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Via Courier

April 1st, 2013

Mr. Jeff Derouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: Docket Case No. 2012-00578

Dear Mr. Derouen:

Enclosed for the filing are an original and ten copies of the *Direct Testimony and Exhibits of Tim Woolf On Behalf of the Sierra Club* and a certificate of service in docket 2012-00578 before the Kentucky Public Service Commission. This filing contains no confidential information.

Sincerely,

Ruben Mojica
Sierra Club Environmental Law Program
85 2nd Street, 2nd Floor
San Francisco CA, 94105
(415)977-5737

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Application of Kentucky Power Company For: (1) A Certificate of Public Convenience and Necessity Authorizing the Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	)	Case No. 2012-00578

AFFIDAVIT OF TIM WOOLF FOR DIRECT TESTIMONY

Commonwealth of)
Massachusetts)

Mr. Tim Woolf, being first duly sworn, states the following: The prepared Direct Testimony and associated exhibits filed on Monday, April 01, 2013 constitute the direct testimony of Affiant in the above-styled cases. Affiant states that he would give the answers set forth in the Direct Testimony if asked the questions propounded therein. Affiant further states that, to the best of his knowledge, his statements made are true and correct.

Tim Woolf
Mr. Tim Woolf

SUBSCRIBED AND SWORN to before me this 1 day of April 2013.

Notary Public

My Commission Expires:
7/27/2018

JANICE CONYERS
Notary Public
Commonwealth of Massachusetts
My Commission Expires
July 27, 2018

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Direct Testimony of
Tim Woolf

On Behalf of
The Sierra Club

On the Topic of
The Company's Economic Analysis of the Mitchell Purchase

April 1, 2013

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1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and occupation.

A. My name is Tim Woolf. I am a Vice-President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues including integrated resource planning; economic and technical assessments of energy resources; electricity market modeling and assessment; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients including attorneys general, offices of consumer advocates, public utility commissions, environmental groups, U.S. Environmental Protection Agency, Department of Energy, Department of Justice, Federal Trade Commission and National Association of Regulatory Utility Commissioners. Synapse has over twenty professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. As a Vice-President at Synapse Energy Economics, I provide consulting services on a range of issues, including electricity industry regulation and planning; technical and economic analyses of electricity systems; energy efficiency program design and policy analysis; renewable resource technologies and policies; clean air regulations and policies; and many aspects of consumer and environmental protection.

Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity I was responsible for overseeing a significant expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the commission, including several electric and gas rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director of the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume is attached as Exhibit TW-1.

Q. Please describe your professional experience as it relates to integrated resource planning and demand-side management.

A. Integrated resource planning (IRP) and demand-side management (DSM) have been a central part of my 30-year professional career. While a Commissioner at the Massachusetts DPU I played a leading role in updating the Department's energy efficiency guidelines, in reviewing and approving the recent three-year energy efficiency plans, in reviewing and approving energy efficiency annual reports, and advocating for allowing energy efficiency to participate in the New England wholesale electricity market.

As a consultant I have reviewed and critiqued utility integrated resource plans and DSM programs in many US states and several Canadian provinces. My work has encompassed all aspects of IRP and DSM program design and implementation, including resource assessment, modeling methodologies, scenario analysis, cost-benefit analysis, risk assessment, and resource plan selection. I have also represented clients on several IRP and DSM collaboratives, where policies, programs and plans are discussed and negotiated among a variety of stakeholders.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review and assess the planning process that Kentucky Power Company (the Company, or KYPCo) used to evaluate the merits of purchasing a fifty percent interest in the Mitchell Generation Station (Mitchell), with an emphasis on the range of alternatives considered and the role that DSM, renewable resources and natural gas resources played in that process. I also address the appropriate use of a request for proposals (RFP) for the purpose of identifying and assessing alternatives to the Mitchell purchase. Finally, I address the appropriate method for valuing an asset that is transferred between two affiliated companies.

Q. Have you previously testified before the Kentucky Public Service Commission (the Commission)?

A. No, I have not.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your primary conclusions.

A. I make the following findings:

- The Company has not demonstrated that the Mitchell purchase is the lowest-cost option for replacing Big Sandy Unit 2, or for meeting future electricity needs.

- The Company's economic analysis fails to properly evaluate several important resource options, including DSM resources, renewable resources, and existing natural gas resources. This approach is inconsistent with current integrated resource planning requirements in Kentucky, and is inconsistent with standard integrated resource planning practices in the US electricity industry.

- The Company has used an out-of-date gas price forecast that overstates the likely price of natural gas, thereby overstating the economic value of the Mitchell purchase.

- The Company did not issue an RFP for new resources, as a means of identifying and assessing resource alternatives to the Mitchell purchase. Consequently, the Company does not have a "market test" to indicate, either for itself or for the Commission, that the cost of the Mitchell purchase is reasonable or that the Mitchell purchase is the lowest-cost option.

- The Commission should be particularly concerned about these shortcomings in the Company's analysis, given that the Mitchell purchase is a transfer of assets between two affiliated electric companies. KYPCo, as a subsidiary of American Electric Power (AEP), the same company that owns Ohio Power Company (OPCo), may have a financial incentive to purchase Mitchell at a cost that is higher than its market value or than the cost of alternative resource options.

- If the Company is allowed to purchase Mitchell, the cost of the purchase should not be on the basis of the net book value of the plant. Whenever a regulated utility is receiving an asset from an affiliate, the transfer should be made at *the lesser of* (a) the net book value or (b) the market value. This is the only way to ensure that all ratepayers are treated fairly, and that the affiliated entities are provided with the appropriate incentives for the purchase and sale of the asset.

- The market value of the Mitchell purchase is likely to be well below its net book value, based on comparisons with recent coal plant sales.

- All of these findings suggest that there is a theme underlying the Company's economic analysis of the Mitchell purchase: that AEP may be selling an uneconomic power plant to its regulated utility affiliate in order to recover the costs of that plant from captive KYPCo customers.

Q. Please summarize your primary recommendations.

A. I offer the following recommendations:

- The Commission should deny the Company's request for a certificate of public convenience and necessity for the purchase of fifty percent of Mitchell.
- The Commission should direct the Company to immediately revisit the alternatives to the Mitchell purchase. This would include issuing an RFP as soon as is practical to purchase energy and capacity necessary to meet future resource needs. This would also include a more thorough assessment of potential natural gas power plant options, renewable resources, and DSM resources.
- The Commission should open a generic docket to establish DSM regulations or guidelines that would apply to all electric and gas utilities in Kentucky. These regulations should require utilities to prepare periodic (e.g., annual) DSM plans that will lead to on-going implementation of cost-effective DSM programs in the future. These regulations should also include a set of policies to ensure that utilities have the proper regulatory guidance and financial support to ensure that the DSM programs are effective, successful, and in the interests of customers.

Q. If the Commission were to accept your recommendation to deny the Company's request for a CPCN, does this mean that the Company should reconsider the proposed retirement of Big Sandy Unit 2?

A. No. The Company's economic analysis of the Mitchell purchase clearly demonstrates that retrofitting Big Sandy Unit 2 is not the least-cost option for KYPCo customers. There is no evidence in this case suggesting that the Big Sandy retirement decision should be reconsidered.

Q. Should the Commission be concerned that if it denies the Company's request for a CPCN for the Mitchell purchase that the Company will not have sufficient resources to meet customer needs when Big Sandy Unit 2 is retired?

A. No. The Company has several resource options available to replace Big Sandy Unit 2. In the short-term, KYPCo can rely upon purchases from the PJM market. It can also commence a competitive bidding process to procure power from neighboring utilities and generation companies, in the same way that it is considering purchasing power to replace Big Sandy Unit 1. For the medium- and long-term, the Company can consider construction of gas combined-cycle or combustion turbine units, to the extent that they are deemed economic. Furthermore, the Company can undertake several initiatives to develop a broader range of DSM and renewable resources. The opportunities available from these alternative resources are described in more detail below.

3. OVERVIEW OF THE COMPANY'S ANALYSIS OF MITCHELL

Q. Please describe the Company's application.

A. The Company requests that the Commission approve a Certificate of Public Convenience and Necessity (CPCN) to transfer a fifty percent interest in OPCo's Mitchell generating station and related assets to the Company (Application, p. 1). The Company requests the CPCN for two primary reasons. First, a Pool Agreement designed to share generating capacity among certain utilities in the east south-central region is expected to terminate on January 1, 2014. Following termination of the Pool Agreement, the Company will be required to have sufficient generation to meet its load and reserve obligations (Application, pp. 8-9).

Second, the Company is expected to retire its 800 MW coal-fired steam electric generating unit, Big Sandy Unit 2, by June 2015. The Company is expected to retire Big Sandy Unit 2 because the unit would otherwise need to be retrofitted with extensive and costly environmental controls in order to comply with federal EPA regulations and a 2007 Consent Decree. (Application, p. 9; Direct Testimony of Pauley, p. 19).

Previously, the Company made a similar CPCN application to retrofit rather than retire Big Sandy Unit 2. The Company eventually withdrew its application to retrofit Big Sandy Unit 2 so as to re-evaluate the resource alternatives available for meeting its energy and capacity obligations (see Case No. 2011-00401). The Company's current CPCN request is a direct result of the Company's Big Sandy retrofit re-evaluation efforts (Application, p. 2).

The Company states that it has conducted in-depth analyses of reasonable portfolio alternatives to determine the best path to ensure adequate and reliable capacity and energy for its customers (Application, p. 2). Based on these analyses, the Company claims that the Mitchell transfer is the least-cost and best alternative to meet its long-term capacity obligations and to meet its customers' energy requirements (Application, p. 15).

Q. What are the portfolio alternatives that the Company considered as part of its determination that the Mitchell transfer is the least cost and best alternative to meet its long-term capacity obligations and customers' energy requirements?

A. The Company examined eleven variations involving six discrete alternative options assumed to be available to the Company to address the unit disposition decisions facing both Big Sandy Units 1 and 2 (Direct Testimony of Weaver, p. 5). The six primary options set forth the alternatives associated with Big Sandy Unit 2 (Direct Testimony of Weaver, p. 7). Except for one option, all six primary options included a subset of alternatives that considered the disposition alternatives for Big Sandy Unit 1 (Direct Testimony of Weaver, p. 7). The six primary options are as follows:

- Option 1: retrofit Big Sandy Unit 2 with dry flue gas desulfurization technology.
- Option 2: retire Big Sandy Unit 2 and replace it with a new-build natural gas combined cycle facility located at the Big Sandy site.
- Option 3: retire Big Sandy Unit 2 and replace it with a repowering of Big Sandy Unit 1 as a natural gas combined cycle facility.

- Option 4: retire Big Sandy Unit 2 and replace it with capacity and energy purchased from projected available PJM markets.
- Option 5: retire Big Sandy Unit 2 and replace it with capacity and energy from a fifty percent ownership interest of Mitchell Units 1 and 2, while converting Big Sandy Unit 1 to burn natural gas.
- Option 6: retire both Big Sandy Units 2 and 1 and replace them with capacity and energy from a fifty percent ownership interest of Mitchell Units 1 and 2 (Direct Testimony of Weaver, pp. 5-7).

The Company believes that this array of unit disposition alternatives reasonably covers, in a broad sense, all operational and economical options (Direct Testimony of Weaver, p. 47; Response to SC 1-25).

Q. How did the Company determine that the Mitchell transfer is the least cost and best alternative to meet its long-term capacity obligations and customers' energy requirements?

A. The Company analyzed the six resource alternatives by employing a proprietary long-term resource optimization tool known as Strategist, and examined a 30-year economic study period (2014 through 2040) to determine the relative least-cost alternative (Direct Testimony of Weaver, p. 15). The generation-related costs/revenue requirements for each alternative were discounted to 2011 dollars and reflected on a Cumulative Present Worth (CPW) basis (Direct Testimony of Weaver, p. 15). The framework through which the Company evaluated the different alternatives focused not on the absolute CPW results for each alternative, but rather on a comparative view of the alternative options' results (Direct Testimony of Weaver, p. 15-16). Therefore, each option was compared to a reference alternative, and the Company established Option 6 as the reference alternative (Direct Testimony of Weaver, p. 28).

The Company concluded that the options with the least-cost attributes over the full study period represented those profiles that would transfer a fifty percent ownership interest of the Mitchell units to the Company (Options 5 and 6) (Direct Testimony of Weaver, p. 40). The Company intends to issue a competitive solicitation in the first part of 2013 for up to 250 MW of long-term capacity and energy to explore other options with respect to Big Sandy Unit 1 (Application, p. 6, footnote 6).

4. CONSIDERATION OF RESOURCE ALTERNATIVES

Q. What must a CPCN applicant do to prove that the statutory standards of public convenience and necessity have been satisfied?

A. As part of its burden of proof, a CPCN applicant, such as the Company, has the obligation to demonstrate that its proposal is part of a least cost approach to meeting its customers' energy needs. In order to do so, the Company should conduct a comprehensive planning assessment, which necessarily includes a robust assessment of alternatives.

A comprehensive planning assessment could take the form of a traditional utility integrated resource plan (IRP). One of the fundamental principles of integrated resource planning is that utilities consider a wide range of different resource types, both supply-side and demand-side, in order to identify the optimal combination of resources to meet future energy needs.

Q. Please explain the standards that govern utility integrated resource planning in Kentucky.

A. The IRP process in Kentucky is governed by 807 K.A.R. 5:058. Utilities are required to submit every three years a plan that discusses historical and projected demand, resource options for satisfying that demand, and the financial and operating performance of the utility's system (807 K.A.R. 5:058, § 1(2)).

The IRP regulation establishes a process that provides for regular review by the Commission Staff of the long-range resource plans of Kentucky's six major electric utilities (807 K.A.R. 5:058, § 11(3)). The Commission Staff have previously stated that:

> The goal of the Commission in establishing the IRP process was to create a comprehensive, but non-adversarial review of demand and supply projections to ensure that all reasonable options for meeting future supply needs were being considered and pursued in a fair and unbiased manner, and that ratepayers will be provided a reliable

> supply of electricity at the lowest possible cost (Case No. 2009-00339, Commission Staff Report on the 2009 Integrated Resource Plan of Kentucky Power Company, March 2011, p. 1).

The Commission Staff has further explained that, in reviewing an IRP, its goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions, and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the least-cost, least-risk plan for the end use customers served by the utility (Case No. 2009-00339, Commission Staff Report on the 2009 Integrated Resource Plan of Kentucky Power Company, March 2011, p. 2).

Q. Has the Company recently filed an IRP?

A. The last IRP submitted by the Company was its 2009 IRP, which the Commission approved on March 17, 2011 (see Case No. 2009-00339). Pursuant to 807 K.A.R. 5:058, §1(2), which is discussed in more detail below, the Company's next triennial IRP was to be submitted to the Commission by August 17, 2012.

On June 28, 2012, the Company requested that the filing of its 2012 IRP be delayed. The Company explained that its then current efforts to re-evaluate its resource options in light of its Big Sandy retrofit CPCN application withdrawal involved much of the same analysis required by an IRP. The Company further explained that, because the Big Sandy units constitute 73 percent of its owned and contracted capacity, an IRP prepared and filed before the re-evaluation was completed would not provide meaningful information to the Commission (Case No. 2012-00344, KYPCo Letter, June 28, 2012).

The Commission granted the Company's request for a filing extension, but stipulated that the Company's 2012 IRP should be filed no later than December 31, 2013 (Case No. 2012-00344, PSC Order, July 30, 2012).

Q. Would you describe the Company's economic analysis of Mitchell as comparable to the analysis that would be undertaken in an IRP?

A. No. There are several reasons why the Company's economic analysis of Mitchell cannot be considered comparable to the analysis that would be undertaken in an IRP. I will elaborate on these reasons below. The general theme of my comments is that the Company's analysis was very narrowly focused on a select subset of available resource options, and therefore did not include a comprehensive review of all supply-side and demand-side options that is typically undertaken in an IRP.

Q. Why do you say that the Company's economic analysis of the Mitchell purchase was very narrowly focused on a select subset of resource options?

The six scenarios considered by the Company included different combinations of the following resource options:

- Big Sandy Unit 2. Retrofit with scrubbers or retire.
- Big Sandy Unit 1. Repower into a new gas combined cycle facility, or convert to burn natural gas, or retire.
- Mitchell. Purchase 50 percent or 20 percent.
- New brownfield gas-fired combined cycle facility.
- New gas-fired combustion turbine facility.
- Purchases from the PJM market; for different amounts and different periods as needed.

This is a very limited set of resource options by IRP standards. The Company's analysis failed to include some critical opportunities that could result in a lower-cost portfolio of resources, including DSM resources (I address these in more detail in Section 5); renewable resources (I address these in more detail in Section 6); and purchases from existing natural gas resources (I address these in more detail in Section 7). Furthermore, the Company did not conduct a competitive solicitation for purchases, which might have produced additional low-cost resource alternatives to the Mitchell purchase (I address this issue in more detail in Section 8).

Q. Before you address these options in more detail, do you have any general comments about the Company's process for selecting resource alternatives to the Mitchell purchase?

A. Yes. The Company dismisses DSM resource options and renewable resource options by arguing that they would not be of sufficient magnitude to replace Big Sandy or to be viable alternatives to the Mitchell purchase (Direct Testimony of Weaver, p. 27; Direct Testimony of McDermott, p. 10; Response to SC 2-19). This logic is inconsistent with standard IRP practice, and precludes the Company from identifying the least-cost plan. There is no need for any one resource type to provide as much capacity and energy as the Mitchell purchase. Instead, a combination of resource types, e.g., DSM, renewables, purchases from existing gas units, and PJM purchases, can be used to meet the Company's resource needs over time.

In addition, this logic leads to an outcome where a large portion of the cost-effective DSM resources remains untapped over the long-term. This logic leads to a cycle that I have seen played out with other utilities. The cycle includes the following phases: (1) The utility does not have a need for a new capacity resources for several years out into the future, and therefore does not pursue all cost-effective DSM, or even a small portion of the cost-effective DSM available, because the need is not apparent. (2) The utility eventually has a need for a capacity resource within the next few years. The utility argues that there is not enough DSM available to meet that need for new capacity, and therefore implements few or no DSM resources. (3) The utility constructs or purchases the new power plant. Once the plant is built its costs are considered sunk costs, and the avoided capacity and energy costs that would be used to evaluate DSM resources plummet. The utility argues that it has no need for new capacity resources, and uses this argument to justify implementing few or no DSM resources. (4) Eventually, a new capacity resource is needed, and the cycle repeats itself. A large portion of DSM resources remains untapped. Customers pay much higher costs than necessary for their electricity. I refer to this as "the cycle of denial."

In fact, this cycle of denial is one of the reasons that IRPs are important – they require regular, periodic assessments of all resource options. This allows utilities to consider and develop the mix of resource options (large, medium, small; base-load, intermediate, peaking; supply-side, demand-side; dispatchable, non-dispatchable) that can be developed *over time* to meet the anticipated long-term resource needs.

This long-term planning approach is especially important for DSM resources because they require time to implement. Achieving anywhere near the full cost-effective potential for DSM requires a combination of many factors, such as comprehensive regulatory policies; utility institutional support and skills necessary to design and implement DSM programs; an infrastructure of trade allies, contractors, architects and other market actors to assist with the implementation of DSM resources; and informed customers. Even when all of these factors are in place, or are in development, it still takes time to work with customers and assist them in adopting energy efficiency measures.

Q. How do you recommend breaking this cycle of denial?

A. In general, two things are needed: comprehensive and meaningful IRP regulations and comprehensive and meaningful DSM regulations. Kentucky already has both IRP and DSM regulations. However, I believe that the DSM regulations need to be expanded to provide more guidance and oversight to the Company's DSM activities. The Company's record of DSM implementation over the past few years provides clear evidence that more guidance and oversight is needed. I will expand upon this point in Section 5.

Q. Do you have any more general comments about the how the Company's resource alternatives were too narrowly focused on a limited set of resource options?

A. Yes. The Company notes in several places that its analysis uses a "portfolio approach," and that the Mitchell purchase will help it achieve an appropriate balance of resource types (Application, p. 2; Direct testimony of McDermott, pp. 3, 7, 9, and 15; Direct testimony of Weaver, p. 40). This is not an accurate representation of their analysis, or the outcome of their analysis. As noted above, the Company essentially ignored several critical resource options in their analysis. With the Mitchell purchase the Company will own two resources (Rockport and Mitchell), and will likely purchase power through a competitive bidding process to replace the 250 MW of Big Sandy 1. This means that their portfolio of resources will be 79 percent old, coal baseload units (Rockport and Mitchell), 17 percent purchases (from the Big Sandy Unit 1 RFP or the PJM market), and less than four percent DSM. If the competitive bidding process leads to the purchase of coal- or gas-fired power, then the company's fuel mix is likely to be 96 percent fossil-fired, and four percent DSM. Such a portfolio of resources cannot be described as a balanced mix.

Q. Do you have examples of where the Company or its affiliates considered a broader array of resource options when evaluating long-term resource plans?

A. Yes. In the 2010 AEP-East IRP, AEP considered a much broader range of resource options than what the Company has included in this analysis. For example, it included biomass resources, wind resources, solar resources, coal gasification technologies, and voltage control options (AEP-East 2010 IRP). Section 6. KYPCo'S 2009 IRP included many of these same options, with the exception of solar resources because Kentucky does not have the same public policies supporting solar power that other states in AEP-East have (KYPCo 2009 IRP. Section C.2.c, p. 4-7.

5. CONSIDERATION OF DEMAND-SIDE MANAGEMENT

Q. Are DSM resources typically considered an important element of integrated resource planning?

A. Yes. DSM is widely recognized as the lowest cost resources available to meet electricity demand. One of the fundamental goals of integrated resource planning is to find the optimal combination of both supply-side and demand-side resources.

Q. Does the Kentucky IRP regulation require the Company to consider DSM resources?

A. Yes, it does. 807 K.A.R. 5:058 requires a utility to consider DSM in developing tis IRP. In sum, this includes identifying and describing existing DSM programs;

accounting for existing and continuing DSM programs in the load forecast; describing DSM resources that are not already in place but are considered for inclusion in the plan; providing detailed information about the energy and peak savings and other impacts of each new DSM program; and describing the criteria used to screen each resource alternative including DSM.

Q. Should DSM resources be considered a priority resource in Kentucky for utility planning purposes?

A. Yes. The Commission has found that "the requirement of the IRP regulation to develop a lowest possible cost resource plan does effectively treat cost-effective energy efficiency programs as a priority resource" (Case No. 2008-00408, PSC Order, October 6, 2011, p. 21.)

In recognition of the increasing importance of energy efficiency and in recognition of the authority granted to the Commission by the IRP regulation, the DSM statute, the CPCN statute, and the Commission's broad investigative authority, the Commission has developed the following Kentucky IRP Standard adopted by all jurisdictional utilities:

> Each electric utility shall integrate energy efficiency resources into its plans and shall adopt policies establishing cost-effective energy efficiency resources with equal priority as other resource options.
>
> In each integrated resource plan, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as a priority resource as required by regulation. In each certificate case, the subject electric utility shall fully explain its consideration of cost-effective energy efficiency resources as a priority resource. (Case No. 2008-00408, PSC Order, October 6, 2011, p. 24).

Q. Has Kentucky established statewide goals for DSM programs?

A. Yes. In November 2008, Governor Steven Beshear issued "Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence." Improving the energy efficiency of Kentucky's homes, buildings, industries and transportation fleet is the first strategy in the Governor's plan to achieving efficient, sustainable energy solutions. The plan highlights DSM's cost-effectiveness potential stating "Not only does energy efficiency result in savings today, the savings are compounded over time as energy prices continue to rise. Dollar for dollar, energy efficiency is one of the best energy investments Kentucky can make" (Intelligent Energy Choices for Kentucky's Future, p. 15). As part of this action plan, Governor Beshear set a goal that energy efficiency will offset at least 18 percent of Kentucky's projected 2025 energy demand (Intelligent Energy Choices for Kentucky's Future, p. 13).

Q. What findings has Commission made with regard to DSM programs offered by the utilities in Kentucky?

A. The Commission has regularly and consistently encouraged Kentucky utilities to increase their DSM program efforts. For over 30 years the Commission has noted the importance of energy efficiency as a ratemaking standard, as "it is intended to minimize the 'wasteful' consumption of electricity and to prevent consumption of scare resources (Case No. 2012-00221, December 20, 2012, p. 7).

Since at least 2001 the Commission has more explicitly noted its support for energy efficiency (Case No. 2008-00408, PSC Order October 6, 2011, p. 22). The Commission has repeatedly stated that "we believe that DSM, energy efficiency, and conservation are important now and will become more important and cost-effective in the future as more constraints are likely to be placed on utilities that rely significantly on coal-fired generation" (Case No. 2008-00204, PSC Order September 30, 2010, p. 14; Case No. 2010-00222, PSC Order, February 17, 2011, p. 15; Case No. 2008-00408, PSC Order October 6, 2011, p. 22).

Even more recently and more explicitly, the Commission stated "with the potential for huge increases in the costs of generation and transmission as a result of aging infrastructure, low natural gas prices, and stricter environmental requirements, we will strive to avoid taking actions that might disincent energy efficiency" (Case No. 2012-00221, December 20, 2012, p. 10).

The Commission has demonstrated its interest in DSM programs by continuously requesting that Kentucky utilities keep the Commission appraised of all DSM program activities, both in Kentucky and in other jurisdictions where utilities have affiliates (Case No. 2010-00222, PSC Order, February 17, 2011, p. 15; Case No.

2008-00204, PSC Order September 30, 2010, p. 14; Case No. 2012-0051, PSC Order, May 30, 2012, p. 10; Case No. 2012-00367, PSC Order, February 22, 2013, pp. 22-24).

Q. What findings has the Commission made recently specifically with regard to the Company's DSM programs?

A. In 2011, the Company proposed to reduce both the projected DSM program participation levels and budget amounts for certain programs. While the Commission ultimately granted the Company's request, it expressed serious concerns regarding reductions to any DSM program participation and budgets (Case No. 2011-00300, PSC Order, January 23, 2012, pp. 8-9, citing, Case No. 2011-00401).

In 2012, the Commission expressed additional concerns regarding the Company's DSM program cost-effectiveness and participation levels. The Commission noted that it is troubled by the Company's high fixed costs associated with administrative costs, the Company's tendency to manage programs in-house rather than through an implementation contractor, and the Company's inability to meet program goals for DSM program participation and expenditures (Case No. 2012-00367, PSC Order, February 22, 2013, pp. 21-23).

The Commission has repeatedly stated that it will continue to closely monitor the Company's efforts to develop and promote cost-effective DSM programs (see Case No. 2011-00300, PSC Order, January 23, 2012, p. 9; Case No. 2012-0051, PSC Order, May 30, 2012, p. 10; Case No. 2012-00367, PSC Order, February 22, 2013, pp. 22-23).

Q. How does the Company's economic analysis of the Mitchell purchase analyze DSM resources?

A. The Company creates a projection of DSM resources, including both energy efficiency and demand response resources, that it expects to implement during the study period. It then assumes that this level of DSM resources will be available in every one of the scenarios used to model the economics of the Mitchell purchase.

Q. Do you have any concerns about this approach to analyzing DSM?

A. Yes. This approach clearly does not consider DSM as a priority resource. It hardly considers DSM to be a resource at all.

First, the Company's assumptions regarding the magnitude of DSM resources that will be available over the study period are very limited. The magnitude of DSM savings assumed in the Mitchell purchase analysis is below what the Company assumed in its most recent IRP, is well below what AEP-East assumed in its most recent IRP, and significantly understates the cost-effective potential for DSM resources in general. I will address these points in more detail below.

Second, using a fixed level of DSM savings in every scenario in the economic analysis precludes the possibility of identifying any additional level of DSM resources; let alone the optimal level of DSM resources. This approach essentially fixes the outcome regarding this critical low-cost resource opportunity. Such an approach is inconsistent with any reasonable effort to identify an optimal, least-cost mix of both supply-side and demand-side resources. This extremely simplistic modeling methodology is especially problematic in this case, because the magnitude of DSM (i.e., energy and capacity savings) assumed in the Mitchell analysis was so limited.

Q. Please summarize the assumptions used by the Company to identify the types of DSM programs that it could implement over the study period.

A. The Company intends to continue offering the DSM programs currently approved by the Commission. The DSM programs are as follows: Target Energy Efficiency; High Efficiency Heat Pump - Mobile Home; Mobile Home New Construction; Modified Energy Fitness; High Efficiency Heat Pump; Community Outreach Compact Fluorescent Lighting; Energy Education for Students; Residential & Commercial HVAC Diagnostic and Tune-up; Small Commercial AC HP; Residential Efficient Products; Commercial Incentive; Pilot Residential and Small Commercial Load Management; Interruptible Load (Response to Staff 1-8).

The Company intends to continue to invest in DSM resources at the approximate level that is currently approved by the Commission (Response to SC 2-6; Response to SC 2-7). The Company does not intend to offer new energy efficiency programs in the near future, but is considering adding demand response capabilities during the forecast period (Response to SC 1-36; Response to SC 2-6).

Q. **Please summarize the DSM savings that the Company assumed in its economic analysis of the Mitchell purchase.**

A. Tables 1 and 2 present a summary of the DSM savings the Company assumed. The DSM savings include savings from both energy efficiency programs and from demand response programs. Table 1 presents annual savings and cumulative savings for both capacity and energy, and Table 2 presents the same information as the percent of peak demand and percent of retail sales.

Table 1. Capacity and Energy Savings of KYPCo DSM Programs (MW and GWh)

	Peak Demand Savings (MW)						Energy (GWh)	
	Energy Efficiency		Demand Response		DSM (Total)		Energy Efficiency	
Year	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.
2012	---	3	---	4	---	7	---	19
2013	1	4	0	4	1	8	14	33
2014	2	6	7	11	9	17	10	43
2015	2	8	7	18	9	26	9	52
2016	4	12	8	26	12	38	25	77
2017	4	16	9	35	13	51	17	94
2018	1	17	1	36	2	53	8	102
2019	2	19	0	36	2	55	8	110
2020	1	20	1	37	2	57	6	116
2021	1	21	1	38	2	59	2	118
2022	0	21	1	39	1	60	1	119
2023	0	21	0	39	0	60	0	119
2024	0	21	1	40	1	61	0	119
2025	0	21	1	41	1	62	0	119
2026	0	21	0	41	0	62	0	119
2027	1	22	0	41	1	63	0	119
2028	0	22	0	41	0	63	0	119
2029	-1	21	0	41	-1	62	0	119
2030	1	22	0	41	1	63	0	119
2031	0	22	0	41	0	63	0	119

Table 2. Capacity and Energy Savings of KYPCo DSM Programs (Percent of Load)

	Peak Demand Savings (Percent of Peak Demand)						Energy (Percent of Sales)	
	Energy Efficiency		Demand Response		DSM (Total)		Energy Efficiency	
Year	Annual	Cum.	Annual	Cum.	Annual	Cum.	Annual	Cum.
2012	---	0.3%	---	0.3%	---	0.6%	---	0.3%
2013	0.1%	0.3%	0.0%	0.3%	0.1%	0.7%	0.2%	0.4%
2014	0.2%	0.5%	0.6%	0.9%	0.8%	1.4%	0.1%	0.6%
2015	0.2%	0.7%	0.6%	1.5%	0.7%	2.2%	0.1%	0.7%
2016	0.3%	1.0%	0.7%	2.2%	1.0%	3.2%	0.3%	1.0%
2017	0.3%	1.3%	0.7%	2.9%	1.1%	4.2%	0.2%	1.2%
2018	0.1%	1.4%	0.1%	3.0%	0.1%	4.4%	0.1%	1.3%
2019	0.2%	1.6%	0.0%	3.0%	0.1%	4.5%	0.1%	1.4%
2020	0.1%	1.6%	0.1%	3.0%	0.1%	4.7%	0.1%	1.5%
2021	0.1%	1.7%	0.1%	3.1%	0.1%	4.8%	0.0%	1.5%
2022	0.0%	1.7%	0.1%	3.1%	0.0%	4.8%	0.0%	1.5%
2023	0.0%	1.7%	0.0%	3.1%	0.0%	4.8%	0.0%	1.5%
2024	0.0%	1.7%	0.1%	3.2%	0.1%	4.9%	0.0%	1.5%
2025	0.0%	1.7%	0.1%	3.3%	0.0%	4.9%	0.0%	1.5%
2026	0.0%	1.7%	0.0%	3.2%	0.0%	4.9%	0.0%	1.5%
2027	0.1%	1.7%	0.0%	3.2%	0.0%	4.9%	0.0%	1.5%
2028	0.0%	1.7%	0.0%	3.2%	0.0%	4.9%	0.0%	1.5%
2029	-0.1%	1.6%	0.0%	3.2%	-0.1%	4.8%	0.0%	1.5%
2030	0.1%	1.7%	0.0%	3.2%	0.0%	4.8%	0.0%	1.5%
2031	0.0%	1.7%	0.0%	3.1%	0.0%	4.8%	0.0%	1.5%

Q. Please summarize the assumptions used by the Company to identify the magnitude of DSM savings over the study period.

A. The Company used the 2009 EPRI study "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the US" (EPRI Study) to estimate the magnitude of DSM resources that it could achieve by 2020 (Response to SC 1-39; Response to SC 2-15). The Company used the "realistically achievable" savings from energy efficiency by 2020 savings level for its energy efficiency assumptions in the Mitchell purchase analysis (Response to SC 2-15, Attachment 1).The Company assumed that energy efficiency can result in cumulative energy savings equal to 3.3 percent of retail sales by 2020, and that demand response can result in cumulative savings equal to 3.6 percent of peak demand by 2020 (Response to SC 2-15, Attachment 1). [1]

[1] The amount of cumulative energy savings by 2020 presented in Table 2 is lower than the savings from the EPRI Study. This is apparently because the Company does not offer DSM programs to its industrial customers. This issue is addressed in more detail below. Also, the EPRI study estimates that demand

Q. Do you have any concerns about relying exclusively upon the 2009 EPRI Study for analyzing DSM resources available to the Company?

A. Yes. First, the EPRI Study used several conservative assumptions that understate the potential for DSM resources. A group of organizations issued joint comments critiquing the EPRI study on the grounds that it used conservative and unrealistic assumptions (Joint Comments of the American Council for an Energy Efficient Economy, the Alliance to Save Energy, the Natural Resources Defense Council and Energy Center of Wisconsin on the January 2009 Report: "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S." issued by EPRI (Joint Comments, Attached as Exhibit TW-3).). Some of the key points from this memo are summarized as follows:

- The study assumes programs do not induce early replacement of technologies before the end of their useful life, even if it is economic to do so (Joint Comments, Attached as Exhibit TW-3, p. 3).
- "The EPRI savings estimates are almost entirely from existing efficiency technologies and contain little that is not already commercialized and cost effective" (Joint Comments, Attached as Exhibit TW-3, p. 2).
- "The EPRI estimates are built around energy-savings technologies...but do not include much in the way of energy-efficient practices, such as improved systems design of new buildings or industrial processes" (Joint Comments, Attached as Exhibit TW-3, p. 2).
- The EPRI estimates do not include "...any new codes, standards, regulatory policies, or other externalities [that] could contribute to greater levels of overall efficiency" (Joint Comments, Attached as Exhibit TW-3, p. 2).
- "[T]he choice on which experiences to rely [for assumptions about customer adaptation] did not always include current best practices, and in at least some

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response can result in cumulative savings equal to 4.6 percent of peak demand by 2020 (EPRI Study, p. 5-9). The Company does not explain why its demand response assumption is lower than the demand response estimate in the EPRI study.

cases, did not take into account recent advances in consumer awareness and program innovations that have demonstrated the possibility for large successes" (Joint Comments, Attached as Exhibit TW-3, p. 3).

Q. Where there other, similar studies available from the same period that the Company could have used instead of, or in addition to, the EPRI Study?

A. Yes. In 2009 McKinsey & Company issued a similar report: entitled "Unlocking Energy Efficiency in the U.S. Economy" (McKinsey Report, Executive Summary Attached as Exhibit TW-4).). This highly-credible report was widely circulated at the time it was released. The McKinsey Report does not contain some of the limitations described above for the EPRI Study, and estimates much higher levels of cost-effective energy efficiency savings than the EPRI Study. Nationwide, the McKinsey Report estimates that there is enough cost-effective energy efficiency to reduce roughly 25 percent of electricity sales by 2020, whereas the EPRI Study estimates that cost-effective energy efficiency could only reduce 10 percent of electricity sales by that time.[2] In other words, the EPRI Study estimates of energy efficiency savings were only 40 percent of the McKinsey Report estimates.

Q. Were there additional studies available from the same period that the Company could have used instead of, or in addition to, the EPRI Study?

A. Yes, In June 2009 the Brattle Group prepared an independent national potential study for the Federal Energy Regulatory Commission, titled "A National Assessment of Demand Response Potential" (Brattle Study, Executive Summary Attached as Exhibit TW-5, study). Like the McKinsey Report, this study estimated significantly higher savings potential than the EPRI Study. The Brattle Study estimates likely demand response savings under a "Business as Usual" case, as well as three expanded levels of future demand response implementation. The Brattle Study found that Kentucky could reduce its peak demand by 2019 by

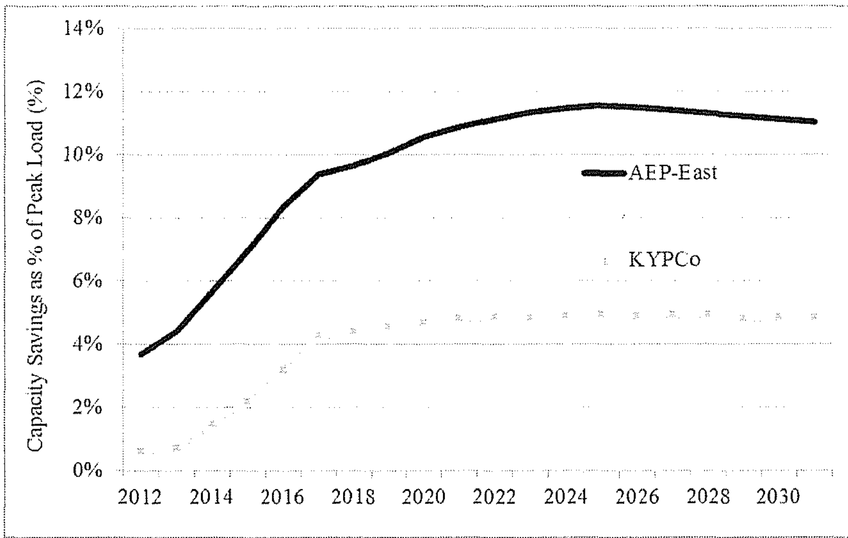
[2] In addition to this level of *cost-effective* efficiency savings (the Economic Potential), the EPRI Study also estimated the portion of this that could likely be achieved through utility energy efficiency programs (the Achievable Potential). The EPRI Study estimates the Achievable Potential was equal to cumulative savings of 3.3 percent of electricity sales by 2020. This was the amount the Company used to determine its energy efficiency savings in the Mitchell analysis.

roughly one percent under the Business as Usual Case; roughly five percent under the Expanded Business as Usual Case; roughly 11 percent for the Achievable Potential Case; and roughly 18 percent for the Full Participation case (Brattle Study, Executive Summary Attached as Exhibit TW-5, p. 118). All of the three expanded levels of demand response savings are higher than the peak demand response savings that the Company assumed in its Mitchell purchase analysis (3.6 percent by 2020).

Q. Please compare the forecast of DSM capacity savings from the Company's Mitchell purchase analysis to AEP-East's forecast of its DSM capacity savings.

A. Figure 1 summarizes the Company's and AEP-East's projected capacity savings from DSM programs for 2012 through 2031 (Exhibit SCW-1, p. 7). This figure presents the capacity savings in terms of the percent of peak demand, in order to provide a metric that can be compared across utilities of different sizes.

Figure 1: Cumulative Capacity Savings as a Percent of Peak for KYPCo and AEP-East



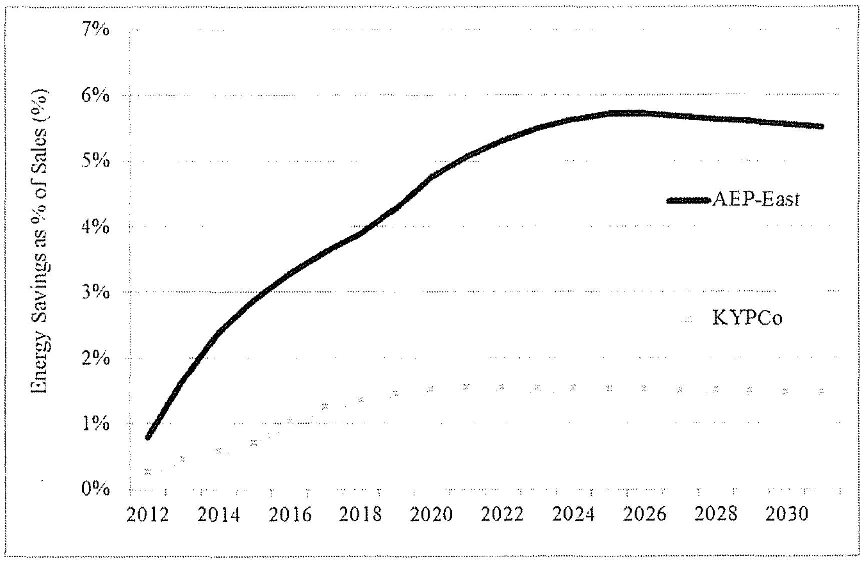
As the figure shows, the Company expects to increase capacity savings from 2012 through 2017, reaching about four percent of peak load by 2017. Thereafter, the Company holds savings flat, consistent with its assumption that it will offer a maintenance level of energy efficiency programs.

Conversely, AEP-East starts off with a much higher savings as a percent of peak load. Its program savings begin at around four percent of peak load in 2012, and continually ramps up through about 2025, when the savings as a percent of load begin to level out.

Q. Please compare the DSM energy savings from the Company's Mitchell purchase analysis to the forecast of DSM energy savings available to AEP-East.

A. Figure 2 summarizes the Company's and AEP-East's projected energy savings from DSM programs for 2012 through 2031 (Exhibit SCW-1, p. 7). This figure presents the energy savings in terms of the percent of energy demand, in order to provide a metric that can be compared across utilities of different sizes.

Figure 2: Cumulative Energy Savings as a Percent of Sales for KYPCo and AEP-East



As the figure shows, the Company expects to slowly increase energy savings from 2012 through 2019, reaching a cumulative amount of about 1.5 percent of sales by 2020. Thereafter, the Company holds savings flat, consistent with its assumption that it will offer a maintenance level of energy efficiency programs. Conversely, AEP-East energy savings increase at a much faster rate than the Company's rate of savings, reaching 5.5 percent of sales by 2023.

Q. What do you conclude from this comparison of the Company's DSM savings estimates to AEP-East's savings estimates?

A. This comparison indicates that the Company is significantly understating the potential for DSM resources in its service territory. The other subsidiaries within AEP-East are expecting to achieve significantly more savings that KYPCo; there is no reason that the Company cannot achieve greater savings than it has forecast.[3]

Q. Do you have other evidence that the Company's forecast of DSM savings are overly limited?

A. Yes. Many states are already achieving much higher DSM savings than what the Company forecasts. As of the 2010 program year, 12 states have achieved annual energy efficiency savings of roughly one percent or more of retail sales *per year*. Some have achieved annual savings of two percent of retail sales *per year* (ACEEE, The 2012 Energy Efficiency Scorecard October 2012, Executive Summary Attached as Exhibit TW-6, p. 31). These savings are for energy efficiency programs only. For comparison, the Company is assuming that its energy efficiency programs will save roughly 0.1 to at most 0.3 percent of retail sales per year through 2020. This is roughly ten percent of what some states are already achieving.

Q. What reasons does the Company provide for not analyzing greater DSM savings in its economic analysis of the Mitchell purchase?

A. The Company broadly dismisses DSM resource options by arguing that they would not be of sufficient magnitude to replace Big Sandy or to be viable alternatives to the Mitchell purchase (Direct Testimony of Weaver, p. 27; Direct Testimony of McDermott, p. 10).

Q. Do you agree with this point?

A. No. As I discuss above in Section 4, there is no need for any one resource type to provide as much capacity and energy as the Mitchell purchase. Instead, a

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3 Note that the KYPCo DSM savings are included in the estimates for AEP-East's DSM savings. If the KYPCo savings were netted out of the AEP-East savings, then the difference between KYPCo and the other AEP subsidiaries would be even greater.

combination of resource types, e.g., DSM, renewables, purchases from existing gas units, and PJM purchases, can be used to meet the Company's resource needs over time. This is one of the fundamental principles of integrated resource planning and of achieving a least-cost resource portfolio. By contrast, KYPCo's logic can lead to a cycle of denial, where a large portion of cost-effective DSM resources remain untapped simply because they are always viewed as being insufficient to meet a particular capacity need.

Q. Does the Company provide other reasons why it did not analyze greater DSM savings in its economic analysis of the Mitchell purchase?

A. Yes. The Company does not offer DSM programs to its industrial customers. Therefore, it would be expected to have less energy efficiency savings than its affiliated utilities in AEP-East (Response to SC 1-39 (h), (j)). The Company also claims that it has a high prevalence of mining operations, which does not lend itself to demand reduction (Response to SC 1-39 (k)).

Q. Why does the Company not offer DSM programs to industrial customers?

A. The DSM provisions in the Kentucky law allow industrial customers to implement their own DSM measures and thereby avoid paying a charge for the Company's DSM programs (KRS 278.285(3)). It is for this reason that the Company does not offer DSM programs to industrial customers (Response to SC 2-16).

Q. Do you agree that the Company should not offer industrial customers DSM programs because they have the option to implement DSM measures on their own?

A. No, I do not agree. The company should offer DSM programs to its industrial customers, for several reasons.

First, the Company has an obligation to provide DSM services to all of its customers, including industrial customers, in order to offer them one of the best means of reducing their electric bills. Some industrial customers may not have the interest or the wherewithal to implement DSM measures on their own, but would be very interested in obtaining assistance from the utility to do so. Denying these customers this option is unfair to them, and limits the extent to which the Company can implement DSM resources to reduce costs for all customers.

Second, the Company's logic presumes that essentially all industrial customers would choose not to participate in its DSM programs if given the option. However, the Company has no evidence as to the portion of industrial customers that would choose not to participate in DSM programs, because it does not offer such programs (Response to SC 2-16). It may well be that the majority of industrial customers would participate, and a minority would not.

Third, the Kentucky DSM law presumes that a utility will offer industrial customers DSM programs, where it states that "the commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs..." (KRS 278.285). To not offer programs at all is inconsistent with DSM provisions of the Kentucky law.(3)). In other words, my understanding is that Kentucky law provides for the Commission to allow individual industrial customers to opt out of programs, not for the utility to simply fail to offer any such programs.

Fourth, the Company's approach is inconsistent with industry practice. Utilities in several states offer industrial opt-out (or, self-direct) programs, but to my knowledge they all offer industrial customers efficiency programs. This includes utilities in Ohio, North Carolina, Texas and others. Many of these utilities have a goal of offering industrial customers efficiency programs that are so well tailored to customers' needs that the customers prefer not to opt-out of them. For example:

> In Wisconsin, where industrial efficiency programs have historically been quite strong, no single customer has chosen to take advantage of the self-direct program. Wisconsin's policy-makers and administrators of the [cost-recovery mechanism or] CRM-funded programming attribute the lack of interest in the self-direct option to industrial companies' perceptions that Wisconsin's Focus on Energy Programs serve them well and provide benefits equal to or greater than their individual CRM fees...In Oregon, companies have increasingly stopped using the self-direct program and instead chose to pay into the CRM-funded programming offered through the Energy Trust of

> Oregon. Customers have noted that they made the switch to take advantage of the Energy Trust's incentives and technical assistance. (ACEEE, Follow the Leaders: Improving Large Customer Self-Direct Programs, October 2011, Attached as Exhibit TW-7, p. 17)

Q. Do you think there is likely to be cost-effective energy efficiency opportunities for industrial customers in Kentucky?

A. Yes. In 2007 the Governor's Office of Energy Policy released a study entitled "An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential," prepared by Kentucky Pollution Prevention Center and the American Council for an Energy-Efficient Economy (KY DSM Potential Study). This study evaluated achievable energy efficiency potential for the residential, commercial, and industrial sectors in Kentucky. The study assessed and combined all energy savings potential including electricity and natural gas, but presented electricity savings separately for the industrial sector. The total achievable electricity savings potential under the "moderately aggressive" scenario is estimated to be 26 percent in 2017 (KY DSM Potential Study, p. 18). In the industrial sector, the study found a lot of efficiency potential available from pumps, motors, sensors, controls, fans, compressed air, lighting, and energy information system. For the residential and commercial sectors, the study found eight percent and seven percent of energy efficiency potential in 2017, respectively (KY DSM Potential Study, pp. 8, 13).

Q. **The Company claims that a large portion of its industrial customers are mining operations, and that these operations do not lend themselves to demand reduction. Do you agree?**

A. No. A study by the US Department of Energy, demonstrates that there are significant cost-effective energy efficiency savings available from mining operations, including coal, minerals and metals mining (US Department of Energy, "Mining Industry Energy Bandwidth Study, Industrial Technologies Program, June 2007, Attached as Exhibit TW-8, pp. 21-24).

Q. Please summarize your findings with regard to the Company's consideration of DSM resources in its economic analysis of the Mitchell purchase.

A. The Company has dramatically understated the potential for DSM resources in its analysis of the Mitchell purchase. Assuming a single level of DSM resources throughout every scenario does not represent a comprehensive analysis of DSM options, and is inconsistent with the fundamental concept of least cost planning recognized in the Commission's integrated resource planning and CPCN standards. The Company's assumptions regarding that single level of DSM resources are overly conservative, and significantly understate the DSM potential available: whether they are compared relative to their own IRP; relative to similar affiliated utilities in AEP-East; relative to recent DSM potential studies; and relative to utilities in other states. The Company analysis clearly does not consider DSM a priority resource; it barely considers DSM a resource at all. Consequently, the Company cannot claim that its analysis demonstrates that the Mitchell purchase would be part of a least-cost plan for the Company.

