COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matters of:

ELECTRONIC APPLICATION OF DUKE ENERGY	)	
KENTUCKY, INC. TO AMEND ITS DEMAND	)	CASE No.
SIDE MANAGEMENT PROGRAMS	)	2022-00251

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ

On Behalf of the Kentucky Office of the Attorney General

November 9, 2022

TABLE OF CONTENTS

DIRECT TESTIMONY OF PAUL J. ALVAREZ

I. INTRODUCTIONS

Q. Please state your name and business address.

A. My name is Paul J. Alvarez. My business address is Wired Group, PO Box 620756, Littleton, CO 80162.

Q. What is your occupation?

A. I am the President of the Wired Group, a boutique consultancy specializing in distribution utility business planning, operations, investment, and performance measurement, including smart meters.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the Kentucky Office of the Attorney General (or "AG").

Q. Please describe your work experience and educational background.

A. I served in product support, product marketing, and product management roles for large corporations (Motorola, Baxter Healthcare, and Walgreens) before beginning the utility portion of my career in 2001. I was hired by Xcel Energy, one of the largest investor-owned utilities in the U.S., to serve as a demand-side management (DSM) product development manager. I oversaw the development of new DSM programs for residential, commercial, and industrial customers. In that role I learned the economics of traditional monopoly ratemaking and associated utility economic incentives, and learned a great deal about DSM program impact evaluation, measurement & verification (EM&V).

I left Xcel Energy to lead the utility practice for sustainability consulting firm MetaVu in 2008. At MetaVu, I employed my EM&V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are two of only three comprehensive, unbiased evaluations of smart grid post-deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[1] and an evaluation of Duke Energy Ohio's smart meter/smart grid deployment for the Ohio Public Utilities Commission in 2011.[2]

In 2012, I started the Wired Group to focus exclusively on distribution utility business optimization. Wired Group clients include consumer, business, and environmental advocates. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I have also taught at Michigan State University's Institute for Public Utilities, where I've educated new regulators and staff on grid modernization and distribution utility performance measurement.

Finally, I am the author of <u>Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment</u>, a book that helps laypersons

---

[1] Alvarez et al. "SmartGridCity™ Demonstration Project Evaluation Summary". Report submitted to the Colorado Public Utilities Commission in the testimony of Michael G. Lamb, Exhibit MGL-1, proceeding 11A-1001E. MetaVu report dated October 21, 2011; filed December 14, 2011.

[2] Alvarez et al. "Duke Energy Ohio Smart Grid Audit and Assessment". MetaVu report to the Staff of the Public Utilities Commission of Ohio in proceeding 10-2326-GE-RDR. June 30, 2011.

understand smart grid capabilities, benefit prerequisites, and post-deployment performance optimization. I have earned an undergraduate degree from Indiana University's Kelley School of Business and a master's degree in Management from the Kellogg School at Northwestern University. Both degrees featured concentrations in Finance and Marketing.

Q. Have you appeared before the Kentucky Public Service Commission previously?

A. Yes, I have prepared testimony on behalf of the Attorney General regarding smart meters in four previous instances. The first instance was Duke Energy, Kentucky's Certificate of Public Convenience and Necessity (CPCN) for Smart Meters (Case No. 2016-00152). In a settlement agreement in that Case, which the Commission approved, Duke Energy, Kentucky agreed to pilot a peak time rebate program, the results of which are the subject of this testimony. The second instance was in LG&E/KU's 2016 rate case, in which the Companies petitioned the Commission for approval to install smart meters (Case Nos. 2016-00370 and 2016-00371). As part of a global settlement in those cases, LG&E/KU ultimately withdrew their smart meter proposal. The third instance was in LG&E/KU's request for a CPCN to install smart meters (Case No. 2018-0005). The Commission denied that request, which appeared to be prompted in part by my testimony questioning the Companies' projected smart meter benefits. The fourth instance was in LG&E/KU's most recent request to install smart meters (Case Nos. 2020-00349 and 2020-00350). In that rate case, the Commission approved a multi-party settlement agreement and authorized LG&E/KU to record AMI project costs to the Construction Work In Progress account and accrue an allowance for funds used during construction, with cost recovery to be considered in a future rate case.

Q. What experience do you have before other state utility regulatory commissions?

A. I have appeared before state utility regulatory commissions on smart meters, associated rate designs, grid modernization, grid investment, and distribution utility performance measurement in California, Georgia, Iowa, Kansas, Maryland, Massachusetts, New Hampshire, New Jersey, North Dakota, North Carolina, Ohio, Oklahoma, Pennsylvania, and Washington. I have also written reports or drafted comments for consumer, business, and environmental advocates engaged in state utility regulatory proceedings in Florida, Hawaii, Illinois, Michigan, South Carolina, and Virginia. Brief descriptions of regulatory appearances, testimony dates, and case numbers are provided in the "Regulatory Appearances" section of my Curriculum Vitae, attached as Appendix A.

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

A. In this testimony I provide recommendations regarding the request by Duke Energy Kentucky ("DEK" or "the Company") to remove the initial participants in the Company's Peak Time Rebate ("PTR")[3] program pilot, and respond to the Company's perspectives on the PTR program generally[4] as provided in the Company's DSM program application in this Case.

Q. What is your recommendation regarding the Companies' request to terminate the original PTR pilot participants?

---

[3] The Company has branded its Peak Time Rebate program to its customers as the "Peak Time Credit" (or "PTC") program. Some documents attached as appendices to DEK's application reference the Peak Time Rebate program by that "Peak Time Credit" brand name.

[4] *Peak Time Credit EM&V Companion Report*. Exhibit F. Duke Energy Kentucky. August 2022.

A. I recommend the Commission reject the Company's request to terminate the original PTR pilot. Instead, I recommend the Commission Order the Company to 1) complete a full launch of the PTR program by June 1, 2023; 2) use its best efforts to maximize participation from all residential and small commercial customers in the program; and 3) enroll all existing pilot participants in the full PTR program. I also offer several recommendations related to a full PTR program roll-out for Commission consideration.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- PTR pilot results to date, program improvement opportunities, and Company perspectives;
- The Company's conclusion that a full PTR program would not be cost effective should not be relied upon;
- AG projections for a full PTR program indicate such a program would be cost effective;
- Review and recommendations.

Q. Before you begin, can you provide some background on smart meters, and how they are related to a peak time credit program?

A. Smart meters are distinguished from their predecessor technology – the traditional analog meter with a magnetic, spinning disk – in several respects. First, smart meters are equipped with wireless communications capabilities. These communications capabilities were designed largely to collect usage data remotely so that manual meter reading costs could be avoided.[5] Second, smart meters are typically equipped with service disconnect/reconnect switches that a utility can control remotely. This allows utilities to disconnect and restore service without having to send personnel to customer premises (outside of disconnections for non-payment, which most regulators have insisted retain a customer premise visit of some type as a consumer protection). Third, and most importantly for the purposes of this testimony, smart meters are digital data recorders that track both how much energy a customer uses, and also when a customer uses it. Using utility-defined time intervals (typically five, ten, fifteen, or sixty minutes), smart meters record how much electricity is consumed in each interval. This capability allows utilities to offer sophisticated time-of-use ("TOU") rate designs such as the PTR rate DEK piloted.

Q. How can smart meters benefit customers?

A. Smart meters can reduce utility costs, from meter reading costs to service disconnect and reconnect costs. Smart meters can also improve revenue recognition by reducing energy theft, bad debt expense, and usage on meters not identified with any customer account. As customers pay all of these costs, such benefits will ultimately reduce customer bills (once such benefits are reflected in the accounting data used to calculate rates in a rate case). Smart meters can even reduce average outage duration, though only marginally, due to "meter out-of-power" reporting capabilities. However, smart meters are very expensive, and must be replaced much more often than simple analog meters. As a result, my research indicates that despite all these potential benefits, smart meters are not cost-effective for customers unless a utility fully unleashes all the energy efficiency and demand response

[5] In addition to communications with utilities, smart meters being installed today typically support communications with customers' digital area networks and energy management systems.

potential that smart meters offer. My primary research into smart meter benefits indicates that energy efficiency and demand response represent somewhere between 35% and 42% of all benefits potentially available from smart meters.[6]

Q. Why wouldn't a utility like Duke Energy Kentucky want to maximize energy efficiency or demand response benefits from smart meters?

