ln(Price)_{it}$	: Logarithm of the daily average of the hourly Price.
$\ln(Price)_{it} x \ln(THI)_t$	: Interaction of ln*(price)* with ln*(THI)*.
$\ln(THI)_t x D\_Month_k$	: Interaction of ln*(THI)* variable with monthly dummies.
$D\_TreatPeriod_t$	: Dummy variable is equal to 1 when the period is June 2008 through September 30, 2008.
$D\_TreatPeriod_t x TreatCustomer_i$	: Interaction of $D\_TreatPeriod_t$ with treatment customer dummy $TreatCustomer_i$.
$TreatCustomer_i$	:is equal to 1 for the treatment customers.
D_Month_k	: Dummy variable that is equal to 1 when the month is k.
D_CPP_k	: Dummy variable that is equal to 1 on the kth CPP day.
$D\_WEEKEND_t$	: Dummy variable that is equal to 1 on weekends.
v_i	: Time invariant fixed effects for customers.
u_{it}	: Normally distributed error term.

The daily equation is estimated to determine the daily price elasticity of the BGE customers. *Daily price elasticity* indicates the percent change in daily consumption due to a one percent change in daily price. Similar to the substitution elasticities, the daily price elasticities are allowed to interact with weather. The estimation results for the daily demand equation are also provided in Table 3.

3.3.3 Estimation of the SEP 2009 models

In the section above, we discussed our methodology in the context of the SEP 2008 Pilot program. The methodology used to analyze the demand impacts from the SEP 2009 Pilot program is very similar to that of 2008 except for a few differences. In order to answer the question of whether the customers were persistent in terms of their price responsiveness across the two years and to reject the null hypothesis that the first year response is simply a novelty, we first identified the group of customers who participated in the SEP pilot both years. This resulted in a sample of 657 treatment and 178 control group customers.[5] Second, we restricted the SEP 2008 sample only to include these 657 treatment and 178 control group customers. Third, we pooled the SEP 2008 and SEP 2009 datasets and created a dataset that covers the hourly interval data on treatment and control customers for April–September 2008 and March–August 2009. Fourth, we created a 2009 dummy variable that takes the value of 1 if the year is 2009 and 0 otherwise. Finally, we differentiated coefficients that capture 2008 effects from those coefficients that capture 2009 effects by creating variables which are interactions of the model variables and the 2009 dummy variable.[6] As a result, the specifications of the substitution and daily equations are slightly different than the equations presented above to accommodate the pooled model structure. Tables 4 and 5 present the estimated models.

4 Results

4.1 SEP 2008 price elasticities

After estimating the parameters of the substitution and elasticity equations, we next calculated the substitution and daily price elasticities. As mentioned earlier, the BGE price elasticities are found to be weather dependent, *i.e.*, they take on different values for different weather conditions. In order to quantify the load impacts from the SEP 2008 pilot, we determined the *average SEP 2008 event day weather* to be used in the calculation of the price elasticities. We identified the average SEP 2008 event day weather by finding the average values of THI_DIFF and THI variables for the top ten hottest event days in the summer of 2008. Only 10 out of 12 were included in the averages, as the last two event days had abnormally mild temperatures and were unlikely to be representative of critical peak event days that would be called in the future.[7]

[5] We excluded 77 out of 734 treatment customers in the SEP 2009 from the persistence analysis as they were not relevant to this analysis. These customers were in a cell that combines PTR with Technology and this program cell did not exist in the SEP 2008.

[6] We also made a slight change to the model specification in the pooled version. ln_price_ratio variable is not included as a standalone variable in the pooled model, but it was included in 2008. We made this slight change to address the multicollinearity problem that emerged when we included several interactions of the ln_price_ratio variable in the pooled model.

[7] These days nevertheless were included in the regression models since additional variability in the exogenous variables leads to greater precision in the parameter estimates.

