SIERRA CLUB
FOUNDED 1892

Via Postage and Electronic Mail

August 6th, 2012

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

Re: Sierra Club Response to BREC Requests for Information
Docket 2012-00063

Dear Mr. DeRouen:

Enclosed for the filing are an original and ten copies of Sierra Club's response to Big Rivers Electric Company's initial request for information, including verification pages. Copies of this letter and all enclosures have been served on each of the persons listed on the attached service list. A copy of the information for which confidential treatment is sought has also been served on each party that has entered into Big Rivers' confidentiality agreement and will be filed with the Commission separately today.

Sincerely,

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

Commonwealth of Kentucky
Before the Public Service Commission

In the Matter of:

APPLICATION OF BIG RIVERS ELECTRIC CORPORATION FOR APPROVAL OF ITS 2012 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, FOR CERTIFICATES OF PUBLIC CONVIENENCE AND NECESSITY, AND FOR AUTHORITY TO ESTABLISH A REGULATORY ACCOUNT.	)	Case No. 2012-00063

BEN TAYLOR AND SIERRA CLUB'S OBJECTIONS AND RESPONSES TO BIG RIVERS ELECTRIC CORPORATION'S FIRST REQUEST FOR INFORMATION TO SIERRA CLUB

Intervenors Ben Taylor and Sierra Club (collectively "Environmental Intervenors") hereby submit their responses and objections to Big Rivers Electric Corporation's ("Big Rivers") First Requests for Information.

GENERAL OBJECTIONS

A. Environmental Intervenors object to Requests that seek information that is not relevant to the above-referenced proceedings, Kentucky Rule of Evidence 401.

B. Environmental Intervenors object to Requests that are not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1).

C. Environmental Intervenors object to Requests that seek information that is protected by the First Amendment of the U.S. Constitution.

D. Environmental Intervenors object to Requests that are overly broad, unduly burdensome,

oppressive, and calculated to take Sierra Club and its staff away from normal work activities, and require them to expend significant resources to provide complete and accurate answers to Big Rivers' Request, which are only of marginal value to Big Rivers, Kentucky Civil Rule 26.02.

E. Environmental Intervenors reserve all of its evidentiary objections or other objections to the introduction or use of any response at any hearing in this action.

F. Environmental Intervenors do not, by any response to any Request, waive any objections to that Request.

G. Environmental Intervenors do no admit to the validity of any legal or factual contention asserted or assumed in the text of any Request.

H. Environmental Intervenors reserve the right to assert additional objections as appropriate, and to amend or supplement these objections and responses as appropriate.

I. The foregoing general objections shall apply to each of the following Requests whether or not restated in the response to any particular response.

CERTIFICATE OF SERVICE

I certify that I mailed a copy of the following documents by first class mail on August 6, 2012 to the below parties of record:

- Sierra Club Responses to First Request for Information

James M. Miller, Esq.
Tyson Kamuf
Sullivan, Mountjoy, Stainback & Miller, PSC
100 Saint Ann Street
P.O. Box 727
Owensboro, KY 42302-0727

Jennifer B. Hans
Larry Cook
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Assistant Attorney General's Office
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36 East Seventh Street, Suite 1510
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David C. Brown, Esq.
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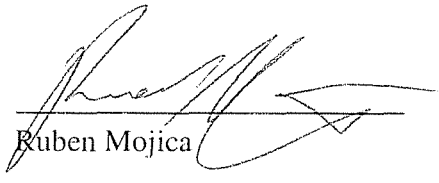
1800 Aegon Center, 400 West Market Street
Louisville, KY 40202



Ruben Mojica

VERIFICATION

STATE OF)
) **SS:**
VERMONT)

The undersigned, Dr. William Steinhurst, being duly sworn, deposes and says that he is an Associate with Synapse Energy Economics, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

William Steinhurst

Subscribed and sworn before me
on this 2nd day of August, 2012

Notary Public

ANNABEL L GONYAW
NOTARY PUBLIC, VERMONT
MY COMMISSION EXPIRES FEB. 10, 2015

VERIFICATION

STATE OF MASSACHUSETTS)
) SS:
COUNTY OF MIDDLESEX)

The undersigned, Rachel Wilson, being duly sworn, deposes and says that she is an Associate with Synapse Energy Economics, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Rachel Wilson

Subscribed and sworn before me
on this 3 day of August, 2012

Notary Public

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

SPECIFIC RESPONSES AND OBJECTIONS

Request No. 1

Please refer to page 10 of Dr. Steinhurst's testimony, lines 13-16, where he states that Synapse compared the Build Case to a natural gas combined cycle unit "using several combinations of more appropriate assumptions." Please list each input and assumption Synapse changed, explain why the input or assumption was changed, and provide all analyses, documents, or other bases supporting the change.

Response to Request No. 1 - Respondent: William Steinhurst

Please see the Sierra Club's response to Commission Staff data request No. 10.

Request No. 2

Please refer to page 11 of Dr. Steinhurst's testimony, beginning at line 20, where he states, "It is also contrary to the experience of national leaders in energy efficiency who have found it possible to achieve savings in excess of 1% of retail sales per year consistently for a decade or more."

a. Please provide all documents upon which Mr. Steinhurst bases that statement.

b. Please list each utility Mr. Steinhurst is referring to in that statement, and for each utility listed:

   i. please provide the percentage of residential load to total load for each of the last 10 years, and

   ii. please state whether all of the energy savings Mr. Steinhurst mentions came from a reduction in residential energy consumption, and if not, provide the annual energy consumption reductions from residential consumers.

Response to Request No. 2 - Respondent: William Steinhurst

a. I am aware of four energy efficiency program administrators in the nation that have achieved savings at or in excess of 1% of retail sales per year over the past 10 years. They are Burlington (Vermont) Electric Department, Efficiency Vermont (the third party administrator for Vermont DSM programs other than Burlington Electric's territory), and two Connecticut investor utilities. Their achievements are found in the following documents:

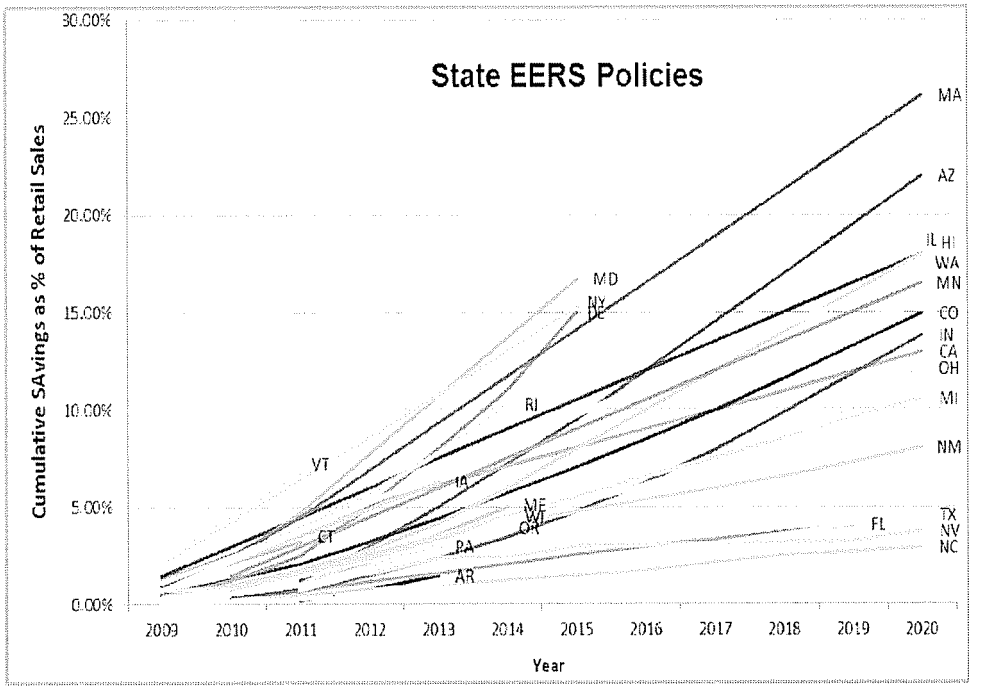
- Burlington Electric Department 2012. 2011 Energy Efficiency Annual Report, Figure 1, available at https://www.burlingtonelectric.com/page.php?pid=35&name=annual_ee_report
- Efficiency Vermont 2011. 2011 Savings Claim, Figure 2, available at http://www.efficiencyvermont.com/docs/about_efficiency_vermont/annual_reports/2011_Savings_Claim_Summary_EfficiencyVermont.pdf
- Connecticut Energy Conservation Management Board. Annual Energy Efficiency Reports from 2001 to 2011, titled "Connecticut's Investment in Energy Efficiency," available at http://www.ctsavesenergy.org/ecmb/documents.php?section=12

In addition, the following two documents provide examples of energy efficiency program administrators or utilities that achieved 1% annual savings or more over multiple years in the past.

- Garvey, E. 2007. "Minnesota's Demand Efficiency Program." Presentation to the National Action Plan for Energy Efficiency – Midwest Implementation Meeting, Minneapolis, Minn. June 21, Slide 14, available at http://www.epa.gov/cleanenergy/documents/suca/mw-jun-07_garvey.pdf
- K. Takahashi and D. Nichols 2008. The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date, proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings, ACEEE, pp. 8-363 - 8-375.

Finally, note that there are many states across the country that have established long-term aggressive energy efficiency goals that go beyond the 1% level to as much as 2 or 2.5%

per year. Some twenty states have set cumulative savings goals for 2020 in excess of 10%. The figure below is taken from a recent study by ACEEE on state energy efficiency resource standards.