A. Based on today's ratemaking model, for-profit utilities like DEK can increase profits (or "earnings" in Wall Street parlance) in three ways: 1) reduce costs between rate cases; 2) increase revenues between rate cases; or 3) invest capital. Energy efficiency reduces revenues between rate cases, and demand response reduces a utility's need to invest capital (to meet customer demand for energy during system peaks). As a result, for-profit utilities like DEK are financially discouraged from maximizing smart meters' energy efficiency and demand response benefits. A study conducted by the American Council for an Energy-Efficient Economy confirms that for-profit utilities are sub-optimizing smart meters' potential to benefit customers through energy efficiency and demand response,[7] and cites utility compensation models as a primary cause.[8]

Q. What does this mean for the Commission and your testimony?

A. It means that a utility like DEK is unlikely to maximize the demand response and energy efficiency value of smart meters absent Commission Orders to do so. By Ordering utilities

[6] Alvarez, P. Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second Edition. Wired Group Publishing, 2018. Table 17, page 158, and Table 18, page 159.

[7] Gold R, Waters C, and York D. Leveraging Advanced Metering Infrastructure to Save Energy. American Council for an Energy-Efficient Economy. January 2020. Pages 41-43.

[8] Ibid, page 31.

to maximize the energy efficiency and demand response benefits of smart meters, for example through an Order to launch a full PTR program, a Commission can help offset the cost of smart meters to customers by increasing customer economic benefits.

Q. Can you please explain what a Peak Time Rebate program is?

A. A PTR program such as the Peak Time Credit program DEK piloted is considered a type of TOU rate. A TOU rate is any rate in which the cost of a kWh on a customer's bill varies by time of day. It is contrasted against the traditional flat rate per kWh, in which customers are charged the same rate per kWh regardless of when the customer uses a kWh. The overall advantage of TOU rates is that they provide an opportunity to more closely align customer charges with a utility's costs (which are disproportionately higher during times of system-wide peak demand for energy). Through such alignment, TOU rates aim to reduce the energy customers use during system peaks by shifting energy use to off-peak periods.

A PTR program is a unique type of TOU rate. Whereas all other TOU rates charge higher prices for the energy a customer uses during system peaks, a PTR program allows customers to keep a traditional flat rate, but adds an *opportunity* for customers to earn bill credits for reducing the amount of energy they use during peaks. Although both PTR and all other TOU programs reduce energy demand during system peaks, the other TOU rates do so through a penalty (or "stick"), while PTR programs do so through a reward (or "carrot"). Research indicates there is no difference in energy usage reduction levels between penalty-based and reward-based demand response rates.[9] However, I believe reward-based rates carry advantages over penalty-based rates, which I will explain in several places in this testimony.

PTR programs make use of defined events to let customers know the hours when energy reductions from baselines will be rewarded with a bill credit. These "critical peak events" ("CPEs") are typically limited in number and hours of duration (for example, DEK limited the frequency of CPEs in its PTR pilot to twelve per year of four hours duration each). A utility with a PTR program typically alerts customers to such events the preceding day via text messages, e-mail messages, robo-calls, social media, and mass media (typically, asking television and radio news programs, and particularly weather segments, to alert all customers in a utility's service area of the PTR event).

II. PEAK TIME REBATE PILOT RESULTS TO DATE; PROGRAM IMPROVEMENT OPPORTUNITIES; AND COMPANY PERSPECTIVES

Q. Please preview this section of testimony.

A. This section of testimony will summarize key results from the PTR pilot to date (Application Appendix E); describe opportunities to improve those results; and respond to perspectives the Company presents in its PTR pilot Companion Report (Appendix F).

Q. What is your reaction to the PTR pilot evaluation report?

[9] Faruqui A and Sergici S. *Dynamic pricing of electricity in the mid-Atlantic region: Econometric results from the Baltimore Gas and Electric Company experiment. Journal of Regulatory Economics*. Volume 40 (2011). Page 98.

A. The PTR pilot was a resounding success from two critical perspectives. First, the Nexant "Peak Time Credit Pilot Evaluation" attached as Appendix E to DEK's application reported an average demand reduction of at least 0.14 kW per participant, per summer CPE over the summer of 2021.[10] There are several reasons to believe the demand response impact from a full PTR roll-out would be larger, which I discuss in the following paragraph. Second, surveys indicate participants were highly satisfied with the program. On a scale of one to ten, with ten representing "Completely Agree", participants responded with an average score of 8.6 to the question "I would recommend the Peak Time Credit program to friends or family".[11] As a career marketing manager with eight years' experience specific to DSM programs, this is the highest score to this standard satisfaction survey question I recall observing. From my perspective, if research indicates a customer offer delivers on its objectives, and that customers are highly satisfied with the offer, the offer is a clear winner. The only other variable to consider is program cost-effectiveness, to be addressed later in this testimony.

Q. What reasons do you have for believing that the demand response impact per participant, per event would be larger in a full PTR roll-out than it was in the pilot?

A. First, and most significantly, there were two critical opportunities to maximize CPE awareness and response that the Company's pilot missed. Second, a full roll-out offers better CPE notification and DSM enabling technology co-promotion opportunities than a pilot, leading to potentially greater impact per participant, per CPE.

---

[10] Appendix E. *Peak Time Credit Pilot Evaluation*. Table 1-2, page 6. March 29, 2022. Nexant is now known as "Resource Innovations."

[11] Ibid, Table 4-26, page 63.

Of the missed opportunities, the largest in my opinion was the Company's belated attempt to secure participant smart phone numbers, enabling notification of PTR CPEs by text message. As a result, customers primarily learned of PTR CPEs by e-mail.

Most customers lead busy lives. As a busy person myself, my personal e-mail account receives almost no timely attention. If I were a participant relying on my personal e-mail for event notifications, I would miss almost every CPE. For a customer program in which success at reducing demand during a CPE depends almost entirely on timely customer awareness, nothing is more effective than a text message. Yet, for the pilot, the Company made enrollment for event notifications via text message available only after participants had already registered for the pilot. Participants were unable to enroll in text message CPE notification during pilot enrollment. As a result, only 8.2% of participants enrolled in text message CPE notification.[12] Encouraging greater numbers of participants to enroll in text message event notification, and making it easy for them to do so (during program enrollment), would undoubtedly increase text message registration, and thus CPE awareness, and thus impact per CPE. Indeed, the most common participant recommendation for the PTR program was CPE "Notification method or timing" (noted by one in three survey respondents).[13]

[12] Response to AG-DR-01-11(b).

[13] Appendix E, Table 4-16, "Summary of Peak Time Credit Program Recommendations". Page 53.

Another missed opportunity involves more thorough, repetitive, and accessible customer education as to how best to reduce energy use during CPEs. Only the initial program recruiting materials contained any conservation tips specific to CPEs. Otherwise, the Company provided no CPE reduction tips other than links to its website. CPE notifications were not employed as additional conservation education opportunities. The Company's tips do not mention electric clothes dryers (a very large load relative to most home appliances), nor is any information provided to help customers prioritize loads to reduce (lighting is listed next to HVAC with no relative "size of load" information, and gas-fired water heaters are not distinguished from the electric type). Indeed, the second most common program recommendation from participants was "More program information/saving tips from Duke Energy" (noted by one in six survey respondents).[14] A more concerted effort by the Company to educate and guide customers would probably have increased demand response per participant, per CPE.

Q. Why does a full roll-out offer potential for greater impact than a pilot?

A. First, once a utility's entire service area has the option to participate in a PTR program, additional event notification channels become available, including social media and mass media. The service territory of DEK's affiliate, Duke Energy Ohio ("DEO"), is immediately adjacent to DEK's service territory, and from a practical perspective, customers of the two companies rely upon many of the same mass media sources. If DEO were to adopt PTR, the two companies' use of mass media to promote PTR CPEs may therefore prove to be mutually beneficial, and would ensure that every publicized PTR

[14] Ibid.

event also serves as a PTR program promotion opportunity. Additionally, the use of common CPE notification channels between the two companies may also provide certain cost savings.

