DEMAND SIDE RESPONSE
TECHNOLOGY DEPLOYMENT AND COSTS SUBGROUP REPORT

(Updated: June 30, 2004)

Introduction

Demand response is about increasing the responsiveness of electricity demand to changes in wholesale electricity prices. The idea is that if consumers have both the incentive and the ability to vary their demands in response to prices in something like real time, then the volatility of prices can be dampened, bringing economic, reliability and even environmental benefits.[1]

"However, what is really needed is the ability to aggregate multiple distributed loads by allowing each metered load sink to be a member of more than one load group. This requires load to be situated across the network for optimal benefits," states Mark Knight, director of product development at Project Yangtze.[2] Grouping residential and small commercial loads both regionally and locally could allow the emulation of current curtailment programs. It would also have the capability to provide distributed load curtailment by reducing load that has been aggregated from geographically dispersed locations. There must be motivation for the customer to reduce load in order for this to be effective. Individually, a residential or small commercial customer is not going to control enough load to influence prices, but if enough of these customers had interval metering with automated meter reading (AMR), their load could be aggregated to a sufficient level.[3]

Demand-side response (DSR) schemes take as many forms as there are companies and jurisdictions, but are broadly split into system-led and market-led approaches. System-led schemes are initiated by system operators such as PJM, and focus on system reliability. In a market-led approach, end-use customers enter into agreements with suppliers, or third-party demand-response aggregators *or EDCs*, to reduce loads in pre-specified ways when triggered by market conditions. One of the earliest market-led strategies was time-of-use (TOU) pricing. However, such schemes, while in many ways an improvement on flat prices, can only approximate real market conditions. As a result, real-time pricing (RTP) schemes have emerged that use smart metering and communications technologies *or information technologies(IT)* to reward demand response behavior in real time. The steps needed will vary widely from market to market, but common threads could include modifying retail price regulation, creating incentives (or removing disincentives—such as load profiling) to invest in smart metering and communications infrastructure, or creating a smooth IT interface among system operators, retailers and customers necessary to enable demand response markets to operate efficiently and in real time.[4]

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[1]Phil Harrington, "The Power to Choose," Energy Markets, pp 30-32 (February 2004)

[2] Mark Knight, "Load Curtailment," Energy Markets (www.energy-markets.com)

[3] Ibid.

Background

This Commission is interested in setting forth a policy statement on DSR that is market-driven, that could be available to any customer on a voluntary basis, and that would be implemented by the Electric Distribution Company (EDC), which currently serves as Provider of Last Resort and plays a major role in determining load-shapes for planning purposes by the PJM. These programs would be available to all customers on a voluntary basis and be ramped up over time. Commission staff surveyed the major Pennsylvania EDCs for DSR technologies and their associated deployment costs for the following:

- Demand-side response program activity (operational and pilot programs);
- Requirements for distribution-wide availability; and
- Existing metering and load control devices.

Commission staff also presented the EDCs with hypothetical questions in order to capture the IT interface technologies, such as those needed for billing systems that would be needed for implementation of DSR across customer classes. Following is our summary analyses related to the costs associated with DSR technology deployment and the IT hypothetical, along with certain noteworthy, detailed specifics received from each EDC.

Effective DSR will require a significant deployment of technology at some cost by electric distribution companies. The degree of this deployment will depend on the nature of an EDC's obligation to its customers. The Commission has not yet defined this obligation, so in order to assess at least one perspective on the information technology necessary to make DSR available upon any customer's request, the following hypothetical, obligation-to-serve scenario was proposed to each major, investor-owned EDC:

> By 2010, all customers must have the opportunity to access a demand side response program within a reasonable time after making a request. EDCs, assuming they are the provider of last resort, will design a proposed plan in accordance with principles set forth in a PUC Policy Statement. They will have the flexibility to implement a program or programs of their choice, provided that they comply with the requirements established by the Commission through a process that entails the receipt and review of comments. EDCs will receive full recovery of reasonable costs, regardless of whether customers ever access or use the available programs or how many customers participate. In order to implement one of the approved programs on a wide-scale basis, the EDC will find it necessary to significantly enhance or completely replace their current billing system and/or other supporting IT infrastructure, so as to permit alternative rate structures that are associated with the DSR technology of choice and to allow customers to participate in DSR programs.

After careful review of the hypothetical, each EDC was presented with an identical set of three questions for responding to the above hypothetical. These questions appear below, followed by an analysis of the responses provided to the hypothetical and an inventory of existing EDC metering and load control devices.