Q. What do you recommend the Commission do with regard to the Company's DSM resource analysis?

A. First, I recommend that the Commission find that the Company has not sufficiently considered DSM resources as part of the economic analysis of the Mitchell purchase, and therefore has not demonstrated that the purchase is part of a least-cost resource plan.

Second, I recommend the Commission direct the Company to conduct a comprehensive reassessment of the energy efficiency and demand response programs that it can implement for the purposes of meeting future resource needs in the absence of Big Sandy Units 1 and 2.

Third, I recommend that the Commission implement DSM regulations or guidelines to clarify the policies and practices needed to encourage the Company to design, plan for, and implement a much broader array of cost-effective energy efficiency programs in the future. These regulations or guidelines are necessary to break the DSM planning cycle of denial (described above), so that the Company will implement more successful and aggressive programs on an on-going basis.

Q. What would you recommend including in such DSM regulations or guidelines?

A. The Kentucky DSM regulations or guidelines can draw from the lessons learned in other states and include a set of policies and practices most likely to promote successful, cost-effective DSM programs. I recommend that they clarify and refine existing DSM policies and include new DSM policies. For example, the regulations should address: a mechanism to provide the Company with a financial incentive to implement aggressive, successful DSM programs; provisions to ensure that all avoided costs are properly estimated and accounted for; provisions to ensure that DSM programs are properly screened for cost-effectiveness; and meaningful stakeholder engagement in the DSM planning and regulatory review process.

6. CONSIDERATION OF RENEWABLE RESOURCES

Q. Did the Company consider renewable resources in determining the least-cost alternative to meet its long-term obligations?

A. No, the Company did not consider renewable resources when evaluating alternatives to meet its long-term obligations (Response to SC 2-19). The Company states that "renewable resources cannot provide the capacity and energy needed to replace Big Sandy 2" (Response to SC 2-19).

Q. Do you agree that it is appropriate to not consider renewable resources as part of the economic analysis of Mitchell?

A. No, I do not. First, the Kentucky IRP law requires the Company to evaluate various resource options including renewables and demand-side programs in its integrated resource planning (807 K.A.R. 5:058). Also, assessing the potential for renewable resources as a part of integrated resource planning is standard industry practice.

Second, the Company's argument that renewables cannot provide the capacity and energy to replace Big Sandy 2 is misguided. As noted above for DSM resources, there is no need for any one type of resource to replace Big Sandy 2 (or the Mitchell purchase) on its own. A least cost approach will generally arise from a mix of many different types of resources, including DSM, renewables, purchases from PJM, combustion turbines, combined cycle plants, and more. The Company's logic essentially limits the economic analysis such that the only likely option for replacing Big Sandy 2 is another large base-load power plant – thereby excluding a variety of potentially low-cost resources from the analysis.

Q. Has the Company considered renewable resources in its recent IRP?

A. Yes. In its 2009 IRP the Company analyzed several types of renewable resources, and even selected some for its Reference Case Optimal Plan. That plan included 100 MW of wind, as well as biomass co-firing on the two Rockport units and on Big Sandy Unit 2 (KYPCo 2009 IRP, Exhibit 4-8, p. 4-36, and Section C.2.c, p 4-7).

The economic conditions for renewable power have changed significantly since the 2009 IRP. When that IRP was prepared the Company was not expecting that it would have to replace Big Sandy with new resources. Presumably the Company was also not aware that many other coal plants in the region would be retired or retrofitted with environmental controls in response to evolving EPA regulations. An economic assessment of renewable resources in 2012, in light of the Big Sandy retirement, would very likely find more cost competitive renewable resource potential than the Company found in 2009.

Q. Do you expect there to be a significant amount of renewable resources in Kentucky and the region?

A. Yes. In 2008 Governor Beshear released a report entitled "Intelligent Energy Choices for Kentucky's Future: Kentucky's 7-Point Strategy for Energy Independence." This report calls for an action plan for Kentucky to improve the quality and security of life for all Kentuckians by creating efficient, sustainable energy solutions and strategies; by protecting the environment; and by creating a base for strong economic growth over the long term (Intelligent Energy Choices for Kentucky's Future, p. iii). The plan examined in detail renewable resource potential in the state for wind, biogas, solar PV, hydro power and forest biomass, and set forth a goal that "[b]y 2025, Kentucky's renewable energy generation will triple to provide the equivalent of 1,000 megawatts of clean energy while continuing to produce safe, abundant, and affordable food, feed and fiber" (Intelligent Energy Choices For Kentucky's Future, p. 31). This study suggests that, at a minimum, the Company should investigate whether some of those renewable resources could contribute to the long-term, least-cost portfolio of resources.

Q. Do you have additional evidence of a significant amount of renewable resources in Kentucky and the region?

A. Yes. In 2012 Synapse Energy Economics prepared a study Entitled "Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky" (Synapse study). The study evaluates the potential costs, bill impacts and economic development benefits of such a portfolio standard. The study identifies roughly 12,000 GWh of renewable generation that could be available to Kentucky by 2022, including generation from in-state wind, out-of-state wind, biomass, hydro and solar resources (Synapse Study, pp. 26-27).

7. CONSIDERATION OF NATURAL GAS RESOURCES

Q. Do natural gas resources play an important role in the economic analysis of the Mitchell purchase?

A. Yes. Natural gas power plants play a very critical role in the economic analysis of the Mitchell purchase (Direct Testimony of Bletzacker, p. 6). First, in the Company's analysis nearly all of the alternative scenarios rely heavily on natural gas power plants instead of the Mitchell purchase. The alternatives to the Mitchell purchase include replacing Big Sandy 2 with a brownfield natural gas combined cycle unit; repowering Big Sandy 1 as a natural gas combined cycle unit; and various combinations of purchases from the PJM market, where the market prices are very much affected by marginal natural gas plants. The only non-gas resource alternative to a Mitchell purchase that was considered by the Company is the retrofitting of Big Sandy 2, which was already determined to be uneconomic. As noted above, the Company did not consider any new DSM or renewable resources as alternatives to the Mitchell purchase. Therefore, the Company's assumptions and estimates regarding natural gas resources will dramatically affect the outcome of the Mitchell economic analysis.

Q. Do you have any concerns with the Company's assumptions and estimates regarding natural gas resources?

A. Yes. First, the Company used an out-of-date gas price forecast, which significantly overstates the price of natural gas and therefore overstates the economic value of the Mitchell purchase. Second, the Company did not consider purchases of or from existing natural gas power plants, thereby excluding one of the more economic options from it analysis.

Natural Gas Price Forecasts

Q. Please explain why you believe that the Company used an out-of-date gas price forecast.

A. The Company's gas price forecast was prepared on November 29, 2011 (Response to SC 1-9). This was a full year before the Mitchell purchase application was filed with the Commission. Both current and projected future gas prices have fallen significantly since then, and therefore it is very important that economic analyses of electricity purchases use the most recent gas price forecast available.

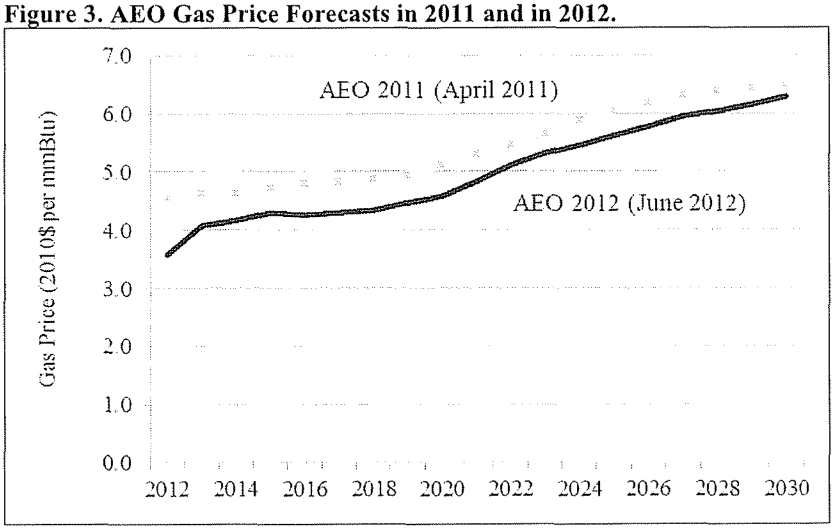
Q. Was there a more recent gas price forecast available when the Company prepared its economic analysis of the Mitchell purchase?

A. Yes. One of the inputs that the Company used in developing its forecast is the Energy Information Administration (EIA) Annual Energy Outlook (AEO) forecast (Direct Testimony of Bletzacker, pp. 4-10). The Company used the EIA forecast as of May 2011 (Response to KIUC 1-58). This forecast would have been from the April 2011 version of the EIA Annual Energy Outlook. In June of 2012 the EIA released its 2012 version of the Annual Energy Outlook, with an updated gas price forecast (EIA Annual Energy Outlook, June 2012). This updated forecast was available to the Company well before it filed the Mitchell purchase application in December 2012. The Company should have updated its gas price forecast for this application, and should have at least considered the more recent EIA gas price forecast.

Q. Is there a significant difference between the EIA 2011 and the EIA 2012 gas price forecasts?

A. Yes. Figure 3 below presents the EIA gas price forecasts from the 2011 AEO and the 2012 AEO. Note that the gas prices are significantly lower in the 2012 AEO forecast; for the first ten years the 2012 prices are roughly 10 percent lower than the 2011 prices. If the Company had used the lower, more recent gas price forecast, the Mitchell purchase would appear to be comparatively less economic than options involving natural gas than in its current economic analysis. The fact that the Company chose to use an out-of-date forecast that favors its proposed Mitchell purchase, is a "red flag" suggesting that it may have biased its analysis in favor of the Mitchell purchase.

Figure 3. AEO Gas Price Forecasts in 2011 and in 2012.

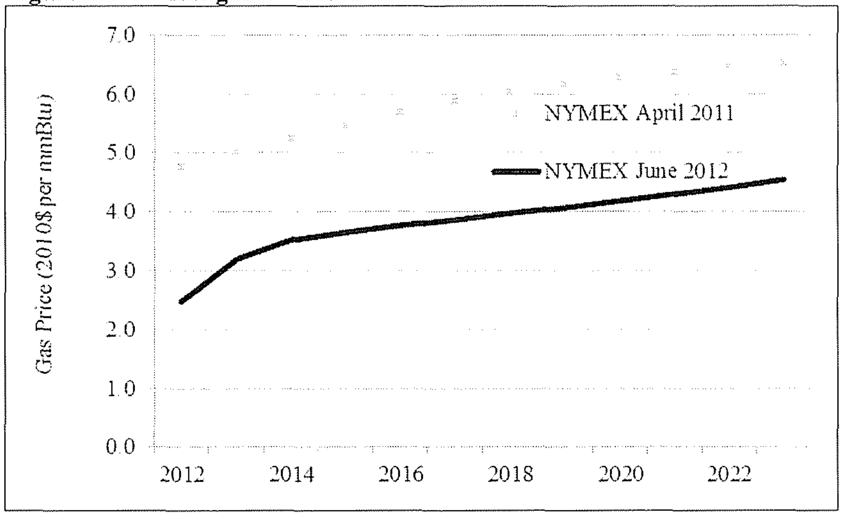


Q. Were there other indications available at the time the Company prepared the Mitchell purchase analysis that gas prices were likely to be lower than previously assumed?

A. Yes. The New York Mercantile Exchange (NYMEX) natural gas price futures are often used as an indication of what the market actors expect for future natural gas prices, at least over the next ten years. This is an important benchmark of future gas prices, and should at least be considered when preparing natural gas price forecasts.

Figure 4 below presents a summary of NYMEX natural gas futures prices that were available in April 2011 and June 2012 (NYMEX Henry Hub natural gas futures on April 14, 2011 and on June 8, 2012). Note that these future prices also indicate a significant reduction in gas price forecasts between 2011 and 2012. In this case, the more recent futures prices are roughly 33 percent lower than the older forecast. Again, this suggests that the Company's older, out-of-date forecast overstates gas prices, and thereby overstates the economic value of the Mitchell purchase.

Figure 4. NYMEX gas futures in 2011 and 2012.



Q. Is it reasonable to rely entirely upon the EIA forecasts or the NMEX futures when preparing a gas price forecast?

A. Not necessarily. There may be other factors to consider when preparing a long-term natural gas price forecast. However, there is no question that the Company should have taken a fresh look at its gas price forecast to see if updating it was warranted. The lower price forecasts in the EIA forecasts and the NYMEX futures should have been sufficient information for the Company to update its gas price forecast.

Q. What reason does the Company provide for not updating its gas price forecast?

A. The Company does not provide much detail on this point. In response to a data request, the Company states that "Based on information available at that time, the Company determined that it was not necessary to update the base case natural gas forecast" (Response to SC 2-43).

Q. Do you find this explanation compelling?

A. No. It is standard industry practice to use the most up to date information available when conducting economic analyses of energy resources, and it is also widely understood that gas prices can have a significant impact on the economics of power plants in today's industry.

Q. Would using an up to date gas price forecast likely affect the economic analysis of the Mitchell purchase?

A. Yes. Even a small change in future natural gas prices can have a significant effect on the economic analysis of the Mitchell purchase. As noted above, almost all of the alternatives to the Mitchell purchase were gas-fired power plants. Also, purchases from the PJM market represent an important option for the Company in many of its alternative scenarios; and natural gas price forecasts will have a significant effect on the cost of those purchases.

<u>**Existing Natural Gas Power Plants**</u>

Q. Did the Company's economic analysis consider purchases from existing natural gas resources?

A. No, it did not. As noted above, all of the scenarios considered by the Company include some combination of retrofitting Big Sandy, purchasing a portion of Mitchell, repowering Big Sandy into a new natural gas plant, building a new natural gas plant, and purchases from the PJM market. While purchases from the PJM market would naturally include existing natural gas plants, this option is not the same as purchasing power outside of the market through a contract with an existing natural gas facility.

Q. Can you provide examples of how the Company might have considered purchases from existing natural gas power plants?

A. Yes. Two examples are relevant here. First, the Company could have issued a request for proposals to solicit bids from utilities and generation companies in the region. This would solicit bids from existing natural gas resources; or at a minimum explore whether such resources are available as alternatives to the Mitchell purchase. I address the role of such a competitive bidding process in the next section of my testimony.

Second, the Company could have considered purchasing a natural gas resource from OPCo, instead of the Mitchell purchase.

Q. Is OPCo divesting itself of its natural gas resources?

A. Yes. OPCo submitted a Corporate Separation Plan to the Public Utilities Commission of Ohio (PUCO) that separates its generation assets from its transmission and distribution business. The OPCo Corporate Separation Plan includes the following elements:

- The retirement of several of the coal plants on the OPCo system (OPCo's Application for Approval of Full Legal Corporate Separation and Amendment to its Corporate Separation Plan, before the Public Utilities Commission of Ohio, Case No. 12-1126-EL-UNC, p. 9).
- The sale of the coal-fired Mitchell plant to KYPCo and Appalachian Power Company (Direct Testimony of Wohnhas, p. 4).
- The sale of the coal-fired Amos Unit 3 to Appalachian Power Company (OPCo's Application for Approval of Full Legal Corporate Separation, page 9).
- The transfer of the remaining OPCo generation assets to AEP Generation Resources (OPCo's Application for Approval of Full Legal Corporate Separation, p. 4).

Q. Does the transfer of OPCo generation assets to AEP Generation Resources include the transfer of any natural gas resources?

A. Yes. The transfer includes the transfer of ownership of OPCo's Waterford natural gas-fired plant located in Waterford Ohio (OPCo's Application for Approval of Full Legal Corporate Separation, Attachment). It also includes the transfer of ownership of a purchase power agreement (PPA) for the Lawrenceburg natural gas-fired power plant located in Lawrenceburg Indiana (OPCo's Application for Approval of Full Legal Corporate Separation, p. 4).

Q. Did the Company consider purchasing the Waterford gas-fired plant or the Lawrenceburg PPA as part of its economic analysis of the Mitchell purchase?

A. Not explicitly. In response to a data request, the Company explains that OPCo "generating assets were not reviewed on a unit by unit basis." Instead, all of the assets of OPCo were "qualitatively screened" to determine which should be considered along with other viable resource options (Response to SC 1-6).

Q. Would the Waterford plant or the Lawrenceburg PPA be good candidates as alternatives to the Mitchell purchase?

A. Yes. These would be natural candidates to investigate as alternatives to the Mitchell purchase. The Waterford plant is a ten-year old, 922 MW gas-fired plant with three combustion turbine units and one steam unit. The Lawrenceburg plant is a nine-year old, 1,232 MW gas fired plant with four combustion turbines and two steam turbines. Either of these resources could potentially be obtained from OPCo in the same fashion as the Mitchell purchase. Either of these resources could provide a very useful benchmark for what the cost of a purchase from an existing natural gas power plant might be.

Q. Do you have any evidence as to what the price might be to purchase the Waterford plant or the Lawrenceburg PPA?

A. In response to a discovery request, the Company states that the book value of the Waterford plant was $188 million, as of December 21, 2011 (Response to SC 1-6). If OPCo were to sell the Waterford plant at its net book value, the same basis that it is using for the Mitchell purchase, the price would be roughly $204/kW. This is less than one-third of the price that KYPCo is paying for the Mitchell purchase ($687/kW).

The Company also states that the net book value of the Lawrenceburg plant was $307 million, as of December 31, 2011 (Response to SC 1-7). If OPCo were to sell the Lawrenceburg PPA at the plant's net book value, the same basis that it is using for the Mitchell purchase, the price would be roughly $307/kW. This is less than one-half of the price that KYPCo is paying for the Mitchell purchase ($687/kW).

Note for comparison purposes, the Mitchell coal plant was built in 1970, while the Waterford and Lawrenceburg gas plants are much newer. The commercial operation dates for Waterford and Lawrenceburg are 2003 and 2004, respectively.

Q. What are the implications of the fact that the Waterford Lawrenceburg plants have such lower net book values than the Mitchell plant?

A. There are several important implications. First, the fact that the Company did not include the potential purchase of this these resources in its economic analysis of the Mitchell purchase suggests that its analysis excluded two potentially very low-cost, feasible alternatives to Mitchell. This is consistent with the points I have made above about how the Company's economic analysis includes only a very limited number of resource alternatives.

Second, the fact that these natural gas resources have such a low net book value suggests that there may be other, similar natural gas plants in the region that could sell power to KYPCo at relatively low costs. The Company should have tested this opportunity through a competitive bidding process, as I discuss in the next section of my testimony.

Third, the fact that AEP has chosen to transfer the Mitchell plant to KYPCo while simultaneously transferring a newer, lower-cost gas plant to AEP Generation Resources suggests that AEP may be trying to benefit its unregulated affiliate at the expense of its regulated affiliate. This is a significant "red flag" that the Commission should take note of. Because of the appearance that AEP might be selling the lowest-cost assets to AEP Generation and the highest-cost assets to KYPCo, the Company should be required to make very clear demonstration as to why the Mitchell purchase is economic to KYPCo customers. As I indicate throughout my testimony, the Company has failed to do so.

8. THE ROLE OF A COMPETITIVE BIDDING PROCESS

Q. Did the Company issue an RFP to solicit proposals for power purchases as an alternative or a complement to the Mitchell purchase?

A. No, it did not (Direct Testimony of McDermott, pp. 10-11).

Q. How does the Company justify not issuing an RFP to solicit proposals for power purchases?

A. The Company essentially argues that it did not need to issue an RFP to solicit proposals for power purchases because its economic analysis achieves the same goal. In other words, the assumptions and estimates used by the Company in its economic analysis were designed to approximate the results that would otherwise be obtained through a competitive bidding process (Direct Testimony of Pauley, p. 17; Direct Testimony of McDermott, pp. 11-12). Therefore, the Company concludes, an RFP would provide no additional useful information (Response to KIUC 1-72 (c)).

Q. Do you agree with this justification?

A. No, I do not. First, the Company's economic analysis is very limited to a narrow set of resource options, as I describe above. The Company has not necessarily identified all of the potential low-cost energy and capacity resources that might be solicited in a competitive bidding process, and so the Company cannot claim that its analysis approximates the likely outcome of such a process. One of the most glaring omissions from the Company's set of resource options is the potential for purchases from existing natural gas-fired power plants, as described in Section 7 of my testimony.

Second, the Company's economic analysis uses an out-of-date gas price forecast, significantly overstating the likely price of natural gas, as described in Section 7 of my testimony. Consequently, the Company cannot claim that its economic analysis approximates the results of a competitive solicitation, because bidders in such competitive process would certainly use the most up to date gas price forecasts available. Given that the Company's forecast overstates the likely price of gas, a competitive solicitation would very likely indicate that there are more economic alternatives to the Mitchell purchase than those analyzed by the Company.

Third, it is standard industry practice to use competitive bidding processes as a way to provide a check on utility analyses, i.e., a "market test." One of the purposes for this market test is to help identify resource options that a utility might not be aware of. Another purpose is to rely upon market actors' assumptions regarding some key planning factors (e.g., gas prices, CO_2 prices, costs of complying with future environmental regulations, risk factors) rather than the assumptions used by a utility. Yet another purpose of a market test is to prevent a utility from using planning assumptions or methodologies that might bias the outcome of the analysis in one way or another. Generally speaking, in a case where one affiliate is selling a capital asset to a regulated utility affiliate, as is the case with the Mitchell purchase, it is especially important to provide a market test to minimize the chance of a bias in the analysis. More importantly, in this case where there are several red flags suggesting that the Company's analysis may be biased in favor of the Mitchell purchase, it is absolutely essential for the Company to provide a market test of its own.

Fourth, an RFP might help identify potential renewable resources that could be used as part of the portfolio of resources to replace Big Sandy. As discussed in Section 6 above, the Company did not include any renewable resources in its economic analysis of the Mitchell purchase.

Q. Does the Company make any more specific arguments as to why they did not need to issue an RFP?

A. Yes. The Company also claims that it is reasonable to assume that a *long-term* (minimum 10-20 year term) competitive purchase power agreement would likely be offered at the cost of a new-build combined-cycle (Direct Testimony of Weaver, p. 37).

Q. Do you agree with this argument?

A. No. This argument is overly simplistic. First, the Company could issue an RFP that solicited competitive proposals for a power contract for less than ten or 20 years. Such a solicitation might be priced at something other than a new-build combined-cycle, and might produce low-cost proposals that could be used in conjunction with other resources to meet customer needs over the long-term.

Second, a purchase power agreement can be designed in such a way that it provides a different type of product than a new-build combined cycle facility. For example, a purchase power agreement could be designed with prices that are indexed to PJM market prices, which may therefore be priced differently than something comparable to a new-build combined-cycle.

9. APPROPRIATE ASSET PRICE FOR AFFILIATE TRANSACTIONS

Q. What is the Company proposing to pay for the Mitchell purchase?

A. According to the direct testimony of Mr. Pauley, the Company is proposing to use the net book value of the plant as the basis for the Mitchell purchase price (Direct Testimony of Pauley, p. 16). The Company projects that fifty percent of the net book value of the plant will be $536 million at the time of the transaction on December 31, 2013 (Direct Testimony of Pauley, p. 13). The Mitchell purchase includes 780 MW of capacity (Direct Testimony of Pauley, p. 13), resulting in a cost of $687/kw for the 50% interest in the Mitchell power plant.

Q. What reasons does the Company provide for using the net book value as the basis for the price of the Mitchell purchase?

A. The Company provides three reasons why the Mitchell purchase price should be based on net book value. First, in his direct testimony Mr. Wohnhas explains that the Public Utilities Commission of Ohio (PUCO) recently directed OPCo to use the net book value as the basis for the price in transferring the Mitchell Plant to AEP Generation Resources, which is the unregulated affiliate of AEP (Direct Testimony of Wohnhas, pp. 5, 6). Mr. Wohnhas implies that the same approach should be used for KYPCo's purchase of Mitchell.

Second, Mr. Wohnhas notes that KYPCo has been paying a share of the Mitchell costs through the Pool Agreement, and that those payments are cost-based. Mr. Wohnhas claims that the Mitchell purchase is equivalent to a transfer from OPCo Company to KYPCo, and that this transfer should use the same net book value basis as the costs in the Pool Agreement (Direct Testimony of Wohnhas, p. 6).

Third, in response to a Sierra Club discovery request on this topic, the Company claims that "net book value is a standard transfer price between wholly owned affiliates" (Response to SC 1-5).

Q. Do you agree that it is appropriate for the Company to pay the net book value for the Mitchell purchase?

A. No, I do not. It is standard industry practice, as well as a requirement of Kentucky law, that when purchasing a capital asset from an affiliate a regulated utility should pay *the lesser* of the market value or the net book value. This approach is necessary to (a) protect the regulated utility's customers from paying more for an asset than it is worth, and (b) prevent inappropriate utility transactions, where a regulated utility pays higher than market value to an affiliate in order to benefit the affiliate.

Q. Why do you say that it is a requirement of Kentucky law that when purchasing capital assets from an affiliate a regulated utility should pay the lesser of the market value or the net book value?

A. There are several provisions in Kentucky law pertaining to the conduct between a utility and its affiliates. One of the provisions specifically addresses the pricing requirements for transactions between a utility and an affiliate. The statute is clear on this point, stating that:

> Services and products provided to the utility by an affiliate shall be priced at the affiliate's fully distributed cost, but in no event greater than the market (KRS 278.2207).

In the case of the Mitchell purchase, this means that the price for the purchase should be the lesser of the book value or the market value.

Q. Is it always true that the price for a transfer between an affiliate and a utility should be at the lesser of market value or book value?

A. No. It depends upon the context, i.e., who is purchasing from whom. If a utility is *selling* a capital asset to an affiliate, then it should charge *the greater* of the market value or the net book value of the asset. This approach is necessary to ensure that the regulated utility customers are fully compensated for their investment in the capital asset, and to prevent self-dealing between affiliates.

Note that this event is contemplated in the same portion of the Kentucky statute:

> Services and products provided by the utility pursuant to a tariff shall be at the tariffed rate, with nontariffed items priced at the utility's fully distributed cost but in no event less than market (KRS 278.2207).

If the context of the Mitchell purchase were reversed, and it were to be provided by a utility and purchased by an affiliate, it should be priced at the greater of the market value or the book value. Again, the context matters.

Q. Are there other provisions of the Kentucky statute that are relevant to this transaction?

A. Yes. The statute allows the utility to file an application with the Commission to deviate from the requirements outlined above. However, "the utility shall have the burden of demonstrating that the requested pricing is reasonable" (KRS 278.2207).

Q. Is the Company's proposal for the Mitchell purchase consistent with the Kentucky statute?

A. No, it is not. The statute is clear that a when an affiliate transfers an asset to a utility, the asset must be priced at the lesser of the net book value or the market value. The Company has not presented a reasonable estimate of the market value the Mitchell purchase. Without such an estimate, the Commission has no way of determining whether the Company is complying with this statute and whether the Mitchell purchase is in Kentucky ratepayers' interest.

Q. Does the Company claim that the Mitchell purchase is consistent with the Kentucky statute?

A. Yes. In its application, the Company claims that "to the extent the statute is applicable, the Transfer and Assumption Transaction and the Mitchell Plant Operating Agreement fully comply with the requirements or KRS 278.2207 and the other provisions of KRS 278.2201 et seq.13 (Application, page 14).

When pressed further on this issue in a discovery request, the Company claims that with regard to KRS 278.2207 "[t]o the extent that this provision is applicable to an asset transfer of this nature, the assets are transferring to Kentucky Power at their net book value. *See also* Page 37 of Company Witness Weaver's testimony. Where he explains that the proposed transfer when compared to a portfolio that initially relies on a market-based solution over the long-term economic study period" (AG 1-5).

On page 37 of his testimony, Company Witness Weaver claims that the Company "effectively considered" a market option/view in its economic analysis of the Mitchell purchase. He notes that based on "indicative" evaluations of "the cost of a new-build CC, for instance, it was determined that such options would likely exceed the cost of the Mitchell generating asset transfer."

Q. Do you agree with the Company's arguments on these points?

A. No, I do not. First, the Company has not provided a direct, thorough comparison of the net book value of the Mitchell purchase to its market value. Such a comparison is necessary to demonstrate that the net book value is the appropriate transfer price for the Mitchell purchase. Mr. Weaver's testimony on page 37 is a discussion of the merits of not conducting an RFP to evaluate the economics of the Mitchell purchase; not a comparison of the net book value to the market value of the Mitchell purchase.

Second, and more importantly, the Company's economic analysis of the Mitchell purchase is wholly inadequate to demonstrate what the market value of what the purchase is likely to be. As discussed above, the Company's economic assessment of the Mitchell purchase has several flaws and limitations which make it unreliable on this point. Most notably, the Company used an out-of-date gas price forecast that favors the Mitchell purchase; the Company did not conduct a competitive bidding process to provide a market test of the economics of the Mitchell purchase; and the Company chose to ignore the potential value of the Waterford natural gas plant or the Lawrenceburg natural gas purchase agreement as economic alternatives to the Mitchell purchase. Furthermore, Weaver's testimony on page 37 refers to a new-build gas combined-cycle unit, which cannot provide a reasonable comparison to the market value of a 30-year old coal plant.

Q. Do you expect the market value of the Mitchell purchase to be less than the book value?

A. Yes. Several recent power plant sales indicate that the current market value of coal plants is well below the $687/kW price that the Company is proposing to purchase Mitchell for. I have not conducted an assessment of the details of these recent power plant sales, but even a cursory review of information provided in the recent trade press indicates that the price of the Mitchell purchase is likely to be well above its market value.

For example, on August 9, 2012 Exelon Power announced that it would sell three of its Maryland power plants it had acquired in its merger with Constellation Energy Group. The three power plants, which were collectively 80 percent coal-fired, were sold for $400 million, which is equal to roughly $151/kW (Excelon Press Release, April 9, 2012[4]). It is noteworthy that two years before the sale the owners of these plants invested $1 billion retrofitting the plants with environmental controls in anticipation of federal environmental regulations. Despite these large capital investments, these coal plants were sold for roughly 22 percent of the price that the Company is paying for the Mitchell purchase.

As another example, Dominion recently announced the sale of its Kincaid, Brayton Point and Elwood plants to Energy Capital Partners. This price of this sale was estimated to be roughly $158/kW (Dominion Press Release, March 11, 2013[5]). Most of these plants have already installed scrubbers. Again, these coal plants were sold for roughly 23 percent of the price that the Company is paying for the Mitchell purchase.

Q. Are the provisions in the Kentucky affiliate transaction statutes consistent with your understanding of industry practice on this issue?

A. Yes, they are. For example, the National Association of Regulatory Commissioners (NARUC) has issued *Guidelines for Cost Allocation and Affiliate Transactions* (Guidelines) that address a variety of affiliate transaction issues. These Guideline are attached to my testimony as Exhibit TW-2. With regard to the transfer of capital assets, the NARUC Guidelines say that:

> Generally, the transfer of capital assets from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation.
>
> Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation.

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4 Available at : http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx.

5 Available at: http://dom.mediaroom.com/2013-03-11-Dominion-To-Sell-Three-Merchant-Power-Stations-To-Energy-Capital-Partners.

> To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators (NARUC Guidelines, Attached as Exhibit TW-2, Section D.3).

Again, the Mitchell purchase is a transfer from an affiliate to a utility, and thus the price should be based on the lower of prevailing market price or the net book value.

Q. Are there other portions of the NARUC Guidelines that are pertinent here?

A. Yes. In the introduction to the Affiliate Transaction section, the NARUC Guidelines state the following:

> The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers (NARUC Guidelines, Attached as Exhibit TW-2, Section D).

I cite this part of the NARUC Guidelines here because it is important that the Commission view the proposed Mitchell purchase in this context. AEP has a choice between selling the Mitchell plant to an unregulated subsidiary (AEP Generation Resources), or to regulated utility subsidiaries (KYPCo and Appalachian Power Company). They have chosen to do the latter, which raises the concern that AEP may be selling its less economic, or even uneconomic, plant to its regulated monopoly operations with captive ratepayers. In such a context, it is important that (a) the Commission be especially vigilant about prohibiting the purchase of an uneconomic resource, and (b) the Company provide a complete demonstration that its proposed purchase will benefit their customers and is in the public interest. The only way to make this demonstration is to show that the purchase price is no higher than the market value of the purchase.

Q. The Company claims that the Mitchell purchase price should be based on the net book value of the plant because that was the value required by PUCO for the transaction between OPCo and AEP Generation Resources. Do you agree?

A. No, I do not agree. First, the Commission has an obligation to protect the electricity customers of Kentucky, and in this instance the customers of KYPCo. This means determining that the price for the Mitchell purchase does not exceed the market value. The recommendation of PUCO is not relevant to this determination.

Second, the sale of generation assets by OPCo to AEP Generation Resources was in a different context than the Mitchell purchase, and thus should be treated differently. As indicated in both the Kentucky affiliate transactions statute cited above and the NARUC Guidelines cited above, context matters very much. In the case where a utility sells capital assets to an affiliate (i.e., OPCo sale to AEP Generation Resources), the purchase price should be *the greater* of market value or net book value, while in the case where an affiliate sells capital assets to a utility (i.e., the KYPCo Mitchell purchase) the purchase price should be *the lesser* of market value or book value. Therefore, the Commission is not bound by the purchase price that was allowed by PUCO.

Q. The Company claims that the Mitchell purchase price should be based on the net book value of the plant because that is consistent with the approach used when KYPCo paid for a portion of the Mitchell plant through the Pool Agreement. Do you agree?

A. No, I do not agree. Again, this is a very different context and thus does not bind the Company or the Commission to a price based on the net book value. Under the Pool Agreement, there were no affiliate transactions between competitive and non-competitive or regulated and non-regulated affiliates. Instead, it was an agreement between several utilities about joint planning, construction and operation of power plants. In that context, it is standard industry practice and completely appropriate to share costs on the basis of cost-of-service. The approach used in sharing costs in the Pool Agreement should have no bearing on the price for the Mitchell purchase.

Q. Please summarize your findings and recommendations with regard to the price of the Mitchell purchase.

A. The Mitchell purchase is an affiliate transaction; it is essentially a sale from an affiliate to a regulated utility. As such it should comply with Kentucky law and industry practice regarding affiliate transactions. Both the law and industry practice are clear that the price for a transfer of capital assets from an affiliate to a utility should be at the lesser of market value or net book value. The Company has not demonstrated that this is the case, or even presented an estimate of the market value for this purpose. Therefore, I recommend that the Commission not approve the Mitchell purchase.

More importantly, because this is an affiliate transaction, the Commission should be especially vigilant about preventing any sort of favoritism toward the affiliate at the expense of KYPCo ratepayers. This means that the Commission should apply greater scrutiny, and require a more complete demonstration from the Company, on all of the key issues addressed in this proceeding. This would include not only the Mitchell purchase price, but also the economic evaluation of the Mitchell purchase; the extent to which the Company considered alternatives to the Mitchell purchase, including DSM resources, renewable resources and natural gas resources; the use of a market test for Mitchell through a competitive bidding process; and the gas price forecast used in the economic analysis of Mitchell. As discussed in my testimony above, the Company has indicated a clear bias toward the Mitchell purchase on every one of these key issues. This bias creates a big warning sign that the Commission should not ignore.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

EXHIBIT TW-1

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Synapse Energy Economics Inc., Cambridge, MA. Vice President, 2011 to present.
Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. Commissioner, 2007- 2011.
Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

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Association for the Conservation of Energy, London, England. Research Director, 1991-1992.

Massachusetts Department of Public Utilities, Boston, MA. Staff Economist, 1989-1990.

Massachusetts Office of Energy Resources, Boston, MA. Policy Analyst, 1987-1989.

Energy Systems Research Group, Boston, MA. Research Associate, 1983-1987.

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TESTIMONY

Nova Scotia Utility and Review Board (Matter No. M04819). Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013-2015. On behalf of Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271). Rebuttal testimony regarding IRP rule compliance. On behalf of Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669). Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

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Rhode Island Public Utilities Commission (Docket No. 3765). Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. February 20, 2007.

Rhode Island Public Utilities Commission (Docket No. 3765). Direct testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275). Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project. On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779). Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005). Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051). Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

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EXHIBIT TW-2

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - *one in which a certified public accountant who is in the practice of* public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

EXHIBIT TW-3

Joint Comments of the American Council for an Energy Efficient Economy, the Alliance to Save Energy, the Natural Resources Defense Council and Energy Center of Wisconsin on the January 2009 Report: "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S." issued by EPRI

This review is intended to answer questions about how the recently released EPRI energy efficiency potential study compares to other recent savings potential estimates, and how to interpret it when assessing energy efficiency potential in the current policy climate.

First, the reviewers strongly agree with EPRI's conclusion that "Energy efficiency represents the greatest near-term potential for climate reduction...[1]," and that "significant investment in energy efficiency program infrastructure, consumer education, and enabling technology beyond current levels are needed to realize the achievable energy efficiency potential."[2]

Notwithstanding this strong finding of the potential for energy efficiency, the reviewers believe that the EPRI estimates of energy efficiency potential significantly understate the potential for energy savings and should be considered a lower bound on savings potential for the reasons discussed below. Regardless of whether one relies on EPRI's lower bound forecast or other credible potential study results that show significantly higher potential, however, the fact remains that substantial cost-effective potential exists and we need to get serious about tapping it.

Embedded Energy Savings

The table below summarizes the EPRI Report's estimates of energy efficiency potential. While the Report starts from the Energy Information Administration's 2008 Annual Energy Outlook (AEO 2008), it relies on a Baseline Forecast which incorporates the energy savings embedded in the AEO 2008 Forecast. These savings, which include the effects of legislation enacted as of 2008 and compliance with codes and standards already signed into law, have been added back to the AEO Forecast to construct EPRI's higher Baseline Forecast.

EPRI Estimates of Energy Efficiency Potential for the U.S.

	AEO 2008 Reference Case	Baseline Forecast	Economic Potential	Realistic Achievable Potential	Maximum Achievable Potential
Forecast - billion kWh					
2020	4,253	4,319		4,112	3,881
2030	4,696	4,858		4,460	4,314
Savings Relative to AEO 2008 Reference Case - billion kWh (% of kWh sales in:)					
2020				141 (3%)	372 (9%)
2030				236 (5%)	382 (8%)
Savings Relative to Baseline Forecast – billion kWh (% of kWh sales in:)					
2020			(12%)	207 (5%)	438 (10%)
2030			(14%)	398 (8%)	544 (11%)
% Energy Savings/Year Through: (Baseline Forecast)					
2020			1%	0.40%	0.85%
2030			0.64%	0.37%	0.51%

[1] p. vi.
[2] p. xxxv.

The Report estimates the achievable potential for energy efficiency to be between 5% and 10% of total sales in 2020, or between 0.40% and 0.85% per year in total load reductions from the Baseline Forecast.[3] When the embedded savings (those in current law or in the pipeline) are taken out, this Report estimates the potential for additional savings to be between 3% and 9% of total sales. This compares to existing energy savings targets of 1% per year or more that utilities or other operators must meet, with several as high as 2% per year, and numerous state, regional and national study results which estimate achievable potential in the 1-2 % range of reduction in total sales per year over the next two decades (see end note).[i] There are a number of assumptions in the EPRI Report that explain this difference.

Some of the EPRI Report Assumptions Affecting the Results:

- The EPRI savings estimates are only for voluntary utility-operated programs and do not include new building codes or equipment efficiency standards. New codes and standards will include energy savings measures not included in the EPRI study and will also increase the penetration rate of measures since mandatory measures will have nearly 100% penetration, significantly higher than the penetrations EPRI assumed for its voluntary utility programs. In fact, the Report states that *"more progressive codes and standards would yield even greater levels of electric savings and peak demand reduction."*[4]
- The EPRI savings estimates are almost entirely from existing efficiency technologies and contains little that is not already commercialized and cost-effective. EPRI essentially estimated 2020 potential and not 2030 potential, and did not take into account technology change or innovation that would create new efficiency opportunities in the 2020-2030 period. The Report does recognize this fact and states that *"since most devices have a useful life of less than fifteen years, it is instructive to examine the results for the year 2020, by which time the existing stock of most energy consuming devices has turned over."*[5] The Report also states that *"the results should not be interpreted as a limitation on future energy efficiency efforts: rather, [these] results [are] from extrapolating present-day technologies over a long forecast horizon rather than speculating about new technologies."*[6]
- The EPRI estimates are built around energy-saving technologies (e.g. efficient lamps and air conditioners) but do not include much in the way of energy-efficient practices, such as improved systems design of new buildings or industrial processes. More broadly, the EPRI industrial savings estimates only include motor, lighting and heating improvements and do not include a wide array of available industrial process improvements. As EPRI notes, with improved/redesigned processes *"there is significant potential for increased savings…"*[7]
- The Report potential estimates do not include *"…any new codes, standards, regulatory policies, or other externalities [that] could contribute to greater levels of overall efficiency,"*[8] which it recognizes would contribute to greater levels of efficiency.[9] In addition, the Report *"includes assumptions about customer adoption predicated on*

[3] While the EPRI Report highlights 2030 results, we focus here on the 2020 estimates since the EPRI Report focuses on efficiency measures that are commercialized and cost-effective today, and includes little in the way of new efficiency measures or investments over the 2020-2030 period.
[4] p. v.
[5] p. 8-1.
[6] p. 4-3.
[7] p. 4-27.
[8] p. vi.
[9] p. 8-3.

experience and observation of the range of results realized by program implementers."[10] However, the choice on which experiences to rely did not always include current best practices, and in at least some cases, did not take into account recent advances in consumer awareness and program innovations that have demonstrated the possibility for large successes. Measures in this category include several shell-related measures, windows and solid state lighting (LEDs) in the residential sector,[11] and custom efficiency measures in the industrial sector.[12] The Report also assumes programs do not induce early replacement of technologies before the end of their useful life, even if it is economic to do so. Taken together, the most aggressive case EPRI analyzed results in savings of 0.85% per year, yet Efficiency Vermont reduced energy use by about 2% of sales from measures installed under its programs in 2008, more than double EPRI's "maximum achievable" case.

- The Report assumes the same *"relatively flat electricity price forecast in real dollars between 2008 and 2030"* that is included in the AEO 2008.[13] Energy prices and energy price forecasts have been climbing significantly and use of higher prices would moderately increase estimates of cost-effective potential.

EPRI highlights the need and expresses its intent to conduct follow-on analysis on the electricity use and savings potentials under alternate scenarios, not included in this report, to reflect different electricity price levels, the establishment of national carbon legislation, the expectation of new codes and standards, new utility regulatory incentives for energy efficiency, and greater investment in end-use technology innovation. The Report acknowledges that such policy efforts *"bear significantly on the future savings potential from energy efficiency programs."*[14]

Conclusion

The EPRI "maximum achievable" significantly understates potential for electricity savings in 2020. The reviewers believe that the findings for 2030 are unrealistically low as EPRI did not fully account for improvements in technologies and practices and/or development of new technologies over the coming two decades. We note EPRI's intent to include these improvements and other policy scenarios in follow-on analysis and look forward to working with EPRI in that that effort.

[10] p. 8-3.
[11] pp. 4-10, 4-14.
[12] p. 4-27.
[13] p. 2-9.
[14] p. 8-4.

[i] **Summary of Aggressive Mandatory State Energy Savings Targets and Accomplishments**

State	Target	Notes
Massachusetts	2%+	Plan to ramp up to 1.5% by 2010, 2-3%/yr over following decade; not adopted yet
Illinois	2.0%	2007 legislation; 2% after 7 year ramp-up; subject to cost caps
Ohio	2.0%	2008 legislation; 2% after 10 year ramp-up; PUC can modify
Maryland	1.88%	2008 legislation; 15% by 2015; includes standards & codes
New York	1.88%	Governor's goal of 15% by 2015; includes standards & codes; proceeding underway
Vermont	1.75%	Approved plan for 2007-2008; achieved ~2% in 2007
New Jersey	1.54%	2007 legislation authorizes target of 20% in 2020, BPU proceeding about to start
Minnesota	1.5%	2007 legislation; includes standards & codes
Connecticut	~1.5%	Derived from utility plan for 2008-2018 that responds to 2007 legislation
California	1.0%	10 year target; achieved nearly 2% from measures installed in 2007

Efficiency Potential Study Results

A recent meta-review of more than 20 state, regional and national electricity efficiency potential studies by ACEEE identified an annual average achievable electricity savings potential of 1.5%. (Eldridge, M, R. N. Elliot, and Max Neubauer. 2008. *State-Level Energy Efficiency Analysis: Goals, Methods, and Lessons Learned.* American Council for an Energy-Efficient Economy.)

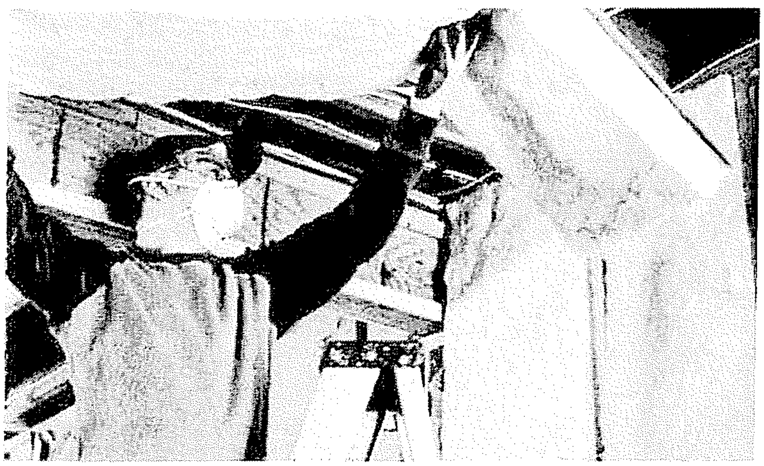
Several other relevant studies have been done and should be considered. For example, according to the McKinsey Global Institute study (2006) of energy-efficiency potential if all energy efficiency measures with internal rates of return of 10% or better are implemented, US residential energy demand could be reduced by 36% below its 2020 baseline and commercial energy use could be reduced by 19%. (McKinsey Global Institute, *Productivity of Growing Global Energy Demand: A Microeconomic Perspective,* November 2006.)

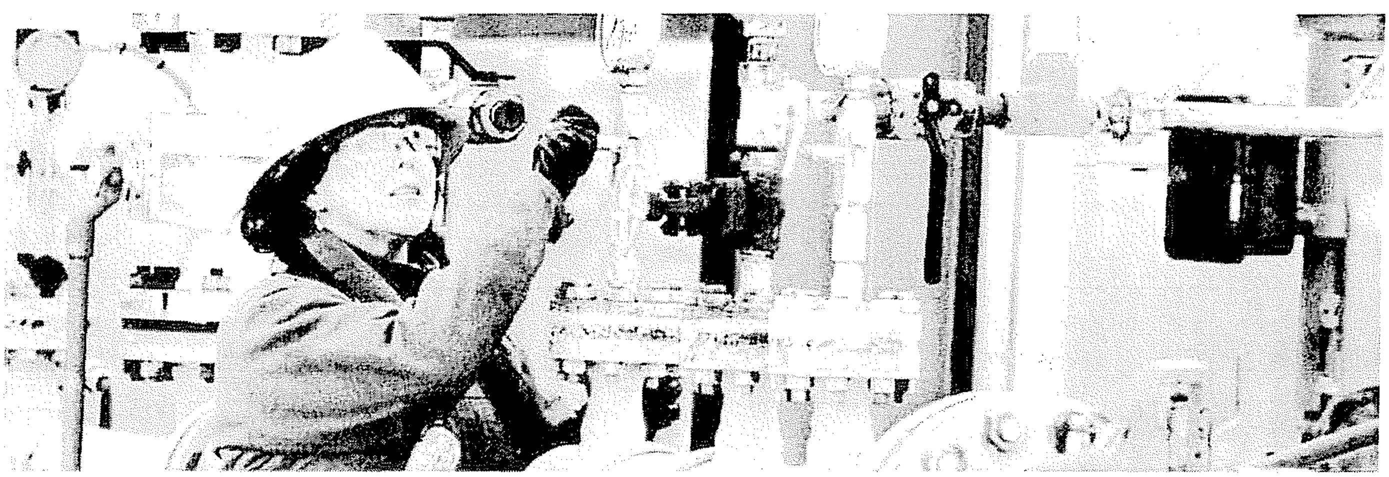
In addition, the American Physical Society found that energy demand from the entire U.S. buildings sector (everything from houses to light bulbs to office towers to retail stores) would not grow *at all* from 2008 – 2030 if we deployed energy efficiency measures costing less than the energy they displaced. (American Physical Society. *ENERGY FUTURE: THINK EFFICIENCY.* September 2008).

EXHIBIT TW-4

McKinsey&Company

Unlocking Energy Efficiency in the U.S. Economy





Executive summary

The efficient use of energy has been the goal of many initiatives within the United States over the past several decades. While the success of specific efforts has varied, the trend is clear: the U.S. economy has steadily improved its ability to produce more with less energy. Yet these improvements have emerged unevenly and incompletely within the economy. As a result, net efficiency gains fall short of their full NPV-positive potential. Concerns about energy affordability, energy security, and greenhouse gas (GHG) emissions have heightened interest in the potential for energy efficiency to help address these important issues.

Despite numerous studies on energy efficiency two issues remain unclear: the magnitude of the NPV-positive opportunity, and the practical steps necessary to unlock its full potential. What appears needed is an integrated analysis of energy efficiency opportunities that simultaneously identifies the barriers and reviews possible solution strategies. Such an analysis would ideally link efficiency opportunities and their barriers with practical and comprehensive approaches for capturing the billions of dollars of savings potential that exist across the economy.

Starting in 2008, a research team from McKinsey & Company has worked with leading companies, industry experts, government agencies, and environmental NGOs to address this gap. It reexamined in detail the potential for greater efficiency in non-transportation uses of energy,[2] assessing the barriers to achievement of that potential, and surveying possible solutions. This report is the product of that effort.