Second, PTR opens a world of potential DSM enabling technology co-promotion opportunities that would serve to increase impact per participant, per CPE. For example, PTR could be paired with a smart thermostat rebate program, or with DEK's Power Manager, or with a pool pump/electric water heater cycling device program, or with an in-home display, to improve response per CPE. (Research clearly indicates that enabling technologies can increase demand response to price signals).[15] The Company even hints at such potential pairings, stating "the Company will consider how PTR and other time-differentiated rates might be elements of a broader effort to effectively shape and reduce peak load."[16]

Q. Does that Company statement provide you with any encouragement regarding the Company's future plans for PTR?

A. No. On the contrary, the inclusion of "other time-differentiated rates" in the statement causes me significant concern. As a career marketing professional, I encourage the Commission to consider that typical TOU rates, and in particular TOU rates with a critical peak pricing component (the kind most effective at reducing demand), are not at all popular with customers. This is because TOU rates (other than PTR) incorporate a built-in penalty:

---

[15] Faruqui A. and Palmer J. *The Discovery of Price Responsiveness – A Survey of Experiments Involving the Dynamic Pricing of Electricity*. EDI Quarterly. Volume 4, No. 1. April 2012. Figure 3, page 5. Also Faruqui A and Sergici S. *Dynamic pricing of electricity in the mid-Atlantic region: Econometric results from the Baltimore Gas and Electric Company experiment. Journal of Regulatory Economics*. Volume 40 (2011). Page 103.

[16] Appendix E. *Peak Time Credit Pilot Evaluation*. Page 7. March 29, 2022

higher rates during peak hours. This is dramatically different than offering a reward for reducing usage during peak hours, as PTR does, for those program participants who elect to reduce usage.

Absent the purchase of an electric vehicle, getting customers to switch to a TOU rate that incorporates a peak period price penalty is one of the greatest marketing challenges I can imagine. TOU rates are inherently riskier than flat rates. A customer considering a TOU rate quickly realizes his or her bill will increase if he or she does not conserve energy during peak times. No marketing campaign in any industry has successfully recruited significant numbers of potential customers to choose a product that is riskier than available alternatives.

While voluntary customer participation in rebate (reward) programs like PTR routinely approach 30%, voluntary customer switches to TOU rates do not typically exceed single-digit percentages, a direct result (in my estimation) of the peak period price penalty. One customer enrollment study states, "(Our) assessment . . . suggests that a utility may expect to achieve at least a 5% recruitment rate for opt-in (voluntary rate) studies."[17] A survey of residential TOU rates nationwide by a respected economics firm found an average enrollment rate of just 3%.[18] In light of this research, a proposal to maximize smart meter

---

[17] Todd A, Cappers P and Goldman C. *Residential Customer Enrollment in Time-based Rate and Enabling Technology Programs*. Lawrence Berkeley National Laboratory report LBNL-6247E. June 2013. Page xxiii.

[18] Hledik R, Faruqui A, and Sergici S. *A Survey of Residential Time-Of-Use (TOU) Rates.* Brattle Group presentation dated November 12, 2019.(https://www.brattle.com/insights-events/publications/a-survey-of-residential-time-of-use-tou-rates/). . Slide 2.

benefits by offering a voluntary TOU rate option that incorporates a penalty rather than a PTR reward is thus being disingenuous at best, and is certain to fail.

The Company's statement heightens my concern that it will offer an unpopular TOU rate, rather than a very popular PTR program, to address the Commission's interest in maximizing smart meter value. All the while, however, the Company will be privately confident that almost all customers will reject such rates, thus presenting no threat to the throughput incentive or capital investment on which the Company relies for profit growth. I advise the Commission that a TOU rate offer which depends on voluntary customer adoption of a penalty-oriented rate will not deliver much if any smart meter benefit.

Q. If TOU rates are effective, but unpopular, do you recommend the Commission order the Company to make a TOU rate the default option – one that customers would have to take action to leave, for example to return to a traditional flat rate?

A. That is an option, though I would not recommend it. The Commission certainly does not want dissatisfied utility customers in its jurisdiction. But even more importantly, default TOU rates can be punitive for low-income customers. Low-income customers are less likely than other customers to take action to switch from a default TOU rate to a traditional flat rate. They are also less likely to own the discretionary loads that can be reduced (such as central air conditioners or clothes dryers) during periods when electricity prices are high. The Commission would not want these customers to jeopardize their health by unplugging their refrigerators during peak price periods, for example. On a similar note, many low-income customers are forced to run a room air conditioner or oxygen concentrator for health reasons; to subject such customers to price premiums during critical peak periods may be inappropriate and unfair. In summary, assuming a PTR program is cost-effective, it should be considered a much better practice than default TOU rates for maximizing smart meter benefits for customers.

Q. Do you have other concerns about the Company's perspectives on PTR?

A. My greatest concern is that the Company errantly concludes that a PTR program available to all its customers would not be cost effective. As my concerns related to the Company's projected cost-benefit analysis[19] for a full PTR program comprise the majority of this testimony, I will not address them here. Another concerning statement DEK makes regarding PTR is that PTR does not qualify for participation in PJM's price-responsive demand (PRD) program.[20] While the statement is correct, this issue is largely a red herring. One way or another,[21] PTR-related reductions in system peak demand will reduce the amount of generation capacity PJM requires DEK to supply or purchase. As all customers, and not just PTR participants, pay for the capacity DEK provides or purchases, all customers would benefit from lower minimum capacity purchase requirements. In fact, the

---

[19] Throughout this testimony, "total resource cost test" (or "TRC") and "cost-benefit analysis" are used interchangeably to describe an analysis completed to determine whether or not a program is cost-effective (meaning, that program benefits to customers exceed program costs to customers).

[20] "PJM" is a Regional Transmission Organization which, among other things, provides a market for buying and selling electric energy and capacity in which DEK participates.

[21] One option is for DEK to enroll its PTR program into PJM's Peak Shaving Adjustment ("PSA") program, though there are pros and cons to this. In the event DEO adopts a PTR program, and in the further event DEK chooses to participate in PJM's PSA program, I would recommend that DEK explore the possibility of aggregating its PSA with DEO's. Another option is to simply wait until PTR-related demand reductions are reflected in DEK's historical system peak demand data, which PJM uses to calculate DEK's minimum capacity requirements. Either way, PTR-related demand reductions will be reflected as a reduction in PJM minimum capacity requirements.

Company appears to include this benefit in the total resource cost test (cost-benefit analysis) it projects from a full PTR program.

Q. Does the Company make any other statements or leave any other impressions in its PTR Companion Report that concern you?

A. The Company devotes a large portion of its PTR Companion Report (Appendix F to the DEK Application) to discussing the differences in PTR demand response from various customer segments. Company-defined customer segments included single-family vs. multi-family dwellings; electric heat vs. gas heat; and smart thermostats (yes/no).[22] This discussion will imply to some reviewers that PTR program financial results can be improved by limiting participation to certain customer segments. A confidential proposal from a marketing consultant obtained in discovery appears to confirm DEK's interest in limiting program participation to certain customer segments. Appearing to play to its potential client's (DEK's) interests, the consultant's proposal states its approaches will [redacted][23]

To the contrary, pilot results to date indicate that any attempt to limit participation will harm the financial results of a PTR program. I encourage the Commission to avoid considering any limits on PTR program participation, whether by design or through customer segmentation and marketing effort manipulation. (A utility could simply fail to promote a PTR program to the customer segments it prefers not participate). All customer

---

[22] Unfortunately the Company did not, and refused to, compare the response of customers notified of PTR events via text message to the response of customers notified of PTR events via e-mail (Response to AG-DR-01-004).

[23] Confidential Attachment provided in response to STAFF-DR-01-002. Page 1.

segments examined show significant reductions in energy use during PTR events.[24] This means that all customer segments contribute to program success, and help cover fixed program costs. The best PTR program is a large PTR program, a conclusion this testimony will later defend.