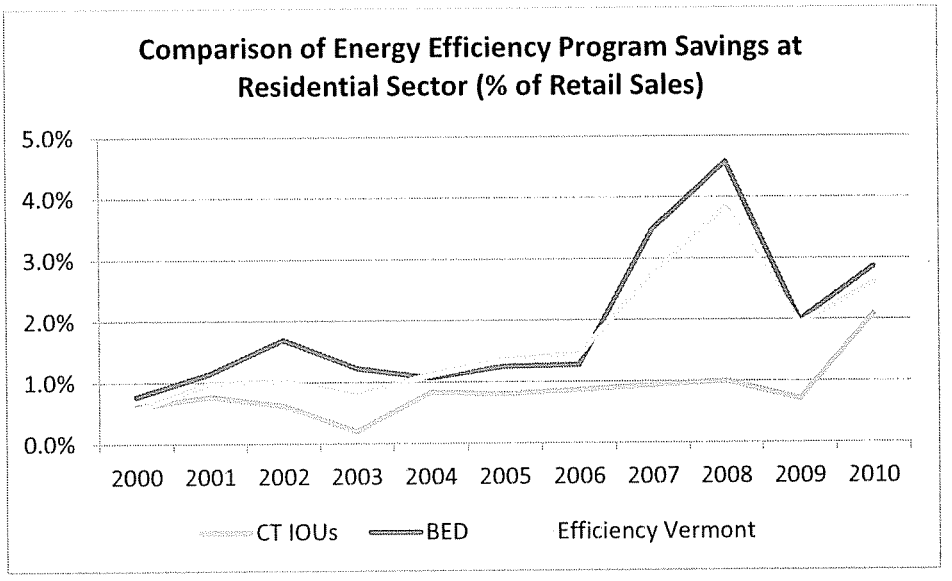
Source: ACEEE 2011. Energy Efficiency Resource Standards: A Progress Report on State Experience, June 2011, available at http://aceee.org/research-report/u112

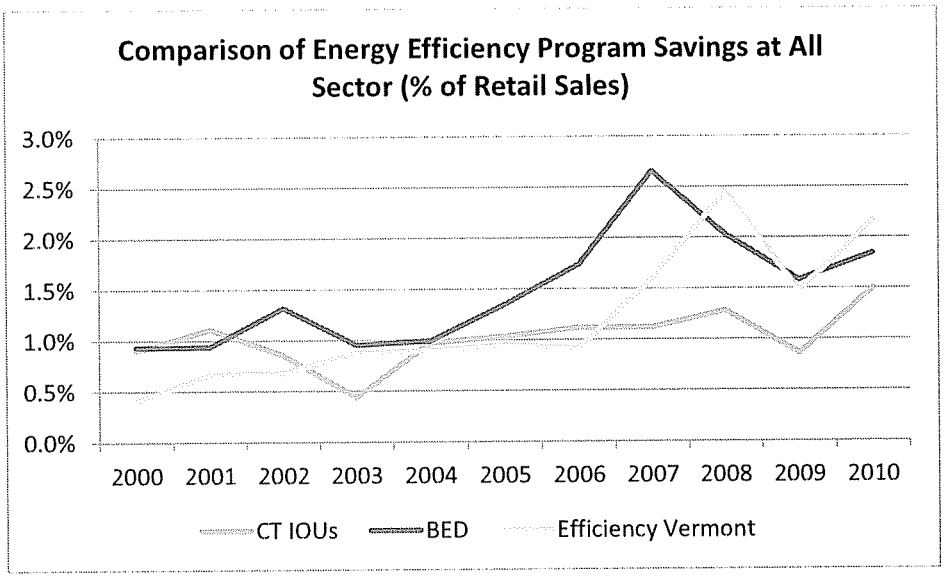
b. i. The following table shows residential load as percentage of total load from 2000 to 2010 for Connecticut investor owned utilities (IOUs) (combining United Illuminating Company and CLx), Burlington Electric Department (BED), and Efficiency Vermont. The underlying sales data are based on the Energy Information Administration's Form EIA-861 data files.[1]

[1] http://www.eia.gov/electricity/data/eia861/index.html

	CT IOUs	BED	Efficiency Vermont
2000	40%	27%	37%
2001	40%	27%	37%
2002	41%	27%	37%
2003	42%	27%	38%
2004	42%	26%	38%
2005	43%	26%	38%
2006	42%	25%	38%
2007	40%	25%	38%
2008	42%	24%	38%
2009	44%	25%	40%
2010	44%	24%	39%

ii. Energy savings achieved by the four leading energy efficiency program administrators mentioned above are based on efficiency implementations at all sectors. The level of residential energy savings (as % of retail sales) by Efficiency Vermont and Burlington Electric Department (BED) are in general higher than the level of savings at all sectors. See the following two figures, which are compiled based on energy savings data provided in annual energy efficiency reports by BED, Efficiency Vermont, and Connecticut Energy Conservation Management Board (ECMB).


Comparison of Energy Efficiency Program Savings at Residential Sector (% of Retail Sales)
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
CT IOUs
BED
Efficiency Vermont


Comparison of Energy Efficiency Program Savings at All Sector (% of Retail Sales)
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010
CT IOUs
BED
Efficiency Vermont

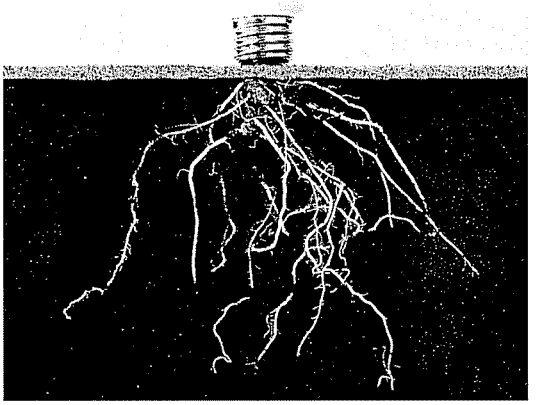
REQUEST 1-2

Attachment 1

CONNECTICUT
ENERGY EFFICIENCY FUND

CONNECTICUT'S INVESTMENT IN ENERGY EFFICIENCY

2010 Report of the Energy Efficiency Board



1 March 2011

The Year in Review: Expanding Our Commitment to Connecticut's Environment

A Message from the Chair and Vice Chair

We are pleased, as the Energy Efficiency Board's Chair and Vice-Chair, to proudly deliver the Board's Year 2010 Programs and Operations Report to the Connecticut legislature. Within this annual report, we will detail how the Energy Efficiency Fund has fulfilled its primary objectives of advancing the efficient use of energy to:

(1) reduce ratepayer bills;
(2) promote economic development and provide energy security/affordability; and
(3) reduce air pollution and other negative environmental impacts.[1]

2010 was a positive year in the fulfillment of our mission. Continuing a positive trend started in 2000, Connecticut has once again been ranked among the top ten states in the nation for energy efficiency policies and implementation. This is a tribute to the willingness of the state's residents and business owners to embrace our commitment to a more energy-efficient future and a tacit endorsement of the policies and legislation that created the Connecticut Energy Efficiency Fund in 1998. Because Connecticut has such a large and active portfolio of successful programs in place, the state was the recipient of American Recovery and Reinvestment Act (ARRA) funding to supplement these award-winning energy-saving programs. This critical funding played an important role in 2010 and will continue to be expended in 2011.

It is important to note that energy-saving programs offered through the Energy Efficiency Fund play a vital economic role for Connecticut. For every $1 spent on energy efficiency, Connecticut receives electric, gas and fuel oil system benefits of more than $3. This return demonstrates that Energy Efficiency Fund programs are a powerful agent in resolving the state's economic crisis: they reduce customer costs, generate critical green jobs, and make the state more competitive by lowering business operating costs.

It is in this context, then, that we urge the state legislature to refrain from allocating Energy Efficiency Fund resources—resources paid by the state's ratepayers—as part of a solution to close the state's budget gap. It will not only stall the momentum we have all worked so hard to achieve, but would represent unsound economic policy as well. The state budget passed in 2010 includes re-allocation of Energy Efficiency Fund resources to the state's General Fund beginning in 2012. We hope this report underscores the importance of continued funding of these programs for the environmental and economic well-being of the state.

The Energy Efficiency Board is grateful for your support in the past and looks forward to enjoying your continued support in the coming years. We are committed to working cooperatively with legislators and all of Connecticut's energy stakeholders to continue the state's leadership position in the important national energy efficiency effort.

Sincerely yours,

Richard W. Steeves
Energy Efficiency Board,
Chairperson

Jeffrey R. Gaudiosi
Energy Efficiency Board,
Vice-Chairperson

[1] Conn. Gen. Stat. §16-245m. reference 16-32f for natural gas measures.

Connecticut Energy Efficiency Fund 2010 Achievements and Highlights

- **ACEEE:** *Exemplary State Energy Efficiency Programs*
  Home Energy Solutions/Office of Policy & Management Clean, Tune & Test joint program.
- **Association of Energy Engineers (AEE-CT):** *Leadership in Energy Efficiency Award, 10 Energy Project Awards*
  Energy Opportunities, Residential New Construction's Zero Energy Challenge, Small Business Energy Advantage, and Retro Commissioning.
- **Business New Haven:** *Connecticut Green Business Award*
  Home Energy Solutions—Income Eligible.
- **ENERGY STAR®:** *Sustained Excellence Award*
  Participant in the Northeast Retail Products Initiative.
- **The Connecticut Quality Improvement Award, Inc.:** *Innovation Prize*
  Gold Prize: Home Energy Solutions/Office of Policy & Management Clean, Tune & Test joint program.
  Silver Prize: Business Sustainability Challenge.

Energy Efficiency Fund programs contribute to the more than 2,675 jobs that result directly from energy efficiency and serves as an economic development engine creating private sector businesses which deliver energy efficiency services.

DOE Grant Funds Green Initiatives

The Energy Efficiency Fund leveraged a $3 million Department of Energy (DOE) grant to create the Connecticut Green and Healthy Homes Initiative (CTGHHI), which offers limited-income families education on energy assistance and health and safety matters. These funds also provide cross training of partner and program staff while expanding the number of homes weatherized, rehabilitated and made safe and healthy beyond the standard scope of the Energy Efficiency Fund's Income Eligible weatherization program. The strength of the grant is due to private and public partnerships with municipalities, healthcare organizations, social service groups and grassroots organizations.

Created in 1998 with the purpose of helping small and large businesses, homeowners and renters, and state and local governments use energy more efficiently.

Who We Are and What We Do

Created in 1998 with the purpose of helping small and large businesses, homeowners and renters, and state and local governments use energy more efficiently, our mission is simple yet powerful:

- To advance the efficient use of energy
- To reduce air pollution and negative environmental impacts
- To promote economic development and energy security

The Energy Efficiency Board (formerly known as the Energy Conservation Management Board) is an appointed group of 14 members who represent private and public entities who serve voluntarily and meet year-round. These members reflect a cross section of interests, providing representation for residential, business, community and municipal consumers. The Board is assisted by consultants who are nationally recognized as experts in their respective fields. The original purpose of the Energy Efficiency Board was to advise and assist the state's two electric distribution companies, The Connecticut Light and Power Company (CL&P) and The United Illuminating Company (UI), in both the development and implementation of Energy Efficiency Fund programs. The Energy Efficiency Board's oversight was expanded with the passage of 2005 legislation to include the energy efficiency programs of the Connecticut Municipal Electric Energy Cooperative (CMEEC) and the state's natural gas utilities—Connecticut Natural Gas Corporation, The Southern Connecticut Gas Company and Yankee Gas Services Company. The inclusion of natural gas measures was integrated into the existing portfolio of programs and services, providing additional savings for customers without having to navigate multiple administrative systems. With receipt of American Recovery and Reinvestment Act funds, we have also been able to leverage our services to include more fuel oil measures, an effort already underway through partnerships with State agencies such as the Office of Policy and Management and the Department of Social Services. Additionally, we have established procedures for public comment to factor into our decisions and actions.

Load Management and Peak Demand

In addition to the Energy Efficiency Fund's work in the area of energy efficiency, we are equally committed to balancing electric supply and demand, otherwise known as load management. Energy efficiency and load management programs reduce peak demand. These programs result in a broad range of benefits to Connecticut's residents and businesses including a reduction of Federally Mandated Congestion Charges (FMCCs) on electric bills, decrease in power plant and capital cost improvements, and improvement of transmission system reliability. Additionally, reductions in the quantity of energy and capacity that consumers will need in the future due to efficiency and/or demand response programs result in lower prices because the wholesale markets do not need to purchase the next most expensive unit. This impact of efficiency programs on market prices is referred to as the Demand-Reduction-Induced Price Effect (DRIPE).