Table 4 Substitution demand equation—pooled model

Dependent variable: ln (peak_Kwh/offpeak_Kwh)			
thi_diff	−0.024**	cpp_day_8	0.031
	(0.000)		(0.115)
thi_diffxapril	0.013**	cpp_day_9	0.239**
	(0.000)		(0.000)
thi_diffxaprilx09	−0.000	cpp_day_10	0.208**
	(0.974)		(0.000)
thi_diffxmay	0.020**	cpp_day_11	−0.027
	(0.000)		(0.089)
thi_diffxmayx09	0.006**	cpp_day_12	0.083**
	(0.000)		(0.000)
thi_diffxjune	0.049**	cpp_day_13	0.159**
	(0.000)		(0.000)
thi_diffxjunex09	−0.001	cpp_day_14	0.093**
	(0.790)		(0.000)
thi_diffxjuly	0.060**	cpp_day_15	0.085**
	(0.000)		(0.000)
thi_diffxjulyx09	−0.012**	cpp_day_16	−0.229**
	(0.000)		(0.000)
thi_diffxaug	0.065**	cpp_day_17	0.025
	(0.000)		(0.121)
thi_diffxaugx09	−0.001	cpp_day_18	−0.002
	(0.662)		(0.919)
thi_diffxsep	0.041**	cp_day_19	0.039*
	(0.000)		(0.021)
TreatPeriodx09	0.115*	cpp_day_20	0.074**
	(0.035)		(0.000)
TreatCustomer	0.000	cpp_day_21	−0.013
	(.)		(0.450)
TreatCustomerx09	−0.002	cpp_day_22	0.059**
	(0.896)		(0.000)
TreatCustomerxTreatPeriod	−0.048**	cpp_day_23	−0.059**
	(0.009)		(0.000)
TreatCustomerxTreatPeriodx09	−0.002	cpp_day_24	0.044*
	(0.891)		(0.012)
ln_price_ratioxthi_diff	−0.017**	April	−0.049
	(0.000)		(0.380)
ln_price_ratioxthi_diffx2009	−0.006**	Aprilx09	0.030
	(0.006)		(0.595)
ln_price_ratioxORBxthi_diff	−0.006**	May	−0.039
	(0.008)		(0.485)

Table 4 continued

Dependent variable: ln (peak_Kwh/offpeak_Kwh)			
ln_price_ratioxORBxthi_diffx09	−0.002	Mayx09	0.059
	(0.603)		(0.289)
ln_price_ratioxORB_TECHxthi_diff	−0.012**	June	0.091
	(0.000)		(0.090)
ln_price_ratioxORB_TECHxthi_diffx09	0.002	Junex09	−0.110**
	(0.324)		(0.000)
cpp_day_1	0.111**	July	0.097
	(0.000)		(0.075)
cpp_day_2	−0.055**	Julyx09	−0.064**
	(0.006)		(0.000)
cpp_day_3	−0.043*	Aug	0.007
	(0.036)		(0.897)
cpp_day_4	−0.037	Sep	0.042
	(0.081)		(0.431)
cpp_day_5	−0.055**	Y_2009	−0.035
	(0.004)		(0.531)
cpp_day_6	−0.101**	Weekend	0.093**
	(0.000)		(0.000)
cpp_day_7	−0.023	Weekendx09	−0.006
	(0.237)		(0.210)
		Constant	0.045
			(0.417)
Observations	294303		
R-squared	0.114		
Number of customerid	835		

Robust p-values in parentheses ** $p < 0.01$, * $p < 0.05$

An important finding from this experiment is that the substitution elasticities for DPP, PTRL, and PTRH rates were found to be statistically indistinguishable from each other when tested separately in the estimation equation[8]. This result has an important implication in that the SEP customers show the same responsiveness to dynamic pricing whether it is expressed as a price increase during critical hours or as a peak time rebate.

Once the model is estimated and the parameters are identified, the substitution elasticities can be derived from the following equations:

$$Subst\_Elasticity_{price} = \alpha_2 + \alpha_3 * THI\_DIFF_t \text{ (Price, Weather)} \quad (1)$$

$$Subst\_Elasticity_{price+ORB} = \alpha_2 + \alpha_3 * THI\_DIFF_t + \alpha_4 \text{ (Price, Weather, and ORB)} \quad (2)$$

[8] These results are available on request.