The central conclusion of our work: *Energy efficiency offers a vast, low-cost energy resource for the U.S. economy – but only if the nation can craft a comprehensive and innovative approach to unlock it. Significant and persistent barriers will need to be addressed at multiple levels to stimulate demand for energy efficiency and manage its delivery across more than 100 million buildings and literally billions of devices. If executed at scale, a holistic approach would yield gross energy savings worth more than $1.2 trillion, well above the $520 billion needed through 2020 for upfront investment in efficiency measures (not including program costs). Such a program is estimated to reduce end-use energy consumption in 2020 by 9.1 quadrillion BTUs, roughly 23 percent of projected demand, potentially abating up to 1.1 gigatons of greenhouse gases annually.*

Five observations are relevant to a national debate about how best to pursue energy efficiency opportunities of the magnitude identified and within the timeframe considered in this report. Specifically, an overarching strategy would need to:

1. Recognize energy efficiency as an important energy resource that can help meet future energy needs while the nation concurrently develops new no- and low-carbon energy sources

2. Formulate and launch at both national and regional levels an integrated portfolio of proven, piloted, and emerging approaches to unlock the full potential of energy efficiency

3. Identify methods to provide the significant upfront funding required by any plan to capture energy efficiency

2 Non-transportation uses of energy exclude fuel used by passenger vehicles, trucks, trains, airplanes, and ships, as well as transport energy used in agriculture, mining, and construction operations. For simplicity of expression, we sometimes refer to the energy covered by our analyses as "stationary energy."

4. Forge greater alignment between utilities, regulators, government agencies, manufacturers, and energy consumers
5. Foster innovation in the development and deployment of next-generation energy efficiency technologies to ensure ongoing productivity gains.

In the body of the report, we discuss the compelling benefits of energy efficiency and why this energy resource warrants being a national priority. We then identify and "map" in detail the complex and persistent set of barriers that have impeded capture of energy efficiency at the level of individual opportunities. We also identify solution strategies, including those proven, piloted, or recently emerged, that could play a role in overcoming these barriers. Finally, we elaborate on the five observations noted above to outline important considerations for the development of a holistic implementation strategy to capture energy efficiency at scale.

We hope that our research and this report will help in the understanding and pursuit of approaches to unlock the benefits of energy efficiency, as the United States seeks to improve energy affordability, energy security, and greenhouse gas reduction.

COMPELLING NATIONWIDE OPPORTUNITY

Our research indicates that by 2020, the United States could reduce annual energy consumption by 23 percent from a business-as-usual (BAU)[3] projection by deploying an array of NPV-positive efficiency measures, saving 9.1 quadrillion BTUs of end-use[4] energy (18.4 quadrillion BTUs in primary energy). This potential exists because significant barriers impede the deployment of energy efficient practices and technologies. It will be helpful to begin by clarifying the size and nature of this opportunity; then we will describe the case for taking action to address the barriers and unlock the energy efficiency potential.

The residential sector accounts for 35 percent of the end-use efficiency potential (33 percent of primary energy potential), the industrial sector 40 percent (32 percent in primary energy), and the commercial sector 25 percent (35 percent in primary energy). The differences between primary and end-use potentials are attributable to conversion, transmission, distribution, and transport losses. We present both numbers throughout as each is relevant to specific issues considered. Capturing the full potential over the next decade would decrease the end-use energy consumption analyzed from 36.9 quadrillion end-use BTUs in 2008 to 30.8 quadrillion end-use BTUs in 2020 (Exhibit A), with potentially profound implications for existing energy provider business models.[5]

This change represents an absolute decline of 6.1 quadrillion end-use BTUs from 2008 levels and an even greater reduction of 9.1 quadrillion end-use BTUs from the projected level of what consumption otherwise would have reached in 2020. Construction of new power plants, gas pipelines, and other energy infrastructure will still be required to address regions of growth, retirement of economically or environmentally obsolete

3 The Energy Information Administration's *Annual Energy Outlook, 2008* represents our business-as-usual projection; our analysis focused on the 81 percent of non-transportation energy with end-uses that we were able to attribute.

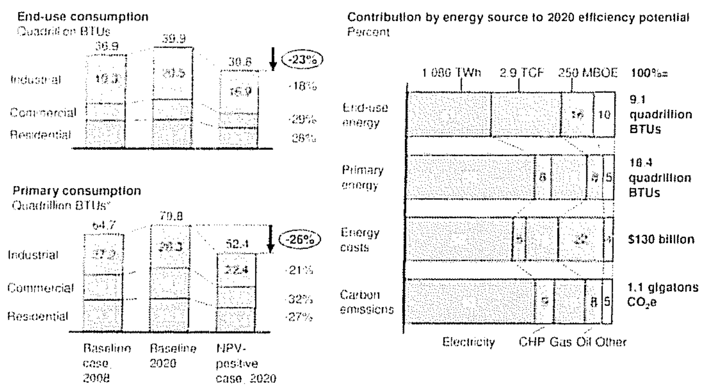
4 End-use, or "site," energy refers to energy consumed in industrial, business, and residential settings, e.g., providing light, heating and cooling spaces, running motors and electronic devices, and powering industrial processes. By contrast, primary, or "source," energy represents energy in the form it is first accounted (e.g., BTUs of coal, oil, natural gas) before transformation to secondary or tertiary forms (e.g., electricity). From the end-use viewpoint primary energy is lost during transformation to other forms and in transmission, distribution, and transport to end-users; these losses are an important energy-saving opportunity but one that is outside the scope of this report. Unless explicitly defined as primary energy, energy usage and savings values in this report refer to end-use energy

5 We examine implications for energy provider business models in Chapter 5 of the full report

energy infrastructure, and introduction of unaccounted-for consumption, such as electric vehicles. However, energy efficiency could measurably reduce the total new infrastructure investment required during this timeframe.

Beyond the economics, efficiency represents an emissions-free energy resource. If captured at full potential, energy efficiency would abate approximately 1.1 gigatons CO_2e of greenhouse gas emissions per year in 2020 relative to BAU projections, and could serve as an important bridge to a future era of advanced low-carbon supply-side energy options.

Exhibit A: Energy efficiency potential in the U.S. economy



* Includes primary savings from CHP of 490 trillion BTUs in commercial and 910 trillion BTUs in industrial
Source: EIA AEO 2008; McKinsey analysis

The left side of the exhibit shows total energy consumption, measured in quadrillion BTUs, for the portions of each sector addressed in the report plus the corresponding consumption if the identified energy efficiency potential were realized. The right side provides different views of the energy efficiency potential in 2020 broken out by fuel type

In modeling the national potential for greater energy efficiency, we focused our analysis on identifying what we call the "NPV-positive" potential for energy efficiency. We defined "NPV-positive"[6] to include direct energy, operating, and maintenance cost savings over the equipment's useful life, net of equipment and installation costs, regardless of who invests in the efficiency measure or receives the benefits. We used industrial retail rates as a proxy for the value of energy savings in our calculations,[7] applied a 7-percent discount factor as the cost of capital, and assumed no price on carbon. This methodology provides a representation of the potential for net-present-value-positive (NPV-positive) energy efficiency from the perspective of policymakers and business leaders who must make decisions in the broad interests of society. This is in contrast to some studies that report on "technical" potential, which applies the most efficient technology regardless of cost, and differs from reports that project "achievable" potential given historical performance and an implied set of constraints.

We acknowledge, however, that there are different views of future scenarios, societal discount rates, and what constitutes "NPV-positive" from the perspective of individual

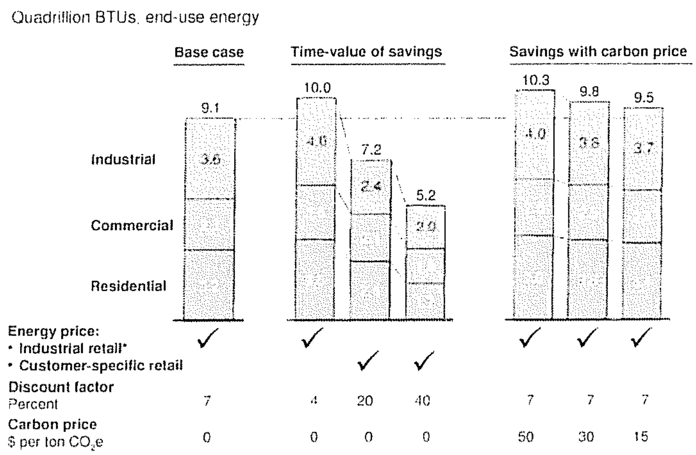
6 See Appendix B of the full report for more details on this calculation methodology.

7 Industrial retail rates represent an approximate value of the energy saved as they include generation, transmission, capacity, and distribution costs in regulated and restructured markets. The bulk of the rate is composed of generation cost, with minor contribution from transmission and capacity, and negligible contribution from distribution costs. Though load factor in these rates underestimates the national average, and thus this rate represents a slightly conservative estimate of the value of the energy savings, the other components are closer to the likely savings if significant energy efficiency were to be realized. We computed the avoided cost of gas also using an industrial retail rate, which likewise is close to the wholesale cost of gas plus a small amount of transport cost. A more detailed discussion of the avoided cost of energy is available in Appendix B of the full report.

actors. Thus we tested the resiliency of the NPV-positive opportunities by adjusting the discount rate (expected payback period), the value of energy savings (customer-specific retail prices), and possible carbon price (\$0, \$15, \$30, and \$50 per ton CO_2e). We found the potential remains quite significant across all of these sensitivity tests (Exhibit B). Introducing a carbon price as high as \$50 per ton CO_2e from the national perspective increases the potential by 13 percent. A more moderate price of \$30 per ton CO_2e increases the potential by 8 percent. Applying a discount rate of 40 percent, using customer-class-specific retail rates, and assuming no future cost of carbon, reduces the NPV-positive potential from 9.1 quadrillion to 5.2 quadrillion BTUs – a reduced but still significant potential that would more than offset projected increases in BAU energy consumption through 2020.

Exhibit B: Sensitivity of NPV-positive energy efficiency potential - 2020

[illegible] represents the energy-efficiency potential in 2020 associated with non-transportation use of energy under the conditions outlined at the bottom of the exhibit – energy price, discount factor, and carbon price. The height of each section corresponds to the efficiency potential in that sector, as labeled at the left, under those conditions.



* AEO 2008 industrial energy prices by Census division (national average weighted across all fuels; \$10.80/MMBTU) are used as a proxy

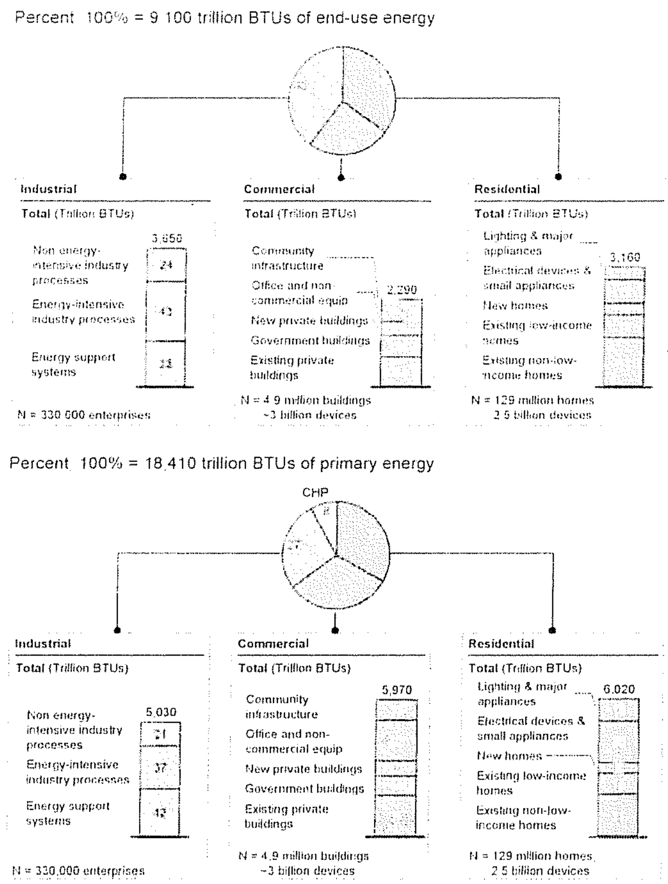
Source: EIA AEO 2008, McKinsey analysis

Our methodology is based on detailed examination of the economics of efficiency potential and the barriers to capture of it. Using the Energy Information Administration's National Energy Modeling System (NEMS) and *Annual Energy Outlook 2008* (AEO 2008) as a foundation, for each Census division and building type, we developed a set of "business-as-usual" choices for end-use technology through 2020. Then, to identify meaningful opportunities at this level of detail, we modeled deployment of 675 energy-saving measures to select those with the lowest total cost of ownership, replacing existing equipment and building stock over time whenever doing so was "NPV-positive."[8] We disaggregated national data on energy consumption using some 60 demographic and usage attributes, creating roughly 20,000 consumption micro-segments across which we could analyze potential.

By linking our models with usage surveys and research on user-related barriers, we were able to re-aggregate the micro-segments as clusters of efficiency potential according to sets of shared barriers and usage characteristics. The resulting clusters as shown in Exhibit C are sufficiently homogeneous to suggest a set of targeted solutions.

8 We modeled the energy-savings potential of combined heat and power installations in the commercial and industrial sectors separately from these replacement measures.

Exhibit C: Clusters of efficiency potential in stationary uses of energy, 2020



Source: EIA AEO 2008 McKinsey analysis

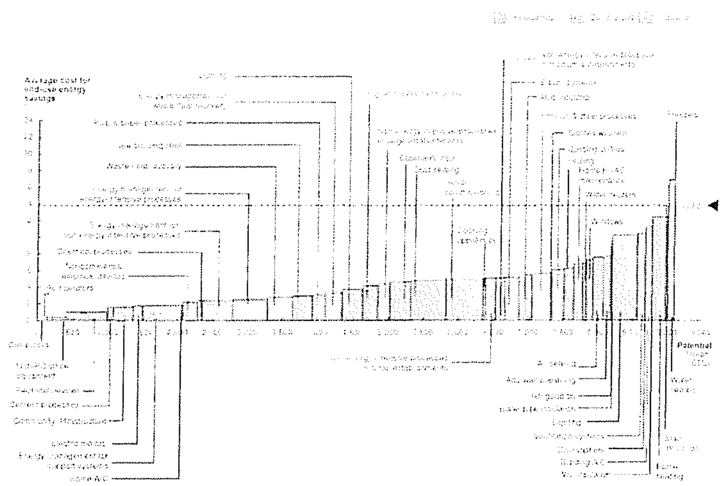
The pie charts show the share (in percent) of energy efficiency potential in 2020 in each economic sector with end-use energy in the upper chart and primary energy in the lower one. Each column chart shows the clusters of potential that make up each sector, with the total potential in the sector (in trillion BTUs) displayed at the top of the column and the share (in percent) in the corresponding segment. Below each column are numbers for relevant end-use settings.

While not all actions that decrease the consumption of energy represent NPV-positive investments relative to alternatives, by definition in our methodology, all the energy efficiency actions included in this report represent attractive investments. The required investment of these NPV-positive efficiency measures ranges upward from $0.40 per MMBTU saved, averaging $4.40 per MMBTU of end-use energy saved (not including program costs). This average is 68 percent below the AEO 2008 business-as-usual forecast price of saved energy in 2020, $13.80 per MMBTU weighted average across all fuel types (Exhibit D), and 24 percent below the projected lowest delivered natural gas price in the United States in 2020, $5.76 per MMBTU. Furthermore, the energy and operational savings from greater efficiency total some $1.2 trillion in present value to the U.S. economy: unlocking this value would require an initial upfront investment of approximately $520 billion (not including program costs).[9] Even the most expensive opportunities selected in this study are NPV-positive over the lifetime of the measure and represent the least expensive way to provide for future energy requirements.

9 The net present value of this investment therefore would be $1.2 trillion minus $520 billion, or $680 billion.

Exhibit D: U.S. energy efficiency supply curve – 2020

The width of each column on the chart represents the amount of efficiency potential (in trillion BTUs) found in the named group of measures, as modeled in the report. The height of each column corresponds to the average annualized cost (in dollars per million BTUs of potential) of that group of measures.



Average price of avoided energy consumption at the industrial price; $35.60/MMBTU represents the highest regional electricity price used; new build cost based on AEO 2008 future construction costs
Source: EIA AEO 2008, McKinsey analysis

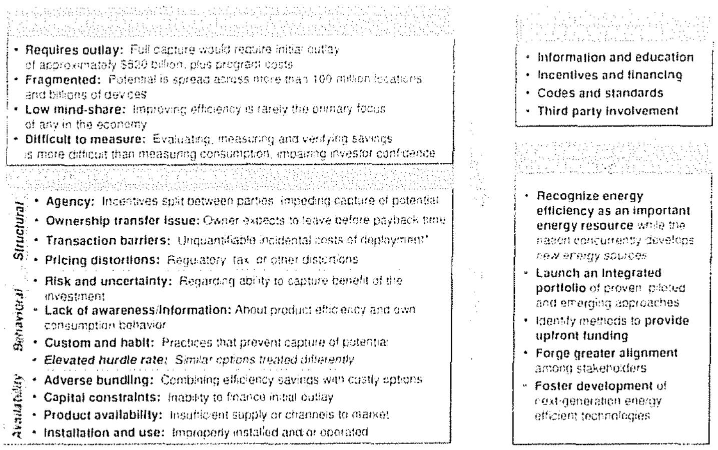
SIGNIFICANT BARRIERS TO CAPTURE

The highly compelling nature of energy efficiency raises the question of why the economy has not already captured this potential, since it is so large and attractive. In fact, much progress has been made over the past few decades throughout the U.S., with even greater results in select regions and applications. Since 1980, energy consumption per unit of floor space has decreased 11 percent in residential and 21 percent in commercial sectors, while industrial energy consumption per real dollar of GDP output has decreased 41 percent. Though these numbers do not adjust for structural changes, many studies indicate efficiency plays a role in these reductions. As an indicator of this success, recent BAU forecasts have incorporated expectations of greater energy efficiency. For example, the EIA's 20-year consumption forecast shows a 5-percent improvement in commercial energy intensity and 10-percent improvement in residential energy intensity compared to their projections of 4 years ago.[10]

As impressive as the gains have been, however, an even greater potential remains due to multiple and persistent barriers present at both the individual opportunity level and overall system level. By their nature, energy efficiency measures typically require a substantial upfront investment in exchange for savings that accrue over the lifetime of the deployed measures. Additionally, efficiency potential is highly fragmented, spread across more than 100 million locations and billions of devices used in residential, commercial, and industrial settings. This dispersion ensures that efficiency is the highest priority for virtually no one. Finally, measuring and verifying energy not consumed is by its nature difficult. Fundamentally, these attributes of energy efficiency give rise to opportunity-specific barriers that require opportunity-specific solution strategies and suggest components of an overarching strategy (Exhibit E).

10 AEO 2004 and 2008

Exhibit E: Multiple challenges associated with pursuing energy efficiency



* Financial transaction barriers and actual quality trade-offs are factored into the initial NPV-positive potential calculation as real costs.
Source: McKinsey analysis

On the left, this exhibit summarizes the fundamental difficulties of pursuing greater energy efficiency and the opportunity-specific barriers that affect and help define clusters of efficiency potential. On the right, it shows opportunity-level solution strategies to overcome barriers and suggests the essential elements of an overarching strategy for capturing energy efficiency potential.

Our research suggests that unlocking the full potential of any given opportunity requires addressing all barriers in a holistic rather than piecemeal fashion. To simplify the discussion, we have grouped individual opportunity barriers into three broad categories: structural, behavioral, and availability. Structural barriers prevent an end-user from having the choice to capture what would otherwise be an attractive efficiency option; for example, a tenant in an apartment customarily has little choice about the efficiency of the HVAC system, even though the tenant pays the utility bills.[11] This type of agency barrier affects some 9 percent of the end-use energy efficiency potential. Behavioral barriers include situations where lack of awareness or end-user inertia block pursuit of an opportunity; for example, a facility manager might replace a broken pump with a model having the lowest upfront cost rather than a more energy efficient model with lower total ownership cost, given a lack of awareness of the consumption differences. Availability barriers include situations when an end-user interested in and willing to pursue a measure cannot access it in an acceptable form; for example, a lack of access to capital might prevent the upgrade to a new heating system, or the bundling of premium features with energy efficiency measures in a dishwasher might dissuade an end-user from purchasing a more efficient model.

11 We refer to space conditioning systems generically as HVAC systems (heating, ventilation, and air conditioning), whether a building has a heating system, a cooling system, an air exchanger or all three systems.

SOLUTIONS AVAILABLE TO CAPTURE THE POTENTIAL

Experience over the past several decades has generated a large array of tools for addressing the barriers that impede capture of attractive efficiency potential, some of which have been proven at a national scale, some have been "piloted" in select geographies or at certain times at a city-scale, and others are emerging and merit trial but are not yet thoroughly tested. The array of proven, piloted, and emerging solutions falls into four broad categories:

- **Information and education.** Increasing awareness of energy use and knowledge about specific energy-saving opportunities would enable end-users to act more swiftly in their own financial interest. Options include providing more information on utility bills or use of in-building displays, voluntary standards, additional device- and building-labeling schemes, audits and assessments, and awareness campaigns.

- **Incentives and financing.** Given the large upfront investment needed to capture efficiency potential, various approaches could reduce financial hurdles that end-users face. Options include traditional and creative financing vehicles (such as on-bill financing), monetary incentives and/or grants, including tax and cash incentives, and price signals, including tiered pricing and externality pricing (e.g., carbon price).

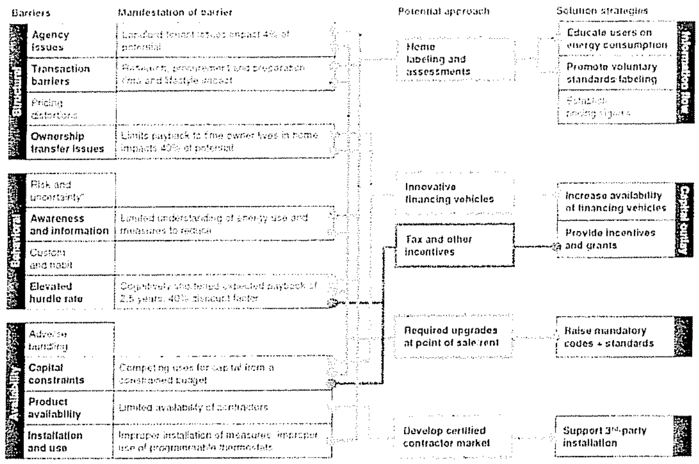
- **Codes and standards.** In some clusters of efficiency potential, some form of mandate may be warranted to expedite the process of capturing the potential, particularly where end-user or manufacturer awareness and attention are low. Options include mandatory audits and/or assessments, equipment standards, and building codes, including improving code enforcement.

- **Third-party involvement.** A private company, utility, government agency, or non-governmental organization could support a "do-it-for-me" approach by purchasing and installing energy efficiency improvements directly for the end-user, thereby essentially addressing most non-capital barriers. When coupled with monetary incentives, this solution strategy could address the majority of barriers, though some number of end-users might decline the opportunity to receive the efficiency upgrade, preventing capture of the full potential.

For most opportunities, a comprehensive approach will require multiple solutions to address the entire set of barriers facing a cluster of efficiency potential. Through an extensive review of the literature on energy efficiency and interviews with experts in this and related fields, we have attempted to define solutions that can address the various barriers under a variety of conditions. Exhibit F illustrates how we mapped alternative solutions against the barriers for a cluster.

We do not believe it is possible to empirically prove that a particular combination of measures will unlock the full potential in any cluster, because the level of impact being considered has never previously been attained. However, we do believe that a holistic combination of solutions that address the full-range of barriers and system-level issues is a prerequisite for attaining energy-productivity gains anywhere near those identified in our analysis.

Exhibit F: Addressing barriers in existing non-low-income homes



* Represents a minor barrier
Source: McKinsey analysis

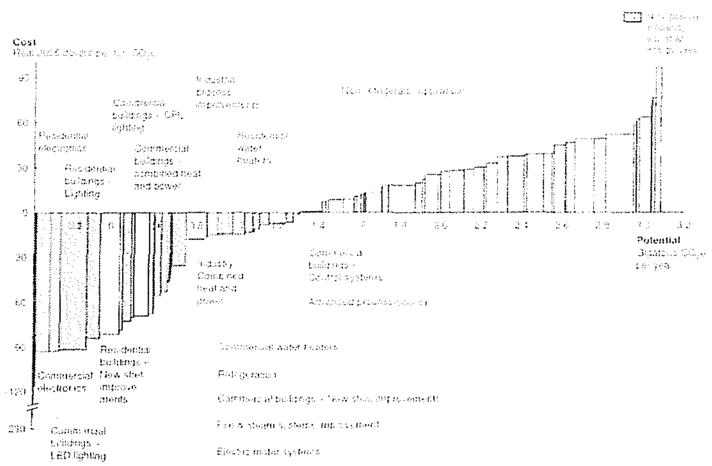
The left side shows categories of opportunity-specific barriers that can impede capture of energy efficiency potential, with a description of the specific manner in which the barrier is often manifested in the cluster extending toward the right. The far right side of the exhibit lists general solution strategies for pursuing efficiency potential, with the near right column describing how this might be combined into specific approaches to overcome barriers in the cluster. The colored lines map specific solutions to specific barriers.

ELEMENTS OF A HOLISTIC IMPLEMENTATION STRATEGY

Capturing the full efficiency potential identified in this report would require an additional investment of $50 billion per year (in present value terms), four- to five-times 2008 levels of investment, sustained over a decade. Even the fastest-moving technologies of the past century that achieved widespread adoption, such as cellular telephones, microwaves, or radio, took 10 to 15 years to achieve similar rates of scale-up. Without an increase in national commitment, it will remain challenging to unlock the full potential of energy efficiency. As noted previously, there are five important aspects to incorporate into the nation's approach to scale-up and capture the full potential of energy efficiency. An overarching strategy would need to:

1. **Recognize energy efficiency as an important energy resource that can help meet future energy needs, while the nation concurrently develops new no- and low-carbon energy sources.** Energy efficiency is an important resource that is critical in the overall portfolio of energy solutions. Likewise, as indicated in our prior greenhouse gas abatement work, new sources of no- and low-carbon generation are also important components of the portfolio. While it may seem counterintuitive initially given the magnitude of the energy efficiency potential available over the next decade, there are important reasons for continuing to develop new no- and low-carbon options for energy supply. First, as described in our original report on U.S. greenhouse gas abatement (Exhibit G), energy efficiency in stationary uses of energy represents less than half of the potential abatement available to meet any future reduction targets. In addition, some areas of the country will continue to experience growth, and some may need to retire and replace aging existing assets. The uncertain growth of electric vehicles could further complicate these requirements. Finally, pursuing energy efficiency at this scale will present a set of risks related to the timing and magnitude of potential capture. Consequently, there remains a strong rationale to diversify risk across supply and demand resources.

This exhibit shows greenhouse gas abatement potential as depicted in the mid-range case in McKinsey's greenhouse gas report (2007), with energy efficiency opportunities associated with stationary uses of energy highlighted. The height of each bar represents the incremental cost in dollars to abate one ton of carbon dioxide (or its equivalent); the width shows the gigatons of such emissions that could be abated per year



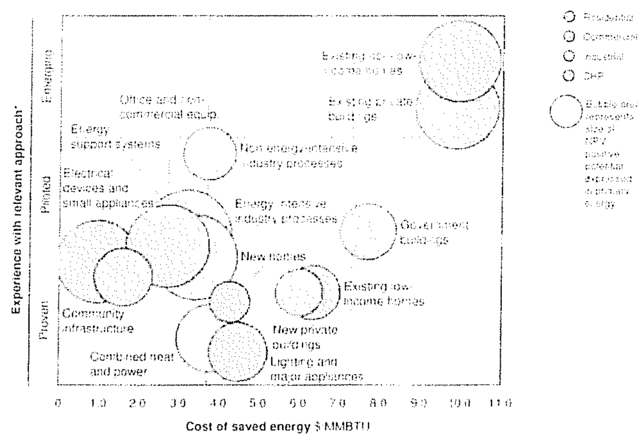
Source McKinsey analysis

2. **Formulate and launch at both national and regional levels an integrated portfolio of proven, piloted, and emerging approaches to unlock the full potential of energy efficiency.** There are multiple combinations of approaches the nation could take to support the scaled-up capture of energy efficiency. In addition to seeking the impact of national efforts, this portfolio should effectively and fairly reflect regional differences in energy efficiency potential. Any approach would *need to make the following three determinations:*

   - The extent to which government should mandate energy efficiency through the expansion and enforcement of codes and standards
   - Beyond codes and standards, the extent to which government (or other publicly funded third parties) should directly deploy energy efficiency measures
   - The best methods by which to further stimulate demand and enable capture of the remaining energy efficiency potential.

   Exhibit H illustrates one example of a portfolio of solution strategies focusing on the most proven solution strategies deployed to date. Such a tool facilitates evaluation of a portfolio against the relevant parameters of cost, risk (i.e., experience), and return (i.e., size of potential).

3. **Identify methods to provide the significant upfront funding required by any plan to capture energy efficiency.** End-user funding for energy efficiency by consumers has proved difficult. Partial monetary incentives and supportive codes and standards increase direct funding by end-users: the former by reducing initial outlays and raising awareness, the latter by essentially requiring participation. Enhanced performance contracting or loan guarantees are relatively untested but could facilitate end-user funding. Alternatively, the entire national upfront investment of $520 billion (not including program costs) could be recovered through a system-benefit charge on energy on the order of $0.0059 cents per kWh of electricity and $1.12 per MMBTU of other fuels over 10 years. This would represent an increase in average customer energy costs of 8 percent, which would be more than offset by the eventual average bill savings of 24 percent. Different solution strategies and policies would result in different administrative cost structures. For example, codes and standards have been shown to typically incur program costs below 10 percent, whereas low-income weatherization



* Drawing an analogy to our work with business transformation, piloted solutions represent those tried on the scale of a state or major city (i.e., over 1 million points of consumption); emerging are untested at that level; and proven have broad success at a national scale

Source: EIA AEO 2008; McKinsey analysis

The bubbles depict the NPV-positive efficiency potential in each cluster, measured in primary energy, with the area of the circle proportional to the potential. The position of the bubble's center on the horizontal axis indicates the cost of capturing this potential with the measures modeled in this report (excluding program costs) in dollars per million BTUs per year. The center's position on the vertical axis represents the weighted average of the national experience with the approaches outlined for the cluster.

programs have averaged between 20 and 30 percent.[12] Federal energy legislation under discussion at the time of this report will likely offer flexibility as to the level of energy efficiency each state and energy provider chooses to pursue. It will therefore be incumbent on states and local energy providers to undertake a rigorous analysis to assess the role of efficiency in the context of their overall regional energy strategy.

4. **Forge greater alignment across utilities, regulators, government agencies, manufacturers, and energy consumers.** Designing and executing a scaled-up national energy efficiency program will require collaboration among many stakeholders. Three tasks in particular will need to be addressed to achieve the necessary level of collaboration. First, aligning utility regulation with the goal of greater energy efficiency is a prerequisite for utilities to fully support the pursuit of efficiency opportunities while continuing to meet the demands of their public or private owners. Second, setting customer expectations that energy efficiency will reduce energy bills, but not necessarily rates, will be important to securing their support. Finally, measuring energy efficiency requires effective evaluation, measurement, and verification to provide assurance to stakeholders that programs and projects are achieving the savings claimed for them. Rather than attempting to provide "perfect" information, such programs can provide "sufficient" assurance by focusing on consistency, simplicity of design, and addressing both inputs and impact.

5. **Foster innovation in the development and deployment of next-generation energy efficiency technologies to ensure ongoing productivity gains.** Finally, having launched a significant national campaign to pursue energy efficiency, part of the national strategy must address sustaining the innovation required to ensure future productivity gains can be realized. By design, given the near-term focus of this report, technology development plays a minor role in the potential identified in this report. However, we expect that innovative and cost-effective energy-saving technology will continue to emerge. Ongoing funding and support of energy efficiency research and development can help keep the U.S. on a trajectory toward even greater productivity gains than those presented in this report.

12 Further discussion of program costs is included in Chapter 5 of the full report.

In the nation's pursuit of energy affordability, climate change mitigation, and energy security, energy efficiency stands out as perhaps the single most promising resource. In the course of this work, we have highlighted the significant barriers that exist and must be overcome, and we have provided evidence that none are insurmountable. We hope the information in this report further enriches the national debate and gives policymakers and business executives the added confidence and courage needed to take bold steps to formulate constructive ways to unlock the full potential of energy efficiency.

EXHIBIT TW-5

A National Assessment of Demand Response Potential

STAFF REPORT

FEDERAL ENERGY REGULATORY COMMISSION

JUNE 2009

PREPARED BY:

THE BRATTLE GROUP | FREEMAN, SULLIVAN & CO. | GLOBAL ENERGY PARTNERS, LLC

EXECUTIVE SUMMARY

Energy Independence and Security Act of 2007

Section 529 (a) of the Energy Independence and Security Act of 2007[1] (EISA 2007) requires the Federal Energy Regulatory Commission (Commission or FERC) to conduct a National Assessment of Demand Response Potential[2] (Assessment) and report to Congress on the following:

- Estimation of nationwide demand response potential in 5 and 10 year horizons on a State-by-State basis, including a methodology for updates on an annual basis;
- Estimation of how much of the potential can be achieved within those time horizons, accompanied by specific policy recommendations, including options for funding and/or incentives for the development of demand response;
- Identification of barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available; and
- Recommendations for overcoming any barriers.

EISA 2007 also requires that the Commission take advantage of preexisting research and ongoing work and insure that there is no duplication of effort. The submission of this report fulfills the requirements of Section 529 (a) of EISA 2007.

This Assessment marks the first nationwide study of demand response potential using a state-by-state approach. The effort to produce the Assessment is also unique in that the Commission is making available to the public the inputs, assumptions, calculations, and output in one transparent spreadsheet model so that states and others can update or modify the data and assumptions to estimate demand response potential based on their own policy priorities. This Assessment also takes advantage of preexisting research and ongoing work to insure that there is no duplication of effort.

Estimate of Demand Response Potential

In order to estimate the nationwide demand response potential in 5 and 10 year horizons, the Assessment develops four scenarios of such potential to reflect different levels of demand response programs. These scenarios are: Business-as-Usual, Expanded Business-as-Usual, Achievable Participation and Full Participation. The results under the four scenarios illustrate how the demand response potential varies according to certain variables, such as the number of customers participating in existing and future demand response programs, the availability of dynamic pricing[3] and advanced metering infrastructure

[1] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007) (to be codified at National Energy Conservation Policy Act § 571, 42 U.S.C. §§ 8241, 8279) (EISA 2007). The full text of section 529 is attached as Appendix F.

[2] In the Commission staff's demand response reports, the Commission staff has consistently used the same definition of "demand response" as the U.S. Department of Energy (DOE) used in its February 2006 report to Congress:

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report).

[3] In this Assessment, dynamic pricing refers to prices that are not known with certainty ahead of time. Examples are "real time pricing," in which prices in effect in each hour are not known ahead of time, and "critical peak pricing" in which prices on certain days are known ahead of time, but the days on which those prices will occur are not known until the day before or day of consumption. Static time-varying prices, such as traditional time-of-use rates, in which prices vary by rate period, day of the week and season but are known with certainty, are not part of this analysis.

(AMI)[4], the use of enabling technologies, and varying responses of different customer classes. Figure ES-1 illustrates the differences in peak load starting with no demand response programs and then comparing the four scenarios. The peak demand without any demand response is estimated to grow at an annual average growth rate of 1.7 percent, reaching 810 gigawatts (GW) in 2009 and approximately 950 GW by 2019.[5]

This peak demand can be reduced by varying levels of demand response under the four scenarios. Under the highest level of demand response, it is estimated that there would be a leveling of demand between 2009 and 2019, the last year of the analysis horizon. Thus, the 2019 peak load could be reduced by as much as 150 GW, compared to the Business-as-Usual scenario. To provide some perspective, a typical peaking power plant is about 75 megawatts[6], so this reduction would be equivalent to the output of about 2,000 such power plants.

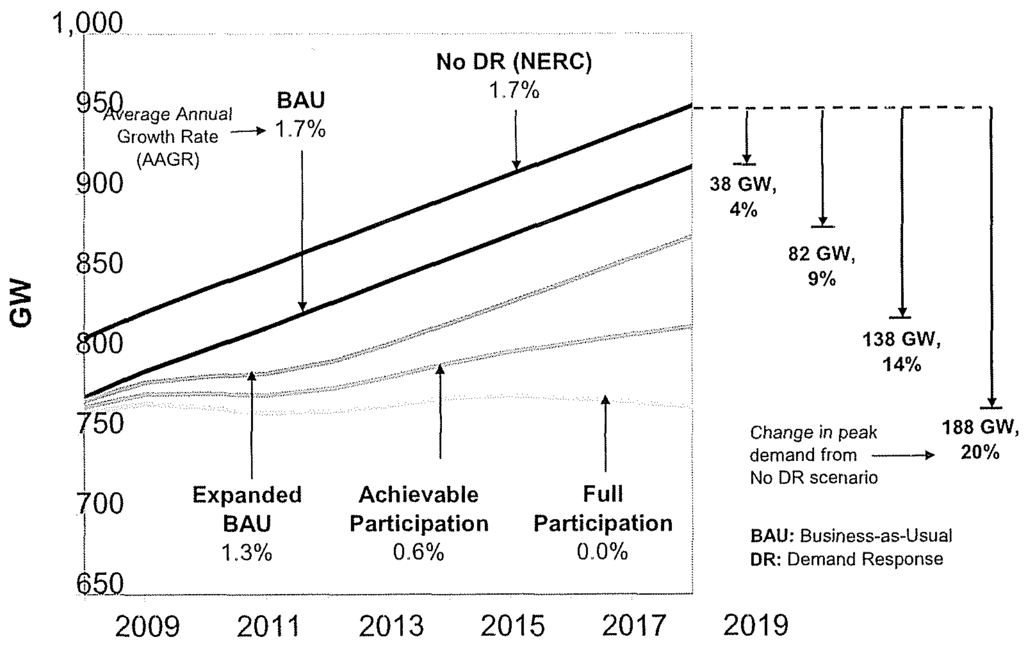


Figure ES-1: U.S. Peak Demand Forecast by Scenario

The amount of demand response potential that can be achieved increases as one moves from the Business-as-Usual scenario to the Full Participation scenario.

It is important to note that the results of the four scenarios are in fact estimates of **potential,** rather than **projections of what is likely to occur**. The numbers reported in this study should be interpreted as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued, market acceptance of the programs, and the overall cost-effectiveness of the

[4] A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point. AMI has the capacity to provide price information to customers that allows them to respond to dynamic or changing prices.

[5] The "No DR (NERC)" baseline is derived from North American Electric Reliability Corporation data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. 2008 Long Term Reliability Assessment, p. 66 note 117; data at http://www.nerc.com/fileUploads/File/ESD/ds.xls

[6] Energy Information Administration, Existing Electric Generating Units in the United States, 2007, available at http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.

As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response.

As with any model-based analysis in economics, the estimates in this Assessment are subject to a number of uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent.[7]

Business-as-Usual Scenario

The Business-as-Usual scenario, which we use as the base case, considers the amount of demand response that would take place if existing and currently planned demand response programs continued unchanged over the next ten years. Such programs include interruptible rates and curtailable loads for Medium and Large commercial and industrial customers, as well as direct load control of large electrical appliances and equipment, such as central air conditioning, of Residential and Small commercial and industrial consumers.

The reduction in peak demand under this scenario is 38 GW by 2019, representing a four percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Expanded Business-as-Usual Scenario

The Expanded Business-as-Usual scenario is the Business-as-Usual scenario with the following additions: 1) the current mix of demand response programs is expanded to all states, with higher levels of participation ("best practices" participation levels);[8] 2) partial deployment of advanced metering infrastructure; and 3) the availability of dynamic pricing to customers, with a small number of customers (5 percent) choosing dynamic pricing.

The reduction in peak demand under this scenario is 82 GW by 2019, representing a 9 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Achievable Participation Scenario

The Achievable Participation scenario is an estimate of how much demand response would take place if 1) advanced metering infrastructure were universally deployed; 2) a dynamic pricing tariff were the default; and 3) other demand response programs, such as direct load control, were available to those who decide to opt out of dynamic pricing. This scenario assumes full-scale deployment of advanced metering

[7] For example, an estimated demand response potential of 19 percent could reflect actual demand response potential ranging from 15 to 23 percent. See Chapter II for a description of one source of error resulting from data limitations, and Appendix E for an analysis of uncertainties arising from the study assumptions.

[8] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. For example, the best practice participation rate for Large Commercial & Industrial customers on interruptible tariffs is 17% (as shown in Table 5). See Chapter V for a full description.

infrastructure by 2019. It also assumes that 60 to 75 percent of customers stay on dynamic pricing rates, and that many of the remaining choose other demand response programs. In addition, it assumes that, in states where enabling technologies (such as programmable communicating thermostats) are cost-effective and offered to customers who are on dynamic pricing rates, 60 percent of the customers will use these technologies.

The reduction in peak demand under this scenario is 138 GW by 2019, representing a 14 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Full Participation Scenario

The Full Participation scenario is an estimate of how much cost-effective demand response would take place if advanced metering infrastructure were universally deployed and if dynamic pricing were made the default tariff and offered with proven enabling technologies. It assumes that all customers remain on the dynamic pricing tariff and use enabling technology where it is cost-effective.

The reduction in peak demand under this scenario is 188 GW by 2019, representing a 20 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Other Results of the Assessment

As shown in Figure ES-1, the size of the demand response potential increases from scenario to scenario, given the underlying assumptions.[9] Comparing the relative impacts of the four scenarios on a national basis, moving from the Business-as-Usual scenario to the Expanded Business-as-Usual scenario, the peak demand reduction in 2019 is more than twice as large. This difference is attributable to the incremental potential for aggressively pursuing traditional programs in states that have little or no existing participation. However, more demand response can be achieved beyond these traditional programs. By also pursuing dynamic pricing the potential impact could further be increased by 54 percent, the difference between the Achievable Participation scenario and the Expanded Business-as-Usual scenario. Removing the assumed limitations on market acceptance of demand response programs and technologies would result in an additional 33 percent increase in demand response potential (the difference between the Achievable Potential and Full Potential scenarios). A conclusion of this Assessment is that at the national level the largest gains in demand response impacts can be made

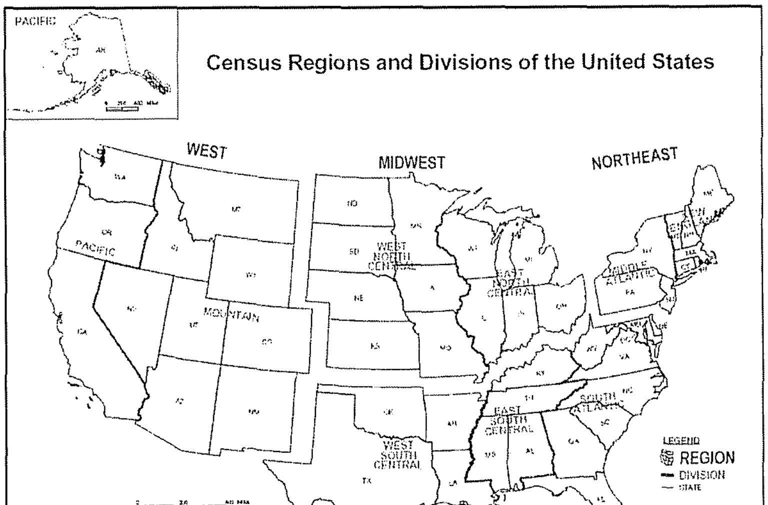


Figure ES- 2: Census Regions

[9] There are other technologies that have the potential to reduce demand. These include emerging smart grid technologies, distributed energy resources, targeted energy efficiency programs, and technology-enabled demand response programs with the capability of providing ancillary services in wholesale markets (and increasing electric system flexibility to help accommodate variable resources such as wind generation.) However, these were not included in this Assessment because there is not yet sufficient experience with these resources to meaningfully estimate their potential.

through dynamic pricing programs when they are offered as the default tariff, particularly when they are offered with enabling technologies.

A mapping of states divided into the nine Census Divisions is provided in Figure ES-2. Regional differences in the four demand response potentials are portrayed by Census Division in Figure ES-3. To adjust for the variation in size among the divisions, the impacts are shown as a percentage of each Division's peak demand.

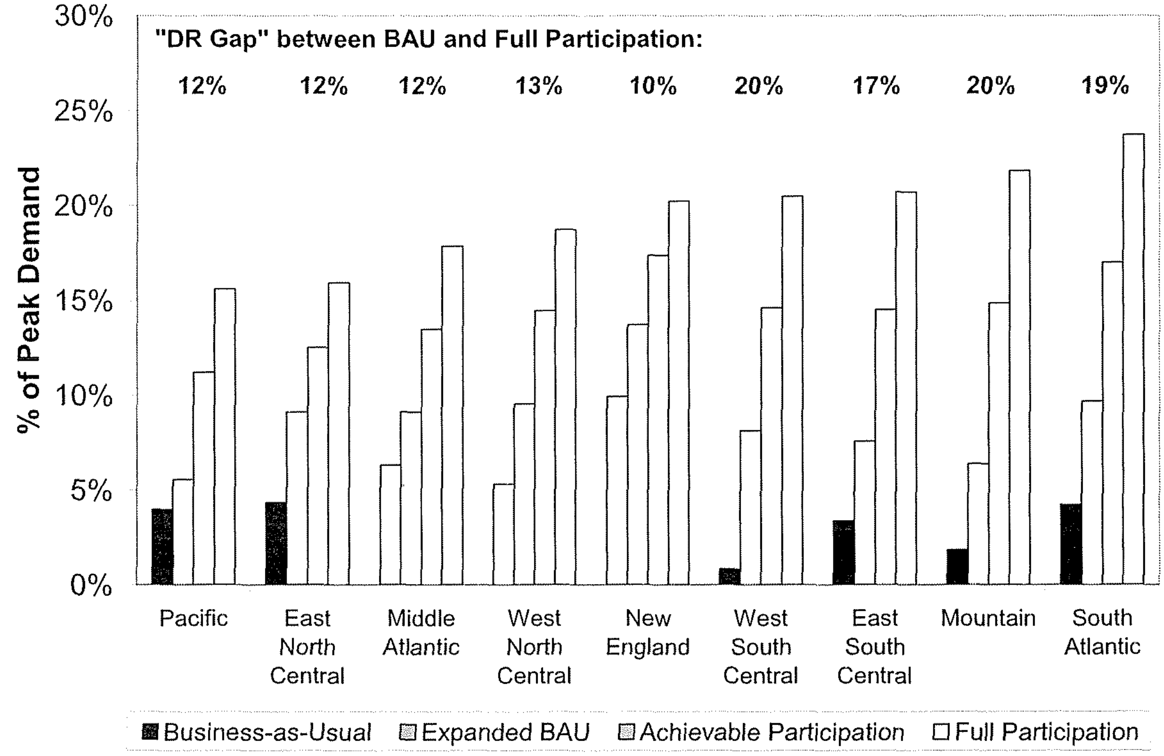


Figure ES-3: Demand Response Potential by Census Division (2019)

Regional differences in the estimated potential by scenario can be explained by factors such as the prevalence of central air conditioning, the mix of customer type, the cost-effectiveness of enabling technologies, and whether regions have both Independent System Operator/Regional Transmission Organization (ISO/RTO) and utility/load serving entity programs. For example, in the Business-as-Usual scenario, the largest impacts originate in regions with ISO/RTO programs that co-exist with utility/load serving entity programs. New England and the Middle Atlantic have the highest estimates, with New England having the ability to reduce nearly 10 percent of peak demand.

The prevalence of central air conditioning plays a key role in determining the magnitude of Achievable and Full Participation scenarios. Hotter regions with higher proportions of central air conditioning, such as the South Atlantic, Mountain, East South Central, and West South Central Divisions, could achieve greater demand response impacts per participating customer from direct load control and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the Achievable and Full Participation scenarios, where dynamic pricing plays a more significant role, than in the Expanded Business-as-Usual scenario.

The cost-effectiveness of enabling technologies[10] also affects regional differences in demand response potential. Due to the low proportion of central air conditioning in the Pacific, New England, and Middle Atlantic Divisions, the benefits of the incremental peak reductions from enabling technologies, as determined in this study, do not outweigh the cost of the devices, so the effect of enabling technologies is excluded from the analysis. As a result, in some of these states and in some customer classes the demand reductions from dynamic pricing reflect only manual (rather than automated) customer response and so are lower than in states where customers would be equipped with enabling technologies. This also applies to the cost-effectiveness of direct load control programs.

The difference between the Business-as-Usual and Full Participation scenarios represents the difference between what the region is achieving today and what it could achieve if all cost-effective demand response options were deployed. Regions with the highest potential under the Full Participation scenario do not necessarily have the largest difference between Business-As-Usual and Full Participation. Generally, regions in the western and northeastern U.S. tend to be the closest to achieving the full potential for demand response, with the Pacific, Middle Atlantic, and New England regions all having gaps of 12 percent or less. Other regions, particularly in the southeastern U.S., have differences of as much as 20 percent of peak demand.

Comparing the results for these four scenarios provides a basis for policy recommendations. For example, the difference between the Business-As-Usual scenario and the Full Participation scenario reveals the "gap" between what is being achieved today through demand response and what could economically be realized in the future if appropriate polices were implemented. Similarly, the difference between the Expanded Business-as-Usual and the Achievable Participation scenarios reveals the additional amount of demand response that could be achieved with policies that rely on both dynamic pricing and other types of programs. The Assessment also provides valuable insight regarding regional and state differences in the potential for demand response reduction, allowing comparisons across the various program types – dynamic pricing with and without enabling technologies, direct load control, interruptible tariffs, and other types of demand response programs such as capacity bidding and demand bidding – to identify programs with the most participation today and those with the most room for growth.