The highest point of customer demand is called peak demand. New England's electrical grid is summer peaking, meaning the highest electrical demand occurs on hot, humid summer weekday afternoons. In addition to the Energy Efficiency Fund-supported and ISO-New England load management programs, the Fund promotes the Wait 'til 8 campaign—a marketing initiative to publicize energy conservation during peak demand times by encouraging residents to voluntarily shift use of major energy-consuming appliances from mid-afternoon to after 8 p.m.

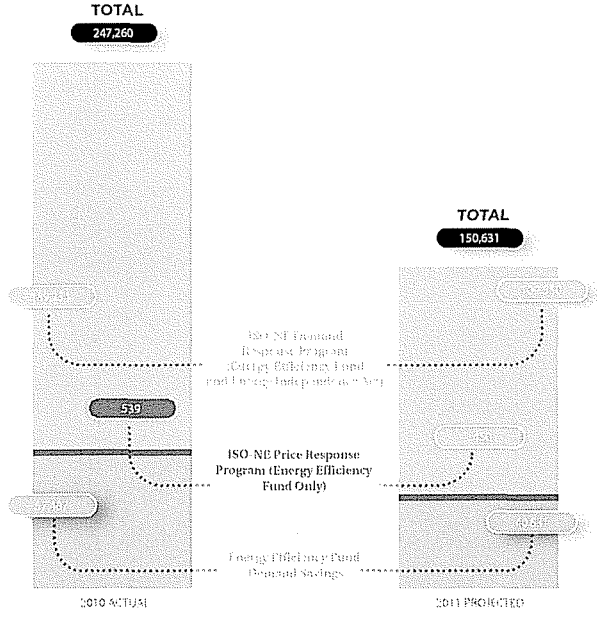
Verification and Evaluation

The Energy Efficiency Board and the Fund's administrators recognize the importance of evaluation studies to support continuous improvement of the programs. The programs undergo impact evaluations on a regular basis that are *conducted by third-party evaluators.* The purpose of impact evaluations is to verify that the reported savings are accurate. Savings are reported to regulatory bodies and used in both the ISO Forward Capacity and Connecticut Class III Renewable markets, and therefore, impact evaluations are a critical aspect of the process.

Customer Segments

The Energy Efficiency Board and its partner utilities tailor programs to ensure energy efficiency savings are broadly realized by all customer segments.

Peak Demand Savings Available from the Energy Efficiency Fund, CMEEC and ISO-New England Programs (in kW)



Summary of Energy Savings by Customer Sector
(in millions of kWh, thousands of dth and thousands of gallons)

	Annual Savings 2010			Lifetime Savings 2010		
Customer Sector	Electric	Natural Gas	Oil	Electric	Natural Gas	Oil
Limited-Income	17	559	727	145	8,230	10,456
Residential (Non Limited-Income)	244	947	981	1,496	18,793	19,428
Commercial & Industrial	162	1,070	0	2,076	14,068	0
Totals	423	2,576	1,708	3,717	41,091	29,884

"We recommend the Home Energy Solutions program to anyone we know that is thinking of changing or supplementing their heating/cooling units."

Ken and Ellen Rosengrant

Home Energy Solutions

Photo credit: Jeff Page

The flagship residential initiative is the Home Energy Solutions (HES) program. The HES Program began in 2006 as a residential duct sealing pilot. Since that time, it has evolved into a multi-million dollar retrofit program with numerous partner vendors delivering services to customers throughout Connecticut. In 2010, HES served approximately 34,000 households, a record for the program since its inception and an increase of nearly double compared to 2009.

In order to simplify our residential offerings and eliminate confusion, HES and the limited income programs formerly known as WRAP and UI Helps have been combined under the HES program umbrella. The limited income programs will now be known as HES-Income Eligible (HES-IE).

The HES program is a "whole-home solution" that focuses on reducing all energy consumption and costs. Building Performance Institute, Inc.-trained technicians perform an energy assessment of the home and provide a variety of on-the-spot efficiency and weatherization measures.

Homes receive diagnostic tests to assess air leakage throughout the home, including the ductwork. Critical leaks are then located with test equipment and professionally sealed. This instrument-guided air sealing is one of the quickest and least expensive ways to improve efficiency and lower heating and cooling bills. Ken and Ellen Rosengrant of Meriden, for example, are now saving just under $400 and approximately 548 kilowatt-hours and 110 gallons of fuel oil annually by installing a ductless heat pump in their new addition, upgrading to efficient lighting, and sealing their heating, ventilation and air conditioning (HVAC) ductwork. Dan and Marsha Carson of Newington enjoyed similar results—an annual savings of approximately $587 and an estimated total lifetime savings from weatherization and water heating services of 3,726 kilowatt-hours and 1,942 gallons of oil.

Lighting and water-saving measures are installed by technicians and the efficiency of insulation and appliances are also assessed. Technicians review the work completed at a "kitchen table" wrap-up to ensure homeowners understand the services performed and the resulting energy savings.

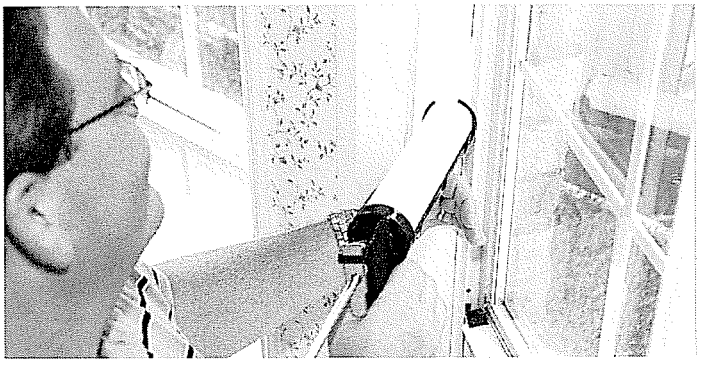
Additional efficiency technologies and energy conservation behaviors are also discussed with the homeowner and the technicians review available appliance/insulation rebates, renewable energy options, tax credits and potential financing opportunities to encourage additional investments in efficiency.

Residential Financing Pilot

New residential financing became available in June, allowing residents to borrow from $2,500 to $20,000 at below-market interest rates for qualifying improvements recommended through the Home Energy Solutions program and performed by an approved contractor. This funding source makes it easier for customers to act on the recommendations made by technicians during a HES evaluation, thereby extending the depth of energy improvements made throughout the state.

New Report Card Tool

A new report card was developed for use by HES technicians to create a home energy estimate measure or "yardstick." The report card helps customers understand the savings and cost-effectiveness of implementing the follow-up recommendations made by the HES technician.



Supporting Fuel Blind Energy Efficiency

The infusion of American Recovery and Reinvestment Act (ARRA) funds has enabled the Energy Efficiency Fund to include oil-heat customers at the same, low $75 co-pay as natural gas and electric-heat customers enjoy. This has been a critical step in promoting fuel blindness in energy efficiency programming and reducing heating oil bills for customers. The HES program took full advantage of the ARRA funding, receiving $6.2 million and expending it on almost 15,000 projects.

Home Energy Solutions - Home Performance (HES-HP)

Home Performance (HES-HP) is an advanced approach to energy efficiency. In HES-HP, participants work with their utility program administrators to identify savings and custom energy efficiency measures beyond the basic HES core services. These measures may include installation of additional insulation, new ENERGY STAR® appliances, efficienct heating systems, etc. Along with the new financing pilot, these incentives encourage and enable residents to make substantial, comprehensive changes in their home. Modeled after the commercial and industrial retrofit program, this program was created to maximize energy savings opportunities in the residential sector.

2010 Home Energy Solutions

Customers Served
34,296

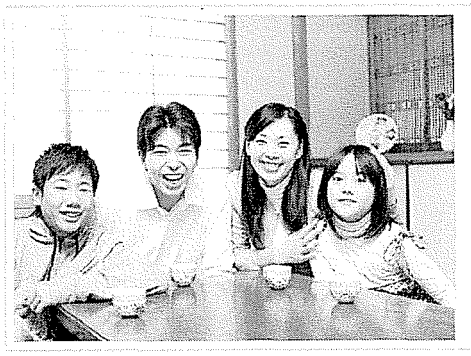
Energy Savings

kWh Annual	CCF Annual	Gallons Annual
37.7 Million	308 Thousand	379 Thousand
kWh Lifetime	**CCF Lifetime**	**Gallons Lifetime**
466.1 Million	15.7 Million	19.4 Million

CO_2 Emissions Reduced
55,757 Tons (Annual)

Annual Savings
$10.4 Million

Lifetime Savings
$150.7 Million



The Energy Efficiency Fund has always made assistance to Connecticut families with limited incomes a high priority.

Home Energy Solutions—Income Eligible (HES-IE)

The Energy Efficiency Fund has always made assistance to Connecticut families with limited incomes a high priority. Energy bills for these families represent a disproportionate percentage of their expenses, especially during this national economic downturn.

We continue to serve this vital need in Connecticut communities largely through partnerships with a myriad of social service agencies and community groups throughout the state. This network of agencies offers the most direct access to the population in need of assistance, and actively promotes the Home Energy Solutions—Income Eligible program to its client base. While we continue to serve income eligible residents directly, the partnerships we have developed with social service and community organizations has proved fruitful in identifying participants who can benefit from the program.

In some cases, the Energy Efficiency Fund covers all the costs associated with the projects. In other cases, we partner with the Connecticut Department of Social Services (DSS) to leverage funding from both sources for projects which are cost-shared. This enables us to provide greater and more comprehensive services and helps extend our reach to more eligible households.

"This is a great service. Everyone who is eligible should take advantage of this service." Karen Banger

2010 Home Energy Solutions — Income Eligible

Customers Served
15,347

Energy Savings

kWh Annual	CCF Annual	Gallons Annual
16.7 Million	558 Thousand	237 Thousand
kWh Lifetime	**CCF Lifetime**	**Gallons Lifetime**
145.2 Million	8.2 Million	10.4 Million

CO_2 Emissions Reduced
20,881 Tons (Annual)

Annual Savings
$6.1 Million

Lifetime Savings
$70.4 Million

HES-IE is similar to the HES core services program, however eligible participants receive the service at no cost and additional energy-saving measures are provided. Energy specialists assess a home's efficiency and perform a range of weatherization services such as installing CFLs, caulking cracks/leaks around doors and windows, and installing insulation. All weatherization measures are designed to reduce heating and cooling losses. Additional efficiency steps include installing water-saving faucet aerators and showerheads, and upgrading appliances and heating systems.