Q.1Is there a ballpark dollar estimate available for enhancement or replacement of the current billing system and/or other supporting IT infrastructure (such as meter data repository or other mechanism for the conversion of billing data) that we could utilize for purposes of giving the Commission some idea what the impact on rates would be if it were to order such upgrades? If possible, it would be helpful if an example could be provided to show the monthly impact on the average residential bill, using some basic assumptions on items such as carrying charges and the length of recovery time, of making system changes that are necessary to allow for consumer access to DSR tools or programs.

Of the six major EDCs, cost estimates for upgrading systems and equipment ranged from $1.2 to over $327 million. These costs are first-costs and do not convey recurring operational costs. Not all companies had a specific program in mind, e.g. Smart Thermostats, when deriving these estimates, but where specific programs served as a model, key assumptions were provided. Cost estimates primarily addressed billing and did not include an array of possible costs such as the capacity for long-term storage of hourly data and real-time feedback capabilities that may be required. No company included program marketing costs in its estimate.

Not all EDCs provided information on rate impacts. However, from the limited data received, the impact on a customer's monthly bill was estimated to be as little as 0.05 mills per kWh, as a non-by-passable surcharge on all customer classes, or as great as $3.75, as an "adder" fee applied to all customers.

PECO Energy appeared to be the only company that considered all customer classes in its total program costs. Others presumably did the same, based upon their existing IT infrastructure and inventory of metering and load control devices. On this basis, existing DSR capacity varied widely. For example, the number of standard residential meters ranged from 543,854 to 1.3 million, with a meter cost from $24 each to as much as $244. Only FirstEnergy and PPL had over 10,000 TOU residential meters installed with a per meter cost of $153 to $259. Duquesne Light was the only company to report that it has load control devices for its residential customers, but the numbers are few (64 at a per meter cost of $200). Regarding existing DSR capability for C&I customers, the only factor all EDCs have in common is the fact that no load control devices are currently available and that the cost per device is unknown.

Allegheny Power stated that only a slight modification to its existing billing system would be needed to accommodate new rates for billing, but that many other IT items such as a new management system would incur the bulk of its costs to upgrade its system. Allegheny Power has 672,831 standard residential meters that cost $24 each. Currently no TOU or interval meters or load control devices are installed on the premises of residential customers. Commercial technology currently available includes 23,917 standard meters at a cost between $70 and $300 each meter. There are 1402 industrial interval meters which do not need upgrading. There are no load control devices available for commercial and industrial customers.

Allegheny Power's estimate assumed implementation of a smart thermostat and appliance control program at a cost of $12 million. The company's assumed participation rate was at about three percent or between 15,000 to 20,000 customers. This estimate included the cost of customer education and enrollment. To put the program in place an average carrying charge of $0.00037/kWh would be assessed to all residential customers (participating and non-participating; shopping and not shopping). This would increase a customer's bill averaging 1000 kWh per month by $0.37.

Duquesne Light Company reported that the estimated cost for enhancement is currently unknown. However the company did report that the estimated costs of replacing its current billing system would range between $11 million and $27 million. The company did not provide an estimate of the monthly impact on the average residential bill.

An inventory of Duquesne Light's metering capacity and load control devices was performed. The company reported it has 543,854 standard residential meters installed that cost between $60 and $150 (meter only). The company has 177 interval residential meters ($289 and $499 per meter) and 64 load control residential meters ($200). For C&I customers, there are currently 61,692 standard meters, 1,754 TOU meters, and 831 interval meters; all meter types cost between $60 and $499. There are no load control devices installed for C&I customers.

FirstEnergy targeted changes that would be needed to apply a rate change for an interval/metering TOU program. The company reported that it currently has no mechanism in place to provide DSR for residential customers, that its capability is limited to the large customer. Regarding FirstEnergy's existing metering and load control devices, the company reported having nearly one million standard residential meters installed ($70/meter), approximately 80,000 TOU residential meters ($153-$183). No interval meters or load control devices are currently available for residential customers. An inventory of FirstEnergy customer metering devices is provided below.

FirstEnergy Meter & Load Control Device Inventory

	Standard Meters #/(Cost)	TOU Meters #/(Cost)	Interval Meters #/(Cost)	Load Control Devices #/(Cost)
Residential	1,000,000 ($70)	80,000 ($153-183)	0	0
Commercial	149,215 ($150-$190)	531 ($190)	406 ($432-$632)	0
Industrial	3593 ($150-$190)	353 ($190)	587 ($432-$632)	0

In order to provide DSR system-wide, FirstEnergy reported that a first-cost estimate for software upgrades is $232 million (in 2004 dollars) with an annual operating cost estimated to be $4.4 million. The per-customer cost is estimated at $3.75 per month with a 14-year declining rate of depreciation for the equipment. These costs include the installation of new substation infrastructure and new metering and metering upgrades.