III. THE COMPANY'S CONCLUSION THAT PEAK-TIME REBATE IS NOT COST EFFECTIVE SHOULD NOT BE RELIED UPON

Q. Please preview this section of testimony.

A. As described in the previous section, the Company is financially discouraged from maximizing the energy efficiency and demand response value of smart meters through programs like PTR. Given the Company's disincentive to maintain a successful PTR program, I encourage the Commission to question the Company's conclusion that a full PTR program would not be cost-effective. This section of testimony describes the two primary deficiencies in the Company's projections of full PTR program financial results that end in its errant conclusion. First, the PTR participation rates the Company assumed are much lower than industry experience suggests should be expected. Second, the Company's projection ignores three types of benefits – one significant in size – that a PTR program would deliver.

Q. What PTR participation rate did the Company assume in its full program projection?

[24] Exhibit F. *Peak Time Credit EM&V Companion Report*. Duke Energy Kentucky. Pages 4 and 5. August 2022.

A. DEK's full PTR program projection assumes 2,005 customers, or about 1.5% of all residential customers, would participate. The Company based its assumption on the fact that 1.5% of recruited customers responded to the pilot program offer,[25] which was only issued once. A concerted, professional marketing effort, employing multiple messages targeted to different customer cohorts, through multiple communications channels, and with repetitive recruiting efforts over time – potentially to include ongoing mass media promotions and PTR CPE notifications – will undoubtedly be much more successful at recruiting a large proportion of DEK customers to a program that has proven so popular as a pilot. Indeed, the Company has received a proposal from a DSM program marketing expert to maximize PTR participation through a concerted, professional marketing effort.[26] Further, the two top reasons for not enrolling that recruited customers provided – inadequate rebate incentives (49%) and "forgot/didn't have time to enroll" (39%)[27] – are relatively easy to address through PTR program design and marketing messages.

Q. What kind of participation rates should be expected for a PTR program?

A. A study examining the impact of different rate designs, offer types, and technology incentives on customer participation in TOU rates offered by 19 utilities included three PTR programs. These three PTR programs (which the study labels CPR, for critical peak rebate) secured 28%, 19%, and 10% customer enrollment.[28] While all three of these programs offered an in-home energy usage display as an enrollment incentive/demand

[25] Response to AG-DR-02-016 (b).

[26] Confidential attachment provided in response to STAFF-DR-01-002.

[27] Appendix E, Figure 4-3, "Non-Participant Reasons for not Joining PTR Program". Page 40.

[28] *Residential Customer Enrollment in Time-based Rate and Enabling Technology Programs*. Chart, page 19.

response support tool, and one also added a smart thermostat, the study concluded that technology incentives did not significantly improve program recruiting efforts. (The program offering both an in-home display and a smart thermostat – the most generous incentives offered of the three programs – had the lowest participation rate).[29] Given these study results, and given the clear popularity of the PTR program demonstrated by pilot participants, I believe a 20% customer participation rate should serve as a minimum expectation for a full PTR program launch, with 30% or even higher serving as a stretch goal. The higher PTR program participation, the greater the benefits customers will receive from a PTR program.

Q. How so?

A. First there is the obvious reason: 26,000 participants will reduce the demand for energy by a greater amount than 2,000 participants. But there is a sliding scale involved, because a significant proportion of the cost of a full PTR program is fixed. Fixed costs do not vary with the number of PTR program participants. Examples of fixed costs include program administration (determining when to call CPEs; calculating baselines; calculating credits; adding credits to customer bills; etc.); CPE notification platform costs (to record, manage, and execute participants' preferred CPE notification methods); consulting services for program improvements; and start-up costs (for initial launch promotions, software development, etc.) The greater the participation rate, the larger the benefits, and the larger the benefits, the easier it becomes for a PTR program to cover its fixed costs. There is likely

[29] Ibid, page 29.

no larger driver of projected PTR benefits, and therefore no larger determinant of PTR program cost-effectiveness, than the PTR participation rate.

Q. What PTR benefits did the Company include in its projected TRC test (cost-benefit analysis) of a full PTR program?

A. The Company appears to have included a reduction in purchased capacity required by PJM in its full PTR program projection. This is indicated by its use of a dollar amount per kW-year of generation capacity avoided by the PTR program, as the Company assumes in its DSM plan application generally. In addition, the Company includes in its projection a dollar amount per kW-year of transmission and distribution capacity avoided by the PTR program, also as the Company assumes in its DSM plan application generally.[30] It is appropriate for the Company to assume these avoided capacity costs as benefits from a full PTR program in its projected TRC test (cost-benefit analysis).

Q. What PTR program benefits does the Company ignore in its projections?

A. The Company appears to ignore three types of PTR benefits in its projections, with one of these being extremely significant in size. First, research indicates that customers who participate in demand response programs like PTR do not only shift energy use from peak periods to off-peak periods; they also reduce overall energy use. In a review of 24 studies of TOU rates in which both demand reductions and energy conservation were measured,

---

[30] Confidential response to AG-DR-01-022(a). Avoided generation capacity costs range from $[redacted] to $[redacted] per kW-yr. from 2023-2046; avoided T&D capacity costs range from $[redacted] to $[redacted] per kW-yr. over the same period.

the overall energy used by participants fell by an average of 4%.[31] One of the studies in the review found a conservation effect as high as 13%. This constitutes an extremely significant PTR benefit the Company ignored in its projections.

The other two types of benefits the Company's PTR program projections appear to ignore are small, but one has potential to grow, particularly if DEO offers a PTR Program to its customers. These benefits all relate, in one form or another, to PJM's energy market. These include, in rough order of benefit potential, 1) DRIPE (demand response imputed price effect, explained in more detail in the next several pages); and 2) The difference in energy prices between peak periods and off-peak periods.

Q. Why should the Commission agree that participation in a PTR rebate program reduces overall energy use by an average of 4%?

A. Researchers typically identify three sources of conservation associated with participation in a demand response program/TOU rate like PTR. All are reasonable. First, not all energy use avoided during a PTR event is shifted to off-peak hours; some energy use, once avoided, is avoided permanently. For example if, during a PTR event, a customer elects to hang his or her wet clothing on a clothes line, rather than use an electric clothes dryer, there is no need to run the dryer later. Once the clothes are air-dried, the need to use electricity to dry them no longer exists. Similar analogies apply to cooking or lighting loads.

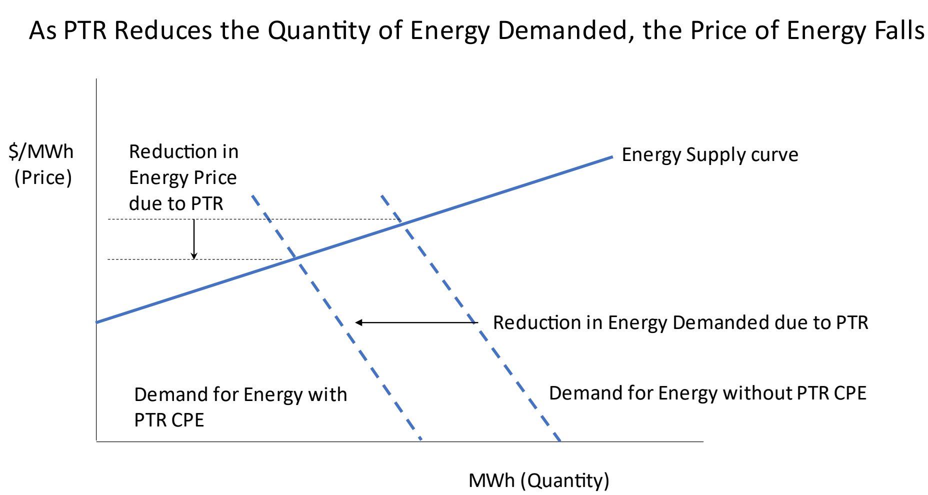
---

[31] King C. and Delurey D. *Efficiency and Demand Response: Twins, Siblings, or Cousins?* Public Utilities Fortnightly. March 2005.

Second, researchers point to the educational effect of a PTR program. A customer participating in such a program becomes aware that energy consumption can be modified, and of the actions the customer can take to modify it. Researchers believe the lessons customers learn during PTR events carry over into energy usage behavior throughout the year. Finally, researchers believe feedback plays a role. When a customer sees a credit or rebate on an electric bill, researchers believe that positive, quantifiable feedback encourages more of the same energy-conserving behaviors, even absent a PTR event.