The Naugatuck Housing Authority's Oak Terrace apartment complex is an excellent example of how the program works in the community. In partnership with the Department of Social Services, major conservation measures were implemented at the 195-unit complex. These measures included air sealing, new ENERGY STAR® Low E Argon windows, energy-efficient lighting, water-saving devices, and the installation of ductless heat pumps. Ductless heat pumps were added to the program services in 2010 after being tested in a limited pilot in previous years. They have proven to be a very cost-effective alternative to expensive electric baseboard heat often found in many apartment complexes and housing authority properties. They reduce heating costs by approximately 40 percent and provide cooling in the summer usually adequate enough to avoid the use of inefficient air conditioning units. Because they do not require ductwork, installation is simple and much less disruptive to the residents. Incentives of more than $414,000 will save the complex approximately 9 million kilowatt-hours over the lifetime of the installed measures, and the average energy savings per unit is estimated at more than $533 per year.

The HES-IE program also serves individuals one household at a time. Through a mailing associated with Bridgeport's B-Green 2020 initiative, Karen Barber of Truman Street was informed about the available program services. Ms. Barber called at once to see if this could actually be true.

> "The technicians were very helpful, polite and really provided understanding to what they were doing," stated Barber.

Contractors arrived at her home and set-up the blower door test to find air leakage. The technicians caulked around the windows and realigned the windows in their tracking. A new door sweep and sealing around the door's frame took care of major air leaks. Additionally, energy-efficient light bulbs and water conservation devices were provided and installed. Ms. Barber will save almost 2,800 kilowatt-hours over the lifetime of these installed improvements.

The CT Zero Energy Challenge allowed us to demonstrate the viability of designing a New England Farm House that uses no energy.

– George and Mary Keithan

Residential New Construction

The Residential New Construction (RNC) program provides financial incentives and technical assistance to make integrating efficient design and technologies feasible in residential construction projects. Incentives are provided to architects, builders and homeowners to design new homes that incorporate energy-efficient technologies during the design phase.

The RNC program challenges architects and builders to move to a new, higher level of efficiency in construction—high-performance and zero-net energy homes. Incentives are available for electric and natural gas efficiency measures such as ENERGY STAR® for home certification, insulation, gas water heaters, geothermal heat pumps and other electrical HVAC equipment to meet greener building standards.

Zero Energy Challenge

In 2009, the Energy Efficiency Fund initiated Connecticut's first residential design and build competition for single- and multi-family homes called the CT Zero Energy Challenge. The Challenge awards monetary prizes to three winners, while serving as an educational platform for the state's building community regarding high-performance homes. All contestants are required to participate in the Residential New Construction program, and, in addition to energy efficiency measures, each home must incorporate clean, renewable energy technologies into the project's design. Zero-net energy means a home uses no more energy from the electrical grid over a given period than it produces. The challenge uses RESNET Rating Standards to determine each completed home's Home Energy Rating System (HERS) Index. The home with the lowest HERS Index, indicating it will use the least energy, wins the competition.

"This home demonstrates that energy efficiency isn't limited to a particular style, shape or look in a home," said Chris Trolle, Principal, BPC Green Builders. "Building a green house can provide high comfort levels and increased durability as well as lower operating costs."

2010 Residential New Construction

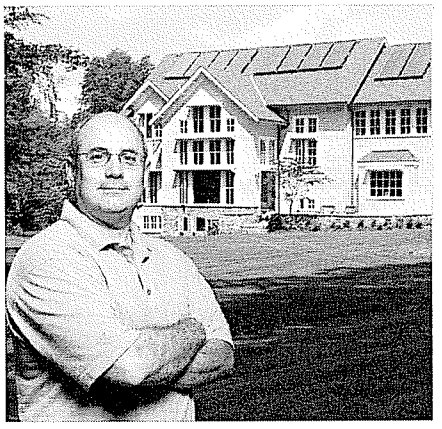
Customers Served
650

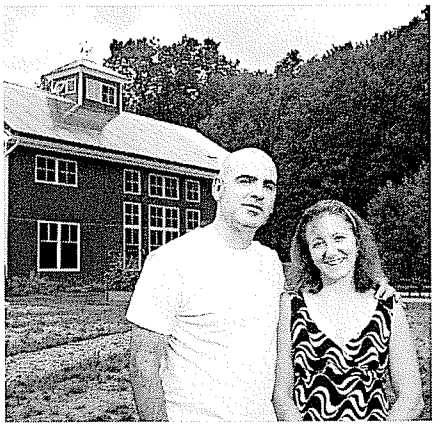
Energy Savings
kWh Annual
17 Million
kWh Lifetime
270 Million
CCF Annual
91 Thousand
CCF Lifetime
1.5 Million

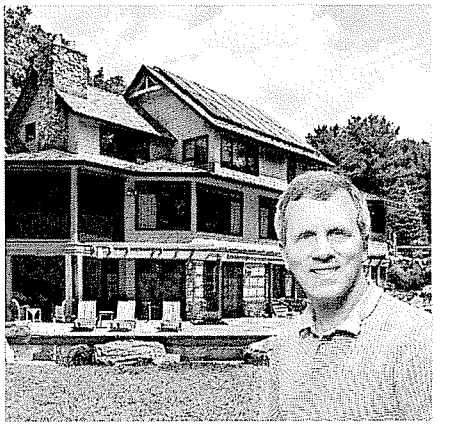
CO_2 Emissions Reduced
1,365 Tons (Annual)

Annual Savings
$417 Thousand

Lifetime Savings
$7.7 Million







Pictured in the photo from L to R: **First Place Winner**, George Keithan, President, Consulting Engineering Services; **Second Place Winner**, Jeremy & Karann Schaller; **Third Place Winner**, Chris Trolle, Principal, BPC Green Builders

Eighteen Connecticut homes participated in the Challenge (visit www.ctzeroenergychallenge.com for a list of participating projects). The following homes were winners in the 2009-2010 Zero Energy Challenge:

$15,000 First Prize:

The Killingworth home of George and Mary Keithan was designed as a classic New England home in a farm setting with all of today's modern systems and conveniences, wrapped up into a home requiring zero energy. By incorporating a geothermal heating and cooling system, passive and active solar systems, and an extremely energy-efficient building envelope, among other features, the home produced the best HERS rating of -7.

$10,000 Second Prize:

The new home of Jeremy and Karann Schaller is in rural New Hartford. The home features a highly energy-efficient structural insulated panel cladding system, passive and active solar design, innovative heating and cooling technologies, energy-efficient fixtures and appliances, and salvaged, recycled, or sustainable products as much as practically and economically possible. As a result, the Schaller's home resulted in a HERS rating of 4.

$5,000 Third Prize:

The New Canaan home of Chris Trolle is designed to look like a traditional Adirondack lodge, yet featured a wide array of energy-efficient technologies that helped to achieve the goal of certification within the Leadership in Energy and Environmental Design (LEED) for Homes program at the platinum level. Some innovative features included a heavily insulated building envelope, triple glazed windows, a solar thermal array for space heating, domestic hot water and summer pool heating, and thermal mass radiant slab heating for the main living area. The new home produced a HERS rating of 14.

2010 Retail Products

Customers Served
79,157

Products Sold
CFLs 5,282,491
Hard-Wired 25,812
Appliance Rebates/
Other Products 45,411

CO_2 Emissions Reduced
38,262 Tons (Annual)

Energy Savings
kWh Annual
204.3 Million
kWh Lifetime
1.0 Billion

Annual Savings
$37.0 Million

Lifetime Savings
$181.5 Million

Retail Products

The highlight of the Energy Efficiency Fund's retail products effort in 2010 continued to center around the promotion of Compact Fluorescent Light bulbs (CFLs). CFLs use 75 percent less electricity than incandescent bulbs while producing the same amount of light. The Fund's award-winning Retail Products program promotes the sale of CFLs in many of Connecticut's grocery, pharmacy, home improvement and big box stores by working with lighting manufacturers to rebate CFLs before they reach the shelf. This allows customers to purchase discounted CFLs without having to submit mail-in rebates or bring coupons to the store.

The Energy Efficiency Fund aggressively marketed the CFL discount program in 2010, including radio and print advertising. That advertising effort, along with in-store signage and promotion efforts, produced notable sales results—more than 5 million bulbs in 2010, which will save customers approximately $36.3 million annually. In addition, the Fund continues to support the emerging Light Emitting Diode (LED) lighting market, positioning itself to bring this emerging technology to more households in 2011.

The Energy Independence and Security Act of 2007 (EISA 2007) will phase out standard use incandescent bulbs beginning in 2012. However, several large manufacturers have started producing EISA-compliant halogen bulbs, which are approximately 30 percent more efficient than standard incandescent bulbs. These halogen bulbs, however, are far less efficient than standard CFLs. Therefore, it appears that there may be opportunities to continue to promote CFL technology even after the onset of EISA.

Lighting Fairs

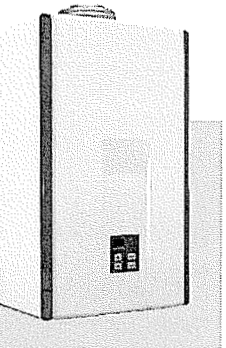
The Fund partners with a local retail lighting vendor and national ENERGY STAR® partner to offer lighting fairs throughout the year. These lighting fairs are hosted by commercial businesses, state agencies, home shows, state and town fairs, and non-profit organizations, allowing consumers to purchase CFLs and other lighting products at a discount.

SmartLiving™ Catalog

A 16-page catalog was developed for distribution at home shows, lighting fairs and other events that highlight a complete line of specialty CFLs, table and desk lamps, ceiling lights, outside lighting, LED products, and kilowatt-measuring meters.

Shining Solutions

A unique fundraising program that allows schools and community organizations to raise money by selling CFLs achieves two important goals: it helps organizations such as schools and community groups raise important funds and expands access to CFLs throughout Connecticut.



RETAIL REBATES

$300 Energy Efficiency Fund Natural Gas Hot Water Heater Rebate—incentive for installing an energy efficient indirect water heater attached to a natural gas ENERGY STAR® qualified boiler or an on-demand natural gas fired tankless water heater.

Connecticut Recovery Appliance Rebates—utilizing more than $5 million in funding from the American Recovery and Reinvestment Act, the Energy Efficiency Fund partnered with the Office of Policy and Management to deliver appliance rebates in 2010 for ENERGY STAR clothes washers, freezers, refrigerators, window air conditioners, central air systems, hot water heat pumps and packaged systems.

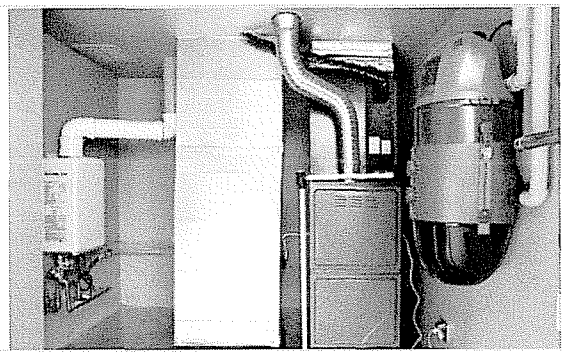
2010 Natural Gas Hot Water Rebates

Energy Savings
CCF Annual
37 Thousand
CCF Lifetime
739 Thousand

Annual Savings
$50 Thousand

Lifetime Savings
$1.0 Million

CO_2 Emissions Reduced
223 Tons (Annual)



Geothermal heat pump equipment

Cool Ways to Stay Warm

Ductless Heat Pumps

The ductless heat pump rebate program for electric heat customers was launched in Fall 2009 and was successfully extended in 2010. A rebate of up to $1,000, together with up to $1,500 in federal tax credits, has made ductless heat pumps a viable retrofit option for residents who currently heat their homes with more costly, less efficient electric resistance heat—they use approximately 40 percent less energy than electric baseboard heating systems.