PECO Energy did not consider the final-form DSR program in its cost estimates; however, the company conceded that a TOU or Smart Thermostat program would not be out of the question. PECO's estimate for upgrading meter data repository and enhancement of its existing billing system to support a new DSR rate is $3 million. With an assumed five-year life cycle for the software at a 10% discount rate, the estimated per-customer monthly charge would be $0.05 or an increase of $0.00005/kWh with carrying charges spread over 1.4 million customers or 20 million MWH. Hardware upgrades were not included in PECO's estimate. A request for an inventory of PECO's meter and load control devices produced only the numbers of standard meters installed: 1.3 million residential; 152,000 commercial; and 3000 industrial.

PPL's estimate relates to the implementation of a suite of DSR programs for TOU, which would require a meter data management system that would cost between $2.5 and $5 million. Unlike Allegheny Power, PPL stated that its billing system is meter-specific, making an upgrade much more complex and costly. PPL stated that its estimate has one caveat—the ability to add a nominal fee for data storage. Following is the metering device inventory prepared by PPL.

PP&L Meter & Load Control Device Inventory

	Standard Meters #/(Cost)	TOU Meters #/(Cost)	Interval Meters #/(Cost)	Load Control Devices #/(Cost)
Residential	1,165,001 ($76-$244)	14,921 ($259)	649 ($244-$311)	0
Commercial	124,741 ($76-$244)	759 ($259)	43,467 ($244-$1200)	0
Industrial	0	16 ($259)	1,396 ($254-$1,200)	0

UGI estimated the cost to upgrade its billing system only. To enhance billing data collection servers and to replace the current billing mainframe would be approximately $1.2 million (in 2004 dollars). The costs of metering and meter-related hardware and software are not included in its estimate. Additional funds would be needed to provide additional data storage required by BCS, to perform unbilled calculations, and to set-up interaction with its current system. UGI's meter and load control device inventory results appear in the following table.

UGI Meter & Load Control Device Inventory

	Standard Meters #/(Cost)	TOU Meters #/(Cost)	Interval Meters #/(Cost)	Load Control Devices #/(Cost)
Residential	53,950 ($75)	7 ($180)	350 ($180)	0
Commercial	5,245 ($120)	0 ($245-$265)	2,013 ($245-$265)	0
Industrial	26 ($120)	0 ($245-$265)	134 ($245-$265)	0

Q.2 How long would it take to make the billing system changes and/or implement other supporting IT infrastructure necessary to allow for implementation of a DSR program on a wide-scale basis?

Deployment time estimates range from12 months to three years. Allegheny Power stated that the time it needed to make the system/equipment upgrades would be between one and two years. Duquesne Light could not estimate the timeframe for enhancements, but estimated that 18 to 24 months would be needed for replacement of its billing system. FirstEnergy decided that 18 to 24 months would be needed for enhancing its billing system; 24-30 months for developing a metering infrastructure. PECO determined that three years would be needed to fully implement its billing system upgrades, which include time to complete a requirements analysis, program design, programming, and testing and training that would need to be performed concurrent with the DSR project and its maintenance workload. PPL's deployment estimate is two years. PPL also suggested that DSR consumer education would hopefully be dovetailed with a POLR. UGI recognized that there would be a need to consider company projects and priorities occurring simultaneously with a DSR-related billing project that it estimated would require approximately 18 to 24 months. *(Editor's note: It took three years to build an IT infrastructure that included development and testing of Electronic Data Interchange (EDI) transactions for enrollment and billing and other customer information communications.)*

Q.3 Once billing system changes and/or other supporting IT infrastructure are implemented, how long would it take to deploy DSR technology to a customer on "demand"? For instance, would an EDC need 30, 60, 90 days, or more or less, to provide the technology after receiving the customer's request? It is understood that any billing changes associated with the DSR technology would not be able to take effect until a meter read date consistent with the standard "switching rules."

Company responses were fairly uniform on this question, that depending on the type of program that on-demand deployment could be achieved within one or two billing cycles, consistent with switching rules. Allegheny Power stated that a phased-in, regional educational approach would be an effective way to roll out a large program like this. For programs requiring equipment installation inside a customer premise, i.e., Smart Thermostat, PECO suggested that a 60-day timeframe would be based on such access.

UGI noted that due to the geography of its service territory, a single wireless communication system cannot be utilized with available technology and, therefore, costs and installation time could be somewhat higher for some customers.

FirstEnergy qualified its response based upon technology selected and level of demand. The company suggested that if there were a high initial demand for the service, installation could take from 60 to 120 days, after which a start date could be 30 to 60 days.