Complete results for each of the fifty states and the District of Columbia are shown in Appendix A.

Barriers to Demand Response Programs and Recommendations for Overcoming the Barriers

A number of barriers need to be overcome in order to achieve the estimated potential of demand response in the United States by 2019. While the Assessment lists 25 barriers to demand response, the most significant are summarized here.

Regulatory Barriers. Some regulatory barriers stem from existing policies and practices that fail to facilitate the use of demand response as a resource. Regulatory barriers exist in both wholesale and retail markets.

- Lack of a direct connection between wholesale and retail prices.
- Measurement and verification challenges.
- Lack of real time information sharing.
- Ineffective demand response program design.

[10] The Assessment evaluates the cost-effectiveness of devices such as programmable communicating thermostats and excludes them where not cost-effective. *See Chapter V for a complete description of the methodology.*

- Disagreement on cost-effectiveness analysis of demand response.

Technological Barriers.

- Lack of advanced metering infrastructure.
- High cost of some enabling technologies.
- Lack of interoperability and open standards.

Other Barriers.

- Lack of customer awareness and education.
- Concern over environmental impacts.

As discussed above, three scenarios estimating potential reductions from the Business-as-Usual scenario have been developed. These scenarios estimate at 5 and 10 year horizons how much potential can be achieved by assuming certain actions on the part of customers, utilities and regulators. Each utility, together with state policy makers, must decide whether and how best to move forward with adoption of demand response, given their particular resources and needs; however, steps can be taken to help inform individual utility decisions and state policies, as well as national decisions.[11]

The increase in demand response under the Expanded Business-as-Usual scenario rests on the assumption that current "best practice"[12] demand response programs, such as direct load control and interruptible tariff programs, are expanded to all states and that there is some participation in dynamic pricing at the retail level. To encourage this expansion to all states and some adoption of dynamic pricing, FERC staff recommends that:

- Coordinated national and local education efforts should be undertaken to foster customer awareness and understanding of demand response, AMI and dynamic pricing.
- Information on program design, implementation and evaluation of these "best practices" programs should be widely shared with other utilities and state and local regulators.
- Demand response programs at the wholesale and retail level should be coordinated so that wholesale and retail market prices are consistent, possibly through the NARUC-FERC Collaborative Dialogue on Demand Response process.
- Both energy efficiency and demand response principles should be included and coordinated in education programs and action plans, to broaden consumers' and decision makers' understanding, improve results and use program resources effectively.
- Expanded demand response programs should be implemented nationwide, where cost-effective.
- Technical business practice standards for evaluating, measuring and verifying energy savings and peak demand reduction in the wholesale and retail electric markets should be developed.

[11] On a separate track FERC issued the Wholesale Competition Final Rule, which recognized the importance of demand response in ensuring just and reasonable wholesale prices and reliable grid operations. As part of the Final Rule, FERC required all RTOs and ISOs to study whether further reforms were necessary to eliminate barriers to comparable treatment of demand response in organized markets, among other things. Most RTOs and ISOs submitted filings that identified the particular barriers and possible reforms for their specific markets. Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64, 100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008).

[12] See definition of "best practices" at note 7.

- Open standards for communications and data exchange between meters, demand response technologies and appliances should be encouraged and supported, particularly the efforts of the National Institute of Standards and Technology to develop interoperability standards for smart grid devices and systems.
- Cost-effectiveness tools should be developed or revised to account for many of the new environmental challenges facing states and the nation, and to reflect the existence of wholesale energy and capacity markets in many regions.
- Regulators and legislators should clearly articulate the expected role of demand response to allow utilities and others to 1) plan for and include demand response in operational and long-term planning, and 2) recover associated costs.

The Achievable Participation and Full Participation scenarios estimate that the largest demand response would take place if advanced metering infrastructure were universally deployed and consumers respond to dynamic pricing. The Achievable Participation scenario is realized if all customers have dynamic pricing tariffs as their default tariff and 60 to 75 percent of customers adopt this default tariff, while the Full Participation scenario is based on all consumers responding to dynamic prices. For this to occur, in addition to the recommendations above,

- Dynamic pricing tariffs should be implemented nationwide.
- Information on AMI technology and its costs and operational, market and consumer benefits should be widely shared with utilities and state and local regulators.
- Grants, tax credits and other funding for research into the cost and interoperability issues surrounding advanced metering infrastructure and enabling technologies should be considered, as appropriate.
- Expanded and comprehensive efforts to educate consumers about the advantages of AMI and dynamic pricing should be undertaken.

The Full Participation scenario is dependent upon removal of limitations to market acceptance through implementation of these recommendations, and all customers must be able to respond under dynamic pricing.

FERC is required by Section 529 of EISA 2007, within one year of completing this Assessment, to complete a National Action Plan on Demand Response. The Action Plan will be guided in part by the results of this Assessment.

EXHIBIT TW-6

The 2012 State Energy Efficiency Scorecard

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Executive Summary

Conversations about energy use in the United States often revolve around the need to expand the supply of energy to support the growth of our national economy. There is, however, a resource that is cheaper and quicker to deploy, and cleaner, than building new supply—energy efficiency. Energy efficiency improvements help businesses, governments, and consumers meet their needs by using *less* energy, saving them money, driving investment across all sectors of the economy, creating much-needed jobs, and reducing environmental impacts.

Governors, legislators, regulators, and citizens are increasingly recognizing that energy efficiency is a critical state resource. In fact, a great deal of the innovation in policies and programs that promote energy efficiency originates in states across the country. The *2012 State Energy Efficiency Scorecard* captures this activity through a comprehensive analysis of state efforts to advance energy efficiency.

In this sixth edition of ACEEE's *State Energy Efficiency Scorecard*, we rank states on their policy and program efforts, document best practices, and provide recommendations for ways in which states can improve their energy efficiency performance. The State Scorecard serves as a benchmark for state efforts on energy efficiency policies and programs each year, encouraging them to continue strengthening efficiency commitments as a pragmatic and effective strategy for securing environmental benefits and promoting economic growth.

Key Findings

- **Massachusetts** retained the top spot in the *State Energy Efficiency Scorecard* rankings for the second year in a row, having overtaken California last year, based on its continued commitment to energy efficiency under its Green Communities Act of 2008. Among other things, the Act spurred greater investments in energy efficiency programs by requiring utilities to save a large and growing percentage of energy every year through efficiency measures.

- Joining Massachusetts in the top five are **California**, **New York**, **Oregon,** and **Vermont,** which together comprise a group of truly leading states that have made broad, long-term commitments to developing energy efficiency as a state resource.

- Rounding out the top ten states are **Connecticut**, **Washington**, **Rhode Island**, **Maryland,** and **Minnesota**. Connecticut appears poised to break back into a top five spot, which it has held in the past.

- This year's most improved states are **Oklahoma**, **Montana,** and **South Carolina**. All three states significantly increased their budgets for electric efficiency programs in 2011 over previous years, and saved more energy from such programs in 2010 than in 2009. Oklahoma put in place natural gas efficiency programs for the first time in 2011, and Montana dramatically increased its budgets for these programs. These funding increases will likely yield further savings in coming years.

- Other states making significant progress include **Arizona**, **Michigan**, **North Carolina**, and **Pennsylvania**, whose implementation of Energy Efficiency Resource Standards led to large increases in efficiency program spending from 2010 to 2011.

- Annual savings from customer-funded energy efficiency programs topped 18 million MWh in 2010, a 40% increase over a year earlier. This is roughly equivalent to the amount of electricity the state of Wyoming uses each year.

- Utility budgets for electric and natural gas efficiency programs rose to almost $7 billion in 2011, a 27% increase over a year earlier. Of this, $5.9 billion went to electric efficiency programs, with the remaining $1.1 billion for natural gas programs. These represent 29% and 18% increases, respectively, over 2010 budgets.

- Twenty-four states have adopted and adequately funded an Energy Efficiency Resource Standard, which sets long-term energy savings targets and drives investments in utility-sector energy efficiency programs. The states with the most aggressive savings targets include **Arizona, Hawaii, Maryland, Massachusetts, Minnesota, New York, Rhode Island,** and **Vermont**.

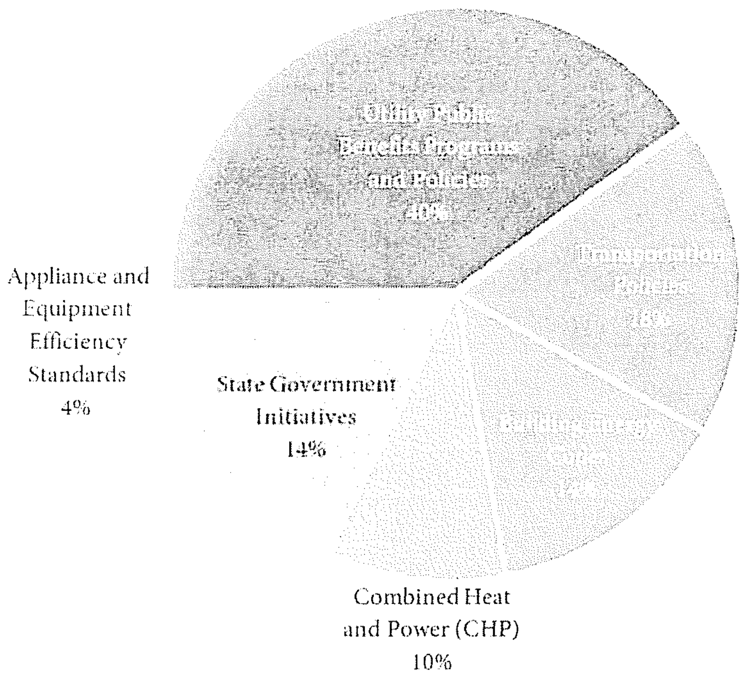
Ten states have adopted energy efficiency codes for new building construction that exceed the IECC 2009 or ASHRAE 90.1-2007 codes for residential and commercial building construction. Two additional states, **Maryland** and **Illinois**, have advanced even further by adopting the most recent and most stringent code for residential construction, the 2012 IECC.

Methodology

The *2012 State Energy Efficiency Scorecard* provides a broad assessment of policy and programs that improve energy efficiency in our homes, businesses, industry, and transportation. This report examines six of the primary policy areas in which states typically pursue energy efficiency: utility and "public benefits" programs and policies; transportation policies; building energy codes; combined heat and power policies; state government-led initiatives around energy efficiency; and appliance and equipment standards. Figure ES-1 provides a percentage breakdown of the points assigned to each policy area.

The baseline year against which we assessed policy and program changes varies by policy category. Most scores are based on policies in place as of September 2012. In Chapter 2 on utility and public benefits programs, however, we scored states based on data from 2011 and 2010, the latest years in which data were available for our metrics.

Figure ES-1: Percent of Total Points by Policy Area



This year we updated the scoring methodology in four policy areas to better reflect potential energy savings, limitations in the data, economic realities, and changing policy landscapes. Regarding utility and public benefits programs and policies (Chapter 2), as in the past, we asked state public utility commissions for net electric savings, but in some cases states only report gross electric savings. To aid in comparison, we have adjusted reported gross savings by a standard factor (a "net-to-gross ratio"). In Chapter 3 on transportation, we consider for the first time whether or not states have adopted legislation that encourages transit investment by state or local governments. This new category takes one-half point from previous scoring of complete streets legislation and high-efficiency vehicle tax credits, based on their relative potential for energy savings. The scoring of building energy codes in Chapter 4 is more stringent this year, with states receiving full points for building code stringency only if they have updated, or have made significant progress toward updating, their statewide energy codes to the IECC 2012 and ASHRAE 90.1-2010 codes. In Chapter 5 on combined heat and power, we made changes to the types of policies considered and their relative weighting in the overall category score, and more clearly defined the criteria that states must meet to receive points.

This year we contacted every state utility commission to review spending and savings data for the customer-funded energy efficiency programs presented in Chapter 2. In an effort to more fully represent states' customer-funded energy efficiency programs, this year we also requested program savings and budget data from 43 of the largest municipal utilities and cooperatives. These were added, where appropriate, to the savings and budget data reported in Chapter 2. In addition, state energy officials were given the opportunity to review the material on ACEEE's State Energy Efficiency Policy Database (ACEEE 2012) and to provide updates to the information scored in Chapter 6.

RESULTS

Figure ES-2 shows states' rankings in the *2012 State Energy Efficiency Scorecard*, dividing them into five tiers for ease of comparison. The scores upon which these rankings are based are detailed in Table ES-1 on the next page. States could score a maximum of 50 possible points allocated across the six policy areas considered. Although we provide individual state scores and rankings, the difference between states is both easiest to understand and most instructive in tiers of ten. This is because the group of states that compose each of the five tiers have tended to be fairly consistent over time, although states can and do move into new tiers from year to year. Therefore, differences between individual states are generally less important than differences between the tiers of states. An identical ranking for two or more states indicates a tie (e.g., Arizona and Michigan both rank 12th).

Figure ES-2: 2012 State Scorecard Rankings Map

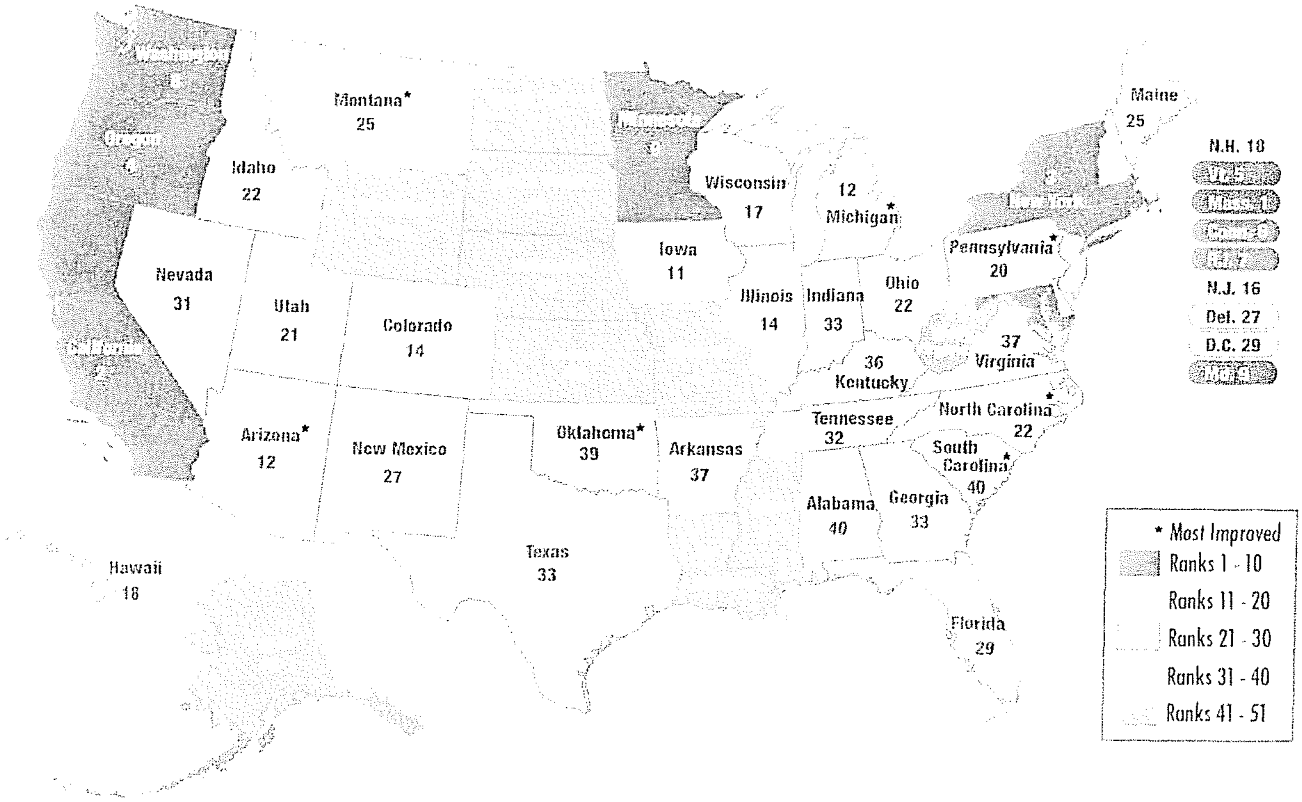


Table ES-1: Summary of State Scores

Rank	State	Utility & Public Benefits Programs & Policies (20 pts.)	Transport-ation Policies (9 pts.)	Building Energy Codes (7 pts.)	Combined Heat & Power (5 pts.)	State Government Initiatives (7 pts.)	Appliance Efficiency Standards (2 pts.)	TOTAL SCORE (50 pts.)	Change in rank from 2011
1	Massachusetts	19.5	6.5	6	4.5	7	0	**43.5**	0
2	California	17.5	7.5	6	2	5.5	2	**40.5**	0
3	New York	17.5	7.5	5	2.5	6.5	0	**39**	0
4	Oregon	16	6	6	2.5	6.5	0.5	**37.5**	0
5	Vermont	19	4.5	5	2.5	4.5	0	**35.5**	0
6	Connecticut	15	5.5	4.5	3	5.5	1	**34.5**	2
7	Rhode Island	18.5	5.5	4	2.5	2	0.5	**33**	-2
8	Washington	14.5	6	6	2.5	2.5	0.5	**32**	-3
9	Maryland	12	6	5.5	1	5	0.5	**30**	1
9	Minnesota	19	2.5	3	1	4.5	0	**30**	-1
11	Iowa	15.5	1	4.5	2	3.5	0	**26.5**	0
12	Arizona	13.5	2	3	2	4.5	0.5	**25.5**	5
12	Michigan	13.5	2	3.5	2	4.5	0	**25.5**	5
14	Colorado	11	2	4	2	6	0	**25**	-2
14	Illinois	8	3.5	6	2.5	5	0	**25**	3
16	New Jersey	9	5.5	3.5	3	3.5	0	**24.5**	-1
17	Wisconsin	10.5	1	4	2	5	0	**22.5**	-1
18	Hawaii	12.5	3	4	0.5	2	0	**22**	-6
18	New Hampshire	10	1	4.5	1.5	4.5	0.5	**22**	3
20	Pennsylvania	5	4.5	4	2	6	0	**21.5**	5
21	Utah	11.5	0.5	4.5	0.5	3	0	**20**	-4
22	Idaho	10.5	0	5	0	4	0	**19.5**	4
22	North Carolina	6	1	5	1.5	6	0	**19.5**	5
22	Ohio	8.5	0	3.5	3.5	4	0	**19.5**	2
25	Maine	8.5	4	2.5	2	2	0	**19**	-13
25	Montana	9	1	5	0.5	3.5	0	**19**	10
27	Delaware	3.5	5	4	2	4	0	**18.5**	4
27	New Mexico	9	2	3.5	1	3	0	**18.5**	0
29	District of Columbia	6	3.5	5	0.5	2	0.5	**17.5**	-7
29	Florida	3.5	4.5	5.5	0.5	3.5	0	**17.5**	-2
31	Nevada	9.5	0	4.5	1	1.5	0	**16.5**	-9
32	Tennessee	1.5	3	3	1.5	6	0	**15**	-2
33	Georgia	1.5	2.5	5.5	0.5	3.5	0.5	**14**	3
33	Indiana	7	0	3.5	2	1.5	0	**14**	-1
33	Texas	3	0	3.5	2	5	0.5	**14**	0
36	Kentucky	4	0	4	0.5	5	0	**13.5**	1
37	Arkansas	7	0	3	1	2	0	**13**	1
37	Virginia	1.5	1.5	4.5	1	4.5	0	**13**	-3
39	Oklahoma	5	0.5	2.5	0	3	0	**11**	8
40	Alabama	2.5	0	3.5	0.5	4	0	**10.5**	3
40	South Carolina	2	1	4	0.5	3	0	**10.5**	6
42	Nebraska	2	0	4	0	3.5	0	9.5	-2
43	Louisiana	2.5	0.5	3.5	0.5	2	0	9	-3
43	Missouri	3.5	0	2.5	0.5	2.5	0	9	1
45	Kansas	1.5	1	1.5	1	3.5	0	8.5	3
46	Alaska	0	1	0.5	0.5	6	0	8	-8
46	South Dakota	4.5	0	1	1	1.5	0	8	-4
48	Wyoming	2.5	0	2	0.5	1.5	0	6.5	2
49	West Virginia	0	0.5	3	0.5	2	0	6	-5
50	North Dakota	0.5	1	1	1	0.5	0	4	1
51	Mississippi	0	0	0	0	2.5	0	2.5	-2

Massachusetts scored a total of 43.5 points, retaining the top spot in the *State Energy Efficiency Scorecard* rankings for the second year in a row, based in large part on its continued commitment to energy efficiency under its Green Communities Act of 2008. It continues to lead California, which remained in second place.

Joining Massachusetts and California in the top five are New York, Oregon, and Vermont. These five states have long supported energy efficiency as a state energy resource, scoring in the top five of the State Scorecard at least five out of six years (see Table ES-2). The states rounding out the top ten—Connecticut, Rhode Island, Washington, Maryland, and Minnesota—all scored more than 29.5 points, significantly higher than the trailing states.

Table ES-2: Leading States in the State Scorecard, by Years at the Top

State	Year in Top 5	Years in Top 10
California	6	6
Oregon	6	6
Massachusetts	5	6
New York	5	6
Vermont	5	6
Connecticut	3	6
Minnesota	0	6
Washington	0	6
Rhode Island	0	5
Maine	0	2
Maryland	0	2
New Jersey	0	2
Wisconsin	0	1

The difference between states' total scores in the second, third, and fourth tiers of the State Scorecard is small: only five points separate the states in the second tier, 2.5 points in the third tier, and six points in the fourth tier. For the states in these three tiers, small improvements in energy efficiency may have a significant effect on their rankings. Therefore, idling states will easily fall behind as other states in this large group ramp up efficiency efforts.

Changes in states' overall scores are a function both of changes in their efforts to improve energy efficiency (as is expected in the scoring) and adjustments to our scoring methodology. Therefore, differences between this and last year's rankings cannot be explained only by changes in states' energy efficiency programs or policies. As noted above, we updated the scoring methodology in four policy areas to better reflect potential energy savings, limitations in the data, economic realities, and changing policy landscapes. See the relevant chapter in the main body of the report for the specifics of these updates to the methodology.

States on the Move

Twenty-two states rose in the rankings this year, with several states moving up more significantly than others. "Most improved" status was granted to states based on their change in rank compared to the *2011 State Energy Efficiency Scorecard* (reflecting their efforts relative to those of other states) and percentage change in score over last year (reflecting their efforts relative to themselves).

This year's most improved states are Oklahoma, Montana, and South Carolina. All three states had significantly higher budgets for electric efficiency programs in 2011 than in previous years, and saved more energy from such programs in 2010 than in 2009. Oklahoma put in place natural gas efficiency programs for the first time in 2011, and Montana dramatically increased its budgets for these programs. Each of these states also earned more points this year for their state-led efficiency initiatives, while South Carolina and Montana also earned credit for transportation efficiency measures. Oklahoma and South Carolina earned credit for, respectively, adopting and pursuing greater compliance with more efficient statewide building energy codes.

The continued implementation of energy efficiency resource standards by Arizona, Michigan, North Carolina, and Pennsylvania led to large increases in efficiency program spending from 2010 to 2011 by these states. While not most improved, Kansas, Wyoming, and North Dakota all improved their scores significantly on a percentage basis.

Strategies for Improving Energy Efficiency

No state received a full 50 points in the *2012 State Energy Efficiency Scorecard*, reflecting the fact that there remain a wide range of opportunities in all states—including the leading states—to further improve energy efficiency. We offer the following recommendations to highlight key ways states may improve their energy efficiency:

- **Put in place, and adequately fund, an Energy Efficiency Resource Standard or similar energy savings target.** Many of the leading states have an Energy Efficiency Resource Standard in place, which can have a catalytic effect on increasing energy efficiency and its associated economic and environmental benefits. The long-term goals associated with an EERS send a clear signal to market actors about the importance of energy efficiency in utility program planning, creating a level of certainty to encourage large-scale, productive investment in energy efficiency technology and services. Long-term energy savings targets require leadership, sustainable funding sources, and institutional support to deliver on their goals. See Chapter 2 for further details.

- **Adopt updated building energy codes and enable the involvement of utility program administrators in building energy code compliance.** Buildings consume more than 40% of total energy in the United States, making them an essential target for energy savings. Utilities can also support code compliance financially by purchasing equipment that code officials can use to measure compliance, as well as generally through new construction programs. See Chapter 4 for further details.

- **Adopt stringent tailpipe emissions standards for cars and trucks, and set quantitative targets for reducing vehicle miles traveled.** States that have adopted California's stringent tailpipe emissions standards (a proxy for energy use) will realize energy savings and pollution reductions greater than those resulting from new federal fuel economy standards. Codified targets for reducing vehicle miles traveled are an important step towards states' achieving substantial reductions in energy use and certain pollutants. See Chapter 3 for further details.

- **Treat combined heat and power as an energy efficiency resource equivalent to other forms of energy efficiency in an Energy Efficiency Resource Standard.** See Chapter 5 for further details.

- **Put in place sustainable funding for state government-led energy efficiency incentive programs; enact policies that require benchmarking of state building energy use and that drive the market for energy service contracting; and invest in energy efficiency-related research, development and demonstration centers.** State government-led initiatives complement the existing landscape of utility programs, leveraging resources from the state's public and private sectors to generate energy and cost savings that benefit taxpayers and consumers. See Chapter 6 for further details.

Conclusions and Looking Ahead

Energy efficiency policies and programs have continued to advance at the state level over the past year. A group of leading states remains committed to pursuing more efficient use of energy in transportation, buildings, and industry; fostering economic development in the energy efficiency services and technology industry; and saving money for consumers to spur growth in all sectors of the economy.

A growing number of states have progressed, some rapidly, over the past few years in the pursuit of their energy efficiency goals. There has been a lot of movement within and outside of the top tier of states, with Connecticut poised to break into the top five again, and with several states potentially able to move into the top tier. This dynamism at the policy and program levels is reflected in growing utility program budgets and savings, as well as in the wide range of other efforts states are taking to improve their energy efficiency.

We see signs that many states will continue to raise the bar on their commitments to energy efficiency in 2013 and beyond. For example:

- A July 2012 draft of Massachusetts' second Three-Year Energy Efficiency Plan (State of Massachusetts 2012), required by the Green Communities Act, proposes annual savings goals of 2.5% of electricity retail sales from 2013-2015, and 1.1% of natural gas retail sales starting in 2013 (and increasing in subsequent years), supported by funding for energy efficiency programs of $2 billion over the three years.

- Oregon's Governor Kitzhaber recently released a draft of his *10-Year Energy Action Plan* (State of Oregon 2012), which calls for energy efficiency and conservation to meet 100% of future growth in the electricity load. He called for improving the energy performance of every occupied state-owned building over the next ten years as a first step towards meeting this goal.

- Connecticut's Governor Malloy has made a commitment to pursue the top spot in the State Scorecard in future years, calling for an increase in spending for utility energy efficiency programs, a strengthening of the bonding authority of the state's clean energy investment authority, and reductions in state building energy use starting in 2013 (State of Connecticut 2012).

- In October 2011, the New York Public Service Commission extended the state's Energy Efficiency Portfolio Standard for an additional 4 years, through 2015, and increased funding for energy efficiency programs operated by the New York State Energy Research and Development Authority and the state's investor-owned utilities by more than $2 billion. The Commission also approved a new Technology & Market Development program providing an additional $410 million in public benefit funding over the next 5 years.

- The State of Vermont released its Final Comprehensive Energy Plan 2011, its first since the late 1990s, which promotes increased use of efficiency as one of its first priorities. The plan recommends: the use of innovative energy efficiency program designs to capture all cost-effective efficiency; changes to building efficiency program design; goals for increasing the stringency of and compliance with building energy codes in new construction (including in public buildings); and a review of state land use provisions and infrastructure needs for electric vehicles. The Climate Cabinet, established through Executive Order No. 05-11, is responsible for implementation of the plan (State of Vermont 2011).

  Oklahoma, one of the most improved states this year, is poised to make further improvements in energy efficiency with the recent enactment of Bill 1096, which calls for a 20% reduction in the energy use of state buildings and educational institutions. Governor Fallin, in her 2012 State of the State address, specifically called for Oklahoma to pursue further strategies for improving the state's energy efficiency (State of Oklahoma 2012).

In addition, numerous states that only recently began implementing utility-sector energy efficiency programs such as Michigan, Ohio, Indiana, Arkansas, and Arizona will likely continue to ramp up efficiency program activity over the next few years to meet those rising goals.[1] As noted in Chapter 2, combined utility investments in electric and natural gas efficiency programs are estimated to more than double from 2010 levels to $10.8 billion by 2025, if current savings targets are met, and more than triple to $16.8 billion if many states give energy efficiency a prominent role as a resource (Goldman et al. 2012).

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[1] See (Nowak et al. 2011) for a full discussion of how states are preparing to meet higher energy savings targets

These projections of an increasing role for energy efficiency will not, however, occur in a vacuum. Both state support for energy efficiency and external factors beyond states' control will likely influence the impact of energy efficiency programs and policies in 2013 and beyond. Continued uncertainty around the economic recovery could dampen consumer demand for energy efficiency upgrades in the residential and commercial sectors, which would impact savings from efficiency programs. More concerning is the impact on budgets for efficiency. Some policymakers have responded to continued strain on state budgets by redirecting funds from utility customers or other sources originally meant for efficiency programs to shore up state finances in other areas,[2] or have not allocated energy efficiency budgets at a level necessary to meet mandated savings goals.[3]

Energy efficiency can save consumers money, drive investment across sectors of the economy, and create jobs. While several states are consistently leading the way on energy efficiency and many more are dramatically increasing their efforts, significant opportunities remain to both sustain current efforts and continue to scale up. Energy efficiency is a resource abundant in every state and reaping its full economic, energy security, and environmental benefits will require continued leadership from a wide range of stakeholders, including legislators, regulators, and the utility industry.

[2] New Jersey Governor Christie redirected $42.5 million from the state's Clean Energy Fund in fiscal year 2011 to cover state energy bills, and will do the same in FY 2013 (which started July 1, 2012), with a reallocation of $210 million (NJ Spotlight 2012; State of New Jersey 2012). At the beginning of this year, New Jersey also withdrew from the Regional Greenhouse Gas Initiative, which had been providing the state with substantial funding for energy efficiency projects (State of New Jersey 2011).

[3] Maine legislators have not sufficiently allocated FY 2013 funds to efficiency programs in the state. This point is discussed more fully in Chapter 2.

EXHIBIT TW-7

FOLLOW THE LEADERS:
IMPROVING LARGE CUSTOMER SELF-DIRECT PROGRAMS

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EXECUTIVE SUMMARY

Energy efficiency offers tremendous system-wide benefits at a portion of the cost of new generation resources. Energy efficiency is highly cost-effective, consistently available at one-tenth to one-third the cost of new renewable or fossil-fuel generation. The benefits of energy efficiency to any given public utility system include lower energy prices, reduced grid congestion, reduced energy-related emissions and increased system reliability. Industrial energy efficiency is some of the most cost-effective energy efficiency available, and investments in industrial energy efficiency benefit users in all sectors of the economy.

Like other utility system resources, energy efficiency is enjoyed by all users and paid for by all users. To fund energy efficiency, states typically implement some cost-recovery mechanism (CRM) on a customer's bill. These moneys are pooled together and are then used to fund cost-effective energy efficiency across multiple sectors. In the industrial sector, CRM fees are used to fund technical assistance, energy management, and incentive programs that encourage energy efficiency investments.

In response to requests by their industrial and large commercial sectors, some states allow those sectors to either "opt out" of paying the CRM fee or "self-direct" all or a portion of the fee into internal energy efficiency investments. Firms that choose to opt out or self-direct their CRM fees are often assumed or required to make energy efficiency investments on their own. These unique programs — opt-out and self-direct programs — are the focus of this report.

This report is based on first-person conversations conducted with over 50 individuals closely acquainted with today's opt-out and self-direct programs. Interviewees included administrators of today's self-direct programs, state regulators, energy efficiency advocates, industrial energy users and officials from other state agencies affiliated with a self-direct or opt-out program's administration. The report discusses the self-direct programs in place today and the policy goals we ought to have embedded within our self-direct programs. It discusses the unique opportunities presented by self-direct programs and the leading self-direct programs in place today. The report also discusses the challenges presented by opt-out programs and poorly structured self-direct programs, and concludes with recommendations of how ideal self-direct programs might be structured.

In some particular cases, well-structured self-direct programs are being used as highly useful tools to industrial customers and other large energy users. Self-direct programs can offer certain tools and a level of flexibility that helps overcome long-standing barriers to greater energy efficiency in the industrial sector. When coupled with strong oversight and extensive measurement and verification of claimed savings, these programs can serve an entire public utility system very well.

Unfortunately, most self-direct programs lack at least one of the critical components of these highly successful (but few) self-direct programs. Forty-one states in the US have some sort of a CRM mechanism in place. Of those, 23 have some sort of opt-out or self-direct provision in place. Only a small number of the self-direct programs are structured to maximize cost-effective energy efficiency and ensure that retained CRM fees are used in a manner that benefits all users of a given public utility system.

This report finds that the structures of opt-out and self-direct provisions vary widely. Opt-out provisions allow customers to simply opt out entirely from a CRM program, and do not measure or verify that a customer has made any energy efficiency investments in exchange for their exemption from paying a CRM fee. Self-direct programs usually assume that customers are making their own energy efficiency investments, but do not usually measure and verify those savings in the manner that would have been done had the customer been making those investments within a CRM-funded energy efficiency program.

In contrast to some of the standout programs identified in this report, the majority of opt-out and self-direct programs are either poorly structured, subject to minimal oversight, or not subject to stringent measurement and verification protocols. This report finds that these programs cannot claim with certainty that they are achieving energy efficiency investments equal to that which would have been achieved had the customers remained within existing CRM-funded energy efficiency programming, or that the industrial customer is being well-served by the program.

The choice by state policymakers to implement an opt-out or self-direct program when developing long-term energy efficiency goals and CRM programs is a popular one. Unfortunately the long-term impact of these programs is not very well known, and program structures in place today generally do not ensure that the CRM funds retained by opt-out or self-direct customers are being well-spent.

Allowing large customers to opt out of CRM programs or self-direct their funds without substantial oversight by regulators or adherence to cost-effectiveness tests, as is found in programs around the country, is unfair to other classes of customers. There are some very good examples of self-direct programs that offer large customers the tools they need to make substantial energy efficiency investments and the peace of mind for regulators that public funds are being spent in a manner that benefits the public good.

This report's appendices include summaries of all known self-direct programs in place today, as well as some suggested model language for effective self-direct programs and a detailed chart of CRM and opt-out/self-direct programs as they exist in each U.S. state.

INTRODUCTION

Energy efficiency, and industrial energy efficiency in particular, offers tremendous system-wide benefits at a fraction of the cost of new generation resources. To fund energy efficiency, 41 states implement a cost-recovery mechanism (CRM) on customers' bills to fund energy efficiency programs. In response to requests by the industrial and large commercial sectors, some states allow those sectors to either opt out of paying the CRM fee or self-direct all or a portion of the fee into internal energy efficiency investments.

These opt-out and self-direct options are growing in popularity. Two years ago 15 opt-out and self-direct provisions were identified in a nationwide assessment (Chittum and Elliott 2009). Today 24 U.S. states allow industrial customers and other large energy users such as institutions to opt out or self-direct a portion of their CRM fees. No single style of opt-out or self-direct program exists, and states around the country have developed a variety of program structures in response to their policy goals and the expressed concerns of their industrial sectors.

It is largely unknown whether or not industrial customers and society at large are best served by opt-out and self-direct programs versus traditional CRM-funded programming. The type of data that would help answer that question is not routinely collected by these programs, and even when it is collected, it is often not subjected to the same rigorous external evaluation as traditional CRM-funded programs.

Optimization of industrial energy efficiency is in the interest of every user of a public utility system because it is a highly cost-effective energy resource. Opt-out and self-direct programs that fail to maximize industrial energy efficiency fail all other energy users in a given public utility system. It is therefore imperative that we understand the state of these programs today, and identify examples of successful self-direct programs, the characteristics of successful self-direct programs, and the challenges facing all self-direct programs.

This report presents substantial new primary research conducted on opt-out and self-direct programs. Between December 2010 and July 2011 interviews were conducted with the administrators or regulators of all identified opt-out and self-direct programs in the US. The interview questions are listed in Appendix IV. Detailed synopses of each self-direct offering can be found in Appendix I. A summary chart of key program characteristics can be found in Appendix III.

The primary focus of this report is self-direct programs. The primary research inquiry addressed by this report is the components of self-direct programs critical to their success and efficacy. This research also revealed challenges facing self-direct programs today, and program characteristics that minimize the overall effect such programs can have.

Self-direct programs can be incredibly effective tools to help certain customers maximize their energy efficiency. In some cases, a well-structured self-direct program can encourage a greater level of efficiency investment than would have occurred in a more traditional CRM-funded program. Self-direct programs, when well-structured and well administered, can give industrial companies and other large energy users the tools they need to overcome barriers to greater energy efficiency investments. For this reason, establishing well-structured and effective self-direct programs is a very worthy policy goal. This report offers examples of successful self-direct programs and discussions of self-direct opportunities and challenges.

The goal is to encourage policymakers and self-direct program administrators to improve their self-direct programs or, if desired, establish new self-direct programs that work. While industrial customers stand to gain the most from well-structured and well-administered self-direct programs, other classes of customers stand to benefit as well.

EFFICIENCY PROGRAMMING

The Importance of Energy Efficiency

The energy supply we rely on in the future will be different from the one we rely on today. As the U.S. works to meet its growing energy needs, the nation will face a number of challenges, including aging plants, constraints on existing transmission and distribution systems, stricter environmental regulations, and the ever-changing economics of fuel acquisition and power generation. U.S. energy demand is projected to continue to grow over the next 25 years. This growth is expected to occur regardless of new policies that may be implemented to help curtail greenhouse gases and reduce demand for energy. Such policies may reduce the rate of growth but will not actually reduce energy use relative to today's consumption (EIA 2011a).

Americans are going to need more electricity, and the cost of electricity is not getting any cheaper (EIA 2011c). With the specter of new and forthcoming EPA regulations, much of the country's existing coal-fired electric-generating fleet, which represents about half of the country's electric generation, will either be retired or will require costly retrofits. Retiring these plants will take a substantial amount of generating capacity offline and raise prices for existing generation in some markets (Elliott et al. 2011). Electricity generators and industries are also going to need more natural gas. Even in a low economic growth scenario, natural gas prices are expected to increase over the next two decades (EIA 2011a).

To meet growing energy needs, policymakers have two primary tools: reducing energy demand and acquiring new energy supply. Reducing demand through the implementation of energy efficiency programs is almost always less expensive than developing new fossil fuel-fired, nuclear, or renewable energy resources. A 2009 review of the cost of saved energy from 14 utility-administered electric energy efficiency programs found an average cost to the utility across all sectors to be 2.5 cents per kWh (Friedrich et al. 2009). Cumulative costs, which include the cost to the customer and utility, have been reported in one study as ranging from .8 cents to 5 cents per kWh (VDPS 2007). Such a low cost places energy efficiency as the cheapest energy resource for a utility by a wide margin. Energy efficiency is consistently one-tenth to one-third the cost of new renewable and non-renewable energy generation resources (Friedrich et al. 2009).

New fossil fuel generation sources range from an average of 6.6 cents per kWh for conventional combined cycle natural gas turbines to an average of 13.6 cents per kWh for advanced coal with carbon sequestration. These numbers do not include costs associated with environmental impacts and other externalities. New renewable-based electricity ranges a bit higher, from an average of 9.7 cents per kWh for onshore wind to an average of 31 cents per kWh for solar thermal power (EIA 2011b). It is important to note that none of these costs for generation sources include additional costs associated with transmission and distribution losses and necessary reserves for generation. Including these expenditures would increase the overall cost of delivered energy from any of these resources.

Figure 1 displays one analysis of the full range of levelized costs of one kWh of electricity from energy efficiency and other major sources. The costs for new generation resources in this figure also do not include costs associated with line losses or maintenance of reserves.

Figure 1. Range of Levelized Costs of Electricity Generation Resources

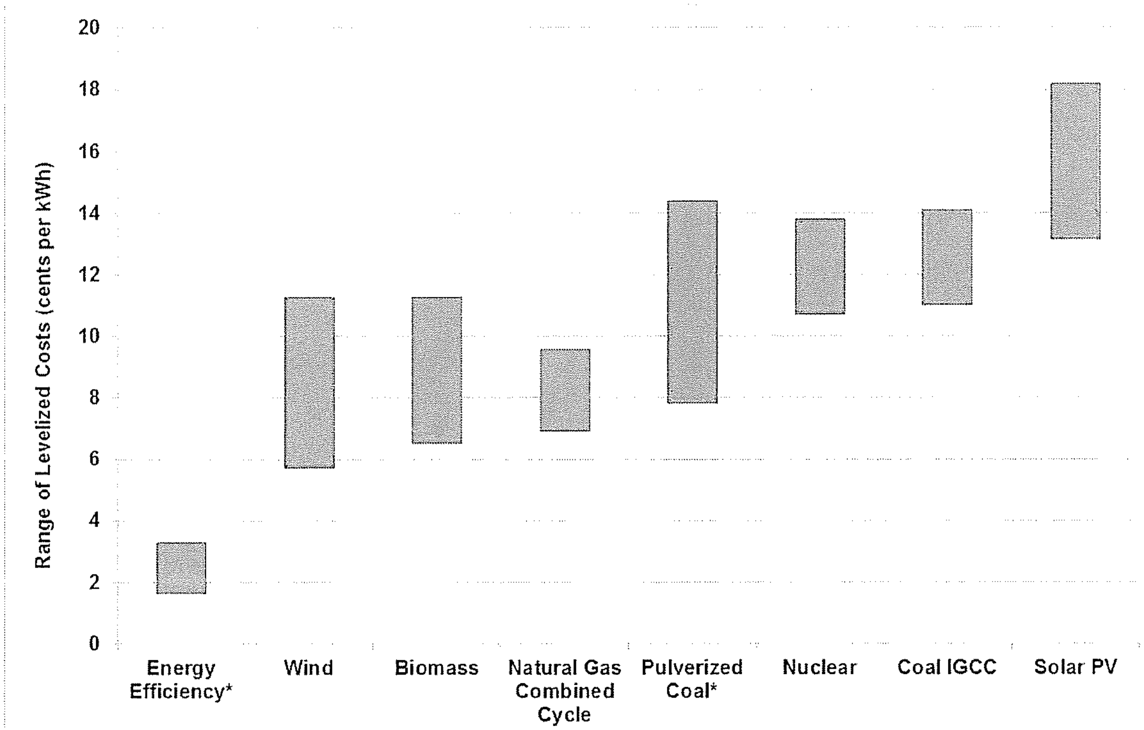

Table notes: Energy efficiency average program portfolio data from Friedrich et al. 2009; all other data from Lazard 2009. High-end range of advanced pulverized coal includes 90% carbon capture and compression.

Energy efficiency offers additional benefits to society besides its low cost:

- It can be brought on line much faster than traditional generation. Each individual energy efficiency investment begins to save energy as soon as it is brought online, unlike larger traditional generation investments that do not become useful until they are completely built, which can take years.
- It helps hedge against future spikes and volatility in energy commodity prices.
- It enhances energy system reliability and puts downward pressure on energy prices.
- Since it is equivalent to delivered energy for a utility, it avoids marginal generation, transmission, and distribution capacity costs, by up to 1.5 times the capacity avoided at a customer's meter. It avoids line losses of about 10% on average, and up to 30% during peak hours (Lazar and Baldwin 2011).
- It reduces the need for new transmission infrastructure.
- It does not suffer from dispatch problems like some renewable resources.
- It reduces overall emissions.
- It can be a powerful economic development tool by generating jobs for people to install and maintain energy efficient equipment and materials.

Policy makers and regulators who recognize the benefits of energy efficiency have increasingly looked to energy efficiency programs to help acquire greater levels of energy efficiency. However, tremendous opportunity for energy efficiency improvements and investments remains in all areas of the country and sectors of the economy.

Acquiring and Funding Energy Efficiency

Many states and utilities[1] have identified energy efficiency as an important system resource because of its low cost and the speed with which it can be deployed. States are increasingly prioritizing the acquisition of cost-effective energy efficiency to improve the affordability and reliability of their energy resources. Energy efficiency is now viewed as a priority when planning for future energy demand despite historically being viewed as supplemental to more traditional generation resources (Kushler et al. 2009). States typically rely on energy efficiency programs, which work with consumers to implement end-use energy efficiency measures, to acquire new energy efficiency resources. Spending on energy efficiency programs in the U.S. has increased every year in the past decade, and total projected energy efficiency budgets for 2010 topped $6.5 billion (Molina et al. 2010, CEE 2010).

Twenty-six U.S. states (Sciortino et al. 2011)[2] have set efficiency savings goals, often in the form of an energy efficiency resource standard (EERS) which sets specific energy savings targets for utilities (Kushler 2006, Kushler et al. 2004). Energy efficiency goals usually seek to obtain the least-cost resources in order to keep the overall cost of energy low for all consumers. The establishment of energy savings goals on the state level is a fairly recent trend. A decade ago energy efficiency programming generally paired monetary spending level goals with cost-effectiveness tests, but did not necessarily establish kWh savings requirements.

Energy efficiency resources are low cost but not free. They typically require an upfront investment in equipment or maintenance or administrative support to acquire the long-term energy savings. With energy efficiency goals in place, utilities, and other entities tasked with meeting these goals, are allowed to recover the costs associated with the energy efficiency program, much the same way utilities can recover the cost of new generation resources.

States employ cost-recovery mechanisms that rely on a small additional fee paid by each customer to pay for energy efficiency. The aggregate funds from the fee are pooled together and used by utilities or other entities to pay for the most cost-effective, or otherwise beneficial, energy efficiency programs across all sectors of the economy. These cost-recovery mechanisms are known by many names, including systems benefit charges, demand-side management tariff riders, energy efficiency riders and public benefits funds. In some cases efficiency program costs are combined with other system costs (such as new generation) and the resultant new costs are reflected in updated rates for consumers. This paper refers to all of these types of mechanisms simply as cost recovery mechanisms (CRMs). According to the primary research, 41 states have some sort of CRM in place to fund efficiency programming in their electric or natural gas sectors.[3]

What We Ask of Energy Efficiency Programs

State regulators approve, and frequently require, public utility funding of energy efficiency programs to provide system and public benefits. Energy efficiency programs can help control energy costs by avoiding the need for new generation and transmission resources. New fossil fuel and renewable generation and transmission facilities are expensive to build, and their costs have historically been borne by all of the customers within the utility's service territory or across the region. Like a new power plant or an investment in transmission infrastructure, energy efficiency programs yield new energy resources that benefit the entire utility system. All customers share the benefits as well as the costs of those resources. Over the past 30 years, regulators, utilities, and the energy efficiency industry have developed rigorous, nationally-accepted practices to measure, verify and evaluate the cost-effectiveness of these programs, to meet statutory requirements that ratepayer funds are prudently spent.

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[1] Throughout this report, "utilities" will refer to regulated electric and natural gas utilities, energy efficiency utilities, and other regulated entities that administer CRM-funded energy efficiency programs, such as the Energy Trust of Oregon and the New York State Energy Research and Development Authority.
[2] Throughout this report, "energy efficiency" will refer to both electricity and natural gas efficiency. All EERS programs apply to electricity; some apply to natural gas. For details on EERS policies in each state, refer to Sciortino et al. 2011.
[3] See Appendix III for a list of states with CRMs in place.

Not all energy efficiency is equally cost-effective or equally beneficial. The industrial sector in particular offers some of the most cost-effective efficiency savings available to any given utility (see Goldberg et al. 2009, Energy Trust of Oregon 2011, Kushler et al. 2004). Industrial energy efficiency resources can be half the cost — $/kWh saved — of efficiency resources in other sectors (Kushler 2011). Industrial efficiency measures also have been shown to offer far better benefit to cost ratios than measures in any other sector (VDPS 2007). Therefore maximizing industrial energy efficiency is a priority for utility resource planning and resource acquisition, and for maximizing ratepayer benefits.

Some energy efficiency programs serve statutory objectives beyond just reducing ratepayer costs. Low-income energy efficiency programs, market transformation programs, research and development programs and programs that support education programs in schools are examples of energy efficiency programs that offer positive externalities to society. These programs are sometimes not as cost-effective as industrial energy efficiency programs, but are pursued for their societal benefits (Kushler et al. 2004). These programs also constitute system resources, and are generally paid for by all system users. All sectors benefit from these programs, including the industrial sector. Highly cost-effective industrial energy efficiency programs help balance out a portfolio of programs that include some less cost-effective ones.

Cost-Recovery Mechanisms and the Industrial Sector

Energy efficiency programs are funded primarily by collecting CRM fees from all customers. States with CRMs in place use the aggregated funds to administer a variety of efficiency programs to all sectors. The industrial sector is often served by dedicated energy efficiency programs, which typically offer energy audits, technical assistance, financial incentives, and rebates for investments in energy efficient equipment or adoption of energy-efficient behavior. Other utilities combined their commercial and industrial programs together.

Since CRM fees are most often based on a percentage of a customer's monthly bill (often 2–5%), energy-intensive industrial firms have long contributed substantially to overall CRM funding pools despite industrial retail rates being much lower than rates for commercial or residential customers. According to current industrial energy efficiency program managers, industrial companies also use substantial amounts of CRM-funded program resources. (NorthWestern Energy 2010, Crossman 2011, Schepp 2011, Chittum et al. 2009).

Some industrial firms around the country have noted at times that they do not receive benefits equal to the amount of CRM funding they contribute. In some cases this is a legitimate viewpoint: industrial program offerings are sometimes not responsive to the needs of customers (Chittum and Elliott 2009). In many recent regulatory filings associated with state energy efficiency regulatory proceedings, representatives of industrial companies or industrial stakeholder groups have submitted filings suggesting that they should not pay CRM fees and should be allowed an option to opt out of the efficiency programs and CRMs (Ambrosio 2011, Haase 2011, IECPA 2009, AZCC 2009).