In addition, the Energy Efficiency Fund has substantially increased its contractor training efforts to build a larger network of installers. That effort will enable the program to be extended to more program participants throughout the state.

Geothermal Systems

Geothermal heat pumps are a clean and efficient option that may help customers save on their heating and cooling costs. Rebates from the Energy Efficiency Fund of up to $1,500 are used to encourage the proper installation and testing of geothermal heat pumps. Customers may also qualify for federal tax incentives for qualifying ENERGY STAR equipment.

Heating/Ventilation/Air Conditioning (HVAC) Rebates

According to the U.S. Department of Energy, heating and cooling accounts for about half of the energy use in a typical American home. This is why the Energy Efficiency Fund provides a $500 incentive for installing certain ENERGY STAR central air conditioning or heat pump systems.

2010 Retail Rebates

Rebates by Category

Natural Gas Hot Water	603
HVAC, Including Geothermal Heat Pump	7,798
Appliances (ARRA funded)	45,064

Ductless heat pump outdoor unit

A fundamental priority of the Energy Efficiency Fund is educating Connecticut residents on the many issues related to living a sustainable, energy-efficient lifestyle.

Education and Outreach: At School, at Work and in Your Community

A fundamental priority of the Energy Efficiency Fund is educating Connecticut residents on the many issues related to living a sustainable, energy-efficient lifestyle. The Fund's educational outreach is delivered through a variety of mediums, including museum exhibits, public forums, school-based programs (kindergarten through college), trade shows and training seminars. These outreach efforts play a vital role in providing the information and tools needed for businesses, municipalities and residents to reduce energy consumption, lower energy bills and protect the environment.

*ee*smarts™

In 2010, the ***ee*smarts** program continued to offer custom and general professional development workshops to nearly 400 educators that gave hands-on, inquiry-based lessons on the basics of energy efficiency, renewable energy and electricity. The program is an energy efficiency and clean, renewable energy learning initiative providing professional development workshops and curriculum free-of-charge to Grade K-9 educators across the state.

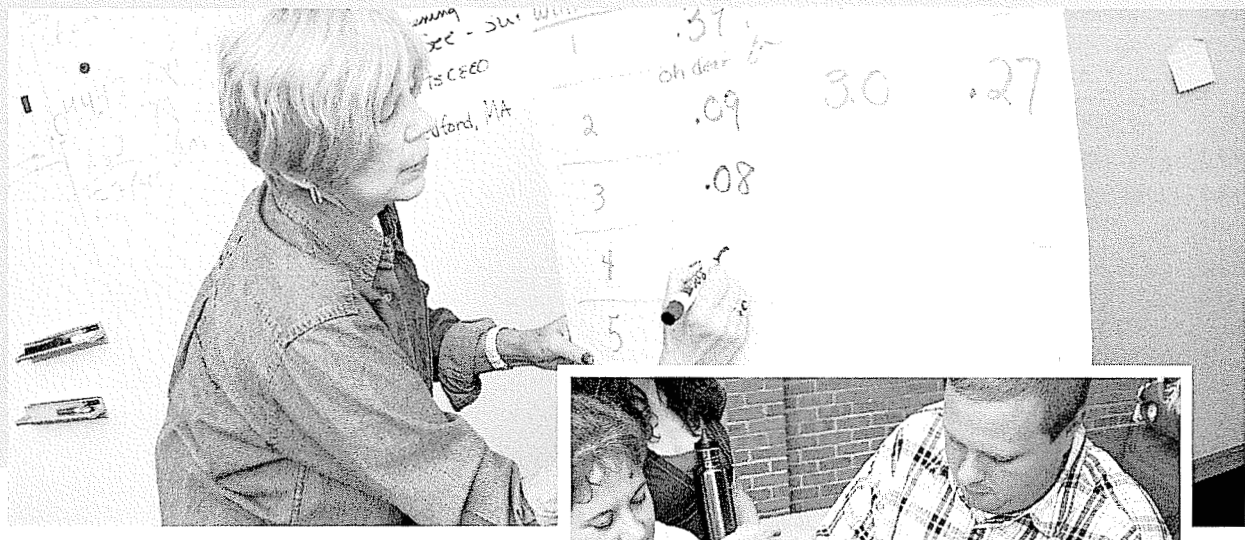
***ee*smarts** provides custom workshops for school districts and a Summer Institute for individual educators across the state from parochial, private, public and home schools. Workshops are led by the Project to Increase Mastery of Mathematics and Science at Wesleyan University. In 2010, the Energy Efficiency Fund began its eeEvents initiative—forums in which staff gave presentations, led classroom lessons and conducted direct outreach with children—not just educators. This highly successful initiative will continue in 2011.

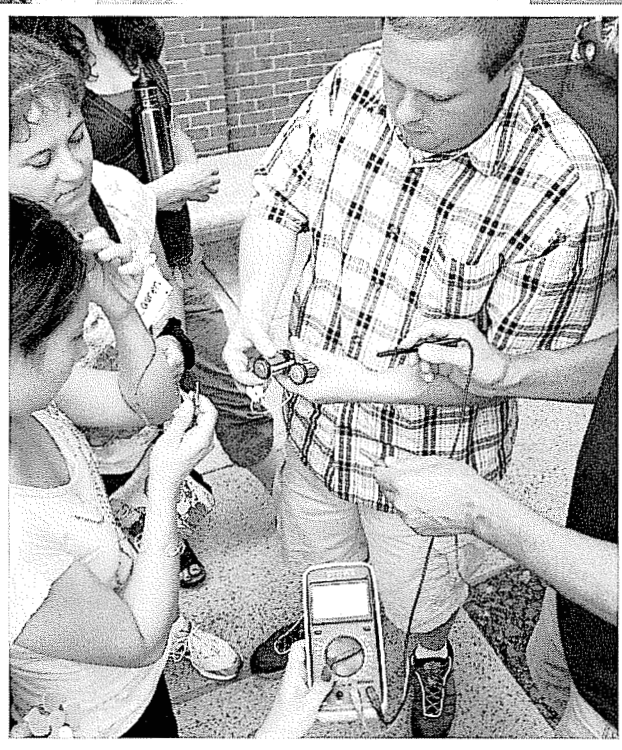
2010 *ee*smarts

Educators Trained
595

Curriculum Lessons Distributed
5,271

Events Held
9





eeCommunities

The eeCommunities program was developed to encourage communities to develop a sustainable and energy efficiency ethic in Connecticut's 169 towns and cities. The objective of this marketing and educational outreach program is to utilize locally organized efforts to help advance the message of energy efficiency and to raise awareness of and promote participation in all of the Energy Efficiency Fund's residential, business and municipal programs through technical, financial, educational and marketing assistance.

In 2011, the eeCommunities program will expand to even more communities by partnering with the Connecticut Clean Energy Fund to deliver an integrated energy community program.

Wethersfield

In 2010, the Energy Efficiency Fund worked closely with the Town of Wethersfield's energy committees on an educational initiative and town-wide Conservation Challenge. Two challenge kick-off educational forums were held at the town hall to educate residents, businesses and municipal officials about energy conservation behaviors and Energy Efficiency Fund programs. Fund-sponsored weatherization kits were distributed to the Challenge participants. In addition, the program recruited more than 200 households to participate in the Fund's Home Energy Solutions program and is working with the town to benchmark its municipal building energy performance.

Cheshire

In 2010, the eeCommunities program collaboratively worked with Cheshire's Town Manager, Cheshire Energy Commission and Home Energy Solutions contractors to leverage American Resource and Recovery Act dollars with Energy Efficiency Fund programs to promote in-home energy assessments. As a result of this partnership, 690 households received Home Energy Solutions program services between April 20 and June 30, 2010.

Fairfield

With support from Congressman Jim Himes (CT-4) and Fairfield First Selectman Ken Flatto, the Energy Efficiency Fund partnered with the Town of Fairfield to provide a credit for the full cost of a home energy assessment to the first 1,500 qualified homeowners to sign up for the Fund's Home Energy Solutions program. During the four-month initiative, more than 1,400 households were served, resulting in 889,883 annual kilowatt-hours savings and 6,458,213 lifetime kilowatt-hours savings.

The Fund's generous support of Energy Lab allows museum visitors to learn about renewable energy and environmental stewardship through hands-on experimentation.

– Sheri Cifaldi-Morrill, Director of Exhibit Design & Delivery, Stepping Stones Museum

Photo Credit: Raw Photo Design

Education and Outreach: At School, at Work and in Your Community – continued from previous page.

Museum Partnerships

Since 2005, the Energy Efficiency Fund has sponsored the creation of several energy exhibits and hosted energy efficiency events as a part of the broader objective of extending information on energy efficiency into as many diverse sources as possible around Connecticut. Exhibits on energy, sustainability and efficiency have been funded at the Connecticut Science Center (Hartford) and the Discovery Museum (Bridgeport).

The SmartLiving™ Center (Orange) continues to function as a science museum, hands-on activity center, home improvement showroom and education resource center all together in one location. Visitors can participate in guided tours and special events throughout the year.

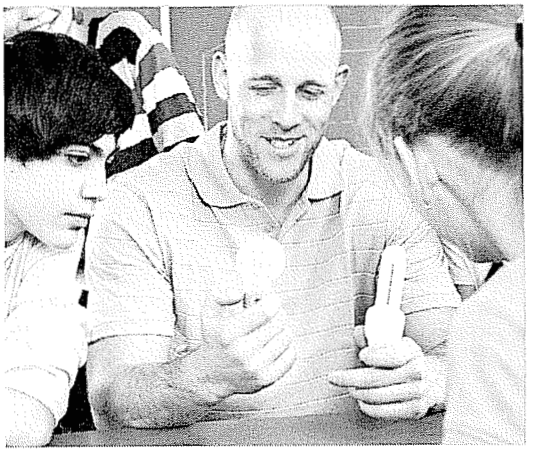
In 2010, the Fund continued its five-year partnership with the Stepping Stones Museum for Children in Norwalk by sponsoring two of the museum's energy exhibit projects and hosting various energy efficiency events.

The Fund-sponsored Mini-Conservation Quest is a traveling exhibit that made its debut in March 2010 at the Rogers International School in Stamford. The traveling exhibit on energy conservation, solar energy and energy-efficient technologies, such as CFLs, traveled to more than 25 schools, libraries and nature centers in 2010. In addition, Stepping Stones underwent an enormous renovation during the fall and reopened in November 2010 with a new energy gallery—Energy Lab. The working laboratory for children inspires a natural curiosity to imagine and invent—creating a fun-filled environment for them to explore the scientific concepts related to energy.