Q. Please explain the demand response imputed price effect benefit.

A. Demand response imputed price effect, or DRIPE, is based on the law of supply and demand. The law of supply and demand dictates that when demand for a product (in this case electricity) falls, while the supply of a product (in this case generation capacity) remains constant, the market price for the product will fall. The phenomenon is illustrated in the chart below.



When a PTR CPE is called, participating customers reduce their demand for electricity. When the demand for electricity falls, the price in the PJM real-time market for electricity will fall. All customers of any utility that purchases electricity in PJM's real-time market during PTR CPE hours will benefit from these price reductions. One study found as much as a 2% price reduction for every 1% reduction in energy demanded during system peaks.[32] DEK does not appear to have included these DRIPE benefits in its full PTR program cost-benefit analysis. Though DRIPE is likely small in size if the Company offers a PTR program in Kentucky but not Ohio, I note that this benefit would grow dramatically if DEO were to launch a PTR program for its 652,000[33] residential customers. This is because DEK and DEO share a PJM market node.

Q. Please explain the on-peak/off peak energy price differential benefit.

A. As the names imply, the price a utility like DEK must pay for energy during on-peak times is much higher than the price it must pay for energy during off-peak times. When PTR participants shift energy use from an on-peak period to an off-peak period, the total cost of energy DEK must purchase for its customers falls. Like all utilities in Kentucky, DEK passes energy costs to customers at no mark-up. Thus, replacing high-cost energy with low-cost energy delivers a benefit to all customers, not just PTR participants. DEK does not appear to have included the benefit from the on-peak/off-peak price differential in its full PTR program cost-benefit analysis.

---

[32] Chernick P and Neme C.*The Value of Demand Reduction Induced Price Effects*. Regulatory Assistance Project Webcast March 18, 2015. Slide 14.

[33] From Duke Energy Ohio's 2020 Energy Information Administration Form 861.

To review, the Commission should not rely on the Company's conclusion that a full PTR program would not be cost effective. The PTR participation rates the Company assumes are much lower than industry experience suggests should be expected, and the Company's projection ignores several types of benefits that a PTR program would deliver. The impact of these deficiencies on the Company's full PTR program projection is significant, as will be shown by a cost-benefit analysis I completed to remedy these deficiencies.

IV. AG PROJECTIONS FOR A FULL PEAK TIME REBATE PROGRAM INDICATE SUCH A PROGRAM WOULD BE COST EFFECTIVE

Q. Please provide a preview of this section of testimony.

A. In this section of testimony I present a conservative cost-benefit analysis that indicates a full PTR program would deliver benefits to customers in excess of costs to customers. I will begin by explaining the corrections I make to DEK's PTR program benefit projections, including the use of a 20% participation assumption and the addition of benefits the Company's projection ignores. I will then describe how I estimated PTR program costs in my projection, based on actual costs the Company incurred in its PTR pilot as available, but augmented by my own extensive experience in rate program design and launch as necessary. I will conclude with a discussion on the sensitivity of projection results to changes in PTR program participation rates and other issues that could impact financial results (customer value, defined as program benefits less program costs, as in a DSM-type TRC test).

My projection of the benefits and costs of a full PTR program is summarized below, with more details available in Appendix B. It indicates that in the first 5 years of a full PTR program, using conservative assumptions, customers would receive $1.60 in benefits for every $1 spent on the PTR program. The customer benefits improve to $1.89 per $1 spent after PTR program start-up costs have been covered, delivering almost $500,000 in value annually to DEK customers. Results improve even further with every increase in customer participation rates, and further still if DEO were to launch a PTR program, or if avoided energy or capacity costs were to rise.

AG Projection of the Likely Benefits and Costs of a Full PTR Program in the DEK Service Area.

($ in 000;s)	2023	2024	2025	2026	2027	Five-year Totals
Participants (20%)	26,616	26,834	27,042	27,237	27,418	
Benefits	978.3	996.8	1013.4	1031.4	1045.0	5,065.0
Variable Costs						
PTC Rebates	107.3	108.2	109.0	109.8	110.6	544.9
Ongoing participant recruiting	53.2	57.6	57.8	58.0	58.1	284.7
Variable Program Admin (cust. svc.)	315.0	79.4	80.0	80.6	81.1	636.2
Total Variable Costs:	475.6	245.2	246.9	248.4	249.8	1,465.8
Contribution Margin per participant per year:	$ 18.89	$ 28.01	$ 28.35	$ 28.74	$ 29.01	
Fixed Costs						
Start-up (marketing, software)	250.0	0.0	0.0	0.0	0.0	250.0
Program Manager (includes benefits)	180.0	184.5	189.1	193.8	198.7	946.1
Fixed Program Administration	23.7	24.3	24.9	25.6	26.2	124.7
Event Notification Platform	43.5	44.6	45.7	46.9	48.1	228.9
Consulting and Misc. Other	29.4	29.6	29.8	30.1	30.3	149.1
Total Fixed Costs:	526.6	283.0	289.6	296.4	303.3	1,698.9
Benefits in Excess of Costs:	-23.9	468.6	476.9	486.6	492.0	1,900.3
Benefit to Cost Ratio:	n/a	$ 1.89	$ 1.89	$ 1.89	$ 1.89	$ 1.60

Full PTR Program Benefit Projections

Q. What corrections did you make to DEK's full PTR program benefit projections?

A. As described earlier, I assumed a 20% participation rate based on experience from other PTR programs, but held all other assumptions in the Company's projection (demand response per participant, value of avoided capacity, etc.) intact. This adjustment alone increased PTR program benefits from the $[redacted] DEK projected[34] to $[redacted] in the 2023 program year. I also estimated and added the energy conservation, DRIPE, and on-peak/off-peak energy price differential benefits the Company failed to include in its full PTR program projections.

Q. How did you estimate the conservation benefit?

A. The average annual energy use of PTR pilot participants was 10,685 kWh annually.[35] I multiplied this usage by a four percent expected conservation impact, and then by the average avoided cost of energy per kWh that DEK assumes in its DSM program application generally.[36] As with all benefits, I also assumed the 20% participation rate identified above, or 26,616 participating customers in 2023, with low customer growth over time.[37] This provided a conservation value of $[redacted] in the 2023 program year.

Q. How did you estimate the DRIPE benefit?

[34] Confidential Attachment 1 provided in response to AG-DR-01-021, tab "test results", cell B57. Note that I was unable to validate this benefit projection calculation due to DEK's use of a proprietary vendor model.

[35] Response to AG-DR-01-007.

[36] Confidential response to AG-DR-01-022(b). Avoided energy value 2022-2046 ranged from $[redacted] to $[redacted].

[37] Residential customer counts by year 2023-2027 per DEK 2021 IRP, page 79.

A. To estimate the DRIPE benefit, I assumed energy cost at peak would fall one percent for every one percent reduction in energy demanded at peak (for example, as a result of a PTR program). To determine the reduction in energy demanded, I multiplied PTR participant counts (26,616 in 2023) by the 0.14 kW reduction per participant found in the PTR pilot (3.726 MW). This amounted to a 0.459% reduction in energy demanded (3.726 MW divided by DEK's peak of 811 MW).[38] I estimated the energy cost per hour at peak to be $66,032 (DEK peak of 811 MW multiplied by $81.42 per MWh during PTR CPEs, see next), and multiplied this by the percentage reduction in energy demanded per hour (0.459%), and by the 48 hours' worth of CPEs likely to be called in any one PTR program year (12 events, 4 hours each). This calculation yielded a DRIPE value of $14,600 in the 2023 program year. This benefit would grow significantly if DEO were to launch a PTR program for its 652,000 residential customers.

Q. How did you estimate the on-peak/off-peak energy price differential benefit?

A. I analyzed the real-time energy prices per kWh reported by PJM for every hour of every pilot PTR CPE (20 events and 80 hours in total).[39] The average energy price per kWh during these events was $0.08142. I compared this to the average energy price per kWh DEK charged to customers throughout 2021 ($0.02861),[40] obtaining an on-peak/off-peak price differential of $0.05281 per kWh. I then multiplied the differential by the average reduction in energy use during PTR CPEs (0.14 kWh per hour), by the 48 hours' worth of events likely to be called in any one year, and by the 20% participant count. This delivered

---

[38] DEK historical average peak 2017-2019 (pre-pandemic).