There are three primary reasons industrial firms believe they should not be subject to CRM fees: 1.) CRM-funded programming is not responsive to their needs. 2.) They already have and will continue to invest in all cost-effective energy efficiency on their own accord. 3.) By paying CRM fees, industrial customers subsidize other rate classes. This report will not determine whether these claims are true, but it is important to understand some of what is known about these issues.

In some instances, the first argument has proven to be true (Chittum and Elliott 2009). However, at least three self-direct programs — in Oregon, Michigan and Wisconsin — reported that customers who had been self-directing or had considered self-directing had chosen to return to paying the CRM fee and using CRM-funded programs because the CRM-funded programs yielded substantial benefits (Stipe 2011, Walker 2011, Schepp 2011). It is worth noting that the CRM-funded industrial offerings in those states all tend to be quite strong.

The second claim — industrial customers will invest in all cost-effective energy on their own, absent any energy efficiency programming — is disputed by many CRM program managers based on their personal experience administering industrial energy efficiency programs. As discussed in the "Self-Direct Challenge" section, self-direct programs themselves offer evidence that the claim is untrue.

The final claim — industrial customers end up subsidizing other rate classes — is a complex one to evaluate. In a recent review of most major energy efficiency programs in the US, utilities acquired 67% of their electric savings from their commercial and industrial customers[4] but only spent 39% of their electric energy efficiency program budgets on those two sectors (CEE 2010). Industrial and commercial customers are enjoying the bulk of programs' energy savings, to be sure. In 2009, US electric sales to industrial and commercial customers by full-service providers accounted for about 59% of all electric sales on a MWh basis, and 55% on a dollar basis (EIA 2011f). Since CRM fees are typically based on a customer's energy consumption (on a kWh or dollar basis), it is possible to suggest that industrial customers contribute, on average, about 55-60% of all CRM fees. It is reasonable to suggest that because industrial and commercial efficiency measures are more cost-effective than those in other sectors, energy efficiency programs get more "bang for their buck" in those sectors and need to spend more of the program dollars in other sectors to achieve a kWh of savings than they do in the industrial and commercial sectors.

Regardless of the above three arguments, the ramifications of letting some large customers choose whether or not to participate in CRM-funded programs are significant. States are increasingly relying on energy efficiency as a low-cost energy resource to meet long-term growth in energy demand and achieve savings targets. Allowing large industrial, commercial or institutional customers to "go it alone" and not participate in CRM-funded programs or well-structured self-direct programs can eliminate a proven low-cost resource, ultimately increasing the cost of energy efficiency savings for everyone.

THE SELF-DIRECT OPTION

The Continuum

As state policymakers have established state EERS and related funding mechanisms, many large energy consumers, especially industrial and large retail corporations, have actively sought to have the option of not paying the CRM fees. As a result, policymakers at the state level have routinely developed "opt-out" options to allow large energy consumers to avoid paying all or part of their assessed CRM funds. In exchange, these consumers are either assumed or required to make their own investments in energy efficiency.

Today, 24 states with CRMs have some option that exempts large energy consumers from paying all or part of their CRM fees or to self-direct the spending of those fees. Some of these programs are called "opt-out" programs, because they allow customers to simply opt out of paying their CRM fees and participating in any energy efficiency programming. Some of these programs are called "self-direct" programs, because they ostensibly allow customers to self-direct some or all of their CRM fees instead of paying into the aggregated pool. These self-direct programs are the primary focus of the remainder of the report.

Many flavors of self-direct program exist. Some states have highly structured and well-considered programs that regularly produce substantial cost-effective energy efficiency savings. Other states have programs that allow companies to opt out of paying their CRM fees, regardless of whether that company ever makes energy efficiency investments. Most self-direct programs are not a strictly defined "type" of energy efficiency program, but rather a point on a continuum of programs that varies dramatically from state to state.

[4] Commercial and industrial data from EIA is combined here for comparison purposes because the complimentary data from CEE is not disaggregated.

Self-direct programs generally have four common elements:

- **They define who is eligible**, either by setting an annual kWh consumption minimum threshold, an average MW demand minimum threshold, or establishing an entire sector or tariff schedule (industrial, transmission customers) as eligible;
- **They offer some "relief" from CRM fees**, by offering an exemption from, rebate against, escrow of, or credit to the CRM fees paid by the participating customer;
- **They are officially sanctioned and administered** by a utility, public service commission or state energy department;
- **They expect some energy savings in return** by assuming, requesting or requiring that the participating customer invest some or all of the saved money back into energy efficiency projects on site.[5]

Though most self-direct programs feature these elements, there are various permutations that are possible. As such, they look and operate very differently from state to state. Self-direct program designs are affected by state energy efficiency goals and mandates, local utility leadership, the opinions and actions of the local industrial sector, and the guidance and involvement of state legislators and regulators.

Since self-direct programs vary widely, it is useful to identify several main categories of self-direct programming because generalizations can be made about each category. Table I presents the opt-out/self-direct continuum and identifies critical categorical distinctions along the continuum, from opt-out to various flavors of self-direct. As we progress to the right across the table, each category yields greater and greater reliability of energy efficiency savings.

Table I: Opt-Out/Self-Direct Program Continuum

	Opt-Out	**Self-Direct**		
Type of program	Opt-out	Less structured	More structured, lower oversight	More structured, higher oversight
Payment of CRM	None	None	Fully/partially on bill	Fully/partially on bill
M&V of savings	None	None/minimal	Minimal, self-reported	Minimal to substantial
How funds used	Firm assumed to use saved CRM funds for energy efficiency	Firm assumed to use saved CRM funds for energy efficiency	Rate credit or project rebate	Personal escrow account, rate credit or project rebate
Follow-up	None	None to minimal	Minimal	Minimal to substantial
Examples	NC, KY	MN, MO	MT, OR	WA, CO
	Public Benefit Maximization			

Sources: Elliott and Chittum 2009, Young 2011, Stipe 2011, Helmers 2011, Landers and Montgomery 2010, Edwards 2011, Schutt 2011, Walker 2011, Mauney 2011, Landers 2011, Goetze 2011, Romero 2011, Zarnikau 2011, Wankum 2011

Table I separates the true opt-out category from the remainder of the self-direct program categories. These true opt-out programs lack significant structure, and cannot truly be called efficiency "programs." Rather, the opt-out provisions in place in these states allow a company to avoid paying the entire CRM fee, with the company not required to provide any information about the energy

[5] For programs that allow industrial customers to aggregate multiple sites to qualify for a self-direct program, the energy efficiency investments are often made at only one or some sites, and the customer may use their aggregated savings from all sites to pay for the investments at one or some of their sites.

efficiency investments that they have made. In some cases, customers are allowed to opt out for economic competitiveness reasons; that is, they make the case that paying the CRM fee is burdensome to them. There are fewer true opt-out provisions than there are self-direct programs. Most opt-out programs offer customers the option of opting out, though in Texas and Maine large industrial customers — those that take service at the transmission level — are simply not allowed the option of participating in CRM-funded electric efficiency programming. Such treatment is common for natural gas CRM-funded programs, where most gas transportation customers are not included in CRM programs at all.

Moving right across the continuum, the less structured self-direct programs will also often exempt a customer entirely from paying their CRM fees. These programs require the customer submit some documentation stating that the customer has invested in energy efficiency in the past or plans to do so in the future. Often this is a single page letter and a copy of a purchase receipt, but the customer is not required to provide detailed information about the investment, and no thorough external analysis or evaluation of a customer's claimed efficiency savings is performed.

Continuing right across the continuum are more structured programs but with low oversight. These programs typically require that a customer wishing to avoid paying all or part of the CRM actually pay the CRM fees up front, and then submit paperwork to the self-direct program administrator to earn back a rebate or to earn a credit on their utility bill. Though these customers do have to submit evidence that investments have been made, the program administrators report they do not have the time, resources or authority to verify the claimed investments or savings.

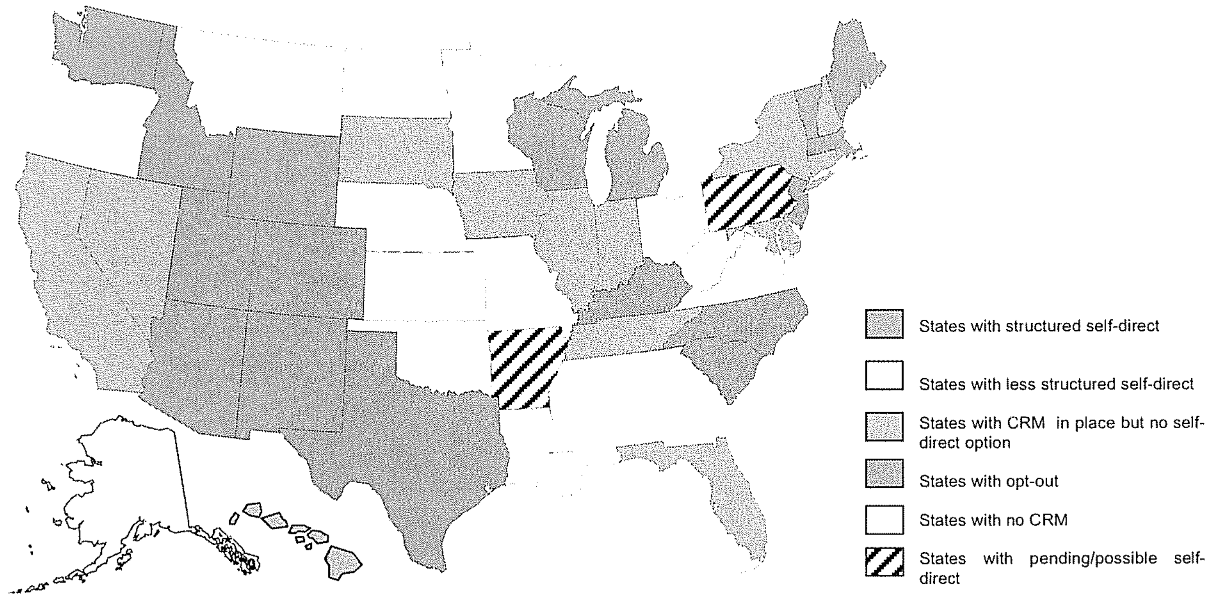
At the far end of the self-direct continuum are the more structured programs with high levels of oversight. These programs can be viewed as true resource acquisition programs, generally subject to evaluation, measurement and verification protocols of the same rigor as other CRM-funded efficiency programs. Customers' CRM fees are often collected and then administered by program staff, funding investments as they are reviewed and approved. These programs usually let a customer self-direct most of their CRM fees, but retain a portion of those fees to fund administration of the program and other programs that serve other public benefits, such as market transformation and low-income programs. Highly structured and well administered programs with substantial oversight offer the best examples of successful and effective self-direct programming.

Opt-Out and Self-Direct Programs Today

In the past several years the number of states with opt-out and self-direct programs has increased from the 15 (identified in Chittum and Elliott 2009) to 25 (profiled in this report). Figure 1 identifies the states where self-direct and opt-out programs can be found currently. It also indicates which states have some sort of CRM in place, but offer no self-direct option.

It is clear that opt-out and self-direct options are gaining popularity, and ACEEE has been approached by other states that are considering these program options. Model self-direct program design guidance is needed because of the potential low-cost energy efficiency opportunity available in industrial sector, and the potential to miss those opportunities with opt-out or poorly structured self-direct programs.

Figure 1: Opt-Out and Self-Direct Program Options in the United States



Sources: ACEEE 2011, APS 2011, Chittum and Elliott 2009, Cross 2011, Stipe 2011, Edwards 2011, Goetze 2011, Goff 2011, Helmers 2011, Landers 2011, Landers and Montgomery 2010, Mich. Comp. Laws 2011, Schepp 2011, Schutt 2011, Timmerman 2011, Walker 2011, Welch and Fraser 2011, Whitehead 2011, Williamson 2011, Xcel Energy 2011, Young 2011

ACEEE's earlier research on opt-out and self-direct programs (Chittum and Elliott 2009) found that while some self-direct programs are very structured and work diligently to verify that self-directed funds are actually spent on cost-effective energy efficiency, most programs were lacking in structure, oversight, or both. Two years later that trend still exists, though some of the newer self-direct programs, such as those found in Michigan, New Mexico and Colorado feature more structure and oversight than earlier programs. Some of the most effective self-direct programs discussed in this report can serve as models for new and emerging offerings.

Table II illustrates how varied the opt-out and self-direct program landscape is currently, listing ten representative self-direct programs and some of their key characteristics. Detailed descriptions and analyses of each opt-out or self-direct program can be found in Appendix I. Self-direct programs have in the past primarily focused on large industrial customers. More recently, self-direct programs have begun to allow other customers to participate, including large commercial and/or institutional customers. As Table II shows, participating companies experience different programs depending on the state.

Besides the expansion into new sectors, several other new trends in self-direct programs can be identified. The first is a trend toward allowing companies to aggregate the loads of multiple facilities in order to meet a self-direct program's minimum threshold. For example, while a state may establish 1 MW average annual demand as the minimum a company must meet in order to participate in the self-direct program, it may also allow a company to aggregate the demands of multiple facilities together to meet the limit. Self-direct programs, along with EERS, are beginning to incorporate natural gas efficiency investments as well as electricity efficiency. Finally, some self-direct programs continue to allow participating customers to receive credit for past efficiency investments when calculating the customer's rebate or credit.

With so many different self-direct options in place, and no established framework for what constitutes a successful and effective self-direct option, the policy question "What should self-direct programs be designed to do?" has remained unanswered.

Table II: Select Opt-Out and Self-Direct Programs and their Critical Characteristics

State	Example administrative body	Eligibility	Who does measurement and verification?	Energy savings goals for customers?	Level of oversight	How much of CRM fee does customer retain?	Level of utility involvement	How is CRM money recouped?	How many customers participating?
CO	Xcel Energy	2MW, 10GWh	Xcel Energy	No	High	Some	High	Rebate per kW or kWh, up to 50% project cost	Less than .5% of eligible
KY	Duke Energy	Transmission customer	None	No	Low	100%	Minimal	Full exemption	13; 100% of eligible companies
MI	All regulated utilities	1MW / 5MW aggregated	Utilities	Yes, same as EERS	High	100% - admin and low-income	High	Partial exemption	47 companies
MT	North-Western Energy	1 MW	None	No	Medium	Up to $500,000 per customer	Minimal — acts as "bank"	Dedicated escrow, quarterly reimbursement	57 companies
NC	Duke Energy	1GWh	No one	No	Low	100%	Minimal	Full exemption	
OH	AEP	700,000 kWh	AEP/PUCO	No	Medium	Up to $225,000 per project / total exemption	High	Rebate or exemption	7 opt out, many more self-direct
UT	Rocky Mountain Power	1 MW/5GWh	RMP	No	High	80%	High	Rate credit	30% of eligible companies
WA	Puget Sound Energy	3aMW, certain schedules	Customer + PSE	No	High	82.5%	High	Dedicated funds, competitive bid	Approx. 44 sites; >75% of eligible
WI	All regulated utilities	1 MW	Company + Public Service Commission	Yes	High to Medium	100% - admin and renewables	Medium	Escrow, milestone payments	0

Sources: Helmers 2011, Cross 2011, Landers 2011, Edwards 2011, Chittum and Elliott 2009, Haemmerle 2011, Mauney 2011, Romero 2011, Schutt 2011, Walker 2011

THE SELF-DIRECT OPPORTUNITY

What Should Self-Direct Programs Do?

Self-direct programs should be designed to achieve desired policy goals. Just establishing a program and calling it "self-direct" does not guarantee the program offerings will truly encourage energy efficiency in the industrial sector or yield cost-effective energy savings. A self-direct program *can* be a reliable resource acquisition program[6], able to produce dependable and measurable energy savings. Well-developed self-direct programs can indeed inspire industrial firms and other participating companies to make substantial energy efficiency investments and help reach state energy efficiency goals that benefit everyone, including themselves. It appears that in some cases, self-direct programs can yield greater savings from certain customers than would have been achieved through traditional CRM programs. They can also leverage a facility's internal technical expertise to multiply the impact of the program dollars dedicated to energy efficiency, perhaps even at a lower cost when compared to CRM-funded programs.

A self-direct program can be a very unique, helpful, and attractive offering to an industrial firm that wishes to make investments in energy efficiency. Self-direct programs can help bridge the gap between existing commercial/industrial energy efficiency programs offered by local utilities and the needs of industrial and other large energy consumers, especially in places where the existing utility program offerings are not very strong. Good self-direct programs allow customers more flexibility in the use of their CRM fees, thereby enabling them to:

- More fully leverage their own internal technical expertise;
- Better make the case for internal support of energy efficiency investments;
- Multiply the impact of program dollars dedicated to energy efficiency;
- Implement projects over longer time periods and enjoy funding for larger percentages of project costs as compared to than traditional CRM programs;
- Meet their facility's individualized energy needs; and
- Capture traditionally hard-to-reach energy efficiency savings.

CRM cost-effectiveness tests and methods for evaluating project costs generally account for a measure's full costs and benefits compared to new generation. Thus, self-direct programs that use a utility's in-place CRM cost effectiveness criteria will likely encourage certain projects that would not have passed an internal payback period test by a customer who was simply comparing the cost and benefits of a project to the cost of avoided energy purchases. Opt-out programs in particular rely simply on a customer's internal investment decision-making criteria. While an opt-out customer might decide that a certain measure does not meet her own internal criteria, it might be beneficial enough to the energy system at large that the utility would find it met its investment criteria. A good self-direct program should not leave those projects languishing.

Self-direct programs have been developed in response to claims by large industrial firms that they will, as a smart business practice, continue to invest in all cost-effective energy efficiency. A self-direct policy framework should measure and verify these savings and be able to incorporate them into long-term energy system planning. The industrial sector offers substantial savings opportunities; whether or not those opportunities are taken advantage of can impact overall system demand for years into the future. Tracking the effect of energy efficiency investments made by self-directing customers enables policymakers to gauge the long-term energy demand of the industrial sector.

Self-direct programs should be able to answer the question, "Is this program yielding the same or better energy efficiency savings than would have been acquired with a traditional CRM-funded efficiency program?" Some large industrial customers have called CRMs "penalties." CRMs are established by utility regulators as a fair condition of electricity or natural gas service to pay for a system-wide resource. Paying little or no CRM fees is a special privilege that customers may earn by offering a countervailing guarantee of performance, like every other use of CRM fees. Quality data collection, a hallmark of today's CRM programs, is one way policy makers and regulators can determine whether a self-directing customer or a self-direct program as a whole is earning the special privilege. To help answer the above question, self-direct programs should be collecting data that will enable an "apples to apples" comparison.

[6] A "resource acquisition program" is a program that can be counted on to deliver a reliable amount of energy savings. An energy efficiency resource acquisition program can then be compared to the acquisition of other energy resources for purposes of energy system resource procurement.

Finally, self-direct programs and the CRM-funded programs serving the utility's service area should help the customer make informed decisions about whether or not to avail themselves of the self-direct option. A customer should be well informed about the services and benefits forgone by opting for self-direct and should be clearly informed of the risks of non-compliance with the terms of a self-direct program. In the cases where a CRM program would clearly better serve a customer, a self-direct program should be able to suggest that a customer might prefer not to self-direct.

Ideal Self-Direct Characteristics

A number of current, successful self-direct programs offer robust and replicable examples of how to structure self-direct programs that work. These programs are effective for a variety of reasons, and have creatively responded to their customers' needs. More successful self-direct programs feature several particular characteristics that make them good at capturing energy efficiency savings. The administrators of today's successful self-direct programs:

- Run them as a resource acquisitions effort,
- Make them flexible,
- Offer CFOs a reason to care,
- Develop smart reimbursement plans,
- Use a stick — if necessary, and
- Stay close and collect meaningful data.

Run Them as a Resource Acquisition Effort

Measurable energy savings can be achieved, though most self-direct programs do not evaluate, measure or verify information pertaining to installed savings. Instead, self-direct programs tend to track the amount of money spent on energy efficiency by self-directing customers, paying far less attention to the amount of energy (e.g. kWh or therms) saved. Like traditional CRM-funded programs, self-direct programs can operate like resource acquisition programs: delivering reliable savings while satisfying desired cost-effectiveness tests.

A useful first step in running a self-direct program that operates like a resource acquisition program is to set some energy saving goals for customers. These goals could be based on state-level efficiency goals for utilities, as in Michigan, or on other parameters, as at Oregon's **Eugene Water and Electric Board (EWEB)**. At EWEB individual self-directing customers develop energy savings goals in collaboration with the utility's staff. EWEB wants to keep the energy savings goals simple to understand and administer, and so it looks at the load shares of their self-directing customers and develops energy savings goals based primarily on the percent of load a customer represents. The customer's load profiles and the average customer conservation activity in the previous year provide EWEB with enough data to develop five-year energy savings goals for their self-directing customers. Annual true-ups of the savings help keep the goal in sight, and EWEB notes that they are acquiring more efficiency from their two self-directing customers than they had in the past when the customers were using EWEB's standard CRM program offerings (Welch and Fraser 2011).

EWEB staff, and staff at other programs that ask self-directors to meet actual energy savings goals, say that developing concrete savings goals help improve the working relationship between the customer and the self-direct program administration. Instead of focusing on dollars, these goals keep the conversation focused on energy. When customers buy into the idea of energy savings goals, they learn to squeeze more energy savings out of a dollar. Their internal goals are different than those of a typical self-direct program that simply asks that customers spend a certain amount of money. The customer is empowered to learn more about making the most cost-effective investments towards his energy goal instead of just trying to satisfy a monetary spending goal. The self-direct program's goals are aligned with those of the customer, and interactions between the two entities are more amicable.

Make the Program Flexible

As with EWEB's savings goal, most self-direct programs establish program periods that span one or more years. The inclusion of multiple years to a program period is one way self-direct programs can offer more flexibility to customers who often study and make investments in different components of a new project over a period of time that spans more than one year. Customers can then plan their energy efficiency investments well ahead of time. This allows them to schedule efficiency investments during planned plant downtimes which may happen very infrequently, avoiding the high costs of lost production during a shutdown done exclusively for energy retrofit purposes.

Rocky Mountain Power takes the goal of flexibility one step further and operates a self-direct program that is project-based instead of year-based. Customers are not presented with an either/or option when choosing whether or not to self-direct. Instead, they may choose to self-direct specific projects, and use CRM-funded programs for other projects. This structure keeps industrial firms connected to and communicating with Rocky Mountain Power, and customers may choose from Rocky Mountain Power's full suite of CRM-funded tools for projects they do not self-direct. While some self-direct programs leave customers entirely on their own, Rocky Mountain Power staff says that only a few customers really are savvy enough to maximize their energy efficiency. The flexible self-direct offerings of Rocky Mountain Power allow customers to access the utility's technical assistance and expertise as needed (Helmers 2011).

Offer the CFOs a Reason to Care

A constant challenge for industrial energy efficiency programs is making the business case for energy efficiency to the holder of a company's purse strings. A facility manager may understand the importance and advantage of substantial energy efficiency investments; a CFO may see a slightly longer payback than other non-energy projects and conclude energy efficiency is a poor use of internal funds. While an energy efficiency program might be comfortable supporting an investment with a five-year payback period (compared to a power plant investment with a financial lifetime of multiple decades) an individual company or CFO may not.

The CRM fee is often just seen as a component of a utility bill and thus an operating expense, further exacerbating the challenge of convincing internal decision makers to engage with CRM-funded programs. The CRM fee is part of the general operations and maintenance (O&M) budget. Since it is such a small portion of a facility's monthly energy bill (usually 2-5%), it is generally paid without much thought, whether or not a company actively uses CRM-funded programs. Whether those programs are worth that fee is not something a CFO bothers with. A CFO would likely prefer to simply see the company's monthly energy bill lowered by removing the CRM charge.

A good self-direct program moves the CRM fee, and energy efficiency funding generally, out of the O&M budget and into the capital expenditures budget. It does this by separating the CRM fee from the rest of the utility bill and showing the customer that the self-direct-able portion of the CRM fee is a dedicated amount of money specifically able to fund energy efficiency projects. This gives facility managers an opportunity to show corporate leadership that the CRM fee is a tangible and manageable amount of money. It is no longer simply embedded in an energy billing rate, lost amid the noise of monthly expenses.

A good self-direct program also helps a customer overcome higher internal hurdle rates — that is, the minimum return a company requires before it makes an investment. It does this by setting aside money specifically for energy efficiency, which the customer must use or forfeit, and encouraging and providing funds for projects that make sense even with a long payback period. The **New Jersey Clean Energy Program** self-directed pilot program empowers customers to tackle both of the above issues by asking them to develop portfolios of desired energy efficiency investments, and funding the portfolio of investments up to certain program maximums.

The New Jersey program is a multi-phase one. After an initial investment plan is developed by the self-directing customer, the New Jersey program sets aside dedicated funds to fund the portfolio. In this way the self-directing customer is encouraged to invest in projects with longer payback periods, because the self-direct program is effectively financing the investments. The internal hurdle rate for investments is minimized in importance, because the funds are coming from an external source. And CFOs are happy to approve and seek energy efficiency investments, because they understand that the money is theirs to use or lose. This type of structure is an effective way to help overcome the entrenched investment-making decisions in industrial firms that can sometimes hinder greater energy efficiency (Ambrosio 2011).

Develop a Smart Reimbursement Plan

Each self-direct program offers its customers a slightly different mechanism of reimbursement for some or all of their CRM fees. While each type offers different benefits, some are more likely to encourage cost-effective energy efficiency than others, especially when coupled with other effective program structures.

Grants and rebates, which fund energy efficiency investments either before or after they are implemented, are common among self-direct programs. They can be simple to administer and generally require that a customer continue to pay their CRM fees on their monthly bills. They offer companies lump sum payments for promised or completed efficiency investments, and are most similar to traditional incentive programs.

Rate credits offer customers a credit against the CRM fees they pay on their monthly bills, usually as a result of demonstrated energy efficiency investments. Rate credits offset part of or the entire CRM fee, and can encourage customers to continue pursuing new energy efficiency projects as they become accustomed to the reduced monthly bills. Rate credits reduce the company's utility bills over time, but still make energy efficiency happen. They can also provide a construct for an internal funding pool for energy efficiency, if a company chooses to earmark the monthly discounts as positive cash flows.

A competitive bidding process aggregates the funds from all self-directing customers. Proposed projects are submitted in for bid and self-direct program administrators decide the best use for the funds, focusing typically on cost-effectiveness and overall energy savings. This type of structure can be effective because it leverages the competitive nature of participating companies. Companies do not want to be left out of the community activity of making energy efficiency investments.

Puget Sound Energy administers one of the more creatively structured self-direct programs in the nation by combining grants with a competitive bid process. Self-direct programs operate with five year windows. PSE works with self-directing customers to track CRM contributions for future use, and allows them to earn an incentive against their tracked contributions whenever an approved project is completed. The program begins with a non-competitive phase during which customers are guaranteed access to their portion of CRM fees. At the end of the non-competitive phase, all remaining funds not committed to projects are aggregated together and disbursed via a competitive bid process among all self-direct customers, encouraging highly cost-effective projects. PSE found that once the competitive bid process neared and a deadline loomed, projects "went like gangbusters" because many companies did not want to relinquish any of their own "use it or lose it" funds to a multi-customer pot of money — particular when it might be used by a competitor.

One important experience of the PSE program has been the very large volume of competitive projects that have been proposed during the competitive bid process. For example in 2009 self-direct customers proposed cost-effective energy efficiency investments of over four times the amount of funding actually available in the multi-customer pot of money. PSE has found that this is common during their competitive bid process, and is evidence of the large supply of cost-effective energy efficiency in the industrial sector not being captured by existing programs (Landers and Montgomery 2010).

PSE says its self-direct program is acquiring energy efficiency at a cost equal to its other CRM-funded programs and that the program is actually acquiring more efficiency than would have otherwise been acquired. This is because the PSE self-direct program customers leave "money on the table" when they do not invest in energy efficiency. Customers just paying a CRM fee may be content paying the monthly bill and not taking advantage of CRM programs and services. The PSE self-direct program brings that same amount of money to their attention and specifically sets it aside for energy efficiency. The PSE program is an excellent example of how to leverage the flexibility inherent in a self-direct program (Landers and Montgomery 2010, Landers 2011).

Use a Stick — If Necessary

Most self-direct programs do not penalize customers for failure to meet energy savings goals. Nor do they check on equipment after it is installed to make sure it is capturing claimed energy savings. While such structures may not be necessary, some self-direct program managers have found that pairing a stick with the carrot — that is, the privilege of self-directing their CRM fees — they can better encourage customers to meet energy savings goals or use up all of their allotted CRM funds. The stick or penalty becomes a tool that facility managers can take to their corporate leadership, allowing them to impress upon the company's financial decision-makers the importance of making substantial investments in energy efficiency.

Penalties in self-direct programs vary, depending on the type of reimbursement plan in place. Where a company earns rate credits or rebates in advance of project implementation, a penalty may be incurred if the planned project does not come to fruition. Customers may have to pay back the portion of the rate credit or rebate attributable to the project that was not implemented. Self-direct programs such as the one found in **Michigan** ask customers to meet set energy savings targets. If a customer fails to meet its targets it must repay CRM fees in proportion to the shortfall. The Michigan program takes into account the reasons behind the customer's failure to meet the energy savings goals and may lessen or deepen the penalty based upon an assessment of the customer's actions. Though the Michigan program features the repayment structure, utilities there have been hesitant to use it, for fear of political consequences (Michigan S.B. 213, Walker 2011).

At **Puget Sound Energy** the "stick" is simply customers lose the CRM funds they have paid if the money goes unused. Other self-direct programs use this method as well to encourage maximization of energy efficiency among their customers. Customers are loath to give their money to another entity and once they understand they have a dedicated amount of money to use on energy efficiency projects, they will do almost anything to avoid leaving "money on the table." Customers are incentivized to determine a use for their money quickly, lest they end up relinquishing it to a neighbor or competitor (Landers 2011).

Stay Close and Collect Meaningful Data

Many self-direct programs, and all opt-out programs, make a one-time decision about a customer's self-direct status and then conduct little to no follow-up, or follow up within several years. While this requires few program administrative resources, it does not allow a utility or regulator to assess the impact of the self-direct program. It also does not allow program administrators to assess whether the self-direct program is serving its target customers well.

Perhaps most alarmingly, keeping self-directing customers at an arm's length prevents program administrators from collecting the kind of useful data that are collected in CRM-funded programs. Program administrators need to know:

- The type of investments,
- The cost of each investments,
- The overall cost of energy saved,

- The amount of energy saved by each individual measure, and
- The overall amount of energy saved.

These are important data points that can help utilities and policymakers better craft and administer energy efficiency programs in the future. If a self-directing customer is not acting in good faith, its behavior can have system-wide impacts. Failing to acquire the most cost-effective energy efficiency can put upward pressure on energy prices and generally increase the overall cost of efficiency programming.

Xcel Energy's self-direct program, administered in its Colorado and New Mexico service territories, maintains strong relationships and communication with its self-direct customers. It engages in substantial communication with its self-direct customers at the beginning of their self-direct application, identifying necessary data points early on in project development. Xcel requires pre-installation energy monitoring and regularly reviews and evaluates self-direct program performance. Xcel tasks its highest level engineers to review self-direct project engineering analyses and energy monitoring plans. The result is that Xcel is equally as confident in the self-direct program's claimed savings as in those claimed in the more traditional CRM-funded incentive programs. Such confidence in savings is rare among self-direct programs (Romero 2011).

The above examples illustrate that self-direct programs can be well constructed and successful in encouraging cost-effective energy efficiency. Some self-direct program managers are confident that their programs are producing savings of similar quality to those achieved through more traditional programs, though data is not usually collected to yield true "apples to apples" comparisons among self-direct programs and more traditional CRM-funded energy efficiency programs. It is clear that in some cases the flexibility and unique tools offered by self-direct programs enable greater efficiency than would have been achieved with more traditional programming. In a few select states, self-direct programs have developed into highly effective tools in a state's suite of energy efficiency programming.

The Self-Direct Challenge

As noted in the previous section, examples of successful self-direct programs exist. Unfortunately, developing and administering a self-direct program can be a challenge. Most self-direct programs and all opt-out programs feature a number of characteristics that are troubling to those interested in maximizing cost-effective efficiency across all sectors. The successful self-direct programs noted in the previous section are the exceptions to this rule. For self-direct programs to establish themselves as essential components of a state's energy efficiency efforts, the following challenges will need to be addressed:

- Unfounded assumptions on which the programs are predicated,
- Lack of data and evaluation within programs, and
- Unfair treatment of self-direct customers and other classes of customers.

Unfounded Assumptions

Self-direct programs are predicated on some assumptions about industrial energy efficiency that are largely unfounded, or at least not substantiated by available data. The assumptions are that industrial companies are better at acquiring energy efficiency than CRM programs and will always acquire all cost-effective energy efficiency on their own, absent any efficiency programs. These assumptions, repeatedly promoted by some industrial sector stakeholders during energy policy discussions, have provided the policy basis for opt-out and self-direct programming in almost every state with such an option, despite their shaky foundations. Instead of establishing self-direct programs because they are effective energy efficiency programs in their own right, self-direct programs have tended to be developed as a response to these assumptions, put forth by some vocal members of the industrial sector.

Industrial Customers Do Efficiency Better

The first assumption on which opt-out and self-direct programs are based is that industrial companies are better at capturing cost-effective energy efficiency than CRM-funded programs. This assumption also includes the inherent belief that CRM-funded programs are not capable of serving the industrial sector well. In many states, evidence suggests otherwise. ACEEE has studied industrial energy efficiency programs for years, and has, over the years, consistently identified industrial energy efficiency programs that are tremendously effective at capturing energy efficiency from their customers (see Chittum et al. 2009, York et al. 2008). Though it is clear that some CRM-funded programs are not as effective as others, examples of CRM-funded programs serving their industrial sectors well are easily found.

In fact, self-direct programs themselves tend to refute this assertion. In Wisconsin, where industrial energy efficiency programs have historically been quite strong, no single customer has chosen to take advantage of the self-direct program. Wisconsin's policy-makers and administrators of the CRM-funded programming attribute the lack of interest in the self-direct option to industrial companies' perceptions that Wisconsin's Focus on Energy programs serve them well and provide benefits equal to or greater than their individual CRM fees (Schepp 2011, Schutt 2011). In Oregon, companies have increasingly stopped using the self-direct program and instead chose to pay into the CRM-funded programming offered through the Energy Trust of Oregon. Customers have noted that they made the switch to take advantage of the Energy Trust's incentives and technical assistance. This has been especially true as the Energy Trust has developed more industrial-focused offerings (Crossman 2011, Stipe 2011).

Industrial Companies Will Maximize Cost-Effective Efficiency

Another assumption frequently made during the development of opt-out and self-direct programs is that industrial customers will always do all cost-effective energy efficiency because doing so makes good business sense. This claim is typically followed by the assertion that the CRM fee is a "penalty" (Chittum and Elliott 2009, Schwartz 2011, Crossman 2011, Lazar 2010). While industrial firms in the U.S. have continued to become more energy efficient per unit of product output, they have not necessarily captured all cost-effective energy efficiency. Again, opt-out and self-direct programs have proven this to be true. In Utah, Wyoming and Oregon, customers can opt out of all or part of their CRM fees if they can prove that they have in fact done all cost-effective energy efficiency. In the case of Utah and Wyoming, "cost-effective" means that a project has a simple payback of eight years or less; in Oregon it is ten years. To date, no company has taken advantage of these exemptions in any of these states, because there are always some cost-effective projects that could be identified during an energy audit (Helmers 2011, Stipe 2011).

Lack of Data and Evaluation

Measuring and evaluating the true costs and benefits of energy efficiency programs and projects is critical to maximizing efficiency's public benefits. Conducting data collection and analysis ensures money is not wasted that could otherwise be used to acquire efficiency. Customers of all classes paying a CRM fee to support system-wide energy efficiency want to know that their dollars are not being wasted. Similarly, when customer rates increase because a new power plant is built, customers want to know that the power plant is running as effectively as possible. Performance data must be collected to know this.

Opt-out programs collect little to no data, and self-direct programs often do a poor job of collecting and analyzing data. This is due largely to the structure of self-direct programs, which generally allow for few if any dedicated staff and few additional resources. Most but not all self-direct programs retain a percentage of a customer's CRM fee to cover program administrative costs, though the amount retained can be quite small and insufficient to pay for all desired program administrative activities. These collections range from about 5% to 20% of a customer's CRM fee. Self-direct programs are also often challenged by competitive concerns of participating customers who may not wish to share data about their operations. Collecting data or verifying data submitted by customers takes time and effort, and self-direct programs are typically shoestring operations that may employ one or two full-time individuals to process paperwork.

Only a handful of self-direct programs evaluate overall program performance, which can offer comparisons between the self-direct program and the alternative CRM-funded program. Most self-direct programs do not collect data on pre-installation energy use of a company's systems to which energy efficiency improvements are applied and therefore, programs cannot develop baseline energy use assessments in order to ascertain the impact of the self-direct program.

Self-direct programs that do ask for more detailed data on specific projects before they provide a reimbursement have to rely on a company's internal or third party energy analysis. Some self-direct programs are better than others at reviewing the customer-provided data on installed measures, but many do not conduct their own measurement and verification of the claimed savings. Several opt-out and self-direct programs give credit for projects that are planned for the future, and very few of those conduct substantial follow-up with customers to verify one, two or three years down the road that planned projects were completed.

Industrial energy efficiency programs already suffer from a general dearth of data. Limited data collection from opt-out and self-direct programs yields missed opportunities to learn more about what works and what fails in the industrial sector. In South Carolina, Duke Energy allows customers to opt out of paying the CRM fee after they submit a letter stating that they have or plan to implement cost-effective energy efficiency investments. No proof is required beyond the letter. Duke staff acknowledge that collecting more data might be useful for their program planning purposes but they are not tasked with data collection or program evaluation and do not have the resources to dedicate to it (Mauney 2011, Duke Energy 2011b).

In some states, such as Montana, different entities are responsible for different aspects of the self-direct program. While one party may assume that the other is more engaged in monitoring and reviewing the energy efficiency investments of self-direct customers, the other party may assume the opposite. In Montana, the utility administering the self-direct program assumes that the state agency reviewing self-direct reimbursement claims is conducting some verification of claimed savings. The utility is not authorized to conduct project savings evaluations, and, in fact, neither is the state agency. The state agency does not evaluate the investments or review them for accuracy of claimed energy savings (Edwards 2011, Trasky 2011, Young 2009).

Beyond understanding how well self-direct programs are working, data from self-direct projects and programs can help a state or region plan for the long term impact of industrial customers' energy use and energy savings. Without proper data collection, there can be no meaningful analysis, no reliable measurement and no useful evaluation of a program's societal worth.

Unfair Treatment

Opt-out and self-direct programs can be unfair to other customer classes. No other class of system user is allowed to opt out of paying for a system benefit or escrow their CRM payments. This is true regardless of the actual amount of benefit each user enjoys. Since all ratepayers enjoy the benefits of energy efficiency, in the form of lower demand for new resources, reduced environmental impacts of energy supply, reduced power and fuel costs and other factors, it is arguably fair that all ratepayers pay for it. All other system resources, such as new generation assets, are generally paid for by all customers.

Some self-direct programs and all opt-out programs take certain select companies out of the communal framework and, if those companies fail to make energy efficiency investments with their saved CRM fees, deprive customers in the remaining classes from the benefits of low-cost industrial energy savings. Opt-out programs in particular allow customers to pay nothing toward energy efficiency and acquire no new efficiency without penalty. Self-direct programs that fail to acquire the amount of efficiency that would have been acquired via a CRM-funded program also do the other classes of customers a disservice. On the other hand, the few self-direct programs that appear to encourage greater levels of efficiency investments among participants bring a greater level of shared energy efficiency benefits to all customers.

Granting Credit for Historic Savings

The primary role of energy efficiency programming is to procure new energy savings. Energy efficiency programs exist because energy efficiency is low-cost and offers ancillary benefits. Self-direct programs that allow free ridership — they pay for energy efficiency that would have been acquired absent any programming — are not serving an overall public good but are instead providing participating customers with added income, at the expense of more efficiency that could have been achieved with additional efficiency programming.

One of the most visible ways opt-out and self-direct programs allow free ridership is through the crediting of historical investments in energy efficiency. North Carolina, South Carolina, Oregon, and Ohio are examples of states whose opt-out and self-direct programs give or have given credit to previously installed energy efficiency investments, implemented prior to the commencement of the opt-out or self-direct program. Giving such credit does not acquire a single new kWh, and it reduces the overall efficiency benefits of a self-direct program. Large industrial customers contend that granting such credit is the only fair way to adequately credit early action on energy efficiency, but there is no reason that large customers need to be credited for earlier investments, since they already benefit from the long-term energy savings which presumably were cost-justified based solely on avoided utility costs.

Giving credit for previous investments is most often done when an opt-out or self-direct program is first established, often in an effort to satisfy industrial customers. Offering such credit is a preferential treatment of a single class of customer and does not serve any energy-saving purpose. It is a politically useful program characteristic, but it does not ensure that new cost-effective energy is procured for the benefit of all. Giving recently installed measures credit in a self-direct program may be a useful political tradeoff to implement new long-term energy efficiency CRM program and savings goals if implemented for a very small window of time, such as one year, and only for outlier investments recently made that greatly exceed the normal average annual efficiency expenditures by those customers.

The Opportunity Costs of Opt-Out and Self-Direct Programs

In recent years states have moved away from setting spending amounts and just watching the dollar amount spent on efficiency In doing so they have moved toward setting specific energy savings goals for their utilities and monitoring kWh saved, treating energy efficiency as a highly reliable system resource and an integral part of an overall resource acquisition strategy (Sciortino et al. 2011). In contrast, most self-direct programs require dollar-for-dollar parity, asking or allowing customers to spend an amount equal to what they would have paid in CRM fees, regardless of the amount of kWh that spending acquires. These structures can make savings by self-direct customers harder to project or plan for, and harder to count on as a system resource. In states where no entity "claims" the savings acquired through a self-direct program, incentives for utilities to encourage energy efficiency, if they exist, will not apply to self-direct savings.[7]

[7] See ACEEE's 2011 report, *Carrots for Utilities,* for more information on shareholder financial incentives designed to encourage investor-owned utilities to provide energy efficiency programming: http://aceee.org/research-report/u111.

Only a few self-direct programs — Michigan, Wisconsin, Eugene Water and Electric Board and Vermont's Self-Managed Energy Efficiency Program — set individual kWh or kW goals for customers and base reimbursement levels on the progress the customer makes toward the goal (Welch and Fraser 2011, Mich. Comp. Laws 2011, Chittum and Elliott 2009, Goetze 2011, Schutt 2011). Most self-direct programs do not set individual customer energy savings goals, or do not link a customer's reimbursement of CRM fees to the meeting of those energy savings goals.

As an opt-out or self-direct customer, spending the same amount of money on energy efficiency measures as they would have spent on CRM fees does not necessarily yield the same amount of energy savings as would be acquired through a CRM-funded program. CRM programs are subject to extensive cost tests and are rigorously vetted to ensure that the dollars spent through CRM programming are in all consumers' best interest. When opt-out or self-direct customers are not required to meet the same cost-effectiveness tests as CRM programs, they will make energy efficiency investment decisions based on their avoided energy costs — their current retail rates. CRM programs set cost-effectiveness rules and make decisions about the economic viability of an individual energy efficiency investment after considering the full cost of new generation resources, since energy efficiency can mitigate or reduce the need for new generation. Energy efficiency projects make much more economic sense when compared to new generation, and so CRM programs can justify investing in energy efficiency projects with longer payback periods. Far fewer energy efficiency projects will be economically justified by individual customers in opt-out programs and self-direct programs that do not require projects be considered within a framework that includes TRC, since they will not have an incentive to invest in projects with longer payback periods.

Few self-direct programs can answer the question, "Could this money be better spent elsewhere?" Only some programs — notably those in Arizona, Washington, Wisconsin, Ohio, Colorado, Utah and Wyoming — require that some cost-effectiveness test be met (Chittum and Elliott 2009, Schutt 2011, Helmers 2011, Landers and Montgomery 2010, Romero 2011, Cross 2011, Williamson 2011). However, just satisfying a cost-effectiveness test offers no guarantee that the self-direct projects are achieving the amount and type of savings that would have been achieved in a traditional CRM program. Additionally, in some self-direct programs, cost-effectiveness tests are based on self-direct customers' own internal decision-making requirements. So while an industrial firm may chose not to make an investment based on its internal cost of capital, the measure might be accepted as fundable and feasible by a well-structured self-direct program using a cost-effectiveness test that includes s. This illuminates why participation in a CRM program or good self-direct program

Opt-out and self-direct programs are not benign policy decisions. Industrial firms offer tremendous efficiency opportunities, and not maximizing those highly cost-effective opportunities can have far-reaching negative effects. Industrial efficiency measures also can offer much higher benefits to costs than measures implemented in any other sector (VDPS 2007). Taking the extensive industrial savings out of both the numerator and denominator of overall year-to-year system savings calculations can eventually increase the overall cost of savings and deprive other classes of customers of the benefits of industrial savings. Additionally, opt-out and self-direct customers often represent substantial system loads and contribute significantly to CRM funding pools. For instance, nearly one third of all CRM fees are self-directed within NorthWestern Energy's Montana territory (NorthWestern Energy 2010). While those firms may be making smart decisions with their funds, they also may not. One-third of NorthWestern's funds are not subject to the kind of scrutiny its CRM-funded programs are.

Self-direct programs run by utilities and those typically tasked with acquiring energy efficiency in a state tend to be more structured and view themselves as more effective than those run by energy offices or other entities operating programs on a more sporadic basis. Utilities and other program implementers already know the market and they know the kinds of investments that self-directing customers have already made. They have experience collecting data from the sector and may already have information on a company's baseline energy consumption. In states like Arkansas, where self-direct program structures being considered explicitly do not include the involvement of a utility, the overall efficiency benefits of a self-direct program could be limited from the beginning.

To summarize, data to determine whether self-direct programs are good policy decisions is usually not collected and does not exist for most self-direct (and all opt-out) programs. As such there may be no reliable way to calculate the opportunity costs of most self-direct programs. Without this data it is impossible to know whether self-direct programs are acquiring savings equal to — or even exceeding — what would have been acquired in a CRM-funded program.

BEST PRACTICES AND RECOMMENDATIONS

There are no perfect self-direct programs, but there are many programs that are good at what they do. Current and future administrators of self-direct programs can learn from the experiences of existing self-direct programs. Below are several best practices and general program design recommendations that current and future self-direct programs ought to consider when building or updating their programs.

Program Development

The voice of large energy consumers is typically quite prominent as new self-direct programs are developed. Letters from large energy consumer coalitions support opt-out provisions or minimally structured self-direct programs in many state-level cases. While the concerns of the industrial and large commercial stakeholders are important for policymakers to consider, there is usually less representation from other customer classes during discussions on large consumer treatment. It is critical, then, that state regulators and policymakers, as representatives working on behalf of all of the state's residents, work to develop offerings to large energy consumers that are still fair to all other classes of customer.

Key Program Elements

Energy efficiency anywhere benefits everyone in an energy system. Industrial energy efficiency savings tend to be the most cost-effective, and thus offer the entire system increased energy efficiency at a low cost. Therefore, a self-direct program that maximizes cost-effective energy efficiency in the industrial sector is an ideal policy goal. To achieve such a program, self-direct program administrators should:

- Develop a program structure that allows facility managers to treat their CRM fee payments as dedicated funds for energy efficiency, either through dedicated escrow accounts, rebates earned only upon project completion, or rate credits earned concurrently with measurable energy efficiency investments and/or energy savings;
- Include a mechanism to recoup paid funds from self-direct customers if it is determined that savings were claimed erroneously or if planned savings did not actually occur;
- Collect and establish self-direct customers' baseline energy use data;
- Focus on energy savings rather than funds expended towards energy efficiency;
- Measure and verify all claimed savings, using the same standards for data collection as industrial CRM-funded energy efficiency programs;
- Retain a portion of a customer's CRM fees to ensure self-direct customers contribute to fund a program's administrative costs and other prioritized program costs (such as low-income programming or market transformation) that all other customer classes pay for via their CRM fees;
- Generally not allow credit for efficiency investments made prior to the commencement of a self-direct program;
- Offer self-direct customers multi-year time frames (e.g., 4 years) in which to expend aggregated CRM fees. If the fees go unutilized, make them available to other customers for cost-effective projects; and
- Employ the same cost-effectiveness tests for self-direct projects as are used for other CRM programs, and develop a reliable account of the cost of saved energy within the program.

Program Variation and Goals

Self-direct programs may vary between states depending on the state's unique needs. However, it is critical that the goals of a self-direct program be well articulated prior to the iterative process usually relied upon to develop and finalize a self-direct program's structure. Such a process can often stay so focused on the details that the larger overall policy goal is lost or never established.

Treating self-direct programs as "throw-away" programs by denying them at least some staff or not counting on them for resource acquisition purposes sends the message to self-directing customers that a utility, regulator, or policymaking entity does not care what they do. Such a statement can have long-term negative consequences, because industrial energy efficiency goals are not taken seriously and as a consequence more power plants are needed: power plants that are typically more expensive per kWh than energy efficiency programs (see Figure 1).

Self-direct programs might consider joining the larger policy trend that is migrating away from setting spending goals in energy efficiency programming and toward a focus on meeting actual energy savings goals. Specific goals for each self-directing customer, and smart aggregation of a self-direct customer's CRM fees, can yield savings that surpass those that could be achieved within a CRM-funded program. Measuring actual energy savings of installed measures, as opposed to simply tracking estimated savings, would also help self-direct programs know the true impact of customer energy efficiency investments.