Duquesne Light's response included a caveat that the physical deployment of interval metering and other necessary equipment would take three to five years at a capital cost of $327 million with an additional O&M cost of about $6.3 million annually. Once that is installed, the on-demand deployment could be achieved in less than 30 days in most cases. The company stated that in all probability it could be implemented at the beginning of the customer's next billing period following receipt of the customer notification and allowing at least one workday for system file maintenance to be processed.

Summary of EDC Responses -- Table 1 Meter & Load Control Device Inventory **Jun-04**

	AP	Duquesne	First Energy	UGI	PECO	PPL
Residential						
# Standard Meters	672,831meters	543,854 meters	989,852 meters	53,950 meters	1.3 million meters	1,165,001 meters
Cost	$24	$60 L;$65 Ave.;$150 H	$70 meter only	$75 meter only	$21L-$130H	$76 L;$244 H
# TOU Meters	0	0	80,408 meters	7meters	12 meters	14,921 meters
Cost			$153-$183	$180	$21L-$130H	$259 L, Ave, H
# Interval Meters	0	177 meters	0	350	0 meters	649 meters
Cost		$289 L;$329 Ave;$499 H	$432	$180	$21L-$130H	$244 L;$283 Ave;$311 H
# Load Control Devices	0	64 meters	0	0	0	0
Cost		$200				0
Commercial						
# Standard Meters	23,917 meters	61,692 meters	149,215 meters	5,245 meters	153,000 meters	124,741 meters
Cost	$70-$300	$60 L; $240 Ave; $499 H	$150-$190	$120	$98L-$530H	$76 I; $244 H
# TOU Meters	0	1,754 meters	531meters	0	0 Meters	795 meters
Cost		$289 L;$414 Ave; $499 H	$190	$245-$265	$98L-$530H	$259 L,Ave,H
# Interval Meters	Combined w/Ind	831meters	406 meters	2,013 meters	0	43,467 meters
Cost		$289 L;$414 Ave;$499 H	$432-$632	$245-$265	$98L-$530H	$244;$261 Ave;$1200 H
# Load Control Devices	0	0	0	0	0	0
						0
Industrial						
# Standard Meters	0	Combined w/ Commercial	3593 meters	26 meters	1200 meters	0
Cost			$150-$190	$120	$1500 Ave	0
# TOU Meters/Cost	0	Combined w/ Commercial	353 meters	0 meters	0	16
Cost			$190	$245-$265	$1500 Ave	$259 L, Ave, H
# Interval Meters	1402	Combined w/ Commercial	587 meters	134 meters	1200 meters	1396
Cost	$300-$1000		$432-$632	$245-$265	$1500 Ave	$254 L;$600 Ave,$1200 H
# Load Control Devices	0	0	0	0	0	0

Table 2. Summary of All EDC Demand Side Response (DSR) Programs

Updated 6/04

EDC	Program	Description/Costs	Eligible Participants	Special Requirements	Tariff (Y/N)
Allegheny Power	**-- Voluntary Generation Buy-Back--** **Intra-Day or Next Day** (Effective 6/01/01)	-- Allegheny Power buys-back or displaces firm load when the market price for generation is expected to reach a certain level. Customers can select 1 of 10 price signals & request to be notified when Allegheny Power declares a buy-back period. -- AP reports it will continue mining for opportunities & customer solutions to grow customers & MWs participating in the program. This program remains in place and available to industrial customers	-- Large C&I	-- On-Site Generation/ Operational Flexibility	-- No
	Real Time Pricing Pilot	This is a limited pilot in which customers are provided with an Internet enabled smart thermostat on enrollment. Each customer can program there thermostat for energy conservation. In addition each customer can pick two energy prices and instruct the system what action to take if those prices are exceeded. Each hour the system looks at the hourly day ahead price and adjust the thermostat based on their instructions several participants have other devices like water heaters, pool pumps or hot tubs also controlled based on hourly price (see below)	-- Resident & Small Commercial	--"Smart" Thermostat	-- No
	Distributed Generation Price PilotProgram	-. These customers are also part of the Real Time Pricing pilot shown above. There are three customers that have generator units in place. Instead of switching other devices on and off these customers systems switch the distributed generation unit on and off based on the price choices they have made. Hourly, the system looks at their price choices and turns the generator on if their price choice is exceeded. The load connected to the generator is then switched off of the electricity grid onto the natural gas fired unit. When the price drops below their price choice the load is transferred back to the grid and the generator is switched off.	-- Resident	-- Standby Generator	