[39] Response to AG-DR-01-009.

[40] Response to AG-DR-01-008.

an energy price differential benefit of $9,400 annually. This benefit will grow as natural gas prices grow (as natural gas prices are a key determinant of electricity prices per kWh.)

Full PTR Program Cost Projections

Q. How did you estimate PTR Program Costs in your projections?

A. I estimated PTR program costs in a conservative manner, addressing both variable costs (costs that vary according to the number of customers participating) and fixed costs (costs that will be incurred regardless of the number of participants). Variable costs include PTR rebates, ongoing customer recruiting costs, and program-related customer service costs. Fixed costs include PTR program launch (start-up) costs; management and administration costs; CPE notification platform costs; and consulting and other miscellaneous costs.

Q. How did you estimate PTR program variable costs?

A. I calculated PTR rebate costs as one would expect: Participant counts multiplied by PTR pilot reductions (0.14kW) multiplied by event hours per year (48) multiplied by the rebate amount ($0.60 per kWh reduced). Ongoing marketing and participant recruiting costs were estimated at $20 per new participant (excluding significant year 1 PTR program launch marketing costs, which I included as a fixed cost), and assumed a 10% annual participant turnover rate.

It is likely new participants will have many questions about the PTR program. New and prospective participants may phone DEK with program questions when considering enrolling, but new participants are also more likely than experienced participants to have questions regarding how baselines are established; about how PTR rebates are calculated/appear on bills; and what they can do to maximize rebate size. A very large customer service cost, based primarily on costs DEK incurred during the pilot,[41] is assumed in PTR program year 1 for this reason. However, after a rush of calls from new and prospective participants in PTR program year 1, participants will become more experienced, and will call far less often. For this reason, I project a dramatic (75%) fall in customer service costs for the program after year 1, though those costs will still be large.

Q. How did you estimate PTR program fixed costs?

A. Start-up costs were assumed to be high, including $200,000 in start-up marketing costs (mass media, social media, bill stuffers, direct mail, e-mail, text messages, etc.) and $50,000 in billing system software modifications (to automate the process of crediting PTR rebates on customer bills). I assumed a well-compensated program manager would be needed, including salary and benefits. I also employed PTR pilot cost data from DEK to estimate fixed program administration and event notification platform costs.[42] Finally, I added some program consulting costs, which could be used for everything from improving usage baseline and PTR rebate calculations to program EM&V studies.

To summarize, I believe the full PTR program projection I developed captures all the largest PTR program benefits and costs, in a conservative manner, and represents a reasonable expectation for how a full PTR program can be expected to perform financially.

---

[41] Response to AG-DR-02-011.

[42] Attachment 2 provided in response to AG-DR-01-021, plus responses to AG-DR-02-010, 011, 012, 013, and 014.

Discussion of results, sensitivity analyses, and other potential impacts to projection results.

Q. Please discuss the overall results of your PTR program projection.

A. As indicated in the introduction to this section, there is no question in my mind that a PTR Program with a 20% participation rate will easily deliver benefits to customers in excess of costs to customers, with an initial ratio over the first five years of $1.60 in benefits for every $1 spent. The ongoing benefits (after significant start-up costs have been covered) are even more impressive, with an ongoing ratio of $1.89 in benefits for every $1 spent, delivering total value to DEK customers (benefits less costs) of close to $500,000 annually. However, within these results are some interesting observations.

Upon completing the projection, I was struck by the large size of fixed costs required to operate a full PTR program. As discussed earlier, high fixed costs make high participation rates essential if the PTR program is to deliver benefits to customers in excess of program costs. But it is worthwhile to consider just how sensitive PTR program results are to participation rates.

For example, as a result of high fixed costs, and given all other assumptions I have described, my projection indicates that a minimum participation rate of 8% is required if a PTR program is to break even on an ongoing basis (meaning, deliver benefits to customers at least equal to program costs). Based on industry experience this participation rate should be easily achievable, though the break-even participation rate is higher than I would have preferred. On the other side of the coin, there is a silver lining to fixed costs: they do not increase with participation. As a result, higher participation rates disproportionately increase benefits. As examples, I project that a 25% increase in the participation rate (from 20% to 25%) will increase PTR program value (benefits less cost) 40%, to almost $700,000 annually; a 50% increase in the participate rate, to 30%, increases PTR program value 80%, to almost $900,000 annually. Due to participation rate sensitivity, and likely Company interest in limiting PTR participation, close Commission oversight of PTR program marketing efforts and participation rates is advised in the event the Commission orders DEK to implement a full PTR program.

I am also encouraged by the size of the contribution margin per participant, which my projection indicates is $28-$29 per participant, per year. In finance, contribution margin is a measure of how many dollars each new unit of sales volume contributes to covering fixed costs. In a PTR program, "sales volume" is analogous to a participant. The contribution margin means that every new customer added "contributes" $28-$29 per year toward program fixed costs (and ultimately, for every participant past the break-even 8% participation rate, to benefits in excess of costs). This is consistent with my earlier recommendation that participation in a full PTR program should not be limited to certain customer segments. Every new participant past 8% will make PTR program value (benefits less costs) larger.

Q. Given how critical customer participation is to PTR program success, are there strategies other than concerted, professional marketing efforts the Company could pursue to increase customer participation?

A. Yes. I believe universal PTR program participation offers a promising way to increase customer participation and demand response. Most utilities require customers to register for PTR program participation before they are eligible to earn rebates. This step in itself limits PTR program participation. Utilities with universal PTR programs pay rebates to all customers who demonstrate a reduction from baseline usage during PTR events without requiring registration. In such programs, all customers are notified of events via mass media, social media, robo calls, e-mails and text messages (the latter to the extent customers have made e-mail addresses and smart phone numbers available to their utility).

Q. What are the risks of universal PTR programs?

A. The criticism levied against universal PTR programs is that they pay rebates to customers who did not earn them, known as "free riders". The concern is that incidental energy usage variations, rather than intentional conservation actions, appears as a usage reduction from baseline in PTR rebate calculations for some customers. While this is a valid concern, it can be managed through improvements over time in baseline development and rebate calculation methods. Further, the research critics cite when levying this critique did not examine the relative size of the free rider payments, nor did it examine whether free rider payments paid in error outweighed the potential increases in participation, demand response, and benefits available from the universal approach.

The research cited by critics of the universal approach to PTR was obtained in discovery.[43] San Diego Gas and Electric (SDG&E) piloted a universal PTR program, including more

[43] Attachment provided in response to AG-DR-01-020.

than 1 million customers who did not register to receive PTR CPE notifications, along with 41,000 who did. The research found that the baseline development methodology performed poorly. Among those who did not register to receive event notifications, the baseline methodology identified 9.9 MW of statistically insignificant demand reduction that turned out to be 14.4 MW of statistically insignificant demand increase. Thus, free rider payments were relatively small (SDG&E's system peak is 4,500 MW), and could be reduced with improvements in the baseline development and rebate calculation methods. Further, it is likely the CPE notification approach used to reach non-registrants (radio and television news) could be improved, making more non-registrants aware of events. Most critically, of the more than 1 million customers who did not register for PTR CPE notifications, the research "found substantially greater usage reductions among (CPE) aware customers than for those who were not (CPE) aware, even among opt-in alert customers."[44] Critics of universal PTR ignore this finding. I encourage the Commission not to dismiss the universal approach to PTR out-of-hand, and believe more research into the costs and benefits of the universal PTR approach is warranted.

Q. What other insights does your full PTR program projection provide?

A. On the whole, I believe that the value provided by a full PTR program is more likely to increase than decrease in the future. If generation, transmission, and distribution capacity costs increase faster than inflation over time (more likely than not), the value delivered by a full PTR program will increase. If energy prices increase faster than inflation over time (more likely than not), the value delivered by a full PTR program will increase. If home

[44] Ibid, page 5.

energy management technologies proliferate over time (more likely than not), the response per participant, and thus the value delivered by a full PTR program, will increase. If DEO launches a full PTR program (more likely if DEK does), the DRIPE benefit delivered by a full PTR program will increase. To summarize, assuming a minimum 8% customer participation rate can be secured, history is likely to look kindly upon a decision now to launch a full PTR program, and the future risk to full PTR program viability is low.