Successful self-direct programs engage self-direct customers and give them added flexibility that they cannot enjoy through traditional CRM-funded programs. These self-direct programs help industrial customers overcome higher internal investment hurdles and help them make long-term investments in their facilities. Exemplary self-direct programs encourage their customers to maximize cost-effective energy efficiency not just because they are required to, but because increasing energy efficiency benefits everyone, including the individual customer.

Self-direct programs are often the result of political processes and may not always be perfect. But they can ensure that funds intended to acquire cost-effective energy efficiency do capture efficiency for the benefit of all.

CONCLUSIONS

There is substantial evidence that very successful and effective self-direct programs exist in some states. However, many self-direct programs are not ideally designed to maximize energy efficiency and many are developed with little thought towards structure or effects. The self-direct programs that are successful are thoughtfully designed by people familiar with industrial decision-making and are often well-utilized by industrial and large commercial customers to acquire cost-effective energy efficiency in those sectors. In some states, well-structured and adequately measured self-direct programs appear to have achieved energy savings equal to or greater than what would have been achieved without a self-direct option. For this reason, policies should support well-structured self-direct options. An opt-out program, however, is never a wise policy decision.

Designing and running an effective self-direct program can be a challenge. The results in this report establish that most self-direct programs lack at least one of the critical components identified as necessary to maximize the cost-effective energy efficiency in their target sectors. Many self-direct programs are hamstrung by minimal staffing and by regulated or legislated structures that do not allow for accurate measurement and evaluation of the program's impacts. Many self-direct programs are held to lower standards of data collection and analysis than the typical industrial and large commercial efficiency programs. Further, many self-direct programs are not subject to the same rigorous cost tests found in other efficiency programs that ensure public benefit funds are being well spent.

While a self-direct option may indeed be an adequate tool to acquire cost-effective energy efficiency in these sectors, the assumptions and arguments used to support the establishment of a self-direct program are often inaccurate and unfounded. Worse, the data to determine whether self-direct programs are beneficial to society simply is often not collected.

The self-direct option was developed largely as an alternative to opt-out provisions, which allow users to completely opt out of paying for system-wide energy efficiency. Self-direct programs respond to the belief among some industrial and large commercial energy users that some utility-administered energy efficiency programs are not responsive to their needs. Self-direct programs are mostly designed to serve a small number of large energy-using customers. Policymakers have rarely established self-direct programs as primary means to acquire efficiency savings. When states have established new energy efficiency goals and programs, the self-direct option has been, in nearly every case, developed in response to requests from large energy users.

The goal of energy efficiency programs and policies is to achieve energy savings in a cost-effective manner. Since industrial energy efficiency is among the lowest cost energy resource, maximizing efficiency in the industrial sector is critical to meeting these goals. Energy efficiency benefits all users within a utility system, regardless of where the actual end-use efficiency investment takes place. Self-direct programs that fail to leverage and take advantage of the highly cost-effective energy efficiency opportunities in the industrial, commercial and institutional sectors do a disservice to every energy consumer.

The good news is that self-direct programs can be very effective energy efficiency programs, and some have proven themselves as creative programs that serve the hard-to-reach industrial sector quite well. In some cases these program even appear to serve their industrial customers and other large energy users even better than other CRM-funded offerings.

Self-direct programs should be viewed as a privilege offered to large energy users since they provide flexibility not accorded to other consumers. With privilege comes responsibility, so participants in self-direct programs should be expected to meet a reasonable level of reporting and savings validation so the benefits of the program are assured to all other energy users. As increasing numbers of states establish self-direct programs, it is imperative that rigorous performance requirements be in place to assure that all consumers are receiving the benefits from the low-cost energy efficiency resource. The opportunity cost of allowing companies to self-direct will remain unknown without strict requirements.

There are exemplary self-direct programs that offer large energy consumers all the benefits of a self-direct program while providing the rest of society a low-cost energy resource. Successful programs represent a model for developing effective industrial self-direct programs and provide evidence that, when done right, self-direct programs can be true assets to states' and utilities' suites of energy efficiency programming.

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APPENDIX I: PROGRAM SYNOPSES

Arizona
(Williamson 2011, APS 2011, ACC 2009)

In Arizona, the Arizona Public Service Company administers a self-direct program that requires that all eligible projects meet existing cost-effectiveness standards applicable to CRM programs. Customers may aggregate multiple facilities together to meet the required minimum of 40 million kWh per year. Customers have access to 85% of their CRM fees, including the DSM cost-recovery amounts embedded in rates. Customers may fund up to 100% of project costs. After contributing CRM fees for one year, customers are given two years to file an energy efficiency project application. They may use all the aggregated CRM fees from that year — minus 15% that is retained for administrative costs, low-income programs and measurement and verification.

If a large enough project is developed and the existing self-direct pool of money from the single year does not cover 100% of project cost, customers may continue to self-direct their CRM fees until the project's cost is covered, for a period of up to ten years. Measurement and verification of project savings is conducted by APS staff in a fashion identical to what is conducted for CRM projects. If customers choose not to continue to self-direct for the following year, they are defaulted back into APS's standard CRM programs. If funds are not used by the self-directing customer, the funds are returned to the overall CRM funding pool. The program has been used by one customer.

Colorado and New Mexico
(Romero 2011, Xcel Energy 2011)

In many respects, Xcel Energy runs its self-direct program like any other industrial offering. The same staff offer custom, prescriptive and self-direct programs to industrial and large commercial customers with average demand greater than 2MW and annual consumption greater than 10 GWh. Companies can aggregate to meet the minimum thresholds and in Colorado, self-direct customers are generally already large enough to be served by one of Xcel's 15 large account managers. Several hundred customers are large enough to qualify for the self-direct program, but less than .5% have chosen to actually self-direct. Ten self-direct projects were completed in 2010.

Self-direct customers continue to pay their assigned CRM fee, and self-direct projects are reimbursed through a rebate. Customers may earn rebates of up to 50% of the incremental project costs, either $525kW or 10 cents per kWh. If customers choose to self-direct, they may not take advantage of Xcel Energy's other incentive and rebate programs. The self-direct rebates are richer than those offered through other incentive programs, in exchange for the in-house engineering analysis required of a self-direct customer.

Xcel Energy holds its self-direct customers to the same cost-effectiveness tests as any of its other efficiency customers. While self-direct customers provide their own engineering analysis, they must meet the same total resource cost tests as all the other industrial and commercial offerings. Customers can get pre-approval for self-direct projects, and have two years to complete the project and earn their rebate. Xcel is responsible for reviewing project implementation and monitoring plans and project total resource cost analyses. It tasks its most senior engineer with review of all major technical details, and works directly with the self-directing customer to come to an agreement on what data will be required of the project.

Results and Discussion
Xcel Energy did not have energy savings goals for its self-direct program in 2009, but in 2010 it exceeded its goals by 200%. Due to the close proximity of Xcel Energy engineers to self-direct customers, Xcel Energy is "just as confident" in the savings reported by self-direct customers as in savings acquired through its other efficiency programs. It views its self-direct program as equally responsible for producing efficiency that maximizes ratepayer funds and believes the self-direct program is a "good steward" of ratepayer funds.

To further ensure ratepayer funds are used in a manner that maximizes system efficiency, Xcel Energy does not offer credit through its self-direct program for previously made efficiency investments. Xcel Energy believes that their self-direct program can only claim savings that they have "influenced," and expects their regulators will hold self-direct program savings to the same scrutiny for free ridership as they do Xcel Energy's other efficiency programs. Attention to rigorous evaluation and cost-effectiveness standards within their self-direct program stood out among most other self-direct programs.

Xcel Energy reports that they are receiving an increasing number of applications to the Colorado self-direct program. The New Mexico self-direct program only began this year and no one has taken advantage of it thus far.

Idaho
(Anderson 2011, Pengilly 2011)

Idaho Power offers its largest customers an option to self-direct the 4.75% energy efficiency rider that appears on all customer bills. Only a small number of customers take advantage of this program, which forecasts out a company's efficiency rider contributions over the course of three years and makes 100% of those funds available to fund up to 100% of project costs. If a company has not used its dedicated self-directed funds after three years, the funds are released to the utility's general fund for energy efficiency.

Self-direct projects are subject to the same criteria as projects in other efficiency programs. Either Idaho Power's own internal engineers or a company's selected third party engineers will review the project. Idaho Power checks to ensure the project has been physically completed prior to releasing payment. In some cases this means engaging in follow-up metering to ensure the claimed savings are accurate.

Results and Discussion
The very small number of self-directing customers represents only a small portion of the utility's load. It is not a heavily used program and is not relied upon for significant industrial savings.

Kentucky
(Storck 2009, KRS 2011, Haemmerle 2011)

Duke's opt-out program in Kentucky is applicable only to electric customers that take transmission service on Rate TT. Duke describes these customers as those with "energy intensive processes" and thus eligible, under the existing statutory language, to opt out of paying for energy efficiency programming. The Kentucky Revised Statutes state that the Kentucky Public Service Commission "shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs" and that customers with "energy intensive processes" who choose to make cost-effective efficiency investments instead of participating in the existing demand-side management programs "shall not be assigned the cost" of those programs.

Customers that opt out of paying the energy efficiency rider must indicate that they either have or will in the future make cost-effective energy efficiency investments in their facilities. Duke does not measure and verify these savings, and customers that opt out may not take advantage of other Duke energy efficiency programming.

Results and Discussion
Currently thirteen customers take TT service and are thus eligible to opt out of the energy efficiency programs, and all of them opt out.

Maine
(Efficiency Maine 2010, Voorhees 2011, Burnes 2011)

Though large industrial customers that take transmission and sub-transmission service do not pay into Maine's CRM programming, federal stimulus funds and collected money from the Regional Greenhouse Gas Initiative have allowed Efficiency Maine to offer energy efficiency programming to the state's largest industrial customers. However, the customers still do not pay into the CRM. The Efficiency Maine incentives and custom grant programs are now used by large industrial customers, and if the additional non-CRM funding is exhausted, the customers will no longer be able to use the efficiency programs.

Since being allowed to use Efficiency Maine programs, industrial customers have used them to do everything from making routine repairs to funding major upgrades.

Massachusetts
(Mosenthal 2011)

Large electric customers in Massachusetts can access a self-direct program called the Accelerated Application Process. Customers still pay their CRM fees, but then have access to 85% of those fees over the course of two years to fund energy efficiency investments. The remaining 15% is retained to fund the administration of the program. Customers develop the projects on their own, and must adhere to some measurement and verification processes and protocols.

Large gas customers do not pay any CRM fees, but are currently pursuing a self-direct-styled program.

Results and Discussion
The electric self-direct program was previously used by some larger industrials and area educational institutions, but interest in the program has waned since many of the participants determined that they could receive greater benefits from remaining in the traditional CRM-funded programming.

Michigan
(Walker 2011, Mich. Comp. Laws 2011, MPSC 2010, SB 213)

Michigan's self-direct option, which was codified in 2008 in conjunction with the state's EERS, is unique among all self-direct programs. Michigan's self-direct program requires that large consumers develop and implement their own energy efficiency savings plans consistent with the energy savings goals required of electric utilities as part of the state's EERS. All but the absolute largest self-direct customers must secure the assistance of an "energy optimization service company" to help assess current energy use and develop the energy savings plan.

Customers with annual demands of 1MW or an aggregated demand among multiple facilities of 5MW may participate in the self-direct program. Over the next few years these peak demand requirements will be further reduced, allowing a greater number of customers to participate in the self-direct program.

Self-direct customers do not pay fully into the CRM fees in exchange for the execution of their energy savings plan, but they do pay a portion of their assigned fees to cover administration of the self-direct program. Customers submit their energy savings plans for review by their utility, and the utility approves the plan and reports aggregated program data to the Public Service Commission.

Results and Discussion
During the first two years of the self-direct option in Michigan, 77 companies signed up statewide. This year the number has dropped to 47, in part because some of the original self-directing companies signed up for self-direct prior to fully understanding the energy efficiency programming that would be offered by their local utility. Companies have also become more reluctant to take on the risk associated with not meeting savings targets within the self-direct program.

The requirement that individual companies meet the same energy savings targets as large utilities has proven difficult to administer in some cases. One of the biggest hurdles is that self-direct customers presently cannot carry over savings from year to year. However, draft rules in place will extend the self-direct window up to five years, allowing customers to make big investments in some years and enjoy a guaranteed self-direct status in future years as they enjoy the savings from the large investment.

For the most part, the self-direct program has yielded reliable and expected savings, and customers have met their savings goals. However, it is unclear whether or not the claimed saving are truly occurring in each self-directing facility. Utilities have proven reluctant to aggressively "police" their customers, but no other entity is responsible for ensuring that claimed savings are occurring.

An additional challenge for the self-direct programs in Michigan is that no companies have applied to become qualified and certified as energy optimization service companies. State regulators are addressing this issue currently.

Minnesota
(Haase 2011, Minnesota Session Laws 2011)

Minnesota offers a self-direct option to its largest customers, allowing full exemption from their assigned CRM fees. Customers with 20MW average electric demand or 500MCF of gas consumption may participate. In addition to meeting these threshold requirements, customers must show that they are making "reasonable" efforts to identify or implement energy efficiency, and that they are subject to competitive pressures that make it helpful for them to be exempted from the CRM fees.

Participating customers must submit new reports every five years to maintain their exempt status. These reports identify the type of equipment purchased in the last five years, the facility's consumption and energy productivity trends. The utility is only minimally involved in the self-direct program administration; the state's Department of Commerce functions as the manager of self-direct accounts and the arbiter of whether a company qualifies for self-direct and is satisfying its obligations.

Results and Discussion
12 customers are taking advantage of the self-direct provision and the program administers have a basic understanding of the efficiency investments that are being made by those that are exempt from paying the CRM. An effort to get additional assessment of claimed savings by an external third party has recently been made by the Department of Commerce, which acknowledges that the energy savings information collected from its self-direct participants is minimal, and substantially less than what would have been collected had they remained in a CRM-funded program.

Every five years companies are reassessed for their eligibility to participate in the self-direct program. To date no companies have been removed from the program for failing to satisfy eligibility requirements.

Missouri
(MOGA 2009, Wankum 2011, MCSR 2009, Sivils 2011, Laurent 2011)

In Missouri, Senate Bill 376, adopted in 2009, established the Missouri Energy Efficiency Investment Act, which permitted utilities to develop and administer energy efficiency programs that achieve "all cost-effective demand-side savings." Embedded within this bill was an opt-out provision that allows customers a full exemption of all CRM fees, called the Demand Side Investment Mechanism. There are three ways to qualify for opt out from utility demand-side and energy efficiency programs: customers may indicate they have a demand of at least 5,000kW in the previous twelve months; they may show that they are an interstate pipeline pumping station, regardless of size; or they may show that they have a "comprehensive" demand or energy efficiency program in place that is saving an amount at least equal to "utility-provided programs," and that they have a demand of at least 2,500kW in the previous twelve months.

A rule in the Missouri Code of State Regulations gives more clarity to how the opt-out program shall be administered. In particular, the rule requires that companies that wish to qualify for opt-out under the 2,500kW/comprehensive DSM plan category must submit their plan to the Missouri Public Service Commission for review. The Commission is to provide the customer with a decision within 30 days. Customers wishing to opt out under either of the other two categories simply provide notification to their utility that they wish to opt out. There is no follow-up or ongoing monitoring of the efficiency investments made by any opt-out customers due to a dispute among interested parties regarding statutory authority.

Results and Discussion
There was a time period of under two years in which the statutory authority for the opt-out provision, SB 376, allowed opt-out, but the rules requiring that the Public Service Commission be notified when companies ask to opt out were not in place. During that time, some customers did choose to opt out, but there was no requirement that these notifications be sent to the Public Service Commission Staff on an ongoing basis. Kansas City Power and Light has two self-direct customers, Ameren Missouri has nine.

Since the rules became effective in May 2011, four customers have chosen to opt out, and none have asked to opt out under the 2,500kW provision. The opt-out mechanism is "still evolving," as the Public Service Commission has not yet been asked to review a company's energy efficiency and demand-side plan.

Montana
(Young 2009, Young 2011, Edwards 2011, NorthWestern Energy 2010, Trasky 2011)

NorthWestern Energy's Large Customer self-directed program operates as a sort of escrow account, allowing customers to direct their CRM funds into an account specifically earmarked for their future use. Customers with demand larger than 1MW are allowed to self-direct their CRM funds. Once a self-direct project is complete, the self-directing company submits the appropriate paperwork and NorthWestern Energy issues payment to the customer on a quarterly basis in order to cover project costs up to their annual CRM contribution, which itself is capped at a $500,000 annual maximum contribution. Companies have two years to use their funds and unused funds are returned to the larger pool of CRM revenues which NorthWestern directs to qualifying low-income energy efficiency projects in following years.

NorthWestern administers the funds but no pre-qualification or measurement and verification is provided by, nor required of, the utility. Self-direct customers file annual reports with the Montana Department of Revenue. The department makes these reports available for public consumption, and a public "challenge" process is provided. Additional scrutiny or review of self-direct projects is not required or performed absent a public challenge.

Results and Discussion
The NorthWestern Energy self-directed program appears to be quite popular among eligible companies. In 2010, of 56 customers on the self-direct program, 50 self-directed all of their eligible funds toward specific projects. Since 2009, all but one of the eligible companies chose to self-direct their CRM funds. Only one company has annual electric consumption the yields the full maximum $500,000 annual CRM contribution. NorthWestern Energy believes that the majority of the participating customers are incentivized through the self-direct program to make efficiency investments that they would not have otherwise made. Since the companies must pay the CRM anyway, they understand that they have to use the funds or lose them, and that motivates company decision makers to use the funds on new efficiency projects or other qualifying activities that deliver value to the company. Additionally, few of these customers would qualify for Northwestern's CRM-funded efficiency programming as those programs are limited to supply customers and most of the self-direct customers buy energy supply in the wholesale market rather than from NorthWestern. At

the end of 2010, $23,028 of unused Large Customer funds were directed to low-income programs. Large Customer companies also self-directed an additional $156,734 to low-income projects.

An unanswered question about the NorthWestern program is to what extent the energy savings claimed by self-direct customers actually occur. In 2010 the Large Customer group contributed $2,740,668 in CRM charges — or about one third of all CRM funds — and self-directed nearly all of those monies. Montana statute and administrative rules do not require evaluation of self-directed activities. The state's Department of Revenue, which is tasked with acting as a "watchdog" of the program, is also not tasked with conducting verification of these efficiency investments. Since the reports issued by self-directing customers are generally "bare bones" ones — with information about the type and amount of expenditure — it is impossible to know whether the self-direct program is acquiring cost-effective energy savings. NorthWestern does not report self-direct energy savings as part of its energy efficiency portfolio.

Large customers of other electric utilities in Montana are also allowed to self-direct CRM funds according to Montana law.

New Jersey

(Ambrosio 2011, NJCEP 2010, TRC 2011)

In New Jersey a pilot self-direct program run by TRC for the CRM-funded New Jersey Clean Energy Program targets large customers in multiple sectors. The budget for the pilot in 2011 is $20 million. To qualify for the program, customers must have contributed at least $300,000 in CRM funds during the 2010 calendar year. Customers may aggregate multiple buildings or sites together to meet the threshold. Individual facilities must have an annual billed peak demand of 400kW or greater as well. Additionally, all applicants will be ranked by the value of CRM contributions in 2010, and approximately the 25 top contributors will be allowed to participate in the program pilot.

The pilot program will reserve a specific amount of CRM contributions for use as a grant towards future energy efficiency investments. This reserved amount may be any of the following: an amount based on the customer's previous CRM contributions, an incentive per saved kWh or Therm, a percentage of the total project cost, or $1 million. The minimum grant per participant is $200,000.

Participants in the program may develop a draft self-direct investment plan, called a Draft Energy Efficiency Plan (DEEP), outlining, among other things, the proposed projects and its estimated savings and costs in dollars and energy, the facility's baseline energy use and a description of additional financing the project will receive. Upon approval of the DEEP, program funds are reserved for the customer.

Funds are committed to the customer only once a customer completes a Final Energy Efficiency Plan (FEEP), which must be certified by a professional engineer and incorporate measurement and verification plans. Once the DEEP is approved, customers have 120 days to submit the FEEP.

Once the FEEP has been approved, customers have one year to install the measure(s) and satisfy the remaining program requirements. Incentives are paid once the customer submits all of the invoices for the installed measure(s), the complete measurement and verification report described in the FEEP, certified by a professional engineer, a certificate of compliance with the prevailing wage, and any descriptions of differences between the project as completed and what was described in the FEEP. If necessary, customers may be granted a six-month extension to install the measure(s).

All projects must demonstrate a simple payback of eight years, and no credit is given for previously installed measures. Combined heat and power projects are eligible for this program.

Customers electing to participate in the self-direct program may not take advantage of other New Jersey Clean Energy Program programs. Self-direct customers may take advantage of other incentive programs offered by other state and local entities, but the total incentives may not exceed 100% of the project costs.

Evaluation, measurement and verification will be similar to that of other projects funded by the New Jersey Clean Energy Program. While measurement and verification may be done by the customer's external engineers, TRC will have a dedicated program manager to monitor and reviews all FEEPs and measurement and verification reports. Customers must comply with all external evaluation activities as requested. Pre- and post-inspections will be conducted as needed.

Results and Discussion

New Jersey's self-direct program is a pilot program, launched in August 2011. The program is anticipated to support approximately 25 projects. The program's savings goals for 2011 are 172,538DTH and 36,046MWh.

The program was designed in response to the desires and concerns expressed by industrial customers, and will likely include customers in the institutional and commercial sector as well. It has been designed to respond to concerns by industrial customers that traditional CRM-funded programs have not lined up with their internal budgeting processes. The pilot program will be evaluated for its ability to work with customer's internal budgeting timelines and investment decision-making activities. The hope by program developers is that the program will encourage greater participation by the state's largest energy users by simplifying the process for receiving incentives for investing in energy efficiency.

Ohio

(Moser 2011, AEP 2011a, Cross 2011, Duke Energy 2011a, AEP 2011b)

Ohio offers different self-direct and opt-out provisions depending upon which utility a customer takes their service from. In the state of Ohio, customers pay an energy efficiency rider on their bill, which serves as a CRM and funds energy efficiency programming in multiple sectors. With the development of new energy efficiency goals and funding mechanisms, Ohio also developed a set threshold — 700,000KWh — at which customers of the state's regulated utilities must be offered the option of opting out of paying into CRM programs.

At AEP, both a self-direct and an opt-out program are offered. The self-direct program offers customers an incentive for previously implemented energy efficiency measures. The one-time incentive is 75% of whatever the calculated incentive under AEP's prescriptive or custom incentive program would be. Projects must have been implemented after January 1, 2008. The AEP program is a consistent "look back" program, and pays customers for projects they have already implemented. New program years will have new "look back" periods, but will move forward as the program year moves forward. Project submitted for incentives must produce 100% of the stated energy savings and/or a reduction in peak demand over a five year time period.

The maximum incentive limit at AEP for self-direct projects is $225,000, and there are limits for individual business entities depending upon which tariff an entity is covered by. Projects must pass a utility cost test and are considered for their payback period. AEP prefers to see self-direct projects fall within a payback period of one to seven years. Customers taking the one-time incentive are still eligible to participate in the utility's other energy efficiency programs because they are still paying the CRM fee.

AEP also offers customers a full exemption — or opt-out — from the CRM fees for a defined number of months. Duke Energy and Dayton Power and Light also offer customers an opt-out provision provided they meet the 700,000KWh threshold. Duke Energy requires that customers submit an application stating that they have implemented savings projects or will implement projects that will meet energy savings and/or peak reduction benchmarks that scale up slightly over future years. FirstEnergy also allows customers a full exemption from the CRM fees if they report they have or plan to meet certain energy savings and demand savings benchmarks.

Results and Discussion

At AEP, providing customers with incentives for energy efficiency investments they have already made appears to qualify the self-direct program as a free rider incentive program, rather than a more typical self-direct program. Between 2009 and 2011, 577 projects received incentives from the self-direct program, totaling 180,273,135 saved kWh. The total incentives issued during that period were $10,164,093, which exceeded the $9,000,000 goal the program set for that same period.

The AEP program is described as a "seed money" program, designed to put money into the market to fund additional energy efficiency. The idea behind the AEP program is that the incentives offered to companies that participate in the self-direct program will be used to fund new investments in energy efficiency or renewable energy going forward. However, there are no requirements that the funds be used as such. It is therefore not a resource acquisition program, and AEP does not set energy savings goals for the program. A recent survey by self-direct customers found that 62% of them said they have used or will use some of their incentive funds for new energy efficiency measures.

The AEP program is designed to always have a rolling three-year look back period, with the understanding the some customers will always be new to the program offerings and will have recently made energy efficiency investments. The expectation is that as more customers make their cost-effective energy efficiency investments and are brought into the full suite of AEP energy efficiency programs, there will be less and less demand for the self-direct incentive program and more demand for incentives that encourage new projects.

AEP's opt-out provision, which is a full exemption from the energy efficiency rider, was taken by seven customers during the first year it was offered, but by zero customers since. AEP strongly discourages people from taking the opt-out provision. FirstEnergy's opt-out program has been used by a handful of large customers, and Duke Energy and Dayton Power and Light have seen their opt-out provisions used by zero and one customer, respectively.

Oregon — Eugene Water and Electric Board
(Welch and Fraser 2011, Welch 2010)

The Eugene Water and Electric Board's (EWEB) unique self-direct program makes the important distinction between financial parity and energy savings parity. Most self-direct programs aim to have the self-directors spend on efficiency measures a dollar amount equal to or similar to what they would have spent on systems benefits charges as typical full rate-paying customers.

In contrast, EWEB eschews any discussion of financial parity and instead develops customized energy savings goals with each self-directing customer. These goals are contractual obligations to achieve a certain kWh of savings annually and each project is validated by a measurement and verification (M&V) plan. The goals are based largely on the percentage of load each customer represents and the average conservation savings achieved by the industrial sector in prior years. If customers fail to meet these goals, they must repay a proportional amount of the rate credit back. While such customized efforts might be difficult for larger utilities, EWEB's two self-direct customers make such an approach manageable.

EWEB's self-director customers continue to pay the regular conservation rate (CRM) of 5%, but receive a rate credit on each monthly bill equal to conservation fee minus utility M&V costs. In this way, companies are directly encouraged to implement efficiency projects because otherwise they'll simply be "losing" their 5%. Such an approach helps facility managers sell efficiency projects to a company's decision-makers, because not meeting the goal will require self-direct customers to pay EWEB a penalty proportional to the unmet goal. When self-direct customers meet their goal, they keep most of the conservation fee and the project benefits. Conversely, an unmet goal results in a payment to EWEB and no benefits from the conservation project. This leverage of a penalty payment with no project benefits has been used to obtain internal corporate funding for projects. The self-direct customers use their own money to pay for the efficiency projects. They may also bank energy savings forward, into future years if applicable.

This strategy could also be used for new construction by calculating the present value of the future rate credit, and incorporating that value into the incremental conservation construction costs. For example, a data center could have an incentive to spend more money during its initial construction phase and increase a building's initial efficiency, since it would receive a future benefit by meeting a savings goal and enjoying a rate credit.

Results and Discussion

The pulp and paper mill was contributing about $800,000 annually in conservation charges, and the semiconductor manufacturer was contributing about $400,000 annually. Prior to their involvement in the self-direct program, the mill was implementing efficiency projects and taking advantage of rough parity between its contributions and the EWEB incentives and services it enjoyed. The semiconductor facility was engaged in very minimal efficiency improvements and was thus receiving only $30,000 or less in incentives and EWEB labor annually.

The paper mill's annual conservation goal was 3.25 million kWh, which it met on average during the self-directing period. This was, on average, more savings than the mill had achieved prior to becoming a self-director. Between 1991 and 2004, the mill had achieved an average annual savings of 2.9 million kWh. The semiconductor facility's annual goal was 1.75 million kWh, which it also met on average during the self-directing period.

In general, EWEB views its rate credit self-direct program as a success, but wonders how well the model will work once customers begin to "run up the resource cost curve." EWEB believes that it achieved the conservation at the two self-directing customers at a cost equal to or lower than the cost of achieving the same savings through its traditional incentive programs. The program views the results at the semiconductor facility as very successful, since the facility had achieved nearly zero conservation in the years prior to the implementation of the rate credit program.

EWEB does not believe its self-direct program has had a negative impact on the administration of its traditional CRM programming. While the traditional CRM programs had smaller budgets once the two self-directors began enjoying their rate credits, the CRM programs also paid out less money in incentives, yielding a neutral net effect on the CRM program. EWEB notes that they may face new challenges in developing rational and mutually accepted energy savings goals for self-directing customers. For now, EWEB intends to maintain this approach to self-direction and use it as a mechanism to strengthen its relationship with its self-directing customers.

Oregon — Oregon Department of Energy

(Crossman 2011, Stipe 2011)

In Oregon, the self-direct option for the largest customers (those with more than 1aMW electricity usage annually) can opt to self-direct their CRM charges. Such large customers are automatically added to the self-direct program and must prove that they are making efficiency investments in order to continue to enjoy a rate credit on their bills. Customers can earn credits up to 68% of their CRM charges on their utility bills to offset efficiency project costs. Once such projects have been fully credited customers must continue to make new investments or they will begin to be billed normal CRM charges.

Administration of the program is "bare bones," and customers generally self-report their efficiency measures into a computer system over the Internet. There is no pre- or post-monitoring of energy efficiency measures. The program does not monitor data in a manner that allows it to know the cost of saved energy within the self-direct program.

An option is also offered to customers who would argue that they have done all cost-effective efficiency. These customers can be eligible for a credit of 54% of their CRM fees.

Results and Discussion

While the Energy Trust of Oregon administers the largest industrial energy efficiency program in the state (funded with CRM moneys) the Oregon self-direct program is entirely administered by the Oregon Department of Energy. Because of this, coordination and information sharing between the traditional industrial and large commercial CRM-funded efficiency programs and the self-direct program suffers. The Energy Trust and other efficiency programs do not always know which facilities are self-directing, or whether they will need to deploy new efficiency projects in the near future in order to maintain their self-direct benefits.

Currently 66 companies are eligible to self-direct, though the majority of them are earning no self-direct credits, so they are effectively paying the normal CRM charges. Of the five largest users that have self-directed in recent years, three have evidently decided that they were better served by paying the CRM and are now taking advantage of the full suite of Energy Trust of Oregon services and incentives. There have been no new self-directing customers in four years, though large institutional customers are now eligible to self-direct if they satisfy the 1aMW threshold. Only one customer has made a "realistic" inquiry into the 54% credit provision.

In the nine years the self-direct program has operated, the administrator has not seen any incidences of "mistreatment" in the program, though rigorous measurement and evaluation of claimed savings is not conducted.

Texas
(Ferland 2011, PUCT 2010, Zarnikau 2011)

In Texas, for-profit customers that take electric service at the transmission level are not allowed to participate in utilities' energy efficiency programming, and therefore do not pay for it. Instead, industrial customers develop their own energy efficiency plans if desired, and work with third party providers to implement and finance energy efficiency investments. There is no measurement or monitoring of the investments these large customers do or do not make.

Results and Discussion
Some industrial customers that are not allowed to participate in Texas' energy efficiency programs would like to be able to have the option of participating. Certain large commercial customers have argued in recent regulatory filings that they should be granted an opt-out provision, but no such provision has been developed to date. In response to requests to create an opt-out provision for commercial customers, the Public Utility Commission of Texas noted that such a provision would be difficult for utilities to administer, and that "there is a risk that a customer might opt out after obtaining the benefits [of the energy efficiency programs], so that it would not share the costs in the same way that other customers do."

Utah, Wyoming
(Helmers 2011)

Rocky Mountain Power (RMP) views its self-direct option as one of a suite of programs targeted at industrial and large commercial entities. RMP's self-direct program is a project-based rate credit program that offers up to an 80% credit of eligible project costs back to customers as a rate credit against the 3.7% CRM charge all customers pay. Customers earn a credit up to 100% of their CRM charge, but do pay a flat $500/project administrative fee for each self-directed project. RMP lets customers choose to engage its self-direct and other, more traditional CRM programs, simultaneously provided the different programs are used to deploy different projects.

RMP believes that over 25% of its eligible customers are participating in the self-direct program, and interest has increased as the CRM charge has risen. Interestingly, RMP allows customers to aggregate multiple meters to meet the program's minimum use requirements, and customers can also spread the rate credit among multiple meters if desired. One example of this approach can be found among a large chain of convenience stores, which has aggregated its load together to qualify.

Eligible self-direct projects must have a payback of 1-5 years and must meet other cost-effectiveness tests as required.

Results and Discussion
RMP finds its self-direct program to be highly cost-effective, with Total Resource Cost test results very similar for self-direct projects as other CRM projects. It believes that its rate credit approach encourages greater efficiency among its participants, because as a self-direct customer begins to near the end of a current credit period, they seek out new efficiency projects so as to avoid paying the full CRM. RMP finds customer satisfaction to be very high in its self-direct program and doesn't believe the administration of the self-direct program has any negative effects on the administration of its other CRM programs.

RMP also offers a self-direct approach that is a true opt-out. If a customer can prove, using an external auditor, that they have achieved all cost-effective efficiency, they may receive a 50% credit of all CRM charges for two years. Tellingly, not a single customer has taken this credit since its offering.

Vermont
(Goetze 2011, VDPS 2011, VPSB 2011)

In 2009 the Vermont Public Service Board, Vermont's utility regulatory body, passed a series of orders that established an option for large energy consumers to self-administer their energy efficiency programs. The first program allows consumers who pay an average annual energy efficiency charge (EEC) of at least $5,000 to apply to the Board to self-administer their energy efficiency programs through the use of an Energy Savings Account (ESA). Customers may be eligible to participate in an ESA if they contributed at least $5,000 in EEC fees in the prior 12 months. Customers may aggregate together multiple meters belonging to one single business entity. Customers apply to join the ESA program, and their application must be approved by the Vermont Public Service Board and the Vermont Department of Public Service.

Consumers participating in the program continue to pay their EEC fee, but may transfer up to 70% of their EEC to the ESA to fund efficiency projects at their facilities. Consumers are required to use the funds within 24 months, after which, unless a consumer receives a waiver from the Department of Public Service, the unused funds are forfeited by the consumer. Every three years, ESA customers must prove they continue to qualify to participate in the ESA program.

All projects must past cost-effectiveness tests equivalent to those used to approve energy efficiency investments made by other entities using the state's EEC fees. Vermont's energy efficiency utility is responsible for substantial review of the projects and evaluation activities. Pre- and post-installation reviews are required.

Vermont's second program established a three-year pilot self-managed energy efficiency program (SMEEP) that allows eligible consumers to be *exempt* from the EEC provided that the consumer commits to spending an annual average of no less than $3 million over a three-year period on energy efficiency investments. Additionally, consumers must demonstrate that they have a comprehensive energy management program with annual objectives. Customers can be eligible for the SMEEP if they are transmission customers, or customers in the industrial class, and paid over $1.5 million in EEC charges in 2008. Customers may also satisfy the requirements of SMEEP eligibility by becoming certified under the ISO 14001 standard. Customers must pay a $50,000 fee to participate in the SMEEP.

Results and Discussion
Currently one company is using the ESA program, and one company is using the SMEEP program. IBM is the company using SMEEP, which was largely designed to accommodate the computer giant.

Virginia
(Dominion 2010, HB 2506 2009)
Customers of Dominion Power in Virginia may qualify for the opt-out program available there by having average demands between 500kW and 10MW. Customers over 10MW do not participate in the state's energy efficiency programming by law.

Once customers have elected to opt out of the energy efficiency programming, they may not take advantage of existing energy efficiency programming nor be charged for the programming. Customers must show that they either have already made energy efficiency investments or plan to in the future. Customers must submit measurement and verification reports yearly in support of their choice of non-participation in the CRM-funded programs. There are no cost-effectiveness tests required of projects.

Washington
(Landers and Montgomery 2010, Landers 2011)

Puget Sound Energy's self-direct program is unique in the country in that it is a long-term program (spanning five years) that combines a dedicated incentive funding structure based on customer contributions with a competitive bidding process for unclaimed funds. Companies that take service from PSE under several rate schedules are eligible for the self-direct program, but most become eligible due to their taking of 3-phase service at greater than 50,000 volts.

Self-direct customers continue to pay their CRM, but PSE tracks individual customer contributions for their specific use. Customers have access to 82.5% of their CRM fees. PSE retains 7.5% for administration of the program, and 10% to fund market transformation activities of the Northwest Energy Efficiency Alliance. While participants in other PSE commercial and industrial programs are limited to maximum incentives of 70% of measure cost, self-direct customers may fund up to 100% of measure cost.

After an initial non-competitive phase (e.g. 24 months) of a program cycle, all unused funds are pooled together into a public pool of funds, and PSE issues a competitive RFP for program-eligible customers to compete for remaining funds. The projects funded as a result of this competitive bid process are generally more cost-effective than those funded during the first two years, as customers compete against each other to make a case for their projects.

All projects must meet PSE's avoided cost requirements. Though the customer submits their own proposal and measurement and verification plan, PSE reviews the proposal and plan. Upon approval, PSE enters into a funding allocation agreement with the company and conducts a post-installation inspection after the measure is implemented. It is very confident that claimed savings are occurring.

Results and Discussion
Each year, more customers qualify for the self-direct program, and for the 2010-2013 program period, 54 customers are currently eligible. PSE has already awarded over $12 million in project incentives for this group of customers, and projects 42,000 MWh/year in annual savings for the group.

PSE reports that right before the competitive bid process, projects "go like gangbusters" because customers desire to use their funds up to avoid losing them to other companies, including competitors.

PSE believes its self-direct program is actually achieving greater savings among participating customers than would have been achieved had they simply used its basic commercial and industrial offerings. Participation rates are also higher in the self-direct program among eligible customer classes than in other programs. This high level of savings and involvement is due to an understanding among firms that their CRM funds are there to lose, and that if they don't use the money to make energy efficiency investments, someone else will.

PSE relies on trade allies such as energy service companies (ESCOs) to help self-direct customers identify and implement energy efficiency projects. As the program matures, it is seeing a shift toward longer payback projects, in part because more commercial customers have begun to participate in the self-direct program. Commercial customers can sometimes tolerate longer payback periods and are interested in some investments that are less cost-effective than those typically found in the industrial sector.

Wisconsin
(WSPC 2009, Schutt 2011, Schepp 2011)

Wisconsin offers its largest energy customers the opportunity to self-direct their CRM funds. Customers must develop a self-direct plan and submit it to the PSC for approval. Self-direct program plans must meet cost-effectiveness standards and include detailed M&V plans. Approved customers implement their plans, adhere to the stated M&V design and submit quarterly reports to the PSC. The amount available for self-directed efficiency measures varies depending on the utility, and the PSC relies on a formula to determine the percentage of CRM that a customer is entitled to use for the program. Upon successful implementation of a self-direct program, and verification of measured savings, participants receive reimbursement checks drawn against their dedicated escrow accounts held by their respective utility. The PSC also may ask that any unused funds be returned to fund additional efficiency programs, such as Focus on Energy.

Results and Discussion
To date, no companies have chosen to self-direct, though the self-direct program was developed in response to requests by large energy consumers. In most cases, large customers have reported that the self-direct program did not offer enough benefits over existing CRM programs, such as Focus on Energy, to warrant a change to self-direct status. Large customers also reported that they found the administrative burden of developing their own implementation and M&V plan too burdensome.

APPENDIX II: MODEL LANGUAGE

Each state or service territory that decides to implement a self-direct option will likely find that their specific geographic needs can be best met by a unique self-direct program structure. ACEEE does not recommend one particular self-direct program approach, but has identified some useful program language to help achieve certain desired aspects within a self-direct program.

The following are selected excerpts from relevant regulatory or legislative language establishing and defining self-direct programs:

Defining eligibility
"Eligibility requirements for the exemption are as follows:

- In 2009 or 2010, the customer must have had an annual peak demand in the preceding year of at least 2 megawatts at each site to be covered by the self-directed plan or 10 megawatts in the aggregate at all sites to be covered by the plan." (Michigan)

"Customers are eligible for the [self-direct program] option if they have made [CRM] payments…of at least $5,000 in the 12 months preceding the customer's request to participate.

- A single business (a single legal entity) with more than one electric account may combine the [CRM] amounts paid on multiple accounts to determine this eligibility.
- Alternatively, a business may be deemed eligible if the preceding three-year average [CRM] amount paid proceeding the customer's application is equal to or greater than $5,000.
- A customer in a new building (with an active electric account) may be deemed eligible to participate if by mutual agreement of the [regulatory body] and the [utility] the projected [CRM] payment will be equal to or greater than $5,000." (Vermont)

Defining eligible expenses:
"For market-driven projects, "Qualified Expenses" are defined as one hundred percent (100%) of the incremental costs associated with identifying, investigating, analyzing, designing, implementing, and/or installing societally cost-effective electric efficiency projects at facilities owned, operated, or controlled by the customer and where the [self-direct program] is in effect. These costs may include the customer's internal design and engineering labor, outside design, engineering and installation labor and equipment costs. However, costs other than actual incremental material and installation labor costs shall only be treated as "Qualified Expenses" for amounts up to 25% of the total project costs.

For market-driven projects, incremental costs are defined as the difference between the actual cost of the equipment, installation labor, engineering, design, and commissioning and the cost of the equipment, installation labor, engineering, design, and commissioning that would meet the current design and construction standard practice (the "baseline cost").

2. For "retrofit" projects, "Qualified Expenses" are defined as costs associated with identifying, investigating, analyzing, designing, implementing, and/or installing societally cost-effective electric efficiency retrofit projects at facilities owned, operated or controlled by the customer and where the [self-direct program] is in effect. These costs may include the customer's internal design and engineering labor, outside design, engineering and installation labor, and equipment costs. However, costs other than actual incremental material and installation labor costs shall only be treated as "Qualified Expenses" for amounts up to 25% of the total project costs. Furthermore, for retrofit projects, "Qualified Expenses" shall be capped at an amount equal to the contribution to total project costs that would result in an estimated 18-month simple payback on the customer's project investment. Payback shall be calculated based on anticipated energy and non-energy benefits, including, but not limited to, reductions in operating and maintenance costs, fossil fuel savings, electricity savings, environmental compliance cost savings, labor savings, and savings from avoidance of future equipment replacements." (Vermont)

Encouraging and claiming energy savings:
In Michigan, all regulated utilities are required to develop their own energy optimization plans, which must meet preset energy savings goals. Self-directing customers must also develop such a plan. Regarding self-directed customers:

"All of the following apply to a self-directed energy optimization plan:

- The self-directed plan shall be a multiyear plan for an ongoing energy optimization program.
- The self-directed plan shall provide for aggregate energy savings that for each year meet or exceed the energy optimization performance standards based on the electricity purchases in the previous year for the site or sites covered by the self-directed plan.
- Under the self-directed plan, energy optimization shall be calculated based on annual electricity usage. Annual electricity usage shall be normalized so that none of the following are included in the calculation of the percentage of incremental energy savings:
    - Changes in electricity usage because of changes in business activity levels not attributable to energy optimization.
    - Changes in electricity usage because of the installation, operation, or testing of pollution control equipment.
- The self-directed plan shall specify whether electricity usage will be weather-normalized or based on the average number of megawatt hours of electricity sold by the electric provider annually during the previous 3 years to retail customers in this state. Once the self-directed plan is submitted to the provider, this option shall not be changed.
- The self-directed plan shall outline how the customer intends to achieve the incremental energy savings specified in the self-directed plan.

Projected energy savings from measures implemented under a self-directed plan shall be attributed to the relevant provider's energy optimization programs for the purposes of determining annual incremental energy savings achieved by the provider...as applicable." (Michigan)

Ensuring cost-effective efficiency projects:
"[Self-direct] customers are expected to demonstrate their ability to successfully administer their electrical energy efficiency efforts over time. [Self-direct] customer performance will be measured in the following areas of self-administration:

- Participating [self-direct] customers must complete cost-effective energy efficiency projects
- Participating [self-direct] customers must submit requests for reimbursement of qualified expenses, thereby utilizing available funds within 24 months of being deposited into their [self-direct] account, or risk forfeiture of funds due to insufficient activity.
- Participating [self-direct] customers must achieve an average net present value of electric benefits per dollar of "available funds" used that is equal to or greater than analogous [CRM-funded] initiative for the most recent rolling three year average for completed projects.
- Participating [self-direct] customers must renew its demonstration of compliance with eligibility criteria every three years.
- Participating [self-direct] customers must provide monthly documentation of their [earned credit] and [CRM] payment to the [utility] and [regulatory body]." (Vermont)

"All customers completing projects through the [self-direct] option must achieve an average net present value of electric benefits per dollar of "Available Funds" used that is greater than or equal to that of the analogous [CRM-funded] initiative for the most recent rolling three-year average. Failure to achieve this standard will be cause to discontinue customer's participation in the [self-direct] option. Multiple projects may be aggregated within a three-year participation period in order to meet the net present value threshold. For these purposes, the [applicable utility]'s average net present value of electric benefits per dollar of "Available Funds" used will be determined by the Department." (Vermont)

Ensuring oversight by regulatory commission:
"An electric provider shall provide an annual report to the commission that identifies customers implementing self-directed energy optimization plans and summarizes the results achieved cumulatively under those self-directed plans. The commission may request additional information from the electric provider. If the commission has sufficient reason to believe the information is inaccurate or incomplete, it may request additional information from the customer to ensure accuracy of the report." (Michigan)
"If a customer has submitted a self-directed plan to an electric provider, the customer, the customer's energy optimization service company, if applicable, or the electric provider shall provide a copy of the self-directed plan to the commission upon request." (Michigan)

Addressing privacy concerns:
"A self-directed energy optimization plan shall be incorporated into the relevant electric provider's energy optimization plan. The self-directed plan and information submitted by the customer under subsection (x) are confidential and exempt from disclosure under the freedom of information act, 1976 PA 442, MCL 15.231 to 15.246." (Michigan)

Defining a program's access to information and customer obligations:
"Customers are responsible for developing project proposals, including estimates of electrical savings and projects costs. Selection and use of a third party to develop, build, install or verify the project, will be the Customer's responsibility. Upon acceptance by the Company, the Customer shall complete the project over the mutually determined time frame, to allow for verification of the Measure installation by deadlines established by the RFPs. The Customer agrees to provide the Company access to information necessary to verify energy savings and cost-effectiveness." (Puget Sound Energy)

Using competitive and non-competitive phases:
"Each program cycle is comprised of a multi-year non-competitive phase followed by a competitive phase followed by a period of time that will allow for Customers to complete projects.

The amount available to each eligible Customer in the non-competitive phase is an allocation of the total funding available under this schedule. The allocation is based on the amount of revenues that are estimated to be collected from the Customer under Schedule 120 of this Tariff through xxx date. The individual Customer shall propose the funding of eligible Measures with the allocated funding during the non-competitive phase of each program cycle.