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Updated 6/04

EDC	Program	Description/Costs	Eligible Participants	Special Requirements	Tariff (Y/N)
Duquesne	**-- Voluntary Contract Load Reduction Program (Effective June-Sept)**	Customers enter an agreement with Duquesne to make their generators or curtailable load available for peak load reductions during times of high energy prices & other system needs. Customers do not make a firm commitment. Duquesne compensates participants to effect the agreed load reductions for the duration of each event. Customers can opt in or out each time an event is called with no penalty. Duquesne worked successfully with Reliant to establish the procedures for determining customer baselines for program participants. While market conditions did not trigger this program during the summer of 2002, the program was initiated on July 29, 2002 as part of the Company's efforts to serve otherwise "shopped" load that was left unsupplied due to transmission constraints. Market conditions again did not trigger the program during the summer of 2003. The program has been communicated to all qualifying customers and is promoted on the Company's website.	-- Large C&I	-- On-Site Emergency Generators-Nameplate Capacity Ratings 500 kW or greater; Willing to reduce 500 kW or greater block of load	-- No
	-- Direct Load Control Pilot Program (Effective June – September)	-- In 2002, Duquesne initiated a <u>pilot</u> direct load control program open to residential and small commercial customer having central air conditioning. Enrollment was limited to 100 customers. Ultimate participation was 83. (No commercial customers participated.) Participants chose one of two options: Option 1 - In return for a $10 monthly bill credit (for the four months of the program) a customer was subject to having air conditioning load eliminated for up to four hours during an event; Option 2 – In return for a $5 monthly bill credit, air conditioning load would be cycled 45 minutes off and 15 minutes on for a period of up to four hours during an event. Events were limited to on-peak weekday hours. Number of events was not to exceed eight over the program application period. Events were triggered by temperatures of 85 degrees or above. Eight events occurred the period. --Sixty-three customers participated in the program during the summer of 2003. Due constraints involving installations and the overall lack of hot weather, no events were called during the application period. --This program will be offered again for the summer of 2004, with enrollment expanded to 200 customers. Enrollment activities will commence in early March.	-- Resident/ Small Commercial	-- Direct Load Control Device—Not Smart Thermostat	-- No

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Updated 6/04

EDC	Program	Description/Costs	Eligible Participants	Special Requirements	Tariff (Y/N)
FIRST ENERGY Met-Ed & Penelec	**-- Voluntary Load Reduction Program**	-- Customers voluntarily commit to reduce specified level of hourly load in response to day-ahead or day-of price offer from FirstEnergy. Offers may be made 12 months of the year according to market energy rates. Program parameters are consistent with and can compliment PJM's programs, where appropriate.	-- C&I	-- Interval Meter; Internet access	-- No
	-- **Seasonal Savings Program**	-- Customers contract to reduce specified level of hourly load in response to two-hour to day-ahead "call". Program provides fixed monthly incentives. Customers are also paid fixed rate ($/kWh) for actual load reductions.	-- C&I	-- Interval Meter; Internet access	-- No
	-- Time of Use Pilot	-- Residential customers can reduce their summer bills by shifting usage from high-cost weekday period. Interested customers can call 800-823-6462. Registration Ends May 31, 2003. Limit - 200 per company. Implementation anticipated Summer 2003.	-- Residential	-- Existing RS full service Customer with at least 1000 kWh use in summer	-- Yes
	-- Rider E / Rule 20	-- Existing Tariff provisions allowing mandatory/semi-mandatory load reductions.	-- C&I	-- Existing full service customers served under these provisions as of 1998	-- Yes
	-- Direct Load Control / Other (Residential / Small C&I)	-- FirstEnergy continues to explore the potential to offer cost-effective load response programs to residential and small C&I customers.	-- Residential & Small C&I	-- Ongoing Development	-- No
	-- Distributed Generation	-- The Companies will explore the use of distributed generation on an individualized basis.	-- C&I	-- On-site Generation	-- No
PennPower	**-- Real time Pricing (RTP)**	-- Program allows participating customers to respond to day ahead hourly price signals based on the Company's quoted price to supply electricity. Customers are provided, via internet, 24 hourly binding price quotes for the following day.	-- C&I	-- Interval Meter	-- Yes Filed 5/11/01 -- Yes Filed 6/15/01