Table 5 Daily demand equation—pooled model

Dependent variable: ln (average_daily_consumption)			
ln_thi	−0.670**	cpp_day_11	−0.004
	(0.000)		(0.677)
ln_thixapril	0.127**	cpp_day_12	0.022
	(0.000)		(0.067)
ln_thixaprilx09	0.269**	cpp_day_13	−0.000
	(0.000)		(0.970)
ln_thixmay	0.892**	cpp_day_14	0.018
	(0.000)		(0.078)
ln_thixmayx09	0.347**	cpp_day_15	0.049**
	(0.000)		(0.000)
ln_thixjune	4.059**	cpp_day_16	0.009
	(0.000)		(0.447)
ln_thixjunex09	−1.260**	cpp_day_17	0.104**
	(0.000)		(0.000)
ln_thixjuly	4.080**	cpp_day_18	0.067**
	(0.000)		(0.000)
ln_thixjulyx09	−0.666**	cpp_day_19	0.007
	(0.000)		(0.511)
ln_thixaug	3.775**	cpp_day_20	0.056**
	(0.000)		(0.000)
ln_thixaugx09	0.513**	cpp_day_21	0.071**
	(0.000)		(0.000)
ln_thixsep	3.171**	cpp_day_22	0.011
	(0.000)		(0.331)
TreatPeriod	0.367*	cpp_day_23	−0.024*
	(0.035)		(0.037)
TreatCustomerx09	0.040**	cpp_day_24	0.002
	(0.001)		(0.832)
TreatCustomerxTreatPeriod	−0.012	April	2.210**
	(0.262)		(0.000)
TreatCustomerxTreatPeriodx09	−0.036*	Aprilx09	−3.829**
	(0.013)		(0.000)
ln_pricexln_thi	−0.009**	May	−0.869**
	(0.000)		(0.000)
ln_pricexln_thix2009	−0.004	Mayx09	−4.301**
	(0.053)		(0.000)
cpp_day_1	0.007	June	−14.442**
	(0.502)		(0.000)
cpp_day_2	0.024*	Junex09	2.517**
	(0.018)		(0.000)

Table 5 continued

Dependent variable: ln (average_daily_consumption)			
cpp_day_3	0.036**	July	−14.505**
	(0.001)		(0.000)
cpp_day_4	0.026*	Aug	−13.234**
	(0.037)		(0.000)
cpp_day_5	0.021	Augx09	−4.968**
	(0.068)		(0.000)
cpp_day_6	0.018	Sep	−10.700**
	(0.073)		(0.000)
cpp_day_7	0.015	Y_2009	2.777**
	(0.156)		(0.000)
cpp_day_8	−0.014	Weekend	0.041**
	(0.204)		(0.000)
cpp_day_9	0.001	Weekendx09	−0.005
	(0.944)		(0.068)
cpp_day_10	0.029**	Constant	−0.137**
	(0.010)		(0.000)
Observations	293973		
R-squared	0.101		
Number of customerid	835		

$$Subst\_Elasticity_{price+ET\_ORB} = \alpha_2 + \alpha_3 * THI\_DIFF_t + \alpha_5\,(\text{Price, Weather, and ET\_ORB}) \quad (3)$$

These equations make it possible to determine a substitution elasticity conditional on a specific weather condition and the existence of an enabling technology.

Just as in the substitution equation, the daily price elasticities from DPP, PTRL, and PTRH rates were not found to be statistically distinguishable from each other when tested empirically. Therefore, there is a single price variable in the equation that incorporates the impacts of DPP, PTRL and PTRH rates. The daily price elasticities from the estimated model can be derived using the following equation:

$$Daily\_Elasticity = \alpha_2 + \alpha_3 * \ln(THI)_t \quad (4)$$

It is possible to estimate a daily price elasticity conditional on a specific weather condition using this equation.

Using the average SEP 2008 event day weather, we find that the substitution elasticity from the DPP, PTRL, and PTRH rates alone is −0.096. This implies that a one percent change in the ratio of peak to off-peak prices leads to −0.096% change in the ratio of peak to off-peak consumption. When the DPP, PTRL, and PTRH rates are paired with the Energy Orb, the substitution elasticity becomes −0.136. Presence of both A/C switch and the Energy Orb yields a substitution elasticity of −0.18. Accord-

Table 6 Substitution and daily price elasticities estimated in the SEP 2008 pilot

Substitution/daily		Based on mild weather	Based on average weather	Based on extreme weather
Substitution elasticity	Price only	−0.073	−0.096	−0.109
Substitution elasticity	Price + ORB	−0.113	−0.136	−0.149
Substitution elasticity	Price + ET_ORB	−0.157	−0.180	−0.193
Daily elasticity	–	−0.019	−0.039	−0.034