Individual allocations not proposed for use by the Customer during the non-competitive phase will be available to all Customers eligible [for the program]." (Puget Sound Energy)

Cited resources:
Michigan language:
http://www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf

Puget Sound Energy Schedule 258:
http://www.pse.com/aboutpse/Rates/Documents/elec_sch_258.pdf

Vermont guidance:
http://efficiencyvermont.com/stella/filelib/ESA_Comprehensive_Guide_2011.pdf and
http://psb.vermont.gov/sites/psb/files/ESA_Order_attachment.pdf

APPENDIX III: DETAILED SUMMARY STATE CHART

State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
Alabama	None	N/A										
Alaska	None	N/A										
Arizona	Utility-defined SBC and/or rate adjustment	Yes	Parity	Use 85% of annual CRM contributions + DSM charges recovered in base rates over following 2-yr period for 100% eligible project costs	Arizona Public Service Company	40 million kWh annual; can aggregate	APS	APS	Yes	No		
Arkansas	Utility-based EE charges	Pending									Collaborative formed, proposal has been filed. Like-ly will not look to utilities to administer.	
California	Public goods charge, cost recovery on rates	No										
Colorado	DSM rider	Yes	Rebate per kWh	Rebate; 50% project cost; per kW or kWh	Xcel Energy	10GWh annual and 2MW demand	Customer / Xcel	Xcel	Yes	No		A "few" customers have applied.
Connecticut	SBC, .3 cents/ kWh	No									Only allowed if they begin to self-generate	

State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
Delaware	Efficiency utility funded by bonds? Not really PBF? Green energy program.	No										
District of Columbia	Sustain-able Energy Trust Fund	No										
Florida	EE Cost-recovery surcharge	No										
Georgia	None	N/A										
Hawaii	PBF for HECO only	No										
Idaho	4.75% EE tariff rider	Yes	Parity	100% funds, 100% project cost	Idaho Power	Special contracts customers only	Idaho Power, third party	Idaho Power	No	Yes		Avista has one customer; Rocky Mountain Power has a few
Illinois	Cost-recovery tariff	No									Can for gas, cannot for electricity	
Indiana	Energy efficiency surcharge	No									Industrial groups continue to lobby but never allowed	
Iowa	Cost recovery rider	No									Have been inquiries about it in the past ten years, but	

State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
											always opposed by utilities and consumer advocates. Only for customers that transport their own natural gas.	
Kansas	None	N/A										
Kentucky	Tariff rider	Yes	Parity	True opt-out	Duke	All Rate TT (transmission) customers may opt out	Customer	Custo mer	No	No		13 companies eligible, all have opted out
Louisiana	None	N/A										
Maine	SBC	Yes	Parity	May use RGGI funds		Transmission/ sub-transmission customers	Efficiency Maine	Efficien cy Maine		Yes	Trans-mission and sub-trans-mission customers had previously not been allowed to participate in CRM programmi ng. Now may opt in, though still don't pay CRM. Use RGGI funds instead	Many that had previously not used programs are now using programs

State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
Maryland	DSM rider or surcharge	No										
Mass-achusetts	SBC; .25 cents/kWh	Yes	Parity	Pay CRM, access to 85%	Utilities		Customer		Yes	No	Two-year program period	Very few
Michigan	Energy Optimizatio n Charge: per meter charge	Yes	kWh goals	Discounted Energy Optimization Charge. Retained funds go toward kWh goals.	Utilities	1MW/single; 5MW/aggrega te	Customer	Utilities	Yes	No		47 participatin g, down from 77 when program first offered
Minnesota	Conservati on cost recovery in rates	Yes	Parity	Full exemption	Department of Commerce	20MW or 500MCF gas annually	Only once every 5 years, not really M&V; company does own		No	No		12 companies
Mississippi	None	N/A										
Missouri	Cost recovery in rates	Yes	Parity	Exemption from DSM programs	Utilities, Public Service Commission	5,000 KW demand or 2,500KW demand + EE plan in place	Customer		No	No		KCP&L: 2 cos.; Ameren: 9 cos.
Montana	Universal SBC - .0009/kwh	Yes	Parity	USB into escrow account, quarterly reimbursement checks	Department of Revenue	1 MW	Departmen t of Revenue	Not utility	No	No		2009: 55 of 56 eligible customers took it. 2010: 57 on program, 50 used up all CRM charges
Nebraska	None	N/A										

State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
Nevada	Cost recovery in rates	No										
New Hampshire	SBC	No										
New Jersey	SBC	Yes	Parity	Grant up to 75%	New Jersey Clean Energy Program	50,000,000kWh or 250,000DTH	NJCEP	NJCEP	Yes	No	Program to launch in fall 2011	Brand new program
New Mexico	Rates	Yes	Rebate per kWh	Rebate; 50% project cost; per kW or kWh	Xcel Energy	10GWh annual and 2MW demand	Xcel/Customer	Xcel	Yes	No	Brand new, just like Xcel program in CO. Developed in 2011	No one using it yet.
New York	SBC	No										
North Carolina	EE rider	Yes	Parity	Exemption from rider	Duke Energy	Commercial accounts over 1,000 MWh; all industrial	None	None	No	No	May opt out if state you have made, or plan to make, energy efficiency investments in facilities.	
North Dakota	None	N/A										
Ohio	EE rider	Yes	Parity/rebate	Incentive payment or CRM exemption	Utilities/PUCO	Varies, large industrial generally	Utilities/PUCO	Utilities	Yes/No	Yes/No		
Oklahoma	None	N/A										

State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
Oregon	3% public purpose charge	Yes	Parity	Rate credit	OR Dept. of Energy	8760 MWh (1aMW)	ODOE	ODOE (but ETO can use to meet overall long-term indus-trial goals)	Yes	If they max out PBF credits; get half incent-ive	Can use up to 68% of CRM payment on new EE measures.	66 companies eligible, few earning rate credits
Oregon [EWEB]	5% conser-vation rate	Yes	kWh goals	Rate credit	EWEB	Individually negotiated contracts	EWEB + 3rd parties if needed	EWEB	Yes	Yes, if do addition al savings		Two facilities (40% of industrial load share)
Pennsylvania	EE funding pending	N/A									Utilities developing EE plans in response to Act 129. Requests for considerati on of self-direct/opt-out provisions have been made.	
Rhode Island	PBF; .556 cents/kWh	No										
South Carolina	Rate structure	Yes	Parity	Exemption	Duke Energy	Industrial accounts	Customer	None	No	No		
South Dakota	Rate structure	No										
Tennessee	Rate structure	No										

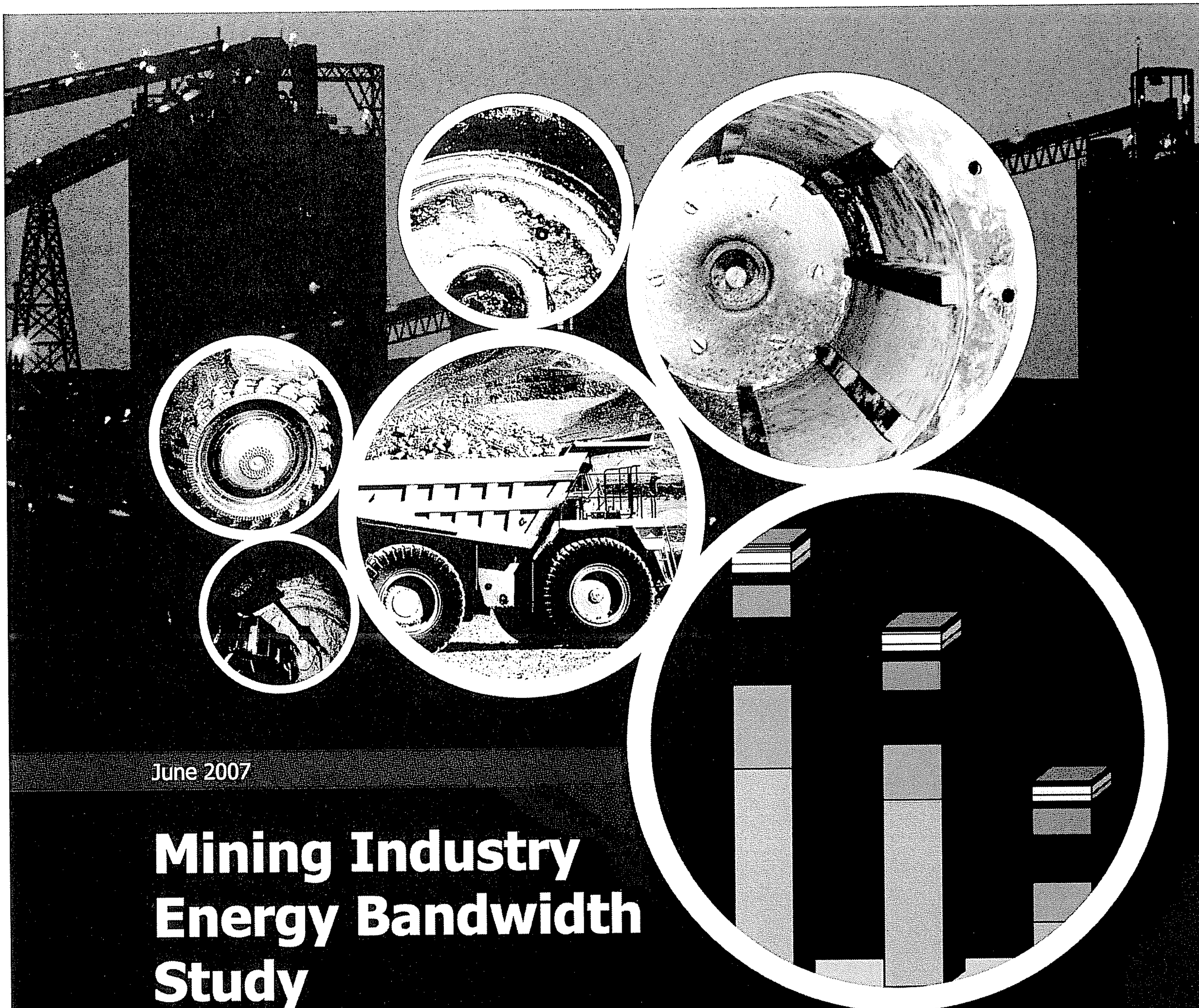
State	CRM Structure	Offer self-direct/ opt-out at all?	$ Parity or kWh?	How $ structured?	Administer-ing entity	Threshold	Who does M&V?	Who claims sav-ings?	Self-Directors Pay Admin/ Low Income?	S-Ds can use some PBF pro-grams?	Notes	How many/ what kind of cos. opt out?
Texas	EECRF	Yes	Parity	Exemption	PUCO	Transmission-level customers	None	None	No	No		
Utah	4.6% PBF	Yes	Parity	Rate credit	Rocky Mountain Power	1MW peak / annual 5,000 mWh	RMP	RMP	Yes: flat $500/project admin fee	Yes, not for same projects	1-5 year simple payback required	25-30% of eligible cos. participating. Primarily industrial, one large convenience store chain
Vermont	Energy efficiency charge (EEC)	Yes	Parity	Pay CRM, earn reimbursement	Utilities, VPSB	If EEC is > $5,000/year	Utilities		Yes	No	Also offers SMEEP: full exemption for largest companies	ESA: one company; SMEEP: one (IBM)
Virginia	Cost recovery rates	Yes	Parity	Exemption	Utilities, SCC	50kW to 10MW	Customer	None	No	No	No cost-effectiveness tests	
Washington	Utility tariff riders	Yes	Parity	Grant lump sum payment/competitive bid	Puget Sound Energy	3 aMW annual	Customer, PSE	PSE	7.5% admin, 10% NEEA	Some after 2 yrs.	After 2.5 years: competitive bid for remaining funds	44 eligible, >75% participation in 2010-2013 cycle
West Virginia	None	N/A										
Wisconsin	Per meter fee	Yes	Parity	Escrow and milestone payments	Wisc. Public Service Commission	1MW monthly demand min / 10,000 Dth of gas + $60K in monthly elec/gas bills	Customer		Pay for some RE portion of CRM		Customers must submit energy savings plan	None participating
Wyoming	Energy efficiency surcharge	Yes	Parity	Rate credit	Rocky Mountain Power	1MW peak / annual 5,000 mWh	RMP	RMP				

Table sources: ACEEE 2011, ACC 2009, AEP 2011a, AEP 2011b, Ambrosio 2011, Anderson 2011, Bell 2011, Borum 2011, Burnes 2011, Cross 2011, Crossman 2011, D'Aloia 2011, Dominion 2010, Duke Energy 2011a, Dunn 2011, Edwards 2011, Goetze 2011, Goff 2011, Haase 2011, Haemmerle 2011, Harris 2011, Helmers 2011, Landers 2011, Laurent 2011, Lawrence 2011, Malley 2011, Malone 2011, Marcylenas 2011, MCSR 2009, MOGA 2009, Mosenthal 2011, Moser 2011, NJCEP 2010, Noonan 2011, Pengilly 2011, Pennsylvania Public Utility Commission 2011, Romero 2011, Schepp 2011, Schutt 2011, Sebastian 2011, Sivils 2011, Stipe 2011, Takanishi 2011, Timmerman 2011, Trasky 2011, VPSB 2011, Walker 2011, Wankum 2011, Welch and Fraser 2011, Whitehead 2011, Williamson 2011, WSPC 2009, Young 2011, Zarnikau 2011, Zuraski 2011.

APPENDIX IV: INTERVIEW FRAMEWORK

1. General structure of self-direct program
    a. Who qualifies?
    b. Minimum usage/size?
    c. Other sectors participating besides industrial?
    d. Number of clients participating (what is percentage of load, if available?)
    e. Can you get kicked out of this self-direct program? Who makes that decision?
2. Who claims self-direct savings?
3. How large (what percentage of monthly bill) would CRM fees be for self-direct customers?
    a. Do self-directors pay any of it?
        i. To support low income programs or other societal benefits?
        ii. To cover program's administrative fees?
    b. Can self-directors use any CRM-funded programs?
4. How much access to internal technical assistance do self-directors have?
5. How did you develop savings targets (if used)?
6. Cost of savings — anyway to calculate or compare to more traditional CRM-funded programming? What data is available to make such a comparison?
7. Do you focus on energy savings or dollar for dollar parity?
8. Can companies receive credit for previous investments?
9. Rate credit / escrow / rebate structure
    a. How exactly works
    b. What do companies submit prior to reimbursement?
    c. Allow full exemption?
    d. Feedback from companies on this?
10. Who conducts evaluation of the program? Who is responsible for measurement and verification?
11. What can you say about the impact of self-direct on other industrial program offerings?
12. What are long term prospects for the self-direct program?
13. Is it producing the savings you hoped/planned for? Did you plan for a certain amount of savings?
14. Macro findings/thoughts about the program in general

EXHIBIT TW-8



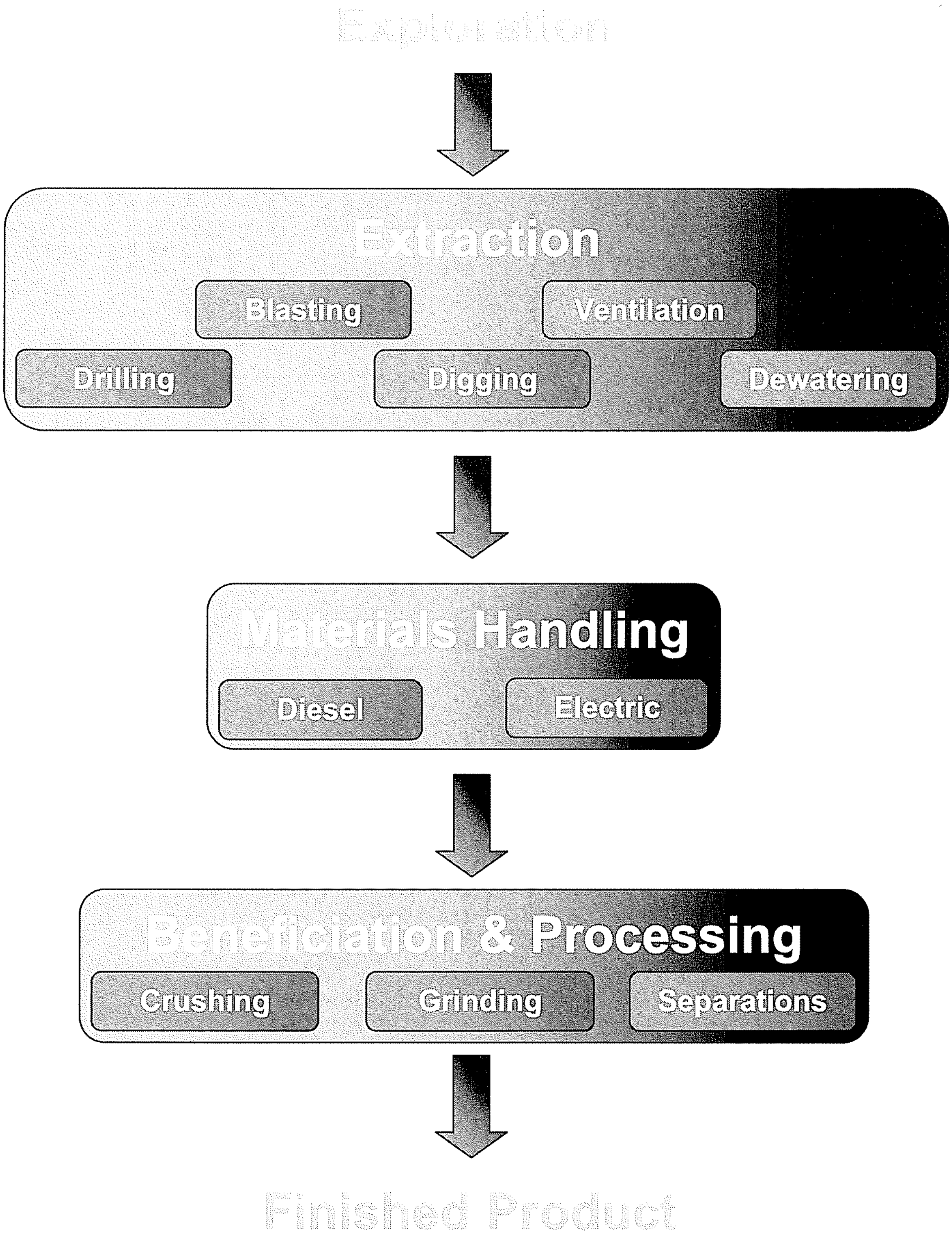
June 2007

Mining Industry Energy Bandwidth Study

U.S. Department of Energy
Industrial Technologies Program
Bringing you a prosperous future where energy is clean, abundant, reliable, and affordable

Contents

Mining Energy Bandwidth Analysis Process and Technology Scope



Executive Summary

The Industrial Technologies Program (ITP) in the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE) works with the U.S. industry to reduce its energy consumption and environmental impact nationwide. ITP relies on analytical studies to identify large energy reduction opportunities in energy-intensive industries and uses these results to guide its R&D portfolio.

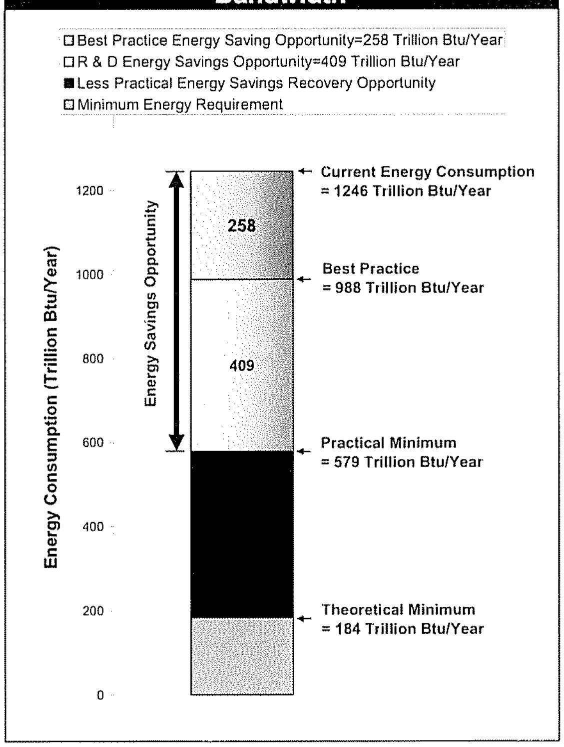
One facet of energy analysis includes energy bandwidth studies which focus on a particular industry and analyze the energy-saving potential of key processes in that industry. The energy bandwidth, determined from these studies, illustrates the total energy-saving opportunity that exists in the industry if the current processes are improved by implementing more energy-efficient practices and by using advanced technologies.

This bandwidth analysis report was conducted to assist the ITP Mining R&D program in identifying energy-saving opportunities in coal, metals, and mineral mining. These opportunities were analyzed in key mining processes of blasting, dewatering, drilling, digging, ventilation, materials handling, crushing, grinding, and separations.[1]

The U.S. mining industry (excluding oil & gas) consumes approximately 1,246 Trillion Btu/year (TBtu/yr). This bandwidth analysis estimates that investments in state-of-the-art equipment and further research could reduce energy consumption to 579 TBtu/yr (Exhibit 1). There exists a potential to save a total of 667 TBtu/yr – 258 TBtu/yr by implementing best practices and an additional 409 TBtu/yr from R&D that improves mining technologies. Additionally, the CO_2 emission reduction achievable from total practical energy savings is estimated to be 40.6 million tonnes (Exhibit 2).

As seen in Exhibit 2, the greatest energy reductions for the mining processes assessed in this study can be actualized in the coal and metal mining industries.

Exhibit 1. U.S. Mining Industry Energy Bandwidth



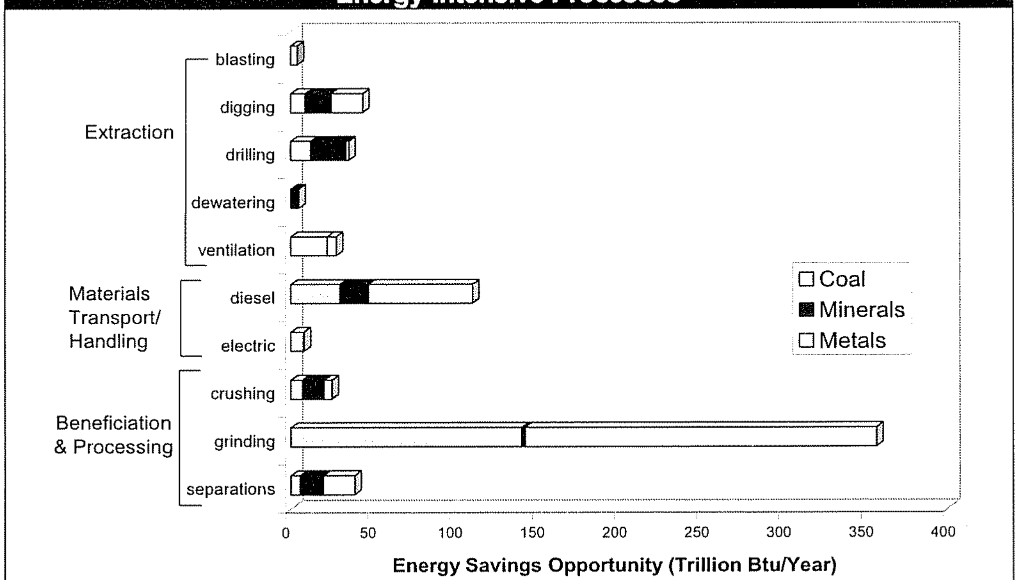
[1] Refer to Glossary of Mining Terms in Appendix E or Section 3 for further clarification of processes.

Exhibit 2. Energy Savings Opportunity by Commodity Type (TBtu/yr)					
	Current Energy Consumption	Energy Savings from R&D Improving Energy Efficiency	Energy Savings from Implementing Best Practices	Total Practical Energy Savings	CO_2 Reduction from Total Practical Energy Savings (million tonnes)*
Coal	485.3	84.2	153.3	237.5	14.4
Metals	552.1	117.5	220.7	338.2	20.6
Minerals	208.9	56.6	35.2	91.8	5.6
Total	1246.3	258.3	409.2	667.5	40.6

* The CO_2 emissions factor for the mining industry (60,800 tonnes / TBtu) was calculated from the fuel mix in the Miing E&E Profile. The fuel consumption was equated to carbon dioxide emissions using conversion factors obtained from EIA.

The two equipment types offering the greatest energy savings potential in the mining industry are grinding and diesel (materials handling) equipment (Exhibit 3). Implementing best practices and new advances through R&D can save 356 TBtu/yr in grinding and 111 TBtu/yr in materials handling. By reducing the energy consumption of these two processes to their practical minimum, the mining industry would save about 467 TBtu/yr, or 37% of current energy consumption. Energy savings illustrated in Exhibit 3 include the full implementation of state-of-the-art technology and installation of new technology through R&D investments.

Exhibit 3. Energy-Saving Opportunity in U.S. Mining Industry for Top 10 Energy-Intensive Processes



It is important to note that the energy-saving opportunities reported in this study are independent of one another (e.g. improving blasting energy savings will increase downstream savings in materials handling, and beneficiation and processing; however these ***potential downstream savings are not accounted for in this study***).

Methodology

The bandwidth analysis relies on estimating the following quantities:

- *Current Energy Consumption* – The average energy consumption for performing a given process
- *Best Practice Energy Consumption* – The energy consumed by mine sites with above-average energy efficiency
- *Practical Minimum Energy Consumption* – The energy that would be required after R&D achieves substantial improvements in the energy efficiency of mining processes
- *Theoretical Minimum Energy Consumption* – The energy required to complete a given process, assuming it could be accomplished without any energy losses

The difference between current energy consumption and best practice consumption corresponds to energy-saving opportunities from investments made in state-of-the-art technologies or opportunity existing today which has not been fully implemented in mine operations. The difference between best practice and practical minimum energy consumption quantifies opportunities for research and development or near-term opportunity with few barriers to achieving it. Finally, the difference between the practical and theoretical minimum energy consumption refers to the energy recovery opportunity which is considered impractical to achieve because it is a long-term opportunity with major barriers or is infeasible.

This analysis uses data on the current energy requirements for mining equipment used in key processes based on calculations from the SHERPA modeling software[2] and published equipment efficiency values. However, no single value for the theoretical minimum energy requirement for mining could be sourced, even for a specific mining commodity, because of the wide variability in mining process requirements. The mining process is unique in that unlike most industrial processes, the starting raw materials and conditions for production vary widely, sometimes by more than an order of magnitude, in energy intensity (Btu/ton produced). Therefore, an average theoretical value was approximated by evaluating the average performance efficiency of mining equipment. Practical minimum energy requirements represent a value between the theoretical and best practice performance of mining equipment. The best practice value can be benchmarked at a specific point in time; however, the practical minimum energy levels are a moving target since today's estimates of practical machine efficiencies are not absolute and may be surpassed via improvement in science and technology over time. For several mining processes, estimates of practical limits were based on literature approximating the maximum efficiency of equipment types. When practical efficiency estimates were unavailable, the analysis assumed the practical minimum to be two-thirds of the way from the best practice energy consumption to the theoretical minimum energy consumption.[3]

To reflect more inclusive energy savings, the bandwidth analysis used tacit energy values of electrical energy consumption (i.e., generation and distribution losses are factored in addition to

[2] Western Engineering, Inc. – SHERPA Software - software used by the mining industry to model mining operations and estimate capital, energy, labor and other costs of production.

[3] Practical Min = Best Practice - (Best Practice - Theoretical Min)* 2/3 (see page 17)

onsite electrical consumption). Including generation and distribution losses in bandwidth estimates is essential as saving 1 Btu of onsite electricity translates to a total savings of over 3.17 Btu using current data (EIA 2006). The practical minimum values were adjusted to reflect 2020 electrical distribution systems, where the ratio of offsite to onsite electricity consumption is assumed to be 3.05 (EIA 2006). Theoretical values, however, assume zero electrical losses.

1. Introduction

The U.S. mining industry provides essential raw materials like coal, metals, minerals, sand, and gravel to the nation's manufacturing and construction industries, utilities and other businesses. Nearly 24 tons of material are consumed annually per capita in the United States;[4] further, common consumer products can use a vast variety of mined materials, for example, a telephone is manufactured from as many as 42 different mined materials, including aluminum, beryllium, coal, copper, gold, iron, limestone, and silica. Mining these materials consumes significant energy – in 2002, the mining industry spent $3.2 billion on energy, or 21% of the total cost of its supplies (not including labor).[5] Given the large role mining industry plays in the U.S. economy and the energy intensity of the mining processes, tapping into the potential for energy savings across different mined commodities could yield significant impact. The magnitude of these potential savings can be quantified using the energy bandwidth analysis – a method for estimating the opportunity in various processes based on their theoretical energy consumption and the practical minimum energy use achievable by implementing R&D results and best practices.

This mining industry energy bandwidth analysis was conducted to assist the Industrial Technologies Program's (ITP) Mining subprogram, an initiative of the U.S. Department of Energy's (DOE) Office of Energy Efficiency and Renewable Energy (EERE), to maximize the impact of its R&D in reducing industrial energy consumption. Although the study focuses on equipment used in coal, metals, and industrial minerals mining, some results can also be applied to the oil & gas exploration and production industries, since similar equipment is used in both industries.

This bandwidth study expands on the previous work conducted in *Energy and Environmental Profile of the U.S. Mining Industry* (*E&E Profile*), a study published by DOE in 2002 to benchmark energy use for various mining technologies.[6] It uses similar methods to estimate the average energy consumption of key equipment used in coal, metals, and mineral mining. In absence of energy data on many mined commodities in the U.S., the *E&E Profile* benchmarks energy consumption for eight mined commodities, collectively responsible for approximately 78% of the energy used in the U.S. mining industry. These commodities were used to define the average Btu/ton for coal, metals, and industrial minerals which was then proportioned against the total mined material for each sector in the mining industry to account for the remainder of the mining industry.

Additionally, there is very little data available on U.S. mining industry for energy use by specific mining process, equipment type or fuel type utilized. Thus the *E&E Profile* assumes a "typical" mine and uses data from a combination of sources including production data from federal and

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[4] National Mining Association. "Per capita consumption of minerals – 2006". February 2007. http://www.nma.org/pdf/m_consumption.pdf

[5] U.S. Department of Commerce, Bureau of Census, *Mining Industry Series*, 2002 (Supplies include minerals received, purchased machinery installed, resales, purchased fuels consumed, purchased electric energy and contract work.) This does not include withheld data.

[6] U.S. Department of Energy. *Energy and Environmental Profile of the U.S. Mining Industry*. 2002.

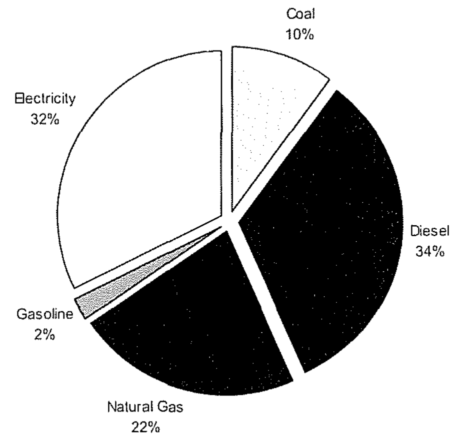
industry sources (Census of Mineral Industries). Estimates are based on the *SHERPA Mine Cost Estimating Model* and *Mine and Mill Equipment Costs, an Estimator's Guide* from Western Mine Engineering, Inc. to model the typical equipment required for various types of mine operations (e.g. longwall mine, western surface mine, etc.) and the energy consumption of each major equipment unit. The SHERPA software was used to identify the type and number of equipment units optimally used in a hypothetical mine based on certain assumptions and inputs. The Estimator's Guide identified the energy cost for particular equipment types, which is determined by annual surveys of U.S. equipment manufacturers and distributors, fuel and energy suppliers, and mining companies. This model and equipment cost guide served the need to establish and manipulate baseline assumptions and inputs in order to develop hypothetical mines deemed reasonable by industry experts.

While the *E&E Profile* provides detailed data for the estimated energy consumption of each piece of equipment required in a typical mine, this report focuses on the average energy consumption of similar equipment types to estimate the potential for energy savings for a given process. Similar equipment was grouped into the following categories based on their process use: blasting, dewatering, drilling, digging, ventilation, materials handling, crushing, grinding, and separations. Thus the analysis in this report identifies the equipment categories which provide the greatest opportunities for energy savings in the U.S. mining industry.

2. Background

2.1 Mining Industry Energy Sources

Exhibit 4. Fuels Consumed in the U.S. Mining Industry



Major energy sources for the U.S. mining industry are petroleum products, electricity (purchased and produced onsite), coal, and natural gas. Diesel fuel accounts for 34% of the U.S. mining industry's fuel needs, followed by onsite electricity at 32%, natural gas at 22%, and coal and gasoline supplying the balance (Exhibit 4).[7] The type of fuel used at a mine site will depend on the mine type (surface or underground) and on the processes employed.

2.2 Materials Mined and Recovery Ratio

Materials mined in the U.S. can be broadly classified into three categories: coal, metals (e.g., iron, lead, gold, zinc and copper), and industrial minerals (these include phosphate, stone, sand and gravel). Each mined product has a different recovery ratio, which has a significant impact on the energy required per ton of product.

Exhibit 5. Mined Material Recovery in 2000

	Commodity	Recovery Ratio	Million Tons Recovered	Million Tons Mined
Coal	Average	82%	1073	1308.5
Metals	Iron	19%	69.6	366.3
	Copper	0.16%	1.6	1000.0
	Lead & Zinc	8%	1.4	17.5
	Gold & Silver	0.001%	0.003	300.0
	Other*	n/a	< 0.05	
	Average	4.50%	72.6	1613.3
	** Other category consists of magnesium, mercury, titanium, vanadium, and zirconium*			
Industrial Minerals	Potash, Soda Ash, Borates	88.30%	13.856	15.7
	Phosphate	33%	42.549	128.9
	Sand & Gravel	n/a	1,148	
	Stone (crushed)	92.60%	1,675.50	1809.4
	Other	n/a	320.1	
	Average	90%	3,200	3556
Mining Total	Average	67%	4,346	6,477

[7] Energy and Environmental Profile for the U.S. Mining Industry. 2002. p. 1-19.

The recovery ratio in mining refers to the percentage of valuable ore within the total mined material. While coal mining has a recovery ratio of 82%, the recovery ratio for metals averages only about 4.5% (Exhibit 5). This means 1.2 tons of material must be mined for every 1 ton of useful coal product, while 22 tons of material must be mined for every 1 ton of metal product.[8] These recovery ratios exclude waste rock from development operations.

The U.S. mining industry produced 1,073 million tons of coal, 72.6 million tons of metal ores, and 3,200 million tons of industrial minerals in 2000[9] (Exhibit 5), amounting to a total of 4,346 million tons of mined products. Factoring in the waste materials that must also be processed by the mining industry, the total amount of material extracted, handled, and processed in the mining industry totaled 6,477 million tons.[10]

Coal, metals, and industrial minerals mining accounted for a total of 13,904 mines in the United States in 2000 with 235,348 employees working in the mines and/or processing plants.

2.3 Mining Methods

The extraction of coal, metals and industrial minerals employs both surface and underground mining techniques. The method selected depends on a variety of factors, including the nature and location of the deposit, and the size, depth and grade of the deposit. Surface mining accounts for the majority of mining (65% of coal, 92% of metals, and 96% of minerals mined) with underground mining accounting for the remaining (Exhibit 6).[11] Underground mining requires more energy than surface mining due to greater requirements for hauling, ventilation, water pumping, and other operations.

Exhibit 6. Underground and Surface Mining in the United States

	Million Tons Of Material Mined	% Produced in Surface Mines	% Produced in Underground Mines
Coal	1,309	65%	35%
Metals	1,613	92%	8%
Industrial Minerals	3,556	96%	4%

[8] Energy and Environmental Profile for the U.S. Mining Industry. 2002. p. 1-17, p. 1-7.
[9] While 2005 data is available, this analysis used 2000 data to stay consistent with the 2000 data presented in the Energy and Environmental Profile of the U.S. Mining Industry. After new data is presented in the E&E Profile, this bandwidth analysis will be updated to reflect the latest industry data. According to NMA and USGS Commodity Summaries (metals and industrial minerals selected based on DOE Mining Annual Report of 2004), production in 2005 was: coal – 1,131 M tons; metals – 62.3 M tons; and industrial minerals – 3,491M tons.
[10] Overburden is included in the total material mined.
[11] Energy and Environmental Profile for the U.S. Mining Industry. 2002. p. 1-13.

3. Mining Equipment

The mining process can be divided into three broad stages, each involving several operations. The first stage is extraction, which includes activities such as blasting and drilling in order to loosen and remove material from the mine. The second stage is materials handling, which involves the transportation of ore and waste away from the mine to the mill or disposal area. At the processing plant, the third stage, i.e., beneficiation & processing is completed. This stage recovers the valuable portion of the mined material and produces the final marketable product. Beneficiation operations primarily consist of crushing, grinding, and separations, while processing operations comprise of smelting and/or refining.

In this study, similar equipment types that perform a given function were grouped into a single category to benchmark their energy consumption. For example, all types of drills and blasting agents, such as ammonium nitrate fuel oil (ANFO) and loaders are grouped into the drilling category to assign energy data. The different equipment types analyzed are listed below. Operations that consume relatively low amounts of energy were omitted, as they offer poor energy-saving opportunities.

- Extraction
  - Drilling
  - Blasting
  - Digging
  - Ventilation
  - Dewatering
- Materials Transport and Handling
  - Diesel powered Equipment
  - Electrical equipment
    - Load Haul Dump
    - Conveyers
    - Pumps
- Beneficiation and Processing
  - Crushing
  - Grinding
  - Separations
    - Centrifuge
    - Flotation

3.1 Extraction

The energy-saving opportunities in the extraction stage of mining were evaluated by analyzing the major equipment units used for extraction of commodities, as listed in Exhibit 7.

Drilling

Drilling is the act or process of making a cylindrical hole with a tool for the purpose of exploration, blasting preparation, or tunneling. For the purpose of this study, drilling equipment includes ammonium nitrate fuel oil (ANFO) loader trucks, diamond drills, rotary drills, percussion drills and drill boom jumbos. Drills are run from electricity, diesel power and to a lesser extent, indirectly from compressed air. The energy is used to power components of the drill that perform tasks such as hammering and rotation.

Exhibit 7. Extraction Equipment
Drilling
ANFO Loader Truck
Diamond Drills
Rotary Drills
Percussion Drills
Drill Boom Jumbos
Blasting
Explosives
Blasting Agents (i.e. ANFO)
Digging
Hydraulic Shovels
Cable Shovels
Continuous Mining Machines
Longwall Mining Machines
Grader
Drag Lines
Ventilation
Fans
Dewatering
Pumps

Blasting

Blasting uses explosives to aid in the extraction or removal of mined material by fracturing rock and ore by the energy released during the blast. The energy consumed in the blasting process is derived from the chemical energy contained in the blasting agents. This sets blasting apart from other processes, which are powered by traditional energy sources, such as electricity and diesel fuel. In this operation, the energy consumed per ton of output is that used directly by the blasting agent, rather than by any equipment used in the operation. Nevertheless, it is important that blasting be included in this report, as blasting efficiency influences downstream processes. Blasting reduces the size of ore before it undergoes crushing and grinding, thereby reducing the energy consumption of crushing and grinding processes. Therefore, optimizing blasting techniques will enable downstream energy savings.

Digging

Digging is to excavate, make a passage into or through, or remove by taking away material from the earth. The goal of digging is to extract as much valuable material as possible and reduce the amount of unwanted materials. Digging equipment includes hydraulic shovels, cable shovels, continuous mining machines, longwall mining machines, and drag lines.

Ventilation

Ventilation is the process of bringing fresh air to the underground mine workings while removing stale and/or contaminated air from the mine and also for cooling work areas in deep underground mines. The mining industry uses fan systems for this purpose.

Dewatering

Dewatering is the process of pumping water from the mine workings. Pumping systems are large energy consumers. This study assumes end-suction pumps (i.e. centrifugal) as the only equipment used for dewatering the mine during extraction.[12]

3.2 Materials Handling Equipment

The materials handling equipment were categorized into diesel and electric for the purpose of this energy bandwidth analysis (Exhibit 8). In general, diesel fuel powers rubber tire or track vehicles that deliver material in batches, while electricity powers continuous delivery systems such as conveyors and slurry lines.

Exhibit 8. Materials Handling Equipment
Diesel Equipment
Service Trucks
Front-end Loaders
Bulldozers
Pick-up Trucks
Bulk Trucks
Rear-dump Trucks
Electric Equipment
Load-Haul-Dump Machines-
Conveyors (motors)
Pipelines (pumps)
Hoists

Diesel Equipment

Much of the equipment used in the transfer or haulage of materials in mining is powered by diesel engines. Equipment includes service trucks, front-end loaders, bulldozers, bulk trucks, rear-dump trucks and ancillary equipment such as pick-up trucks and mobile maintenance equipment. Diesel technologies are highly energy intensive, accounting for 87% of the total energy consumed in materials handling.[13] Materials handling equipment is powered by diesel 80%, 100%, and 99.5% for coal, metals and industrial minerals respectively as per the mine equipment modeled in this study using SHERPA software.

Electric Equipment

Electric equipment includes load-haul-dump (LHD) machines, hoists, conveyor belt systems and pipelines for pumping slurries. The percentage of materials handling equipment run by electricity is 20% for coal, 0% for metals,[14] and 0.5% for industrial minerals, according to the mines modeled with SHERPA. It must be noted, however, that the actual use of conveyor systems in metal and industrial mineral mines is more extensive than was modeled by the *E&E Profile*. The SHERPA software model identifies the optimal type and number of equipment units used in hypothetical mines by considering many variables including different inputs and assumptions. In this instance, the SHERPA model did not output conveyor belt energy data because it determined that haul trucks were the best option for materials handling. Thus, the hypothetical mine scenario does not show greater conveyor usage based on the inputs entered.

[12] Industry expert. Oral communication - "Deep-well/Vertical turbine pumps are predominantly used by deep coal mines because they are more efficient." April 2007.
[13] Mining Industry of the Future Fiscal Year 2004 Annual Report. p. 6
[14] While electric conveyors are used in certain metal mines, this analysis was based on the SHERPA mining software from Western Mine Engineering which did not output electric equipment for metals mines based on inputs.

3.3 Beneficiation & Processing Equipment

Beneficiation comprises crushing, grinding and separations, while processing operations include roasting, smelting, and refining to produce the final mined product (Exhibit 9).

Exhibit 9. Beneficiation and Processing Equipment	
Crushing	**Separations**
Primary Crusher	*Physical:*
Secondary Crusher	Centrifuge
Tertiary Crusher	Flotation
	Screen
Grinding	Filter
SAG Mill	Cyclone
Ball Mill	Magnetic Separator
Rod Mill	Pelletizer
	Solvent Extraction
Processing	Thickener
Roasting	Trommel
Smelting	Washing
Refining	
	Chemical:
	Electrowinning

Crushing
Crushing is the process of reducing the size of run-of- mine material into coarse particles. The efficiency of crushing in mining depends on the efficiency of upstream processes (rock fragmentation due to blasting or digging in the extraction process) and in turn, has a significant effect on downstream processes (grinding or separations).

Grinding
Grinding is the process of reducing the size of material into fine particles. As with crushing, the efficiency of grinding is influenced by upstream processes that fragment the rock prior to the grinding stage. In the case of both crushing and grinding, estimates of their energy efficiency in the literature vary widely based on the metrics involved (creation of new surface area per unit energy applied, or motor efficiency of crushing equipment).

Separations
The separation of mined material is achieved primarily by physical separations rather than chemical separations, where valuable substances are separated from undesired substances based on the physical properties of the materials. As shown in Exhibit 9, a wide variety of equipment is used for separations processes, the largest energy-consuming separation method amongst these being centrifugal separation for coal mining, and floatation for metals and minerals mining.

Centrifuges consist primarily of a spinning basket designed to receive solid-liquid slurries and remove the liquid. The "centrifugal force" created by the spinning action sends the liquid out of the bowl through a perforated medium and leaves the desired solid material behind.

Flotation machines are designed to isolate valuable ore from other non-valuable substances. The surfaces of mineral particles are treated with chemicals that bond to the valuable product and make them air-avid and water-repellent. The ore is suspended in water that is mechanically agitated and aerated. The treated minerals attach to air bubbles and rise to the surface where they can be collected.

Final Processing
Final processing includes steps that further prepare the ore to yield the desired product in its purest and most valuable form. Roasting, smelting, and refining are different processes falling under this category. While a component of the mining industry, these processes require relatively much less energy. These processes were, therefore, not investigated in this study.

4. Bandwidth Calculation Methodology

This bandwidth study estimates the achievable energy savings for different commodity groups – coal, metals and industrial minerals. The analysis examines energy-saving opportunities in common processes rather than opportunities for operational improvement (e.g., using more efficient fans rather than more efficient fan utilization, or improving diesel engines rather than improving routing for diesel equipment).

Mining process equipment was analyzed according to three main stages: extraction, materials transport and handling, and beneficiation and processing (section 3). Similar equipment units that perform a given function were grouped into a single category to benchmark their energy consumption. See section 3, Mining Equipment (page 9) for equipments analyzed.

For each equipment type, the current energy consumption, best practice energy consumption, practical minimum, and theoretical minimum energy consumption were estimated.

- *Current Energy Consumption* – The actual average energy consumption for performing a given process
- *Best Practice Energy Consumption* – The energy consumed by mining sites with above average energy efficiency
- *Practical Minimum Energy Consumption* – The energy that would be required after R&D achieves substantial improvements in the energy efficiency of the mining technology
- *Theoretical Minimum Energy Consumption* – The energy required to complete a given process, assuming it could be accomplished without any energy losses

The energy-savings opportunity is calculated as the difference between the current energy consumption and the practical minimum energy consumption, assuming that mining production rates remain constant.

Energy Savings Potential = Current Energy Consumption – Practical Minimum Energy Required

The bandwidth analysis is based on energy data on eight mined commodities that in sum account for 78% of the total energy use by the U.S. mining industry. The eight commodities are coal; potash, soda ash and borate; iron; copper; lead and zinc; gold and silver; phosphate rock; and limestone. These commodities were used to define the average Btu/ton for coal, metals, and industrial minerals which was then proportioned against the total mined material for each sector in the mining industry to account for the remainder of the mining industry.

Values are reported in Btu/ton of material handled, as well as Btu/yr consumption. Quantifying the above measures of energy consumption for each equipment type enabled an estimate of the entire mining industry's current energy consumption and potential for energy reduction. It also identified the equipment types that would provide the greatest opportunity for energy reduction in mining operations.

4.1 Method for Determining Current Mining Energy Consumption

This study estimates current energy consumption relying on the same data sources and assumptions as used in the *E&E Profile.*[15] The *E&E Profile* used the *SHERPA Mine Cost Estimating Model* along with *Mine and Mill Equipment Costs, an Estimator's Guide* from Western Mine Engineering, Inc. The SHERPA software was used to model several mines differing by ore type, mining technique, and production rate. For each mine, the energy consumption (Btu/ton) of key processes (drilling, digging etc.) was calculated. These values were then used to determine the average energy consumption of key processes in coal, metal, and mineral mining.

Step 1: Determine equipment energy requirements for individual model mines

The SHERPA model allows the user to input parameters describing seam and ore body characteristics, and it outputs the equipment required by the mine. Model mines were selected to represent the majority of commodity production from U.S. mining. Four coal mines were modeled – an eastern longwall, eastern underground, western surface, and interior surface mine – each with differing production rates. Mineral mines included potash, limestone, and phosphate mines, while metal mines included iron, copper, lead, and gold mines. SHERPA provided a list of equipment required for each mine as well as the number of operating hours expected for each equipment unit. In cases where additional information was required (for example, SHERPA does not include beneficiation and processing equipment), typical equipment requirements were determined through correspondence with industry experts. Each equipment unit's energy consumption was then obtained from the *Estimator's Guide.* Exhibit 10 below displays an example of equipment lists and data derived from SHERPA and the *Estimator's Guide.*

Exhibit 10. Extraction and Materials Handling Equipment for Assumed Interior (Coal) Surface Mine (9,967 tons per day produced)

Equipment	Number of Units	Daily hours/unit	Btu/hr (single unit)
Hydraulic Shovel	1	9.38	4,102,318
Rear Dump Trucks	11	14	1,656,897
Front-end Loaders	5	14	3,640,682
Bulldozer	2	14	5,115,421
Pick-up Trucks	8	14	207,112
Rotary Drills	2	14	805,991
Pumps	2	14	331,549
Service Trucks	2	14	339,364
Bulk Trucks	2	13.58	339,364
Water Tankers	1	2.94	1,502,187
Graders	1	0.56	618,841

[15] U.S. Department of Energy. *Energy and Environmental Profile of the U.S. Mining Industry.* 2002.

Step 2: Calculate total energy consumption for major processes/equipment types

The energy consumption of key processes (such as drilling, digging, etc.) in each mine was determined by summing the energy consumption of each associated equipment unit generated by the SHERPA model. For example, in the case of the interior surface coal mine modeled in the *E&E Profile*, the energy consumption required for materials transport/handling is the sum of energy consumed by the rear dump trucks, front-end loaders, bulldozer, service trucks, and bulk trucks (see Exhibit 11 below). The energy consumed per ton of material (Btu/ton) was determined by dividing all the equipments' daily energy consumption by the tons of material mined each day. This calculation was repeated for each of the four coal mines analyzed.

Exhibit 11. Diesel-Powered Materials Handling Equipment for Assumed Interior (Coal) Surface Mine (9,967 tons per day produced)

	Number of Units	Hours/ Unit	Btu/hr (single unit)	Btu/ton of material handled
Rear Dump Trucks	11	14	1,656,897	25,601
Front-end Loaders	5	14	3,640,682	25,569
Bulldozer	2	14	5,115,421	14,371
Pick-up Trucks	8	14	207,112	2,327
Service Trucks	2	14	339,364	953
Bulk Trucks	2	13.58	339,364	925
			Total	69,746

Step 3: Estimate average energy consumption across multiple mines

The energy consumption estimates for each individual mine were used to calculate the weighted average energy consumption, based on the productivity of the different mine types in the United States. The resulting value for energy consumption was assumed to be representative of the coal mining industry. The energy consumed by diesel-powered materials handling equipment in coal mining is shown below in Exhibit 12.

Exhibit 12. Diesel-Powered Materials Handling Equipment: Average Energy Consumption for Coal Mines Modeled

	Energy Consumption (Btu/ton)	Materials Mined in the United States (Thousand Short Tons)[b]	Proportion of Total Mines Analyzed
Eastern Underground	68,320	178,934	17.80%
Longwall	NA[a]	152,584	15.18%
Interior Surface	69,746	109,232	56.15%
Western Surface	41,960	564,401	10.87%
Weighted Average Energy Consumption (Btu/ton)	43,303		

[a] *Longwall mining machines are electric powered*, according to Western Mine Engineering Mine & Mill Equipment Costs – An Estimator's Guide. 1999.

[b] Calculated based on EIA Annual Coal Report 2000 (Production/Average Recovery Ratio).

4.2 Best Practice, Practical Minimum, and Theoretical Minimum Energy Consumption

General methods for determining the best practice, practical minimum, and theoretical minimum energy consumption are discussed below. Detailed assumptions are listed in Appendix D (page 37).

Best Practice Energy Consumption

Estimates of best practice energy consumption were based on a variety of published sources reporting the energy efficiencies of top-performing mining equipment. In cases where equipment characteristics varied significantly, or when equipment efficiency data was unavailable, this study used other indicators of efficiency such as the motors used to power electric equipment.

Theoretical Minimum Energy

The theoretical minimum energy is defined as the minimum energy needed to complete a given process, in absence of any energy losses to heat, noise etc. For example, theoretical minimum energy describes the energy required to haul rock from a mining area to a process area, but excludes the energy lost in the diesel engine powering the truck. Since mining is predominantly a mechanical process, no single value for the current or theoretical minimum energy requirement for mining can be derived, even within a single mineral group, since the depth at which the material is mined and the type of refining required varies widely. Every commodity that is mined has different mechanical and physical properties. Therefore, different mines will have drastically varying energy requirements for a given process, and it is difficult to pinpoint the theoretical minimum energy necessary for such operations. At best, average values for energy consumption may be approximated by evaluating the average performance of mining equipment. Theoretical minimum energy was calculated using current energy consumption and published estimates of equipment efficiency.

Equipment efficiency can be expressed as:

$$\text{Efficiency} = \frac{\text{Theoretical Minimum Energy}}{\text{Energy Consumption}}$$

The theoretical minimum energy for completing a process could thus be calculated as follows:

$$\text{Theoretical Minimum Energy} = \text{Energy Consumption} * \text{Efficiency}$$

The calculations used direct equipment efficiency foremost, but in cases where these data were unavailable, indirect equipment efficiency was used as the next best alternative. For example, in the case of conveyer belts for materials transport, the efficiency of the motor powering the conveyer was used. In another case, centrifuge minimum energy consumption was not based on efficiency values but rather on a theoretical calculation for the kinetic energy of a solid-liquid slurry.