Table 2. Summary of All EDC Demand Side Response (DSR) Programs

Updated 6/04

EDC	Program	Description/Costs	Eligible Participants	Special Requirements	Tariff (Y/N)
PECO	**-- Interruptible Rider-2** (Experimental) **Effective April 6, 2001 to May 31, 2003** **"Smart Returns Program"**	-- **Active Load Management Contract**: PECO notifies customer to reduce load at certain times of production, transmission, or distribution limitations. Customer receives Interruptible Demand Credit ($/kW per month). Or -- **Economic Curtailment Contract**: Customer compensated for voluntarily curtailing energy usage during periods of high-energy prices, when requested by PECO. Customer receives "Curtailed Energy Credit per contract. The curtailed energy credit is the amount paid to the customer for reducing usage. It can be a fixed price or a % of savings and can be based upon day ahead or day-of prices. The customer chooses the options they prefer. Customer pays $101.59 monthly charge. Supplement 47 revises IR-2 to make permanent. Reduces load requirement to 100 kW and incorporates other minor enhancements.	-- Large C&I; General Service-- Rate HT, GS, Energy Efficiency Rider Customers	-- Interval Meter; Ability to curtail, at minimum, 100 kW of load or 5% of peak demand	--Yes Approved 4/5/01 Supp. 47 approved 5/15/03
	-- "GoodWatts" Pilot (Summer 2003)	-- Installed and tested Invensys GoodWatts system on approximately 100 residential customers in summer of 2002. System allows utility to shift air conditioning loads from peak to off peak periods and provides real time verifiable data on customer usage. Trial will be extended through the summer of 2003 with 85 customers. Curtailment tests focused on measuring maximum acceptable curtailment. Trial to continue in summer of 2004. Goal is to test realistic program curtailments including pre-cooling. Economics of this technology does not support full-scale implementation at this time.	-- Small Commercial Residential	***Pilot*** participants need to be digital Cable subscribers Central A/C	--No

Table 2. Summary of All EDC Demand Side Response (DSR) Programs

Updated 6/04

EDC	Program	Description/Costs	Eligible Participants	Special Requirements	Tariff (Y/N)
PPL	**-- Demand Side Initiative Rider (DSI) (Supplement No. 16)** 6/1/01 to 1/1/ 2005 Experimental	-- Provides eligible customers with an opportunity to respond to changes in the electric generation market by adjusting their load requirements. Customers would have an option to pay actual market prices for all, or a portion, of their energy needs. As market prices for energy change, customers can increase, decrease or shift their load requirements. Customer enters 1 year contract and pays PPL $349.27 monthly rate. Customers have inquired about the rider, but none have elected to take service.	-- C&I Rate Schedules LP-4;LP-5; LP-6; IS-P; and IS-T	-- Interval Meter & 1,000kW demand; Dedicated phone line; Access to internet to obtain metering & MP data.	--Yes • Filed 5/10/01 •Approved 5/24/01
	-- **Demand Side Response Rider -- Residential (Supplement No. 23)** 4/16/02 to 4/16/05 Experimental	-- Provides eligible residential customers with an opportunity to shift energy usage away from peak demand hours that can occur during the summer months when wholesale electricity prices are high. Takes unbundled generation rates approved in the settlement and further unbundles them during the months June through September into on-peak and off-peak rates of approximately 8 cents on-peak and 3 cents off-peak. Program was introduced in the summer of 2002 to approximately 22,000 residential customers in Allentown/Bethlehem. Consumer Education on equipment energy use and possible actions to use the rate to save money was provided to all eligible customers. A total of 21 customers participated during 2002. Program was expanded to all of the Allentown/Bethlehem area and to Lancaster and Harrisburg areas in 2003 with a total number of participants increasing to 265.	--Residential Rate Schedule RS	-- Automatic Meter Reading device & monthly energy usage of 1000 kwh or greater during each of the months June, July, August, and September. -- Customers may not receive Off-Peak Water Heating or Separate Water Heating Service under Rate Schedule RS. -- Limited to 300 eligible customers.	--Yes Filed 2/15/02 Approved 4/11/02 No. of participants increased from 200 to 300 on 6/1/03

PPL	-- Interruptible Service – Economic Provisions –	**--** Permits PPL to request customers to reduce load for economic conditions. In exchange, those customers receive significant rate discounts. Economic load control events are limited to not more than 10 hours per occasion and not more 5 occasions per year. Other limitations exist in combination with Interruptible Service – Emergency Conditions (see below). Total of 67 customers.	-- C&I Rate Schedules IS-P; and IS-T	-- Interval Meter & 1,000 kW of interruptible load. Program is closed to new applicants.	--Yes
	-- **Interruptible Service – Emergency Provisions**	-- Permits PPL to request customers to reduce load for emergency conditions. In exchange, those customers receive significant rate discounts. Emergency load control events are limited to not more than 10 hours per occasion. The total of economic (see above) and emergency load control events is limited to not more than 15 per calendar and not more than 5 per month. Total of 72 customers.	C&I Rate Schedules IS-P; and IS-T	-- Interval Meter & 1,000 kW of interruptible load. Program is closed to new applicants	--Yes
	-- Price Response Service –	-- Permits customers to respond to market price signals with a portion of their load. Note that interruptible customers can also take price response service (Rate Schedule PR-2). Total of 9 firm customers. For the purposes of this summary, nterruptible customers are included in the Interr4uptible program above.	C&I Rate Schedule PR-1.	-- Interval meter and communications link to PPL. Customers must have monthly max demand of 2000kw or greater and are served under Rate Schedule LP-4, LP-5, or LP-6. Program is closed to new applicants.	-- Yes