Note: We also identified the mildest, and the most extreme event day levels of the weather in the summer of 2008 and calculated the substitution and daily elasticities that correspond to these weather conditions. Accordingly, CPP Day 11 which fell on September 23, 2008 was the CPP day with the mildest weather (THI_DIFF = 2.91); whereas CPP Day 9 which fell on September 3, 2008 was the one with the most extreme weather (THI_DIFF = 8.89)

Table 7 Substitution and daily elasticity comparison—SEP 2008 vs. SEP 2009

Substitution elasticity comparison: SEP 2008 vs. SEP 2009			
Elasticity	SEP 2008 (thi_diff = 6.65)	SEP 2009 (thi_diff = 5.25)	SEP 2009 (thi_diff = 6.65)
Price only	−0.096	−0.121	−0.153
Price + ORB	−0.136−0.152	−0.193	
Price + ORB + TECH	−0.180	−0.184	−0.233
Note: Average SEP 2008 thi_diff = 6.65 and Average SEP 2009 thi_diff = 5.25			
Daily elasticity comparison: SEP 2008 vs. SEP 2009			
Elasticity	SEP 2008 (ln_thi = 4.31)	SEP 2009 (ln_thi = 4.31)	
Daily	−0.039	−0.039	
Note: Average SEP 2008 ln_thi = 4.31 and Average SEP 2009 ln_thi = 4.31			

ingly, the substitution elasticity increases with the existence of enabling technologies as well as with hotter and more humid weather, as can be seen in Table 6.

The daily price elasticity from DPP, PTRL, and PTRH rates is calculated as −0.039 using average SEP 2008 event day weather information. This implies that for one percent change in the average daily price, the average daily consumption changes by −0.039%. The daily price elasticity didn't vary with the presence of enabling technologies when tested empirically. Therefore there is no technology variation in the daily price elasticities. However, similar to the substitution elasticities, the daily price elasticities increase with the hotter and more humid weather, as can be seen in Table 6.

4.2 Persistence of price responsiveness

As we mentioned above, we also estimated the price elasticities using the SEP 2009 pilot data to find out whether the residential SEP customers were persistent in their price responsiveness to dynamic pricing in the second year of the pilot.

Since we pooled 2008 and 2009 data together and fit one model for both years of the pilot, the variables which are interacted with the 2009 dummy variable capture the difference of the 2009 coefficients from the 2008 coefficients. For instance, as one can see from Table 4, the coefficient of the ln_*price_ ratioxthi_ diff* variable is estimated to be −0.017 in the substitution equation and represents the price responsiveness parameter for the PTR-only (or price only) group in the SEP 2008. In the same equation, ln_ *price_ ratioxthi_ diffx* 2009 variable is estimated to be −0.006 and represents the difference of the price responsiveness parameter for the PTR-only group in 2009 compared to that in 2008, resulting in a price responsiveness parameter 1 of −0.023 (−0.017 plus −0.006) in 2009. This implies that PTR only group not only retained their price responsiveness going from 2008 to 2009, but they have also become *more price-responsive* in 2009. PTR + ORB and PTR + ORB + TECH groups have the same incremental effects in 2008 and 2009 (as the 2009 interactions are not statistically significant) relative to the PTR-only group, however since the PTR-only customers have become more responsive in 2009, PTR + ORB and PTR + ORB + TECH customers are also more price responsive in 2009 compared to that in 2008.

However, similar to the SEP 2008 price elasticities, the parameters presented in Tables 4 and 5 should first be evaluated at the appropriate weather conditions before we interpret them as substitution and daily elasticities. Table 7 presents SEP 2009 price elasticities (evaluated at *average SEP 2009 event day weather conditions*). It also compares them to the SEP 2008 elasticities as well as to the SEP 2009 elasticities which are evaluated at the summer 2008 event day weather conditions.

Table 7 shows that the SEP customers were *more* price-responsive in the summer of 2009 compared to the summer of 2008 even though the weather conditions were milder in the summer of 2009. SEP 2009 elasticities would have been much higher if the summer 2008 weather conditions held true for the summer of 2009. This is to say that the SEP customers displayed persistence in their price-responsiveness in the second year of the pilot program. In fact, not only did they sustain their price responsiveness, they also increased it as compared to the first year of the pilot program, suggesting that a learning or habit formation process may have been at work.