Practical Minimum Energy

The practical minimum energy is considered to be the closest approach to the theoretical limit allowed by implementing current best practices and technologies developed by ongoing R&D.

Practical minimum energy values are however a moving target. Science and technology continuously improve energy efficiency and waste recovery. New technologies will be developed that will change what is now perceived as the practical minimum. In some cases, the practical minimum energy for a process was determined from published estimates of future attainable efficiencies for equipment. In other cases where no published practical minimum target could be found, this study assumes that practical minimum energy is two-thirds of the way between best practical energy requirement and theoretical minimum energy requirements.

"2/3 approximation" for Estimating Practical Minimum Energy Consumption

Practical Min = Best Practice - (Best Practice - Theoretical Min)* 2/3

Practical minimum energy calculations for equipment using motors, pumps, and diesel engines were all based on published estimates of practical efficiency limits. Had the practical minimum energy consumption for diesel engines, motors and pumps been calculated using the 2/3 rule, the error would range from 0.02 to 14%, as shown in Exhibit 13. For pumps, motors, and diesel engines, the 2/3 approximation provides a good approximation of practical minimum energy consumption, though slightly overestimating in each case (this would lead to underestimating potential energy savings). While these results do not prove that the practical minimum energy consumption can be calculated using the 2/3 rule for all equipment types, it does demonstrate that the 2/3 rule can provide a useful approximation in some cases, when published values are unavailable. This rule was used in calculating **onsite** practical minimum energy, which is later adjusted for generation and distribution losses (see section 4.3).

Exhibit 13. Error Associated with "2/3 approximation" for Materials Handling Equipment used in Mineral Mining

Equipment	Practical Minimum Energy Requirement (Btu/ton), based on *current energy consumption and* published estimates of practical efficiency limits	Practical Minimum Energy Requirement (Btu/ton), calculated using the "2/3 rule"	% Error
Diesel Equipment	4515	5162	14%
Conveyor (Motor)	11	11	~2%
Pumps	221	221	~0.02%

4.3 Factoring in Electricity Generation Losses in the Analysis

Much of the equipment included in this analysis relies on electricity. Since electricity generation and distribution is associated with substantial energy losses, it is important to utilize the tacit energy consumption values, i.e., the energy used onsite plus the energy lost in generating and distributing that energy, instead of only onsite consumption. According to data reported by the Energy Information Administration (EIA, 2006), 2.17 Btu are lost in transmission and distribution for every 1 Btu delivered to the industrial sector.[16] In other words, consuming 1 Btu

[16] EIA AEO 2006, Table 2

of electricity onsite requires a total electricity consumption of 3.17 Btu. Conversely, saving 1 Btu onsite translates to saving 3.17 Btu. Therefore, tacit energy was included in this study in order to quantify energy saving potential more accurately.

The current and best practice energy consumption of electrical equipment was, therefore, multiplied by a factor of 3.17 to estimate the total energy consumption. However, total energy consumption was calculated differently for practical minimum and theoretical minimum energy consumption estimates. Since the practical minimum energy consumption would hypothetically be obtained in the future, EIA predictions for 2020 are used to determine electricity losses. EIA predicts that in 2020, the ratio of offsite to onsite electricity consumption will be 3.05—the value used in this analysis to calculate the tacit practical minimum energy. Further, the definition of theoretical minimum energy consumption requires that all processes involve zero energy losses. Therefore, theoretical minimum energy estimates assume zero electricity losses.

4.4 Estimating Annual Energy Consumption and Energy-Savings Opportunity

In order to benchmark energy savings opportunities in the mining industry, energy consumption estimates (Btu/ton) were converted to yearly energy consumption estimates (TBtu/yr). Estimates of current, best practice, practical minimum, and theoretical minimum energy (Btu/ton) were multiplied by the tons of material mined in the U.S. for each commodity to calculate potential annual energy savings (see Exhibit 14).

Exhibit 14. Current Energy Consumption by Commodity Group

	Million Tons Recovered	Average Recovery Ratio*	Million Tons Of Material Mined	Btu/Ton of Material Mined	TBtu/yr Consumed by the Mining Industry
Coal	1,073	82%	1,309	370,628	485.3
Metals	72.6	4.5%	1,613	342,200	552.1
Industrial Minerals	3,200	90%	3,556	58,757	208.9
Total/Average	4,345.6		6,477	192,373	1,246

Similar methods were used for determining best practice, practical minimum, and theoretical minimum energy consumption (TBtu/yr)
* Refer to Exhibit 5.

5. Uncertainties and Data Quality

A major challenge in analyzing the mining industry's energy consumption is the variability in mining operations. Even within a single mineral group, processes will differ according to the depth at which the material is mined and the degree of refining required. Moreover, every commodity that is mined has different mechanical and physical properties. These properties can vary over an order of magnitude between deposits and can vary significantly even within individual mines. For example, the work indices (a measure of energy required to grind rock) of mined commodities vary from 1.43 kWh/ton for calcined clay to 134.5 kWh/ton for mica.[17] This results in large variations in grinding equipment energy requirements. Therefore, different mines will have drastically different energy requirements for a given process. A mine could be designed for maximum efficiency, yet consume more energy than an inefficient mine with the same output.

The large variation in mine's energy consumption is evidenced by two recent Canadian studies benchmarking the energy consumption of 10 underground mines and 7 open pit mines. The average energy requirement of the underground mines was 25,000 Btu/ton, with a standard deviation of 11,000 Btu/ton, while the average energy requirement of the open pit mines was 1,000 Btu/ton with a standard deviation of 700 Btu/ton (CIPEC, 2005). The variation in these mines' energy consumption can arise from a number of factors, including mining method, equipment selection, geology, economies of scale, ore composition, and customer requirements.

It is also important to keep in mind the small sample size used in this bandwidth study. This report is based on the *E&E Profile,* which studies eight commodities selected by the Department of Energy and the National Mining Association for analysis. Further, the energy estimates for each commodity are limited by the number of mining methods analyzed for that commodity. Given the small sample size, there are obviously uncertainties associated with extrapolating energy requirements across the mining industry. Nevertheless, the eight commodities analyzed account for over 78% of energy consumption in U.S. mining, representing the majority of the energy-saving opportunity. Moreover, many of the commodities analyzed can be representative of other commodities (e.g., copper of molybdenum and gold of platinum).

Despite the uncertainties involved in estimating the entire mining industry's energy consumption, this study's estimates correspond well with other estimates of mining energy consumption. According to the EIA Annual Energy Outlook 2006, the mining industry (including oil and natural gas) consumes approximately 2,500 TBtu/yr,[18] or approximately 3,000 TBtu/yr including electricity losses. The EIA data include oil and natural gas mining along with other mining activities in its published values for mining industry energy consumption. This report estimates that the coal, metal, and mineral mining industries alone consume 1,246 TBtu/y, or about 1/3 of total mining energy consumption (including oil and natural gas).

[17] SME Mineral Processing Handbook. Table 10. Average Work Indexes. 1985.

[18] Annual Energy Outlook 2006 Supplemental Tables: Table 32

6. Conclusion

The U.S. mining industry's (coal, metals, and industrial minerals) current energy consumption is approximately 1,246 TBtu/yr (10^{12} Btu/yr); metal mining accounts for the largest amount of energy (552 TBtu/yr), followed by coal (485 TBtu/yr) and minerals (209 TBtu/yr).

As illustrated in the bandwidth chart in Exhibit 15 below, the industry can potentially save 667 TBtu/yr (258 TBtu/yr from implementing best practices and 409 TBtu/yr from R&D that improves mining technology). The largest energy savings can be realized in the metal mining industry (338 TBtu/yr), followed by the coal mining industry at 237 TBtu/yr (Exhibit 16).

Exhibit 15. U.S. Mining Industry Energy Bandwidth

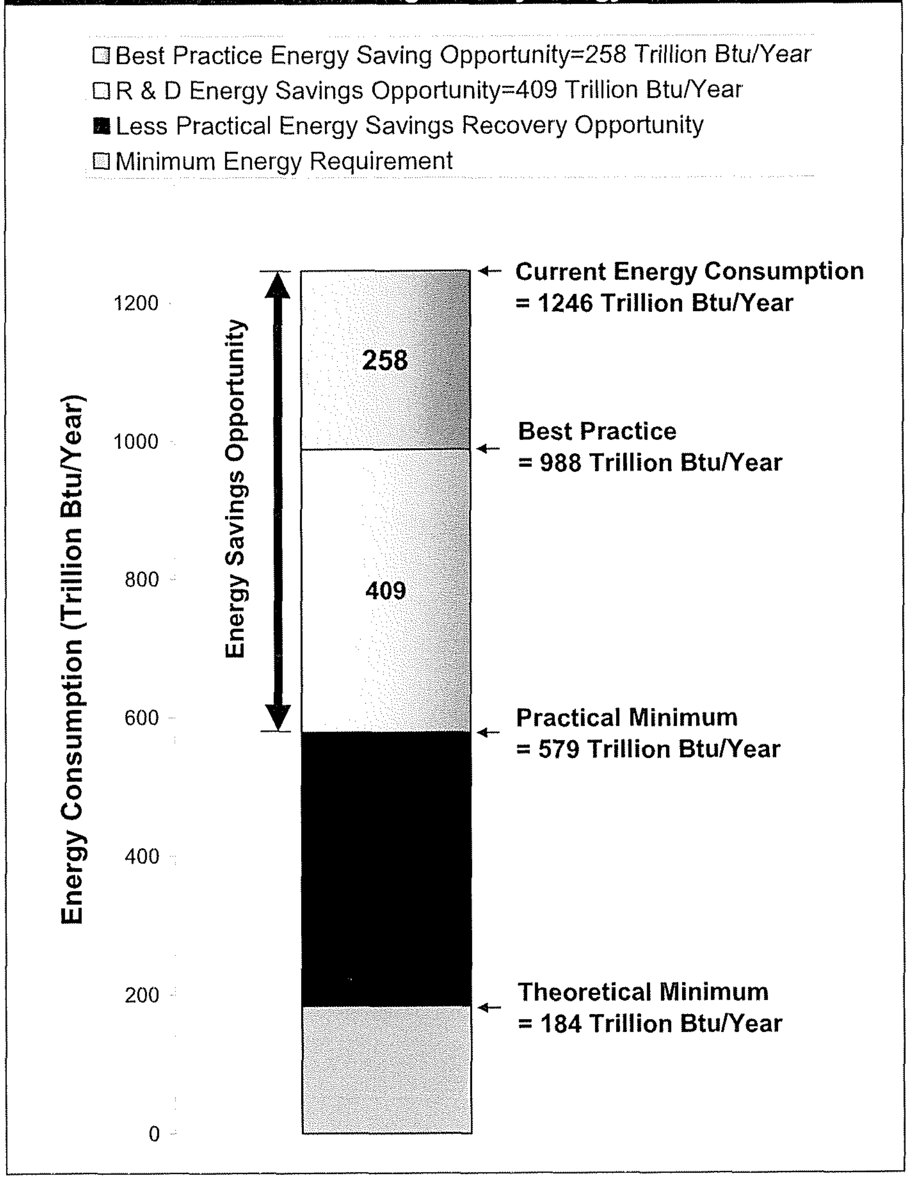


Exhibit 16. U.S. Mining Industry Energy Bandwidth for Coal, Metal, and Mineral Mining

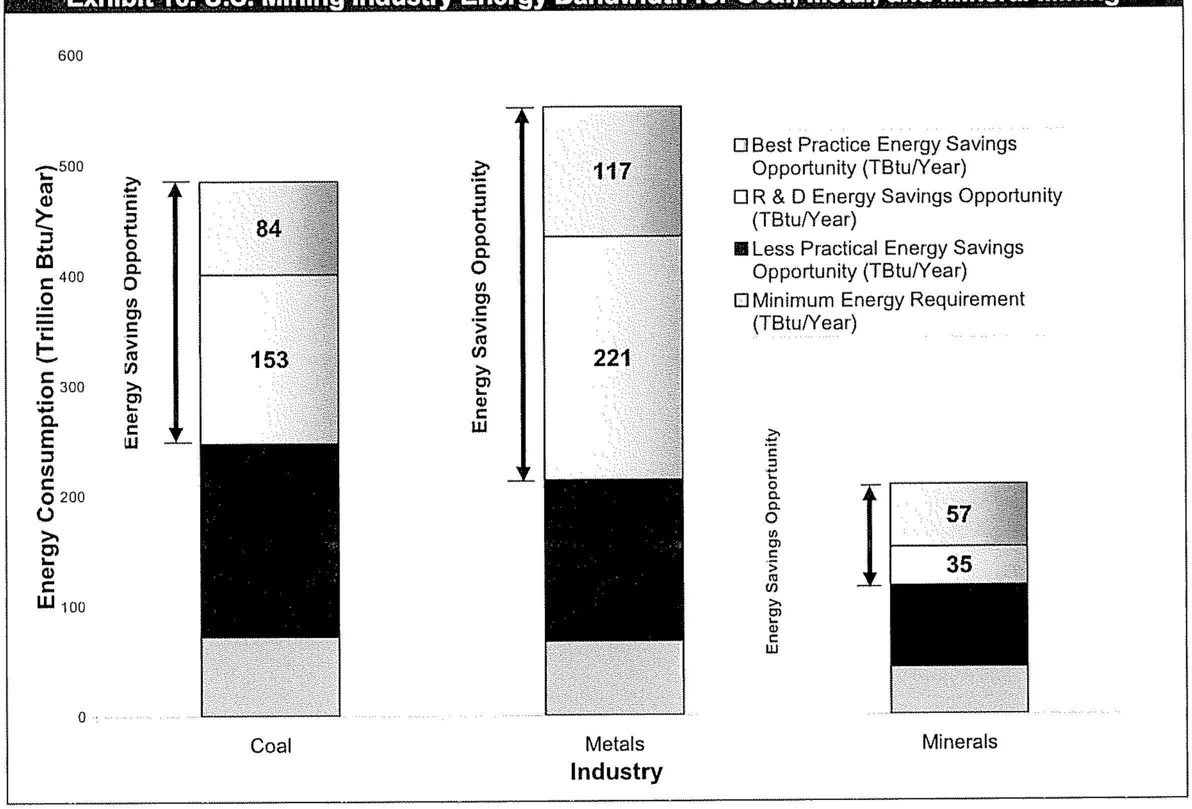


Exhibit 17 describes the current energy use by equipment category in the U.S. mining industry. The largest energy consuming equipment types are grinding (40%) and materials handling (17%).

Exhibit 17. Contribution of Current Energy Use by Equipment across the Mining Industry (Values account for electricity losses)

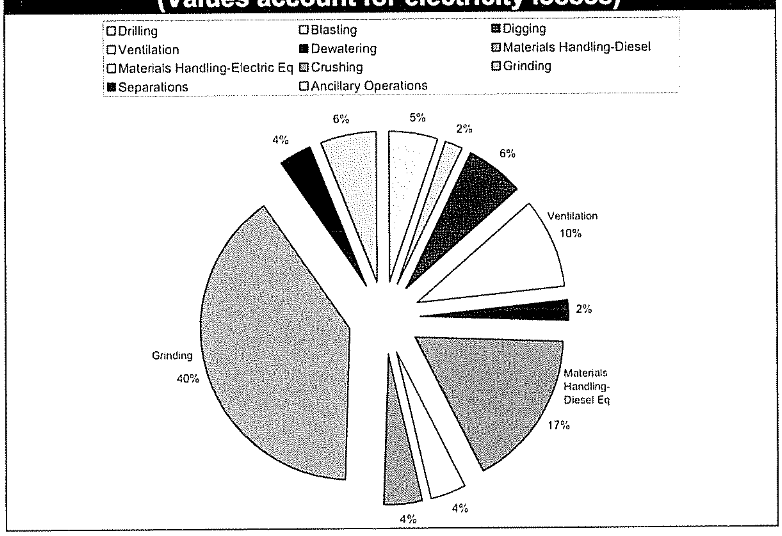
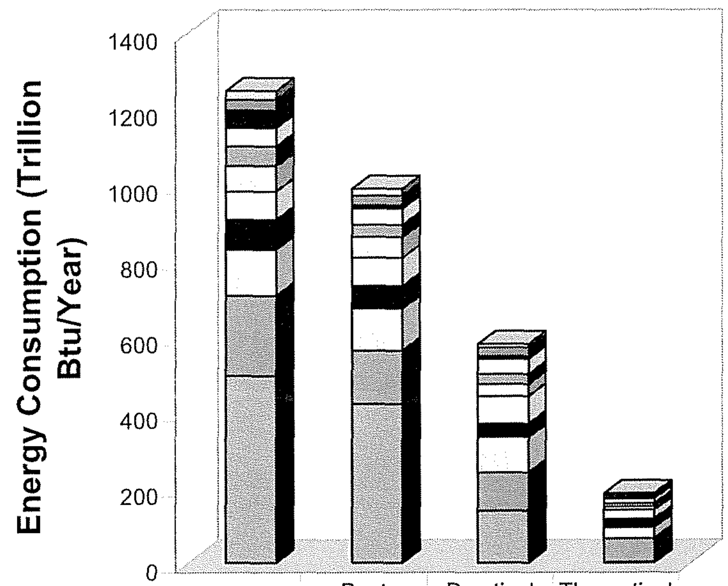


Exhibit 18 below displays the estimated current, best practice, practical minimum, and theoretical minimum energy consumption for each equipment type. It is noteworthy that the energy consumption associated with grinding far outweighs the energy consumption of other operations. Grinding currently consumes about 494 TBtu/yr, while materials handling diesel equipment is the next largest energy consumer, using only 211 TBtu/yr, or less than half of the energy required for grinding. The third largest energy consuming equipment is ventilation, requiring only 122 TBtu/yr. Equipment energy consumption for individual industries – coal, metals and minerals – is provided in Appendix B, while percent contribution of each equipment type to the industry's total energy consumption can be found in Appendix C.

Exhibit 18. Energy Consumption and Saving Potential by Equipment Type (TBtu/Yr)

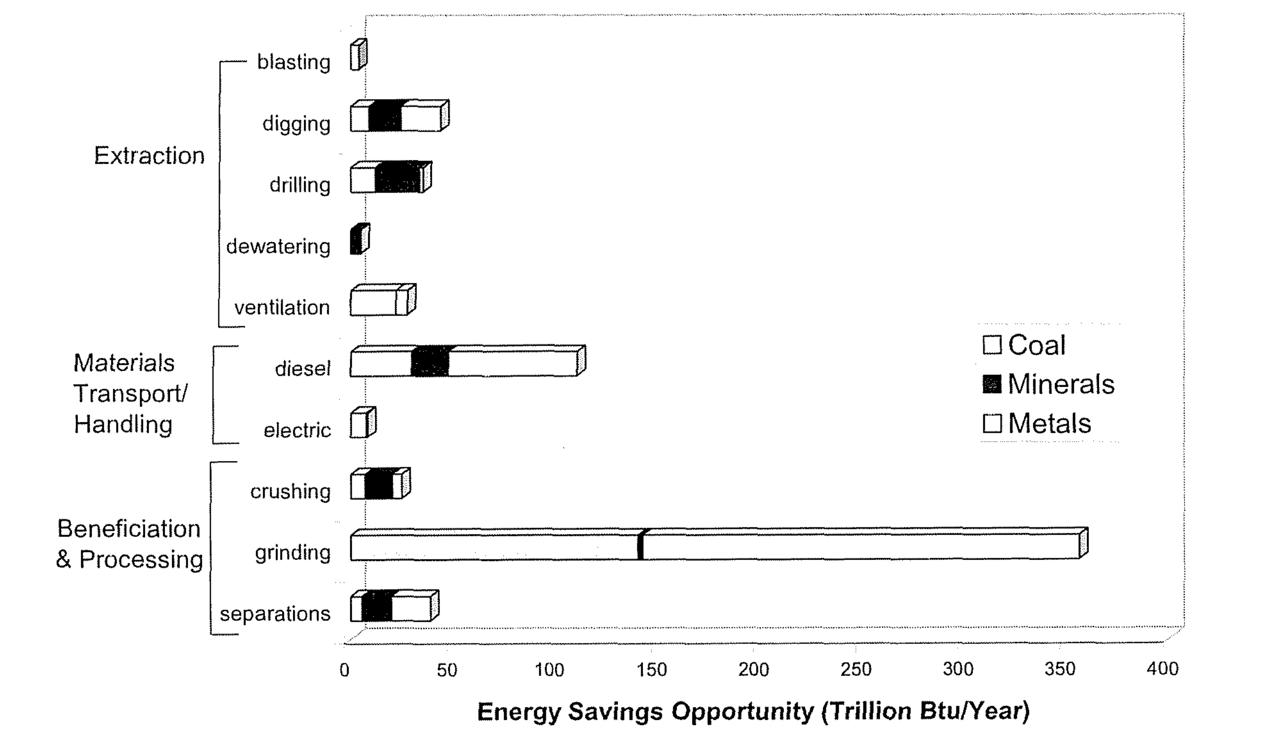


	Current	Best Practice	Practical Minimum	Theoretical Minimum
Blasting	24	18	10	5
Dewatering	28	25	23	7
Separations	46	8	7	2
Electric Equipment	48	43	40	13
Crushing	52	32	27	8
Drilling	67	54	32	9
Ancillary Operations	75	75	72	24
Digging	79	60	35	22
Ventilation	122	111	94	29
Materials Handling-Diesel	211	141	101	63
Grinding	494	420	138	2

Note: Values assume that production rates remain constant and are based on coal, metals, and minerals mining data.

The top two energy-consuming processes, grinding and materials handling (diesel equipment), offer tremendous opportunities for energy savings, as shown in Exhibit 19. If the energy consumption of grinding and materials handling diesel equipment alone could be reduced to their practical minimum, then the mining industry would save approximately 467 TBtu/yr, or about 70% of the 667 TBtu/yr energy savings achievable if **all** processes were reduced to their practical minimum energy consumption. The majority of savings potential is offered by the metals and coal mining industries.

Exhibit 19. Energy Saving Opportunity in U.S. Mining Industry for Top 10 Energy-Intensive Processes (includes energy savings from implementing best practices and R&D)



Key Findings of Bandwidth Analysis

- Implementation of best practices in coal, metal and mineral mines could save 258 TBtu/yr.
- Continued R&D developing more energy-efficient technologies could save an additional 409 TBtu/yr.
- A combined energy savings from best practice investments and further R&D could allow for total savings of 667 TBtu/yr or 54% of the total energy consumption of the mining industry.
- CO_2 emission reduction achievable from total practical energy savings is estimated to be 40.6 million tonnes.
- The largest energy savings opportunity (70%) lies in improving the energy efficiency of the two most energy-consuming processes – grinding and materials handling, particularly in the metal and coal mining industries.

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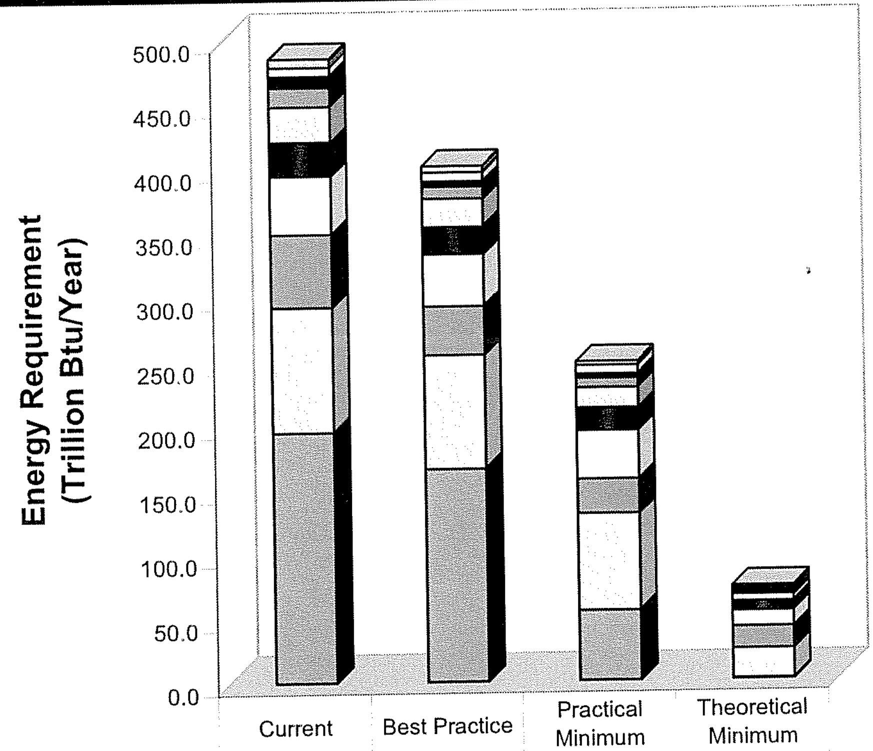
Appendix A: Current Energy Consumption and Savings Potential by Equipment Category in Coal, Metal, and Mineral Mining

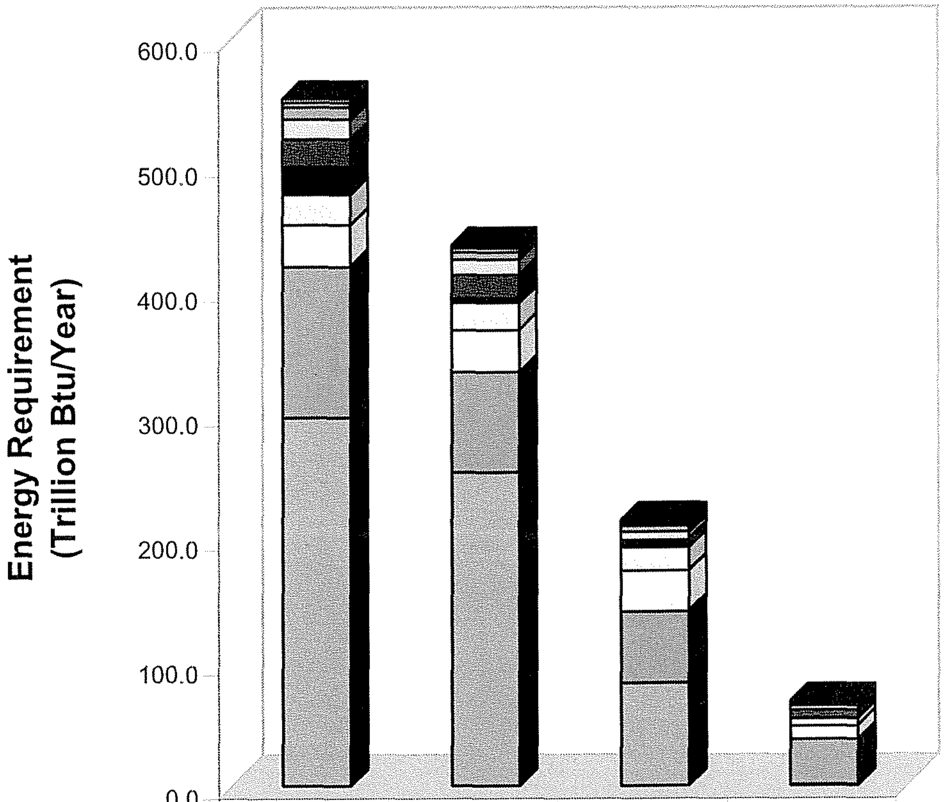
Note: Values are reported in TBtu/yr, assuming that mining production rates remain constant. Electricity losses are included.

Exhibit 20. Energy Consumption by Equipment Category in Coal Mining Industry (TBtu/yr)



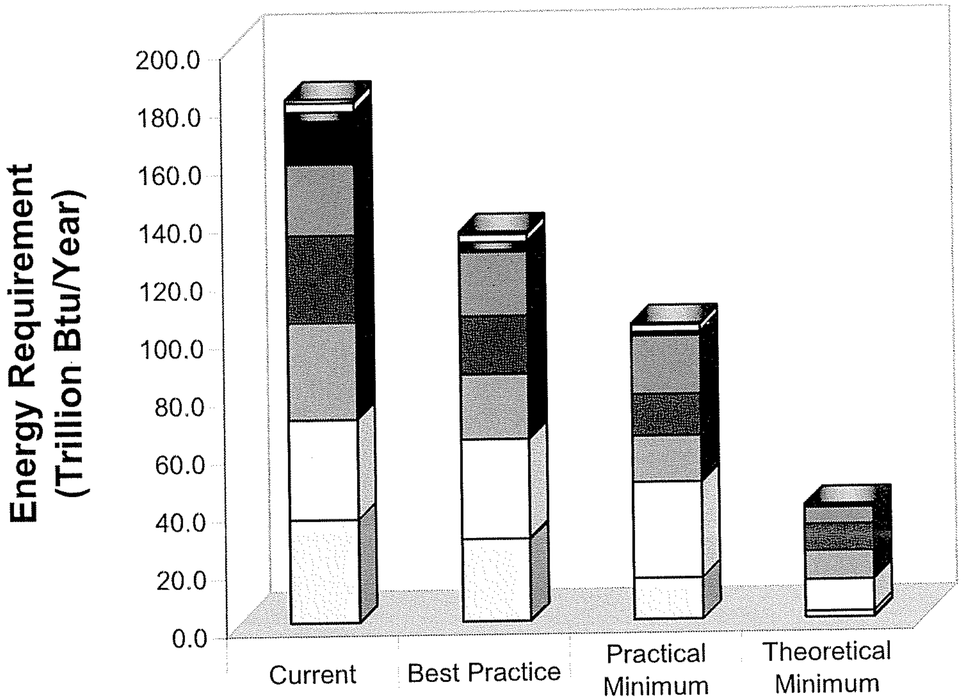
	Current	Best Practice	Practical Minimum	Theoretical Minimum
Blasting	6.7	5.0	2.7	1.5
Ancillary Operations	6.9	6.9	6.7	2.2
Separations	8.8	4.2	3.3	0.9
Crushing	14.6	9.1	7.6	2.3
Drilling	27.7.	22.1	15.6	5.4
Digging	26.4	21.3	17.6	7.3
Materials Handling Electric Equipment	45.3	40.4	37.7	12.1
Materials Handling Diesel Equipment	56.7	37.8	27.0	17.0
Ventilation	97.3	88.5	75.3	23.0
Grinding	194.8	165.6	54.4	0.6

Exhibit 21. Energy Consumption by Equipment Category in Metal Mining Industry (TBtu/yr)



	Current	Best Practice	Practical Minimum	Theoretical Minimum
Dewatering	3.1	2.8	2.6	0.7
Drilling	3.7	3.0	2.1	1.3
Crushing	9.6	6.0	5.0	1.5
Blasting	16.0	12.3	6.6	3.7
Digging	22.1	18.6	2.9	6.0
Separations	22.2	3.6	3.2	0.9
Ventilation	24.3	22.1	18.8	5.7
Ancillary Operations	33.8	33.8	32.5	10.6
Diesel Equipment	120.9	80.6	57.6	36.3
Grinding	296.3	251.9	82.7	0.9

Exhibit 22. Energy Consumption by Equipment Category in Mineral Mining Industry (TBtu/yr)



	Current	Best Practice	Practical Minimum	Theoretical Minimum
Blasting	1.3	1.0	0.5	0.3
Electric Equipment	3.1	2.8	2.5	0.7
Grinding	3.2	2.7	0.9	0.0
Separations	14.9	0.6	0.5	0.1
Dewatering	24.6	22.2	20.2	5.8
Digging	30.1	20.1	14.3	9.0
Diesel Equipment	33.7	22.5	16.1	10.1
Ancillary Operations	34.5	34.5	33.3	10.9
Drilling	35.8	28.6	14.3	2.2

Appendix B: Energy Requirements and Efficiencies of Equipment Types in Coal, Metals and Minerals Mining

Exhibits 23, 24, and 25 below display the calculated energy requirements of coal, metals, and minerals mining. Values include only onsite energy consumption and neglect electricity losses. See Appendix D for assumptions used. Exhibit 26 provides energy data by equipment based on tacit electricity consumption, or inclusive of electricity losses.

Exhibit 23. Energy Requirements and Efficiencies of Equipment Types in Coal Mining in Btu/yr (neglecting electricity losses)

Mining Area	Equipment	Current Energy Requirements (Btu/ton)	Current Practice Efficiency	Best Practice Efficiency	Best Practice Energy Requirement (Btu/ton)	Maximum Attainable Efficiency	Practical Minimum Energy Requirement (Btu/ton)	Theoretical Minimum Energy Requirement (Btu/ton)
Extraction	**Drilling**	8,800	47%	59%	7,000	81%	5,100	4,200
	Blasting	5,100	23%	30%	3,800	56%	2,000	1,100
	Digging	10,500	53%	66%	8,500	78%	7,200	5,600
	Ventilation	23,400	75%	82%	21,300	93%	18,800	17,600
	Dewatering	NA						
Materials Handling	**Diesel Equipment**	43,300	30%	45%	28,900	63%	20,600	13,000
	Electric Equipment	10,900			9,700	0%	9400	9,300
	Conveyor (motor)	500	85%	95%	400	98%	400	400
	Load Haul Dump	10,400	85%	95%	9,300	98%	9000	8,900
	pumps							
Beneficiation and Processing	**Crushing and Grinding**	50,400			42,100		15,500	2,200
	Crushing	3,500	50%	80%	2,200	92%	1,900	1,800
	Grinding	46,900	1%		39,900		13,600	500
	Separations	2,100			1,000		800	700
	Centrifuge	1800	27%	41%	700	86%	600	500
	Flotation	400	64%	79%	300	86%	300	200
	Subtotal	**154,600**			**122,300**		**79,500**	**55,900**
	Ancillary Operations	**1,700**			**1,700**		**1,700**	**1,700**
	Total	**156,200**			**124,000**		**81,200**	**57,600**

Exhibit 24. Energy Requirements and Efficiencies of Equipment Types in Metal Mining in Btu/yr (neglecting electricity losses)

Mining Area	Equipment	Current Energy Requirements (Btu/ton)	Current Practice % Efficiency	Best Practice Efficiency	Best Practice Energy Requirement (Btu/ton)	Max Practical Efficiency	Practical Minimum (Btu/ton)	Theoretical Minimum Energy Requirement (Btu/ton)
Extraction	**Drilling**	1,800	45%	57%	1,500	80%	1,000	800
	Blasting	9,900	23%	30%	7,600	56%	4,100	2,300
	Digging	6,000	63%	75%	5,000	84%	4,500	3,700
	Ventilation	4,700	75%	82%	4,300	93%	3,800	3,600
	Dewatering (pumps)	600	75%	83%	600	88%	500	500
Materials Handling	**Diesel Equipment**	74,900	30%	45%	50,000	63%	35,700	22,500
	Electric Equipment	NA						
	motor	NA	85%	95%		98%		
	load haul dump	NA						
	pumps	NA	75%	83%		88%		
Beneficiation and Processing	**Crushing and Grinding**	59,800			50,400		17,800	1,500
	Crushing	1,900	50%	80%	1,200	92%	1,000	900
	Grinding	57,900	1%	1%	49,200	3%	16,800	600
	Separations	4,300			700		600	600
	Centrifuge	NA						
	Flotation	900	64%	79%	700	86%	600	600
	Subtotal	**162,148**			**120,017**		**68,043**	**35,445**
	Ancillary Operations	**6,599**			**6,599**		**6,599**	**6,599**
	Total	**168,746**			**126,616**		**74,642**	**42,044**

Exhibit 25. Energy Requirements and Efficiencies of Equipment Types in Mineral Mining in Btu/yr (neglecting electricity losses)

Mining Process	Equipment	Current Energy Requirement (Btu/ton)	Current Practice Efficiency	Best Practice Efficiency	Best Practice Energy Requirement (Btu/ton)	Maximum Attainable Efficiency	Practical Minimum Energy Requirement (Btu/ton)	Theoretical Minimum Energy Requirement (Btu/ton)
Extraction	**Drilling**	5,200	22%	27%	4,100	53%	2,100	1,100
	Blasting	400	23%	30%	300	56%	100	100
	Digging	8,500	30%	45%	5,600	63%	4,000	2,500
	Ventilation	3	75%	82%	3	93%	3	2
	Dewatering	2,200	75%	83%	2,000	88%	1,900	1,600
Materials Handling	**Diesel Equipment**	9,500	30%	45%	6,300	63%	4,500	2,800
	Electric Equipment	271	75%	84%	245	88%	231	205
	Conveyor (Motor)	12	85%	95%	11	98%	11	11
	Load Haul Dump	NA						
	pumps	259	75%	83%	234	88%	221	194
Beneficiation and Processing	**Crushing and Grinding**	2,700			1,780		1,414	1,233
	Crushing		50%	80%	1,537	92%	1,332	1,230
	Grinding	300	1%		240		82	3
	Separations	1,300			100			
	Centrifuge							
	Flotation	100	64%	79%	100	87%		
	Subtotal	**30,000**			**20,400**		**14,400**	**9,700**
	Ancillary Operations	**3,100**			**3,100**		**3,100**	**3,100**
	Total	**33,000**			**23,500**		**17,400**	**12,800**

Exhibit 26. Current, Best Practice, Practical Minimum, and Theoretical Minimum Energy Consumption (TBtu/yr, including electricity losses)

		Coal				Metals				Minerals			
Mining Process	**Equipment**	**Current**	**Best Practice**	**Practical Minimum**	**Theoretical Minimum**	**Current**	**Best Practice**	**Practical Minimum**	**Theoretical Minimum**	**Current**	**Best Practice**	**Practical Minimum**	**Theoretical Minimum**
Extraction	**Drilling**	27.7	22.1	15.6	5.4	3.7	3.0	2.1	1.3	35.8	28.6	14.3	2.2
	Blasting	6.7	5.0	2.7	1.5	16.0	12.3	6.6	3.7	1.3	1.0	0.5	0.3
	Digging	26.4	21.3	17.6	7.3	22.1	18.6	2.9	6.0	30.1	20.1	14.3	9.0
	Ventilation	97.3	88.5	75.3	23.0	24.3	22.1	18.8	5.7	0.0	0.0	0.0	0.0
	Dewatering	0.0	0.0	0.0	0.0	3.1	2.8	2.6	0.7	24.6	22.2	20.2	5.8
Materials Handling	**Diesel Equipment**	56.7	37.8	27.0	17.0	120.9	80.6	57.6	36.3	33.7	22.5	16.1	10.1
	Electric Equipment	45.3	40.4	37.7	12.1	0.0	0.0	0.0	0.0	3.1	2.8	2.5	0.7
	motor	1.9	1.7	1.6	0.5	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0
	LHD	43.3	38.7	36.1	11.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	pumps	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.9	2.6	2.4	0.7
Beneficiation and Processing	**Crushing and Grinding**	209.4	174.7	63.9	2.9	305.9	257.9	90.6	2.4	30.9	20.0	15.4	4.4
	Crushing	14.6	9.1	7.6	2.3	9.6	6.0	5.0	1.5	27.7	17.3	14.5	4.4
	Grinding	194.8	165.6	56.3	0.6	296.3	251.9	85.6	0.9	3.2	2.7	0.9	0.0
	Separations	8.8	4.2	3.3	0.9	22.2	3.6	3.2	0.9	14.9	0.6	0.5	0.1
	Centrifuge	7.3	3.0	2.2	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Flotation	1.5	1.2	1.1	0.3	4.5	3.6	3.2	0.9	0.7	0.6	0.5	0.1
	Subtotal	478.3	394.1	243.0	70.3	518.3	400.9	184.3	57.2	174.4	117.8	83.8	32.8
	Ancillary Operations	6.9	6.9	6.7	2.2	33.8	33.8	32.5	10.6	34.5	34.5	33.3	10.9
	Total	485.3	401.0	249.7	72.5	552.1	434.6	216.8	67.8	208.9	152.3	117.1	43.6

Appendix C: Total Energy Consumption by Mining Stage across Coal, Metals and Minerals Mining (TBtu/yr)

Exhibit 27. Current, Theoretical Minimum, Best Practice, and Practical Minimum Energy Consumption across Coal, Metal, and Mineral Mining (TBtu/yr, including electricity losses)

Mining Process	Equipment	Current	Best Practice	Practical Minimum	Theoretical Minimum
Extraction	Drilling	67	54	32	9
	Blasting	24	18	10	5
	Digging	79	60	35	22
	Ventilation	122	111	94	29
	Dewatering	28	25	23	7
Materials Handling	Diesel Equipment	211	141	101	63
	Electric Equipment	48	43	40	13
	motor	2	2	2	1
	LHD	43	39	36	12
	pumps	3	2.6	2.4	0.7
B&P	Crushing and Grinding	546	453	165	10
	Crushing	52	32	27	8
	Grinding	494	420	138	2
	Separations	46	8	7	2
	Centrifuge	7	3	2	1
	Flotation	7	5	5	1
	Subtotal	**1171**	**913**	**506**	**160**
	Ancillary Operations	**75**	**75**	**72**	**24**
	Total	**1246**	**988**	**579**	**184**

Appendix D: Assumptions for U.S. Mining Industry Bandwidth Analysis

Exhibit 28. Assumptions Used in Estimating Theoretical Minimum, Practical Minimum, and Best Practice Energy Consumption

	Theoretical Minimum Energy Consumption	Practical Minimum Energy Consumption	Best Practice Energy Consumption
Notes	The theoretical minimum energy requirement is based on the current efficiency of equipment and current equipment energy consumption. Theor. Energy=Curr. Energy x efficiency Efficiency estimates and sources are listed below.	Practical minimum energy is the energy that would be required after R&D achieves substantial improvements in the energy efficiency of mining technology. Values are derived from researchers' estimates of practical efficiency improvements. In cases where such estimates were unavailable, this study uses a "2/3 rule of thumb" to estimate practical minimum energy. As explained in the text, the practical minimum energy consumption is assumed to be 2/3 of the way between best practice energy requirement and theoretical minimum energy requirements. PM = BP -2/3(BP-TM) where PM = Practical Minimum, BP = Best Practice, and TM = Theoretical Minimum.	Best practice energy consumption was determined from a variety of sources describing mining operations that use significantly less energy compared to typical operations.
Equipment Category			
Extraction			
Drilling	Calculations for the theoretical minimum energy requirement are based on the current energy efficiency of drilling. Nordlund (1989) simulates drill efficiency of the drill bit for various levels of thrust. 0.72 was a midway value for drill efficiency. In this study, 0.72 is used as the current average efficiency of the drill bit but not the drill rig. The drilling efficiency is combined with the efficiency of diesel engines (30%) and electric motors (85%). The distribution of electric and diesel drilling equipment was approximated using the SHERPA model equipment lists. The efficiencies of motors and diesel engines are	2/3 rule (see above)	Assumed the best practice mine consumes 80% of the energy of the typical mine. This was based on a study benchmarking the energy consumption of Canadian mines (CIPEC 2005). Mines ranking in the lower quartile for energy consumption consumed 80% of the energy of typical mines.

	discussed in the "materials handling section below."		
Blasting	Eloranta (1997) reports a blasting efficiency of 15% to 30%. An average value of 23% was used for current blasting efficiency.	2/3 rule	Best practice blasting efficiency was assumed to be 30%, the upper estimate provided in Eloranta (1997).
Digging	Assumed that the efficiency of digging equipment corresponds to the efficiencies of diesel engines and electric motors. The distribution of diesel and electric powered equipment was approximated using the SHERPA model equipment lists.	Assumed that the practical minimum efficiency of digging equipment corresponds to the practical minimum efficiencies of diesel engines and electric motors.	Assumed that the best practice efficiency of digging equipment corresponds to the best practice efficiencies of diesel engines and electric motors.
Ventilation	Basu (2004) provides an example of a large complex underground mining ventilation system using a combined fan and motor efficiency of 75%	2/3 rule	Basu 2004 provides a best practice example with 97% motor efficiency and 85% fan efficiency, yielding 82% combined efficiency
Dewatering	Assumed dewatering efficiency is described by the efficiency of pumps used to remove water from the mine workings.	Assumed practical minimum dewatering efficiency is described by the efficiency of pumps used to remove water from the mine workings.	Assumed best practice dewatering efficiency is described by the efficiency of pumps used to remove water from the mine workings.
Materials Handling			
Diesel Materials Handling Equipment	U.S. DOE (2003) reports 45% efficiency for diesel equipment. However, conversations with industry experts indicate that 30% is a more appropriate estimate, due to older equipment in use.	U.S. DOE (2003) reports further advances for diesel engines are possible up to 63%	U.S. DOE (2003) reports 45% efficiency for diesel equipment.
Electric Materials Handling Equipment			
Conveyer (motor)	The average efficiency of conveyers was assumed to correspond to the efficiency of typical electric motors. U.S. DOE (1996) reports a variety of efficiencies for electric motors. 85% is a typical value for motor efficiency.	2/3 rule	U.S. DOE (1996) reports a variety of efficiencies for electric motors. The most efficient motors are around 95% efficient.
Load Haul Dump	The average efficiency of Load-Haul-Dumps was assumed to correspond to the efficiency of typical electric motors (85%, see above)	2/3 rule	Based on 95% best practice efficiency for motors (see above).
Pumps	According to the Hydraulic Institute (2003), the current catalogue mean for pump efficiency is 75%.	Hydraulic Institute (2003): Maximum attainable efficiency is approximately 88%.	Hydraulic Institute (2003): highest efficiency pumps currently available operate at about 83% efficiency.

Beneficiation and Processing			
Crushing	AOG (2005) reports current crushing efficiency of 50%.	2/3 rule	Eloranta 1997: Highest estimate of crushing efficiency at about 80% efficiency
Grinding	Grinding efficiency estimates vary significantly, depending on methods used. 1% efficiency was found to be the most common estimate. Sources citing 1% efficiency include AOG (2005), Eloranta (1997), Perry's (1963), Hukki (1975), Willis ((1998), Greenwade and Rajamani (1999).	2/3 rule	Greenwade and Rajamani (1999): Recent R & D improving grinding mills can reduce energy consumption 15%.
Centrifuge	Assumes the theoretical minimum energy of a centrifuge is the amount of energy required to bring a unit mass of coal in a centrifuge to a target rotational speed. If sufficient time is available, the centrifuge speed could operate at a fairly slow speed. Theoretical minimum energy calculated for a unit mass of coal with 0.7 mass concentration, in a 70 in. diameter centrifuge rotating at 300 rpm. Current efficiency values were based on this calculation of theoretical minimum energy.	2/3 rule	Mine and Mill Equipment Costs (2005). Best practice centrifuge energy consumption based on lowest energy consuming centrifuges in equipment list.
Flotation	Mechanical equipment in flotation machines includes air compressors and rotating impellers. Efficiency is assumed to be the product of electric motor and pump efficiency.	Practical efficiency is assumed to be the product of practical maximum electric motor and pump efficiency.	Best practice efficiency is assumed to be the product of best practice electric motor and pump efficiency.

Appendix E: Glossary of Mining Terms

ANFO	Ammonium Nitrate Fuel Oil, used as a blasting agent.
Beneficiation	The dressing or processing of coal or ores for the purpose of (1) regulating the size of a desired product, (2) removing unwanted constituents, and (3) improving the quality, purity, or assay grade of a desired product.
Blasting	Blasting uses explosives to aid in the extraction or removal of mined material by fracturing rock and ore by the energy released during the blast.
Byproduct	A secondary or additional product.
Coal	A readily combustible rock contain more that 50% by weight and more than 70% by volume of carbonaceous material, including inherent moisture; formed form compacting and in duration of variously altered plant remains similar to those in peat. Difference in the kinds of plant materials (type), in degree of metamorphism (rank), and in the range of impurity (grade) are characteristic of coal and are used in classification.
Crushing	Crushing is the process of reducing the size of run-of- mine material into coarse particles.
Dewatering	Dewatering is the process of pumping water from the mine workings.
Digging	Digging is to excavate, make a passage into or through, or remove by taking away material from the earth. The goal of digging is to extract as much valuable material as possible and reduce the amount of unwanted materials.
Drilling	Drilling is the act or process of making a cylindrical hole with a tool for the purpose of exploration, blasting preparation, or tunneling.
Electrowinning	An electrochemical process in which a metal dissolved within an electrolyte is plated onto an electrode.
Emissions	A gaseous waste discharged for a process.
Grinding	Grinding is the process of reducing the size of material into fine

	particles.
In situ	In the natural or original position. Applied to a rock, soil, or fossil occurring in the situation in which it was originally formed or deposited.
Materials Handling	The art and science involving movement, packaging , and storage of substances in any form. In this study, the materials handling equipment were categorized as diesel and electric equipment. In general, diesel fuel powers rubber tire or track vehicles that deliver material in batches, while electricity powers continuous delivery systems such as conveyors and slurry lines.
Mill	(a) A plant in which ore is treated and minerals are recovered or prepared for smelting. (b) Revolving drum used in the grinding of ores in preparation for treatment.
Ore	The naturally occurring material from which a mineral or minerals of economic value can be extracted profitably or to satisfy social or political objectives.
Overburden	Designates material of any nature, consolidated or unconsolidated, that overlies a deposit of useful materials, ores, oar coal that are mined from the surface.
Reclamation	Restoration of mined land to original contour, use, or condition.
Refining	The purification of crude metallic products.
Separations	The separation of mined material is achieved primarily by physical separations rather than chemical separations, where valuable substances are separated from undesired substances based on the physical properties of the materials.
Slurry	A fine carbonaceous discharge from a mine washery.
Surface Mining	Mining at or near the surface. This type of mining is generally done where the overburden can be removed without too much expense. Also called strip mining; placer mining, opencast; opencut mining; open-pit mining.
Tailings	The gangue and other refuse material resulting from the washing, concentration, or treatment of ground ore.
Underground	Mining that takes place underground. This type of mining is

Mining	generally done where the valuable material is located deep enough where it is not economically viable to be removed by surface mining.
Ventilation	Ventilation is the process of bringing fresh air to the underground mine workings while removing stale and/or contaminated air from the mine and also for cooling work areas in deep underground mines.

CERTIFICATE OF SERVICE

I certify that I mailed a copy of Direct Testimony and Exhibits of Tim Woolf on Behalf of the Sierra Club by first class mail on April 1st, 2013 to the following:

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