Table 2. Summary of All EDC Demand Side Response (DSR) Programs

Updated 6/04

EDC	Program	Description	Eligible Participants	Special Requirements	Tariff (Y/N)
UGI	**--2003 Voluntary Load Reduction Program** (June-August)	-- UGI offers participating customers a monetary incentive to curtail load upon request. Incentive based on a percentage of savings achieved by UGI as determined from the difference between the lost billed revenue and the power cost savings realized by the Company which result from the customer's load reduction. Predetermined thresholds for a load reduction event are the combination of LMP & potential load reduction amount of the participant. There are no additional charges. ■ Areas where customers may be able to reduce load including: maintenance outages; shifting processes from peak to non-peak hours. UGI provides metering equipment at no cost to the customer and calculates corresponding settlement amounts.	-- Large C&I customers capable of: Reducing or Self-Supplying at least 100 Kw of their load.	-- Interval Meter; Hourly load reduction; Ability to curtail load between 9 am and 9 p.m.; Curtail load for multiple hrs. with 1 hr. notification.	-- No
	-- Time-of-Use (Rate RTU)	-- RTU is a time differentiated rate where residential customers pay higher prices during pre-defined on-peak hours than off-peak. Company is currently operating under a rate freeze which prevents a change in TOU rates. UGI is in the process of examining all generation rates so that when the rate freeze expires, generation rates can better reflect the cost of power. -- UGI continually educates customers on the benefits of reducing power consumption during peak and/or high priced periods. Conservation tips in newsletter.	-- Residential Customers	-- TOU Meter	--Yes

Table 3. Summary of EDC Steps Needed to Make DSR Available to ALL Its Customers

Date 6/04

EDC	DSR Technology	Overview of Infrastructure Requirements (Include every aspect from operations center, software to customer location)	Summary of Deployment Costs	Approximate Deployment Timeframe
Allegheny Power	-- **Interval Meters** 1400	-- All customers with existing interval meters are eligible to participate in Allegheny Powers's generation buy- back program as previously outlined.	None These are existing $600 one time cost for interval meters where not rate required with $30 monthly processing charge.	Enrollment is open
	-- Time of Use None	--NA		
	-- Smart Thermostats	-- 17 customers are currently participating in Allegheny Power's residential Real Time Pricing pilot.	This option includes a single-phase recording meter with phone access. The approximate cost to deploy one location is $ 600 with a recurring cost of $20 per month, at this scale. This is available now.	Assuming customers are prepared to bare the costs in a post rate cap environment these installation could be made fairly quickly. An estimate of 1000 points per year would be a reasonable rollout.

Table 3. Summary of EDC Steps Needed to Make DSR Available to ALL Its Customers

Date 6/04

EDC	DSR Technology	Overview of Infrastructure Requirements (Include every aspect from operations center, software to customer location)	Summary of Deployment Costs	Approximate Deployment Timeframe
Duquesne	-- **Interval Meters**	-- Installation of 608,258 Interval Meters and all associated infrastructure and operating requirements	Capital $327.2M O&M $ 6.3M	-- 3 To 5 Years
	-- Time of Use	--Installation of 608,258 Time Of Use Meters and all associated infrastructure and operating requirements	-- Capital $168.9M O&M $ 0.6M	-- 3 To 5 Years
	-- Load Control	-- Installation of 587,221 load control devices on all residential and small commercial accounts	-- Capital $206.5M	-- 3 To 5 Years