Photo Credit: Raw Photo Design

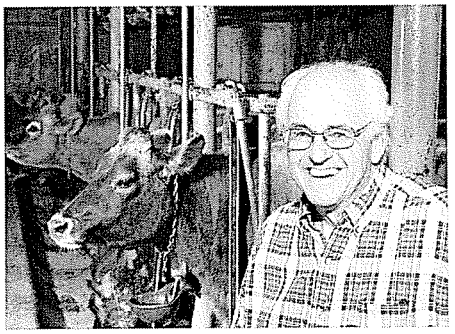
Technical Training Seminars

In 2010, the Energy Efficiency Fund offered 28 technical training seminars for commercial and industrial customers, trade allies and utility program administrators to learn about emerging technologies, best practices, and new building design standards and codes. More than 1,200 professionals attended these seminars. Topics included day lighting controls, innovative cooling technologies, performance contracting, retro commissioning, high-performance lighting and LEDs, as well as energy efficiency financing and tax incentives. The Fund and utilities also hosted numerous technical sessions to educate and inform energy efficiency trade allies about new technologies, processes, programs and rebates offered affecting 2010 business operations.



ENERGY REPORTS CONSERVATION PILOT

The Energy Efficiency Fund and its partner utilities are always seeking new opportunities to help customers achieve energy savings. The Energy Reports Conservation Pilot is an innovative educational platform to educate consumers regarding their energy consumption, how they compare to their neighbors, and the steps they can take to cut their energy use. These steps include installing new energy conservation behaviors (turning off lights and electronic equipment) and participating in Energy Efficiency Fund programs and rebates. The pilot was launched in late 2010 and will run through 2012.



Financial incentives from the Energy Efficiency Fund made it possible to purchase new, more energy-efficient equipment.

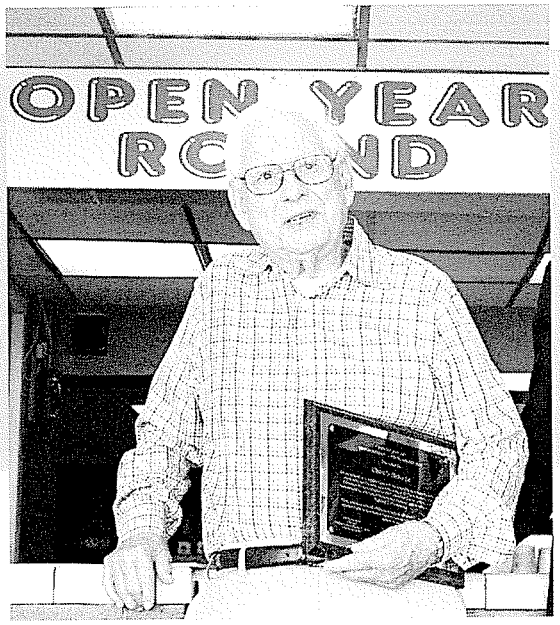
– Donald Fish, Owner, Fish Family Farm

Small businesses are an essential and integral part of Connecticut's communities and towns but continue to face financial challenges associated with a difficult economic environment, rising energy costs, and increased global competition. The Energy Efficiency Fund's Small Business Energy Advantage (SBEA) program offers cost-effective, turnkey, energy-saving products and services to small business customers who do not have the time, financial resources, or in-house expertise necessary to analyze and reduce their energy usage. This program gives those small businesses a competitive edge by increasing their bottom line.

Each SBEA project starts with an energy assessment from a contractor who proposes all possible energy efficiency measures, the complete costs and estimated energy savings, along with available program incentives and financing options. For qualifying small businesses, project costs not covered by the incentives may be eligible for zero-percent financing and the loan payments appear right on the electric bill. The energy-efficient improvements translate into monthly electric bill savings that result in a quick payback and a low out-of-pocket investment. In many cases, the energy savings completely offset the cost of the measures.

In 2010 the SBEA program saw an increase in the number of comprehensive projects. The program started years ago as a simple lighting retrofit program, matching pre-qualified lighting retrofit vendors with customers who typically did not have a pre-existing relationship with an electrical contractor, and then expanded to include cash incentives for those retrofit projects. Today, the program's authorized contractors perform energy-efficient upgrades for lighting, HVAC, air compressors and refrigeration systems. They utilize energy-saving technologies including CFLs, variable frequency drives, premium efficiency motors, solid-state LEDs, and low-maintenance induction lighting technology, all of which is financed interest free on the customer's utility bill.

The Fish Family Farm in Bolton is a great example of a business that took advantage of the SBEA program. New energy-efficient lighting and refrigeration equipment were installed, which will help the creamery and dairy farm save approximately $5,600 annually.



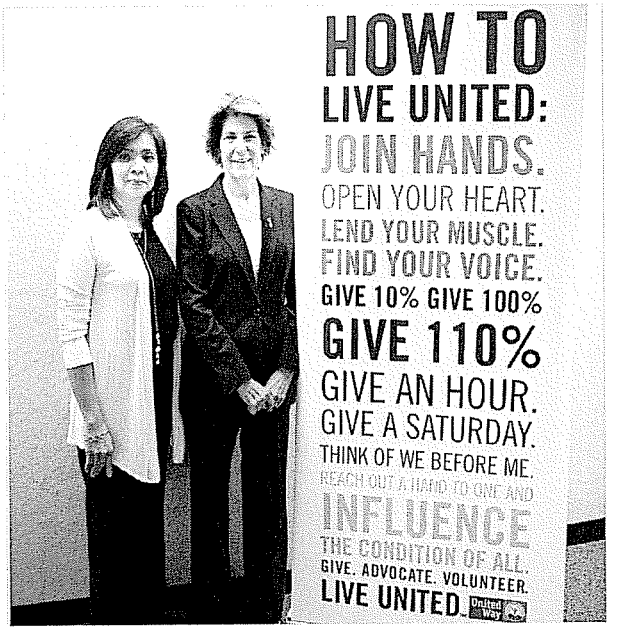
> "I never thought the savings would be as much. I would recommend it to everyone."
>
> —Joseph Celentano, Owner, Chick's Drive-In

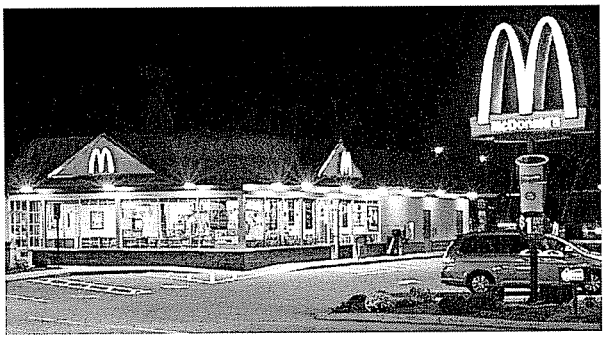
A SBEA program energy assessment of The United Way of Coastal Fairfield County found the non-profit's lighting to be outdated. Old fluorescent and incandescent lighting was replaced with energy-efficient, high-performance T8 technology and compact fluorescent lighting (CFL), respectively. From these improvements, the United Way's lifetime savings is expected to total $72,408.

McDonald's restaurant in Vernon was able to upgrade to more energy-efficient induction lighting and make improvements to its refrigeration unit to dramatically reduce energy usage. A financial incentive and a zero-percent interest loan enabled property owners Tim and Tom Walsh to offset the cost of the upgrades and resulted in cost savings of approximately $9,000 a year.

Chick's Drive-In in West Haven also was able to make improvements to lighting and refrigeration equipment that are saving owner Joseph "Chick" Celentano hundreds of dollars each month on his electricity bill. The seafood landmark eatery will save approximately 468,000 killowatt-hours over the lifetime of the new equipment—the equivalent of planting 56 acres of trees or saving more than 17,000 gallons of gas.

SBEA program participants can save natural gas as well by taking advantage of the Fund's Energy Opportunities program, which is for business customers looking to retrofit existing operational equipment.





2010 Small Business Energy Advantage Program

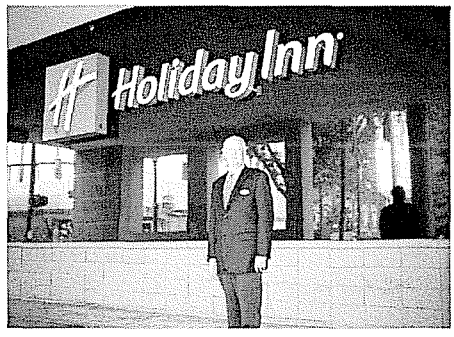
Customers Served
1,886

CO_2 Emissions Reduced
18,350 Tons (Annual)

Energy Savings
kWh Annual
58.2 Million
kWh Lifetime
473.8 Million

Annual Savings
$5.8 Million

Lifetime Savings
$72.1 Million



After completing the Energy Conscious Blueprint project, the Bridgeport Holiday Inn's total annual energy savings is $124,555.

Commercial & Industrial: New Construction & Equipment

Energy Conscious Blueprint

The Energy Conscious Blueprint (ECB) program is geared toward business customers planning new construction, major renovations, or replacement of existing equipment near the end of its useful life. Specifically, the program seeks to increase the energy efficiency and performance of lighting systems, HVAC systems, motors, process equipment, and other energy components of commercial and industrial buildings or projects. Technical services and financial incentives for this program are based upon the proposed project's complexity, energy savings potential, and the desire of the owner and his or her design team to participate.

The ECB program had a banner year, signing more letters of agreement in 2010 than in any previous year. As these projects typically have long lead times and tend to be very complex, many of them initiated in 2010 will be completed during the next two years.

One project that was completed in 2010 was at the newly renovated Bridgeport Holiday Inn. Improvements in the heating, air conditioning and water delivery systems were made, and an energy management system was installed. The Bridgeport Holiday Inn's anticipated total annual energy savings are 830,368 killowatt-hours, or approximately $124,555.

University of New Haven was another successfully completed project consisting of an energy efficiency plan for its Soundview Hall, a 400-bed apartment-style residence hall. Variable refrigerant volume heating and cooling systems and new lighting were installed, which reduced the university's annual energy usage by more then 235,000 killowatt-hours, which equals approximately $40,000.

2010 Energy Conscious Blueprint

Business Served
304

Energy Savings
kWh Annual
32.8 Million
kWh Lifetime
508.3 Million
CCF Annual
627 Thousand
CCF Lifetime
9.1 Million

CO_2 Emissions Reduced
19,547 Tons (Annual)

Annual Savings
$5.6 Million

Lifetime Savings
$85.7 Million

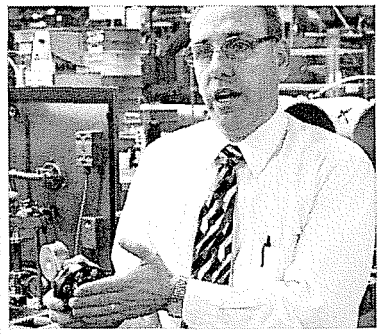
Comprehensive Projects

In 2010 the Energy Efficiency Fund aggressively pushed for an increase in comprehensive Energy Conscious Blueprint projects. This includes making improvements to more than one energy end-use such as lighting and heating, or a combination of natural gas and electric energy efficiency measures.