4.3 Impacts using PRISM

After estimating the substitution and daily demand equations, the next step in our study is to determine the load impacts from the rates tested in the SEP pilot. We determined the impacts through the *Pricing Impact Simulation Model (PRISM)* software. Although PRISM was originally developed for California, it has been adapted to conditions in other parts of North America. We calibrated the PRISM model to BGE conditions by updating the model with BGE's weather dependent price elasticity terms, standard BGE rates as well as the SEP rates and the average BGE customer load profile. The PRISM model generates several metrics including percent change in peak and off-peak consumption on critical and non-critical days and percent change in total monthly consumption. These metrics are generated by solving the estimated substitution and daily demand equations which are included in the Appendix.

4.3.1 SEP 2008 residential customer impacts

SEP 2008 pilot results clearly demonstrated that residential customers were responsive to the dynamic prices. On average, residential customers achieved critical peak period load reductions ranging from 18 to 33% across all program types. In the absence of enabling technologies, the reduction in critical peak period usage ranged from 18 to 21%. When the Energy Orb was paired with dynamic prices, the critical peak period load reduction ranged from 23 to 27%. When the switch on the central air conditioning (CAC) unit was activated in addition to the Energy Orb, the impacts ranged from 29 to 33%. SEP 2008 provided clear evidence that enabling technologies boosted the impact of dynamic rates. More specifically:

1. The DPP rates alone lead to 20.1% reduction in load during peak hours on critical peak days and 1.8% reduction in peak period load on non-critical days. When the rates are paired with the Energy Orb and the A/C switch technologies (ET_ORB), the peak period load reductions reach to 32.5% on critical days and 4.4% on non-critical days. In addition to the peak period load impacts, the DPP rates also yield some total consumption impacts. Total monthly consumption increases by 0.9% with the DPP rates alone and by 1.2% when the DPP rates are paired with the ET_ORB technology combination. This is a result of the off-peak rates that are lower compared to the peak and the standard rates which give customers incentives to be less cautious about their consumption. Moreover, the off-peak hours represent a large percentage of the total hours during the pilot period.
2. The PTRL rates alone yield an average peak load reduction of 17.8% on the critical peak days. When the PTRL rates are paired with the Energy Orb, the average load reduction reaches 23%. The presence of both the Energy Orb and the A/C switch lead to an average load reduction of 28.5%, on the critical peak days. We do not observe load impacts on non-critical days as the SEP PTRL rates on these days are the same as the standard BGE rates. PTRL rates yield some conservation during the SEP Pilot period. PTRL rates, regardless of the presence of the enabling technologies, lead to a 0.5% reduction in total monthly consumption. This implies that some of the load reductions in the peak period on critical days represented conservation rather than load shifting.
3. The PTRH rates alone yield an average peak load reduction of 21% on the critical peak days. When the PTRH rates are paired with the Energy Orb, the average load reduction reaches 26.8%. The presence of both the Energy Orb and the A/C switch lead to an average load reduction of 33%, on the critical peak days. We do not observe load impacts on non-critical days as the SEP PTRH rates on these days are the same as the standard BGE rates. PTRH rates yield some conservation during the SEP Pilot period. PTRH rates, regardless of the presence of the enabling technologies, lead to a 0.6% reduction in total monthly consumption. This implies that some of the load reductions in the peak period on critical days represented conservation rather than load shifting.

Table 8 presents these results.

Table 8 SEP 2008 and 2009 residential customer impacts

SEP	Rate	Price only (%)	Price + ORB (%)	Price + ORB + ET (%)
2008	DPP	20.1	–	32.5
2008	PTRL	17.8	23.0	28.5
2008	PTRH	21.0	26.8	33.0
2009	PTR	22.6	26.9	31.0

4.3.2 SEP 2009 residential customer impacts

Our analyses reveal that the SEP customers reduced their critical peak demand by 22.6% in the absence of enabling technologies. When the Energy Orb was paired with PTR tariff, customers reduced their critical peak demand by 26.9%, on average. When the enabling technology was added to the Energy Orb, the impacts reached 31%. Moreover, SEP customers reduced their total monthly consumption by 0.8% as a result of dynamic prices in the summer of 2009.[9] These results are also presented in Table 8.

5 Conclusion

Using the data from the pilot participants and the control group customers both before and during the pilot period, we estimated demand models to determine the load impacts from the programs tested in the SEP Pilot.