Further, a full PTR program may offer reliability benefits. As intermittent renewable generation becomes a greater proportion of the generation mix, implying greater variability in generation capacity, a full PTR program might come in quite handy in an emergency. One can even imagine PTR being employed locally (as opposed to DEK-wide), for example to reduce local loads in response to a substation outage. A full PTR program may even offer reliability benefits outside of an event. For example, imagine a situation in which a large regional grid disturbance prompts PJM or DEK to call on customers to voluntarily conserve energy. With the benefit of experience, PTR participants will know just what to do to maximize conservation in such instances. Given that smart meters are already in place (a sunk cost), it just makes sense to take advantage of the capabilities they make available.

Q. Your testimony has yet to cover winter PTR events. What do you make of those?

A. As DEK is a summer peaking utility, almost all the demand response value from a PTR program comes from reducing demand on hot summer weekday afternoons. There is also a practical limit to the number of PTR CPEs per year to which customers will respond. As a result, care must be taken to spread the limited number of PTR CPEs a utility can call over the seasons when demand reductions will deliver the greatest economic benefit.

While it may not make sense to preclude winter events from ever being called, neither does it make sense to avoid calling CPEs late in the summer simply to preserve some number of callable events for winter months. My advice is to define a program year as June 1 to the following May 31 (just like PJM), and to establish a reasonable number of CPEs a utility can call per year under an assumption that all of those CPEs will be called in the summer. Ten to twelve CPEs is common; more than that in a single summer may reduce program participation and demand response per CPE. If, at the end of a particularly mild summer, a utility like DEK has a few CPEs remaining within program limits, those events could always be used the following winter if needed. But I would discourage a utility from avoiding calling a summer event simply to preserve a few events for winter months.

Q. What do you think of the Company's plans to test a higher PTR rebate?

A. I look forward to seeing the results of this test. Once the test is complete, and results published, I advise the Commission to complete a projection like the one I have developed to determine whether the increased response to a higher incentive is worth the cost of the higher incentive when placed in the context of full PTR program financials.

Q. So, based on all of this, you recommend the Commission Order DEK to add a full PTR program as part of its demand-side management offerings?

A. Not exactly. I do recommend the Commission Order DEK to launch a full PTR program. Whether or not the PTR program DEK launches qualifies as a DSM program is a separate matter entirely. It could be argued that PTR is a tariffed rate, not a DSM program. Power Manager, Smart $aver, and Home Energy House Call are clearly not tariffed rates. Further, customers are already paying for the smart meters which enable a PTR program in the first place, including DEK profits and taxes on top of the $49 million investment.[45] From my perspective, a full PTR program constitutes a minimum smart meter expectation that helps customers offset the cost of the Company's smart meter deployment. Viewed from this perspective, DEK owes its customers benefits from investments for which customers are paying; customers do not owe DEK for lost revenues associated with smart meter-related programs like PTR.

V. REVIEW AND RECOMMENDATIONS

Q. Please review your testimony.

A. This testimony began with an introduction to smart meters, TOU rates generally, and PTR programs specifically. The key takeaways from the introduction are that smart meters are not likely cost-effective unless their potential energy conservation and demand response benefits are maximized, and that PTR programs can help pursue these objectives. Another key takeaway is that for-profit utilities are financially discouraged from securing energy conservation and demand response benefits by the ratemaking model, which encourages sales volume growth and capital investment (to meet system peaks).

[45] Kentucky PSC Case No. 2016-00152. CPCN Application dated April 25, 2016. Page 10.

The testimony continued with a review of PTR program pilot results to date, described missed opportunities to increase the demand response during the pilot, and addressed claims and implications DEK makes in its PTR pilot results Companion Report. Pilot results indicate the PTR program has been a resounding success. Not only did participants reduce energy use during PTR events, program satisfaction was sky-high. These results came despite missed opportunities to maximize demand response and PTR bill rebate size, including minimal use of text-message event notification and minimal energy conservation education for participants. (These were the top two program recommendations participants offered in program satisfaction surveys.) I also explained why the demand response from a full PTR program (made available to all residential and small commercial customers) might be higher than indicated by pilot results, including opportunities for mass media event notifications and DSM program/enabling technology co-promotion.

The testimony also addressed Companion Report statements and discussions from which some reviewers might draw errant conclusions. DEK indicated it might pursue PTR "and other TOU rates" as part of a broader demand response initiative. I advised that TOU rates are unpopular with customers, and that voluntary switches to such rates are unlikely to exceed mid-single digit percentages of customers, thus delivering low benefits. (I also provided my perspective on why TOU rates should not serve as the default rate for residential customers.)

Another Companion Report conclusion is that the PTR program demand reductions cannot be bid into the PJM capacity market. While true, this testimony described other PJM-related avenues through which PTR program demand reductions will deliver economic benefits to customers, and DEK's own PTR program projections validate this. The Companion Report also devotes attention to customer segmentation, implying a DEK interest in limiting PTR program participation to certain customer segments. A confidential proposal from a marketing consultant obtained in discovery appears to validate that limiting customer participation in any potential PTR program is indeed one of the Company's interests. This testimony advised that placing limits on PTR program participation is a bad idea, as all customer segments demonstrated significant reductions in energy use during PTR events, and contributed to PTR program success and value. I explained that from a financial perspective, there is no larger driver of PTR program success than the customer participation rate.

An entire section of this testimony explained why the Commission should avoid relying on the Company's conclusion, expressed in its Companion Report, that a full PTR program would not be cost effective. First, DEK assumed unreasonably low customer participation rates (1.5%) relative to industry experience (10% to 28%), and ignored several types of benefits available from PTR programs. My own projection indicated that the largest of these, the conservation benefit, was almost as large as the demand response benefit. (Research indicates TOU rate participants reduce energy use by 4% throughout the year on average.)

I presented my own financial projection of a full PTR program in the final section of this testimony. The testimony described the calculations behind all benefit and cost projections, and indicated that an ongoing benefit-to-cost ratio of $1.89 to $1 is likely at a 20% participation rate. My analysis also indicated that an 8% participation rate is the break-even point (meaning, that at least 8% participation is required before benefits exceed costs). My analysis also supported my conclusion that the best PTR program is a large PTR program, indicating the $500,000 annual benefit delivered by 20% PTR program participation would increase to $700,000 annually at 25% participation and to $900,00 annually at 30% participation.

Other observations and insights I offered on a full PTR program included:

- The Commission should not dismiss out-of-hand a universal approach to PTR (which pays rebates for demand reductions without requiring customers to register);
- The value of PTR benefits are more likely to increase over time than to decrease over time, and that even reliability improvements might one day be available;
- Winter PTR events are not as valuable as summer PTR events;
- The higher incentive amount the Company plans to test should be evaluated in the same manner as I have in this testimony (through a full program cost-benefit analysis);
- A full PTR program should be considered an expected and integral part of DEK's smart meter investment rather than part of DEK's demand-side management portfolio.

Q. What are your recommendations to the Commission regarding the PTR pilot?

A. My primary recommendation is that the Commission Order DEK to launch a full PTR program for all residential and small commercial customers by June 1, 2023. This recommendation is based on strong pilot results and conservative projections of full PTR program benefits and costs. Further, due the Company's likely interest in limiting program participation, and due to the critical nature of customer participation rates to full PTR program success, I encourage the Commission to maintain close oversight over the Company's PTR program marketing plans, their effectiveness, and resulting participation rates. The Commission should expect the Company to use its best efforts to maximize PTR program participation, which could be enhanced through the use of a marketing expert to better target marketing messages to different customer segments. However, the Commission should ensure that customers segmentation and marketing is not used to limit program participation, as all customer segments tested to date demonstrate significant usage reductions during PTR events, and therefore contribute to PTR program value.