One project that fit this model was a new Price Chopper store in Middletown. Among the many energy-saving aspects incorporated into the new building was a high-performance lighting design, energy-efficient HVAC roof-top units, and electrically commutated motors in the reach-in coolers and freezers. All of the measures will save the store approximately 639,518 killowatt-hours and 320 ccf annually, which results in nearly $100,000 savings per year on energy bills.

Building Code Changes

The Energy Efficiency Fund actively supported changes to building codes in Connecticut to better reflect what is happening in the design community. This included working with the State's Codes and Standards Committee and the Department of Public Safety on new code adoption. Multiple training workshops were offered to architects and engineers to educate them on the new proposed codes and how they would be impacted in the future.



With assistance from the Energy Efficiency Fund, Ashcroft Inc. has improved the appearance of our manufacturing operation while greatly reducing our energy consumption.

– Bruce Albright, Manufacturing Manager, Ashcroft

Commercial & Industrial: Existing Buildings

Energy Opportunities

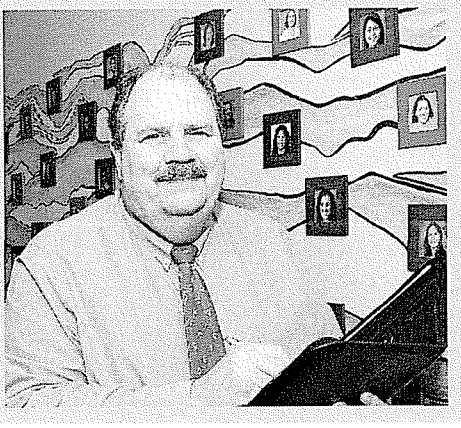
Similar to the Energy Conscious Blueprint program, conducting comprehensive projects was a focus for the Energy Opportunities (EO) program, which is designed for businesses looking to retrofit existing operating equipment that has at least 25 percent of its useful life remaining. This program incorporates financial incentives, which may include zero-percent or low-interest rate financing, to help commercial, industrial or municipal customers evaluate the choice of either maintaining their older, inefficient equipment or upgrading to a higher-efficiency option. Potential areas of improvement are lighting, HVAC systems, refrigerators, water heaters, and process-related equipment.

Ashcroft, Inc., a manufacturer of high-quality pressure gauges in Stratford, learned that it was eligible for a $55,464 incentive through the EO program to upgrade its main manufacturing floor lighting to more energy-efficient lamps, reducing electrical use 2,628,639 kilowatt-hours over the lifetime of the products.

Advanced Lighting

Lighting upgrades are a major component of the Energy Opportunities program, and the Fund's administering utilities are influential in pushing the most cutting-edge, qualified lighting products to the market. As part of this effort, utility energy engineers are actively involved with the DesignLights™ Consortium, a collaboration of utility companies and regional energy efficiency organizations committed to raising awareness of the benefits of efficient lighting in commercial buildings. In 2010 the EO program supported several emerging technologies such as Light-Emitting Diodes (LED) lamps, which are more rugged and damage-resistant than compact fluorescent lamps and incandescent lamps, as well as induction lighting, which is an advanced, more energy-efficient form of fluorescent technology.

EO program participants can also take advantage of the Fund's Lighting Express Rebate program, which allows facility managers and business owners to be paid expeditiously for the incremental cost of installing high-efficiency lighting fixtures.



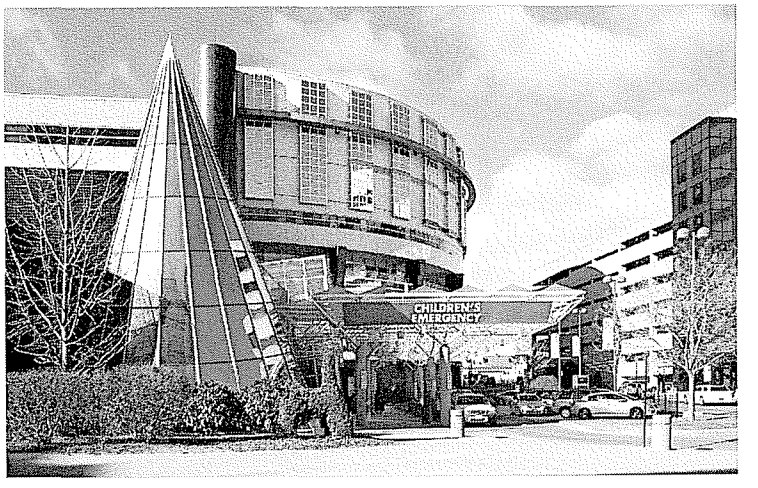
"The Energy Efficiency Fund helped pay for equipment that saves us thousands in monthly operating costs — and reduces our payback to less than two years."

– Bob Wall, Facilities Manager
Connecticut Children's Medical Center

Beyond Lighting

Lighting is just one area that businesses can upgrade through the Energy Opportunities program. Energy-saving improvements can also be made to HVAC systems, refrigeration, water heating, and process-related equipment. As an example, the Connecticut Children's Medical Center in Hartford turned to the EO program to improve its HVAC system. Financial incentives helped pay for high efficiency controls that reduce energy consumption by approximately 287,700 killowatt-hours annually, or $23,000 in savings, on cooling the Center's facilities year round.

DRS Fermont, a provider of military generator sets, has taken advantage of several Energy Efficiency Fund programs throughout the past few years. Most recently, the company participated in the EO program to make comprehensive upgrades to lighting and cooling equipment in its two Bridgeport locations, along with the installation of a new energy management system. The result was a savings of nearly 1,170,000 killowatt-hours annually.



2010 Energy Opportunities

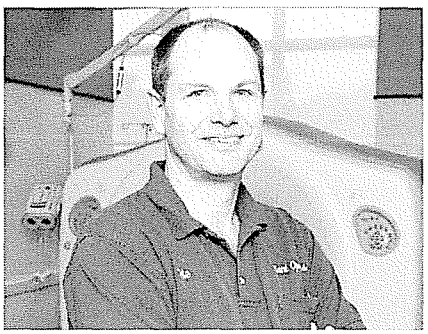
Business Served
1,355

Energy Savings
kWh Annual
84.2 Million
kWh Lifetime
1.0 Billion
CCF Annual
364 Thousand
CCF Lifetime
4.2 Million

Annual Savings
$13.0 Million

CO_2 Emissions Reduced
42,654 Tons (Annual)

Lifetime Savings
$161.0 Million



We've knocked down energy consumption by 35 percent and raised our ENERGY STAR® designation from 47 to 88.

– Peter Rogers, Chief Plant Operator, Greenwich Hospital

Commercial & Industrial: Existing Buildings

Operations and Maintenance

Inadequate maintenance can lead to drastic energy losses and high energy costs. The Energy Efficiency Fund's Operations & Maintenance Services (O&M) program helps customers improve the electrical and thermal efficiency of their operations by making changes and repairs, rather than making costly capital investments. Energy efficiency experts work with customers to identify both electric and gas efficiency O&M improvements. Once these measures are installed, the improvements may qualify for financial incentives to offset a portion of the project cost.

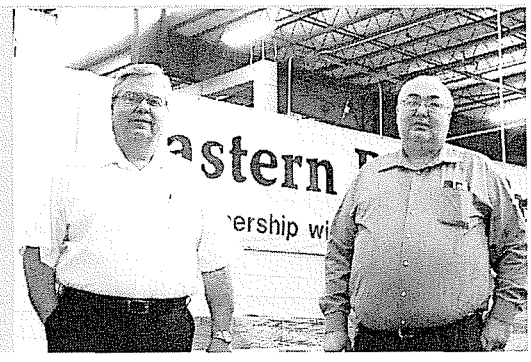
O&M improvements are custom designed for a building's site, as each facility is unique. Common O&M measures include economizer repairs/conversions, repairs/replacements of steam traps, and rewiring of lighting circuits for more efficient switching. In addition to identifying efficiency measures, energy efficiency experts provide outreach and training to the customers' in-house personnel so energy-efficient improvements can be maintained over time.

Retro Commissioning

The Retro Commissioning program identifies energy savings in existing commercial and industrial buildings that are at least 100,000 square feet by improving the operation of a building's management system. Similar to other Energy Efficiency Fund programs, financial and technical assistance are provided through the Retro Commissioning program. Additionally, this program documents how a facility should be operated to maximize energy-saving opportunities that improve overall performance while helping to develop long-term, sustainable energy management strategies.

Greenwich Hospital needed to reduce energy consumption and costs of its 520,000 square-foot facility, as its energy bills were well over the hospital's budget. Through the Retro Commissioning program, dozens of measures were implemented across the building, including upgrades to lighting and process systems, as well as improvements to the heating and cooling plants. The result was a 35-percent reduction of energy consumption, which will save the hospital almost $304,000 annually. Also, the facility's ENERGY STAR® rating went from 47 to 88 (buildings with a score of 75 or over are eligible for the ENERGY STAR label).

> "The Business Sustainability Challenge will continue to be an ongoing effort to reduce our organization's carbon footprint and help position us as an environmental leader within the distribution industry."
>
> – Don Burton, Vice President of Operations, Eastern Bag & Paper



Process Reengineering for Increased Manufacturing Efficiency (PRIME)

Manufacturers looking for a competitive edge need to take a systematic approach to evaluating and identifying inefficiencies and waste in their operations. The PRIME program provides businesses with training in "lean manufacturing" techniques in order to streamline product flow, eliminate or reduce waste, improve production efficiency, minimize environmental impact, and reduce electrical energy consumption. Without this program, access to this type of specialized training was often limited to very large businesses that have the foresight and resources to invest in the training.

Business Sustainability Challenge

The Business Sustainability Challenge (BSC) is specifically designed to help businesses increase their bottom line through an overall operations analysis and ultimately improve their "triple bottom line" of financial, environmental and social value.

Empowering organizations to change their behaviors while providing access to the necessary tools and resources enables them to achieve deeper and longer lasting energy savings and carbon footprint reduction, and helps them meet the challenge of becoming a sustainable business.

Eastern Bag & Paper is a success story for the BSC program, which helped the Milford-based food service product manufacturer develop a comprehensive energy management and sustainability plan and goals. From there, the company was able to implement several measures such as establishing new facility shut-down procedures, installing motion sensors for lighting, and replacing cathode ray tubes with liquid crystal display technology. After the completion of the first year of a three-year commitment to the program, Eastern Bag & Paper reduced its peak demand, and its estimated annual energy savings were 169,375 killowatt-hours, or approximately $27,100.