Based on the analysis of SEP 2008 pilot data, the load reduction during the critical peak hours varied across all program types, from a low of about 18% to a high of about 33%. These estimated impacts were statistically significant at the 5% level.[10] In the absence of enabling technologies, the reduction in critical peak period usage ranged from 18 to 21%. When the Energy Orb was brought into the picture, critical peak period load reduction impacts ranged from 23 to 27%. When the switch on the central air conditioner was added to the Energy Orb, the impacts ranged from 29 to 33%. There was clear evidence that enabling technologies boosted the impact of the dynamic pricing rates.

When we combined the SEP 2009 and SEP 2008 Pilot datasets and estimated a pooled model to find out whether the demand response impacts were sustained in the second year of the pilot, we found that the BGE SEP customers were persistent in their price responsiveness in the second year of the pilot program despite experiencing milder summer conditions. In fact, they increased the extent of their price responsiveness suggesting that learning and adaptation were taking place. We found that the SEP

[9] Also, our analysis of the hourly impacts revealed that most of the laod was shifted to off-peak hours preceding and following the peak window. This suggests that customers were pre-cooling their homes before the start of the peak period and post-cooling their homes right after the peak period ended.

[10] Statistical significance at the 5% level implies that there is only 5% probability of incorrectly rejecting the null hypothesis that the estimated value is equal to zero, i.e., SEP rates do not lead to load reductions.

customers reduced their critical peak demand by 22.6% in the absence of enabling technologies in the second summer of the pilot. When the Energy Orb was paired with the PTR tariff, customers reduced their critical peak demand by 26.9% on average. When enabling technology was added to the Energy Orb, the impacts reached 31%. It is important to note that the PTR rate that was tested in the SEP 2009 falls in between the PTRL and PTRH tariffs tested in the SEP 2008 in terms of its rebate component.

Another significant finding of the SEP pilot is the equivalence in price elasticity between the DPP and PTR tariffs. This equivalence is line with the findings of previous pilots that have been carried out in Anaheim, California and Ottawa, Ontario, Canada (Wolak 2006; Ontario Energy Board 2007). Whether it will stand the test of time remains to be seen. New data from experiments in Connecticut, the District of Columbia, Florida, Illinois and Michigan may either confirm or reject this hypothesis of equivalence.

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Appendix: The algebra of PRISM[11]

1.1 Definitions

t is the total time period under consideration, e.g. a day or month
a_i is rate structure period i, which occurs during t
h_i is the number of hours per rate structure period (h/a_i)
w_i is the (average) power consumption during each rate structure period (kW)
q_i is the total energy used per rate structure period (kWh/a_i)

$$q_i = h_i w_i, \quad \forall i = 1, \ldots, I$$

n_i is the number of times rate structure period a_i occurs per time period t $(\#a_i/t)$
$\bar{Q}$ is the total energy used per time period (kW h/t)

$$\bar{Q} = \sum_{i=1}^{I} n_i q_i \tag{1.1}$$

p_i is the price of electricity during each at rate period ($ / kW h)
q_i is the quantity of electricity consumed during each at rate period (kW h)
p_i' is the price of electricity during each dynamic rate period ($/kW h)
q_i' is the quantity of electricity consumed during each dynamic rate period (kW h)

[11] We thank our colleague Doug Mitarotonda for his help in developing this appendix.

1.2 Regression

Assume $I = 2$. In the base case with constant prices, define a regression relationship between the price and quantity of electricity consumed during each flat rate period.

$$\ln\left(\frac{q_1}{q_2}\right) = \alpha + \sigma \ln\left(\frac{p_1}{p_2}\right) \tag{1.2}$$

In Eq. 1.2, α is the intercept and σ is the elasticity of substitution. A similar regression relationship can be defined during each dynamic rate period, using the same intercept and elasticity of substitution.

$$\ln\left(\frac{q_1'}{q_2'}\right) = \alpha + \sigma \ln\left(\frac{p_1'}{p_2'}\right) \tag{1.3}$$

Now solve for the unknown variables, q_i' in terms of the known variables, q_i, p_i, and p_i'.