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EDC	DSR Technology	Overview of Infrastructure Requirements (Include every aspect from operations center, software to customer location)	Summary of Deployment Costs	Approximate Deployment Timeframe
FirstEnergy **Met-Ed Penelec, PennPower**	**-- Interval Meters** **-- Time of Use**	-- Without a better understanding of potential cost recovery and/or rate making mechanisms, the Companies are unable to postulate any deployment strategies at this time. Description and estimates will be provided following clarification through discussion and improved definition of concept. Suggest addressing DSR product concepts by customer class, and functionality (e.g. RTP, TOU, direct control, or combinations of the above). Cost estimate investigation should specifically include: - Billing System Enhancements - Marketing - Hardware - Installation (including any permitting and other process management…) - Communications - Maintenance and Attrition - Reporting - Customer contribution		
	-- Smart Thermostats	- Current energy & capacity values could not begin to support the magnitude of dollars indicated in the next column. In addition, these figures do not ongoing communication, software and maintenance costs. The same discussions and cost investigations as mentioned above would be necessary in order to refine the estimate. The estimate is based on the assumption that central AC saturation is at 30 % of Met-Ed Customers & 15% of Penelec & Penn Power Customers. Target 50% of Eligible Customers = approximately115,000 installations.	Installation $28,750,000 Meters $6,900,000 Infrastructure/Professional Services $100,000 Software/Licensing $25,000 Total Costs $35,775,000 Smart T-Stat costs are based on the same cost estimates presented previously, updated to reflect estimated anticipated installations	5 to 10 plus years

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Date 6/04

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UGI	-- **Interval Meters**	■ Two way communication system(s) in order to transmit pricing as well as receive hourly usage information ■ New billing systems (hardware and software) to accommodate hourly billing ■ Consumer Education ■ Interval Meters	N/A: These costs are not developed at this time	N/A
	-- Time of Use	■ Time of Use Meters ■ Consumer Education	N/A: These costs are not developed at this time, however TOU Metering would be the least costly of these three DSR initiatives.	N/A
	-- Smart Thermostats	■ Two way communication system(s) ■ Control systems (hardware and software) ■ Interval Meters ■ Personnel to administer program ■ Consumer Education	N/A: These costs are not developed at this time, although in the past this type of offering appears to be the most costly with very limited customer interest.	N/A

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EDC	DSR Technology	Overview of Infrastructure Requirements (Include every aspect from operations center, software to customer location)	Summary of Deployment Costs	Approximate Deployment Timeframe
PECO	-- **Interval Meters**	1**) meter reading costs**. Peco's AMR system is already deployed. Interval reads for up to 60,000 customers are available as a service upgrade.	Incremental per read charge.	6-12 months
		Above 60,000 customers, contract negotiation required. System upgrades to the network required based upon the number of customers on interval metering. 2) IT Costs a. Upgrades required to internal meter data storage systems required for both CIS and PAC b. Billing system changes required to allow billing on interval data. c. Data warehousing/data storage enhancements required. d. EDI changes to handle billing for shopping customers. 3) Training a. call center. b. Large accounts Note: Cost estimates will assume current customer information systems can be modified to handle interval data. Detailed requirements analysis may show that new CIS system id required.	Price unknown.	1-3 years.
	-- Time of Use	1) Meter reading costs. TOU reads are available. 2) IT costs a. Use existing rate or develop new TOU rate. b. EDI for shopping customers. 3) Training for call center.	Incremental per read charge.	90 days.

EDC	DSR Technology	Overview of Infrastructure Requirements (Include every aspect from operations center, software to customer location)	Summary of Deployment Costs	Approximate Deployment Timeframe
PECO	-- **Smart Thermostat**	1) Customer Recruitment	Dependent on size of program.	6-12 months
		2) Hardware	Depends on type of technology chosen.	
		3) Install costs	Assume 2 trips per house.	
		4) Metering	Incremental per read fee. Sample or 100% verification?	
		5) Service Provide subscription or license fee	Per contract.	
		6) Customization of service provider software	TBD	
		7) Billing system changes	New Rate or modify existing rate?	
		8) Credit or incentive payments	TBD. Based upon program design.	
		9) Call center training		
		10) Ongoing equipment maintenance .		

Table 3. Summary of EDC Steps Needed to Make DSR Available to ALL Its Customers **Date 6/04**

EDC	DSR Technology	Overview of Infrastructure Requirements (Include every aspect from operations center, software to customer location)	Summary of Deployment Costs	Approximate Deployment Timeframe
PPL				
	-- **Interval Meters** **-- Time of Use**	-- AMR meters can be queried on demand so they could be considered to satisfy both functions. However, a meter data management system and billing interface is required to automate those functions if DSR programs were to be offered to large numbers of customers. The next step, depending on the nature of the program, would be to provide data back to the customer so that he can monitor his performance. We are attempting to develop information regarding both of these additional functions, but have nothing to offer yet.	The AMR deployment totals approximately $116 million. The cost of communications equipment, computer hardware, and computer software is an additional approximately $44 million. This does not reflect the costs to operate the system which includes personnel dedicated to operation and maintenance, and the cost of communication.	
	-- Smart Thermostats	-- No Knowledge		
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