Regarding the Company's specific request to terminate the initial group of pilot program participants, I recommend the request be denied. If the Commission adopts my primary recommendation, it would not make sense to remove these participants from a PTR program they like, and require them to re-join it. Instead, in the event the Commission adopts my primary recommendation, current pilot participants should be automatically enrolled in the full PTR program (with appropriate notice and with opportunity for participants to cancel further event notifications if they wish).

If the Commission does not Order a full PTR program launch, I recommend the initial pilot group be retained anyway. An extra year's data regarding demand response to PTR events is never a bad thing, and such an extension presents other valuable research opportunities the Commission may wish to investigate. For example, the demand reduction impact of more extensive use of text message CPE notifications and improved CPE conservation education could be tested.

Other recommendations I make for Commission consideration include:

- To require the Company to complete research, perhaps including a pilot, into the costs and benefits of a universal approach to PTR;
- To exclude a full PTR program from the Company's demand-side management portfolio, as PTR is more appropriately considered a smart meter requirement (particularly given that customers are already paying for smart meter capabilities in rates).

Q. Does this conclude your testimony?

A. Yes, it does.

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed conflicts between ratemaking and benefit maximization. Since 2012 Mr. Alvarez has led the Wired Group, a boutique consultancy serving consumer, business, and environmental advocates, and regulators in matters of distribution planning, investment, and performance measurement.

Appearances and Research Projects in Regulatory Proceedings

Evaluate Georgia Power's Transmission & Distribution Spending Proposals. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44280. October 20, 2022.

Evaluate Pacific Gas & Electric's 2023-2026 Multi-year Rate Plan. Panel testimony with Dennis Stephens on behalf of AARP. California PUC A.21-06-021. June 10, 2022.

Evaluate the Distribution Business Components of Georgia Power Company's Integrated Resource Plan. Panel testimony with Dennis Stephens on behalf of Public Interest Advocacy Staff. Georgia PSC 44160. May 6, 2022.

Evaluate Policy Issues and Precedents Associated with Oklahoma Gas & Electric Company's Grid Modernization Factor. Testimony on behalf of the Office of Attorney General in PUD 2021000164. April 27, 2022.

Evaluate Grid Modernization and Advanced Metering Proposals by Massachusetts Utilities. Panel testimonies with Dennis Stephens on behalf of the Office of Attorney General in D.P.U. 21-80, 21-81, and 21-82. January 19, 2022.

Evaluate Dominion's Grid Transformation Plan. Testimony on behalf of Appalachian Voices/Southern Environmental Law Center. Virginia SCC PUR-2021-00127. September 13, 2021.

Investigate Avista Utilities' Electric Distribution and Wildfire Spending, Plans, and Processes. Panel testimony with Dennis Stephens on behalf of Public Counsel. WUTC 200900. April 29, 2021.

Evaluate Kentucky Utilities/Louisville Gas & Electric's CPCN to Install Advanced Meters. Testimony on behalf of the Attorney General. Kentucky PSC 2020-00349/00350. March 5, 2021.

Examine Potomac Electric Power Company's Electric Distribution Spending and Plan. Panel testimony with Dennis Stephens on behalf of the Office of People's Counsel. MD PSC 9655. March 3, 2021.

Determine If Customer Interest Is Served by Smart Meter Stipulation. Testimony before the Ohio PUC on behalf of the Office of Consumer Counsel. Ohio PUC 18-1875-EL-GRD. December 17, 2020.

Critique Public Service Electric & Gas Company's Smart Meter Deployment Plan. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Rate Counsel. NJ BPU EO18101115. Aug. 31, 2020.

Examine Oklahoma Gas and Electric's $800 million Grid Enhancement Plan. Testimony before the Oklahoma Corporations Commission on behalf of AARP. PUD 202000021. August 25, 2020.

Examine Baltimore Gas and Electric's 2021-2023 Grid Investment and Operations Plan. Panel testimony before the Maryland Public Service Commission with Dennis Stephens on behalf of the Office of People's Counsel. MDPSC 9645. August 14, 2020.

Critique of Duke Energy Carolinas/Duke Energy Progress $2.3 billion Grid Improvement Plan. Testimony before the North Carolina Utilities Commission on behalf of a coalition of consumer and environmental advocates. NCUC E-7, Sub 1214 February 18, 2020, and E-2, Sub 1219 March 25, 2020.

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

Alternative Ratemaking in the US: A Prerequisite for Grid Modernization, or an Unwarranted Shift of Risk to Customers? With Kenneth Costello, Sean Ericson and Dennis Stephens. Electricity Journal. Volume 35 (October, 2022).

Utility Regulation Through Legislation: A Cautionary Tale for Legislators, Regulators, Stakeholders, and Utilities. With Sean Ericson and Dennis Stephens. Electricity Journal. Volume 34 (August, 2021).

Florida Storm Protection Plans: A Bonanza for Utilities, a Bust for Consumers and the State. Whitepaper co-authored with Dennis Stephens for AARP-Florida. October 5, 2020.

Challenging Utility Grid Modernization Proposals. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. Part 1, August, 2020, pages 59-62; Part 2 September, 2020.

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators*. Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional, Product Development and Management Association.

Total Resource Cost Test -- Benefits & Costs, AG Projection							
($ in 000's)						5-yr	
	2023	2024	2025	2026	2027	Totals	
Participants	26,616	26,834	27,042	27,237	27,418		20% of residential customer counts per DEK most recent Integrated Resource Plan
Benefits ($)							
Value of Demand Reduction	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Count of participants X kW reduction per participant X DSM $ value/kW-yr
Value of Energy Conservation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	Count of participants X average annual energy use per participant X Annual conservation estimate (%) X DSM $ Value per kWh
Value of DRIPE	14.6	14.7	14.8	14.9	15.0	73.9	Energy cost per hour at peak X percentage reduction from PTC (participants x reduction/participant / 811,000) X count of event hours
Value of Energy Shift	9.4	9.5	9.6	9.7	9.7	48.0	Count of participants X kW reduction per participant X count of events hours X energy price differential (event ave. price less annual ave. price)
Total Annual Benefits	978.3	996.8	1,013.4	1,031.4	1,045.0	5,065.0	
Variable Costs ($)							
Incentives ($0.60/kWh)	107.3	108.2	109.0	109.8	110.6	544.9	Count of participants x kW reduction per participant X count of events X hours per event X $ incentive per kWh
Recruiting/Ongoing Marketing	53.2	57.6	57.8	58.0	58.1	284.7	(Turnover participants+new participants) X Cost per new participant
Variable Program Admin (cust svc)	315.0	79.4	80.0	80.6	81.1	636.2	Calls to call center regarding program (participation, rebate calculations, conservation tips, etc.); 75% drop after year 1
Fixed Costs ($)							
Launch	200.0					200.0	AG estimate
Billing System SW development	50.0					50.0	Based on credit calculation software development of $43,500 (per DEK)
Billing System SW Maintenance	5.0	5.1	5.3	5.4	5.5	26.3	Based on credit calculation software maintenance of $4.35 (per DEK)
Credit Calculation SW Maintenance	4.4	4.5	4.6	4.7	4.8	22.9	per DEK
Program Management	180.0	184.5	189.1	193.8	198.7	946.1	AG estimate ($120,000 annual program mgr. salary + 50% benefits)
Fixed Program Administration	23.7	24.3	24.9	25.6	26.2	124.7	Event mgmt (50% 0f DEK "CCO Program Support and DR Implementation). Balance (50%) used to inform Variable Program Admin estimate.
Communications (e-mail, text)	43.5	44.6	45.7	46.9	48.1	228.9	per DEK
DSM overhead & EM&V costs	-	-	-	-	-	-	AG estimate (PTR is a rate, not a DSM program, and an expected part of a smart meter deployment)
Program Consulting	20.0	20.0	20.0	20.0	20.0	100.0	AG estimate (to improve program over time: baselines, credit calcs, marketing, etc.)
Total Variable and Fixed Costs	1,002.2	528.2	536.5	544.8	553.0	3,164.7	
Total Benefits less Total Costs	(23.9)	468.6	476.9	486.6	492.0	1,900.3	
Benefit-to-Cost Ratio					$ 1.89	$ 1.60	For every $1 in program costs (line 10 divided by line 28)
					Ongoing	First 5 Yrs.	
					(2027+)	(2023-2027)	