Begin by subtracting Eq. 1.2 from Eq. 1.3.

$$\ln\left(\frac{q_1'}{q_2'}\right) - \ln\left(\frac{q_1}{q_2}\right) = \sigma\left(\ln\left(\frac{p_1'}{p_2'}\right) - \ln\left(\frac{p_1}{p_2}\right)\right)$$

Put the unknown variables in terms of the known variables.

$$\ln\left(\frac{q_1'}{q_2'}\right) = \ln\left(\frac{q_1}{q_2}\right) + \sigma\left(\ln\left(\frac{p_1'}{p_2'}\right) - \ln\left(\frac{p_1}{p_2}\right)\right) \tag{1.4}$$

The price ratio under a flat rate is equal to one. In other words, $\frac{p_1}{p_2} = 1$. Therefore, the logarithm of this term equals zero and drops out of the equation. Throughout the analysis, the price ratio of the dynamic rates will be considered, not the individual prices. Therefore, define $p' \equiv \frac{p_1'}{p'2}$. For notational simplicity, let the right-hand-side of Eq. 1.4, without the flat rate price ratio, be defined as A.

$$A \equiv \ln\left(\frac{q_1}{q_2}\right) + \sigma \ln\left(p'\right)$$

Now solve Eq. 1.4 for q_1'.

$$
\begin{aligned}
\ln\left(\frac{q_1'}{q_2'}\right) &= A \\
\ln\left(q_1'\right) &= A + \ln\left(q_2'\right) \\
e^{\ln(q'1)} &= e^{A+\ln(q_2')} \\
q_1' &= e^A q_2'
\end{aligned}
\tag{1.5}
$$

From Eq. 1.1, we can define $\bar{Q}'$.

$$
\bar{Q} = n_1 q_1' + n_2 q_2' \tag{1.6}
$$

Now, make the assumption that the total quantity of energy consumed remains constant over each month, i.e. $\bar{Q} = \bar{Q}'$. Substitute Eq. 1.5 into Eq. 1.6 and solve for q_2'.

$$
\begin{aligned}
\bar{Q} &= n_1 e^A q_2' + n_2 q_2' \\
\bar{Q} &= q_2' \left(n_1 e^A q_2' + n_2\right) \\
q_2' &= \frac{\bar{Q}}{n_1 e^A + n_2}
\end{aligned}
$$

In summary, the unknown q_i'variables are solved in terms of known variables.

$$
\begin{aligned}
q_1' &= \frac{\bar{Q} e^A}{n_1 e^A + n_2} \\
q_2' &= \frac{\bar{Q}}{n_1 e^A + n_2}
\end{aligned}
\tag{1.7}
$$

1.3 Curves

The fraction of peak demand change (assuming $i = 1$ is the peak dynamic rate period),δ, is a function of $q_1'$and q_1.

$$
\delta = \frac{q_1' - q_1}{q_1} \Leftrightarrow q_1' = q_1 (1 + \delta) \tag{1.8}
$$

Equations 1.7 and 1.8 provide a relationship between three variables of interest: the dynamic rate price ratio$\left(p'\right)$, the elasticity of substitution (σ), and the fraction of peak demand change under the dynamic rate (δ).

The variables σ and $p'$are embedded in A. A only appears as a exponent of e in (1.7), so reduce e^A.

$$
\begin{aligned}
e^{A} &= e^{\ln\left(\frac{q_1}{q_2}\right)+\sigma\ln(p')} \\
&= e^{\ln\left(\frac{q_1}{q_2}\right)} e^{\ln(p'^{\sigma})} \\
&= \left(\frac{q_1}{q_2}\right) p'^{\sigma}
\end{aligned}
$$

For notational simplicity, let $q \equiv \frac{q_1}{q_2}$.

$$
e^{A} = qp'^{\sigma} \tag{1.9}
$$

1.3.1 Elasticity of substitution

In order to graph curves representing various elasticities of substitution, peak demand change must be solved for in terms of the dynamic rate price ration and the elasticity of substitution.

Substitute Eqs. 1.8 and 1.9 into Eq. 1.7 and solve for δ.

$$
\begin{aligned}
q_1(1+\delta) &= \frac{\bar{Q}qp'^{\sigma}}{n_1 qp'^{\sigma} + n_2} \\
\delta &= \frac{1}{q^1}\left(\frac{\bar{Q}qp'^{\sigma}}{n_1 qp'^{\sigma} + n_2}\right) - 1
\end{aligned}
$$

Substitute for q.

$$
\delta = \frac{1}{q_1}\left(\frac{\bar{Q}\left(\frac{q_1}{q_2}\right)p'^{\sigma}}{n_1\left(\frac{q_1}{q_2}\right)p'^{\sigma} + n_2}\right) - 1
$$

1.3.2 Peak reduction

In order to graph curves representing various levels of peak demand change, the elasticity of substitution must be solved for in terms of the dynamic rate price ratio and peak demand change.

Now substitute e^{A} (q_1' will be substituted at the end) and solve for σ.

$$
\begin{aligned}
q_1' &= \frac{\bar{Q}qp'^{\sigma}}{n_1 qp'^{\sigma} + n_2} \\
q_1' &= \frac{\bar{Q}}{n_1 + \frac{n_2}{qp'^{\sigma}}} \\
n_1 + \frac{n_2}{qp'^{\sigma}} &= \frac{\bar{Q}}{q_1'} \\
\frac{n_2}{qp'^{\sigma}} &= \frac{\bar{Q}}{q_1'} - n_1
\end{aligned}
$$

$$\frac{n_2}{qp'^{\sigma}} = \frac{\bar{Q} - n_1 q_1'}{q_1'}$$

$$p'^{\sigma} = \frac{n_2 q_1'}{q\left(\bar{Q} - n_1 q_1'\right)}$$

$$\sigma \ln\left(p'\right) = \ln\left(\frac{n_2 q_1'}{q\left(\bar{Q} - n_1 q_1'\right)}\right)$$

$$\sigma = \frac{\ln\left(\frac{n_2 q_1'}{q\left(\bar{Q} - n_1 q_1'\right)}\right)}{\ln\left(p'\right)}$$

Substitute for q_1' and q.

$$\sigma = \frac{\ln\left(\frac{n_2 q_1 (1+\delta)}{\left(\frac{q_1}{q_2}\right)\left(\bar{Q} - n_1 q_1 (1+\delta)\right)}\right)}{\ln\left(p'\right)}$$

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WITNESS / RESPONDENT RESPONSIBLE:
PAUL ALVAREZ

QUESTION No. 17
Page 1 of 1

Refer to the Alvarez Testimony, page 21, lines 19–20.

a. Provide the rebate paid for Duke Kentucky's pilot Peak Time Rebate Program.
b. Provide a list of Commission approved rebates paid for all Peak Time Rebate Programs.

RESPONSE:

a. In Kentucky PSC Case No. 2019-00277, the Commission approved a settlement between the parties in which Duke Energy Kentucky agreed to pay a credit of $0.60 per kWh in a peak-time rebate pilot.
b. In Maryland, the PSC has approved peak-time rebate credits of $1.25 per kWh for BG&E, Pepco, and Delmarva Power & Light peak-time rebate programs.

WITNESS / RESPONDENT RESPONSIBLE:
PAUL ALVAREZ

QUESTION No. 18
Page 1 of 1

Refer to the Alvarez Testimony, page 22, lines 18–20. Explain how a Peak Time Rebate Program will provide a reason for customers to look forward to smart meters.

RESPONSE:

As Staff is likely aware, a portion of utility customers oppose smart meters due to electromagnetic frequency (wireless communications) concerns. Others oppose smart meters out of a concern that their usage activities can be monitored. Still other customers are likely to resent the intrusion into their yards or premises for smart meter installation. Some tangible benefits from smart meters are needed to counteract these negative perceptions. Unfortunately, other than the small number of customers likely to use the detailed energy data and capabilities available on the ePortal, the vast majority of customers will perceive absolutely no difference in electric service delivery after smart meters are installed.

Universal peak-time rebate is an extremely popular program enabled by smart meters in Maryland. The program is popular because it provides ALL BG&E, Pepco, and Delmarva Power & Light customers a feasible way to reduce their electric bills 1) in a manner which was previously unavailable to them before AMI; and 2) without any program registration requirements. The program has also proved popular because the rebates customers receive on their bills are tangible evidence of the benefits of their efforts. The rebates are also a reminder to customers of the tangible benefits smart meters make available to them. Finally, as described in my testimony, there is absolutely no downside for customers who chose not to conserve (or who are unable to conserve) during a called event. For all these reasons, universal peak-time rebate provides customers with a reason to embrace, rather than to oppose, or to be ambivalent towards, smart meter installation.