2010 Operations & Maintenance/Retro Commissioning/PRIME

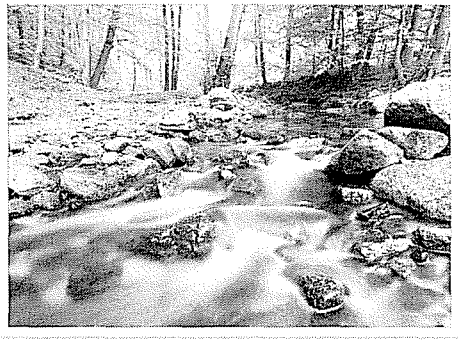
Business Served
136

Energy Savings
kWh Annual
6.5 Million
kWh Lifetime
46.0 Million
CCF Annual
78 Thousand
CCF Lifetime
781 Thousand

Annual Savings
$1.0 Million

CO_2 Emissions Reduced
3,581 Tons (Annual)

Lifetime Savings
$7.5 Million



The primary focus of the Energy Efficiency Fund continues to be reducing air pollution and improving air quality in the Northeast.

Protecting the Environment

Energy Efficiency Reduces Pollution

The primary focus of the Energy Efficiency Fund continues to be reducing air pollution and improving air quality in the Northeast. The generation of electricity from non-renewable fossil fuels (e.g., coal and oil) is the single largest source of carbon dioxide emissions in the United States. Reducing the amount of energy used by businesses, homes and schools results in less plant operation time and significantly lowers the emissions of carbon dioxide, nitrous and sulfur oxides—which are associated with environmental issues such as ozone, climate change, public health problems, acid rain, and smog.

However, legislation has already been put in place to reduce these effects. On June 2, 2008, Governor M. Jodi Rell signed "An Act Concerning Global Warming Solutions," [2] into law. The law established a statewide greenhouse gas emissions reduction target of 10 percent below 1990 levels by 2020.

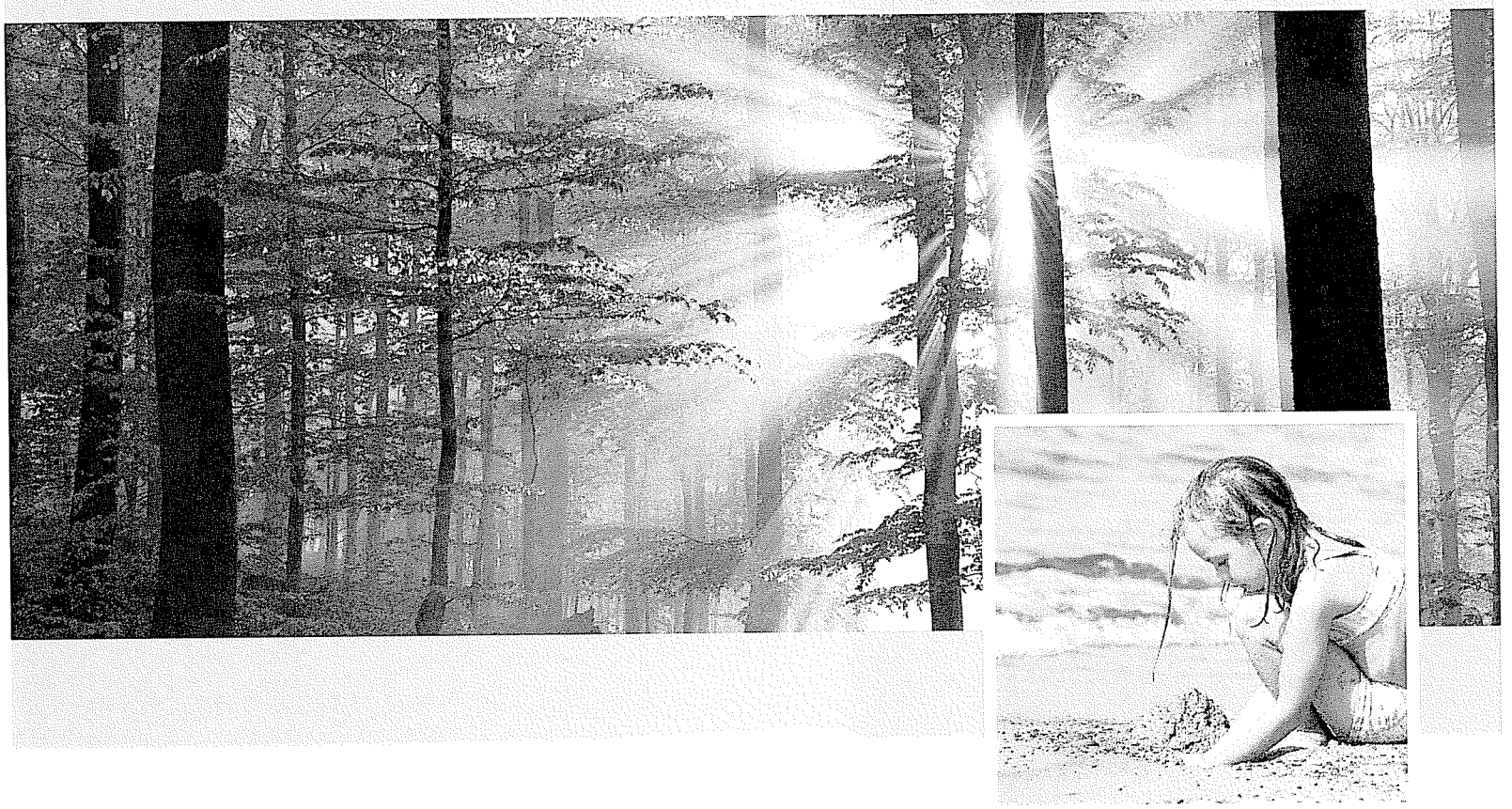
Investing in energy efficiency programs also helps to reduce the need for power generation, especially during times of peak demand. This helps Connecticut energy generation owners avoid having to purchase tens of millions of dollars in pollution control equipment. While this abatement equipment does reduce emissions, it does not eliminate them completely, and in fact, decreases the overall efficiency of power plants, resulting in the emission of more air pollutants.

The Energy Efficiency Fund's programs play an integral part in helping reduce greenhouse gas and air pollutant emissions in Connecticut and the surrounding region. In 2010, program activities resulted in significant environmental benefits, which are all part of the push for greater sustainability across the state.

Reflecting Reduction in Criteria Pollutants and Carbon Dioxide (in Tons)

	Annual Savings 2010			Lifetime Savings 2010		
	Electric	Natural Gas	Oil	Electric	Natural Gas	Oil
SO_x	344	—	—	3,031	—	—
NO_x	119	—	—	1,044	—	—
CO_2	202,860	15,532	22,232	1,786,292	247,764	388,993

[2] PA 08-98, An Act Concerning Connecticut Global Warming Solutions.



The lifetime energy savings achieved through Energy Efficiency Trust programs in 2010 results in greenhouse gas reductions equivalent to:

442,476

Homes powered with electricity for a year

354,676 Cars off the road for a year

504,355

Acres of trees reducing carbon

Demonstrating Economic Benefits Throughout Connecticut

Job Growth

Since Connecticut does not have any indigenous fossil fuel resources, much of the spending on energy is for fuel imported from other parts of the country and the world. Spending on efficiency however, is largely done in state. A 2009 independent study* analyzed the size of Connecticut's green jobs marketplace and showed that 2,675 jobs are directly attributed to energy efficiency. These jobs create $137 million of employment income, at an average of $50,000 per year across all industry segments (residential, small business, commercial and industrial). An even greater number of jobs result from the energy savings the programs deliver, as consumers and businesses spend and invest the money they would otherwise have spent on energy. Another 4,280 indirect and induced jobs can be attributed to energy efficiency activity in Connecticut.

* Navigant Consulting, CT Renewable Energy/Energy Efficiency Economy Baseline Study. Phase I Deliverable, March 27, 2009

Assistance to Customers in Connecticut Towns

This list includes energy efficiency and conservation benefits provided to residential, commercial and industrial customers of the electric and gas utilities and the Connecticut Municipal Electric Energy Cooperative (CMEEC), which exceeds $98 million in incentive benefits.

ANDOVER	$	41,139
ANSONIA	$	477,390
ASHFORD	$	86,434
AVON	$	414,504
BARKHAMSTED	$	31,419
BEACON FALLS	$	95,481
BERLIN	$	918,053
BETHANY	$	85,102
BETHEL	$	204,589
BETHLEHEM	$	42,664
BLOOMFIELD	$	900,251
BOLTON	$	80,425
BOZRAH	$	73,006
BRANFORD	$	986,317
BRIDGEPORT	$	3,710,382
BRIDGEWATER	$	42,628
BRISTOL	$	1,011,141
BROOKFIELD	$	1,051,388
BROOKLYN	$	65,552
BURLINGTON	$	106,419
CANAAN	$	18,243
CANTERBURY	$	63,704
CANTON	$	321,450
CHAPLIN	$	20,396
CHESHIRE	$	1,080,208
CHESTER	$	71,937
CLINTON	$	380,159
COLCHESTER	$	305,861
COLEBROOK	$	14,763
COLUMBIA	$	67,924
CORNWALL	$	31,875
COVENTRY	$	195,672
CROMWELL	$	479,877
DANBURY	$	3,033,812
DARIEN	$	348,485
DEEP RIVER	$	192,005
DERBY	$	389,128
DURHAM	$	254,514
EAST GRANBY	$	205,236
EAST HADDAM	$	128,093
EAST HAMPTON	$	177,359
EAST HARTFORD	$	1,040,058
EAST HAVEN	$	453,498
EAST LYME	$	311,101
EAST WINDSOR	$	298,953
EASTFORD	$	12,575
EASTON	$	292,760
ELLINGTON	$	275,723
ENFIELD	$	1,794,830
ESSEX	$	130,010
FAIRFIELD	$	3,184,254
FARMINGTON	$	1,009,782
FRANKLIN	$	19,705
GLASTONBURY	$	1,138,748
GOSHEN	$	62,677
GRANBY	$	132,368
GREENWICH	$	886,124
GRISWOLD	$	70,535
GROTON	$	1,245,595
GUILFORD	$	369,896
HADDAM	$	169,826
HAMDEN	$	2,940,048
HAMPTON	$	14,695
HARTFORD	$	4,922,518
HARTLAND	$	8,683
HARWINTON	$	47,341
HEBRON	$	101,384
KENT	$	119,515
KILLINGLY	$	559,230
KILLINGWORTH	$	112,297
LEBANON	$	50,059
LEDYARD	$	111,441

LISBON	$	145,093
LITCHFIELD	$	203,706
LYME	$	17,119
MADISON	$	265,149
MANCHESTER	$	2,118,448
MANSFIELD	$	699,903
MARLBOROUGH	$	84,762
MERIDEN	$	1,239,537
MIDDLEBURY	$	250,763
MIDDLEFIELD	$	166,138
MIDDLETOWN	$	2,035,168
MILFORD	$	2,335,222
MONROE	$	334,986
MONTVILLE	$	616,596
MORRIS	$	52,293
NAUGATUCK	$	969,825
NEW BRITAIN	$	1,881,663
NEW CANAAN	$	390,477
NEW FAIRFIELD	$	143,207
NEW HARTFORD	$	202,629
NEW HAVEN	$	2,604,921
NEW LONDON	$	1,717,089
NEW MILFORD	$	632,152
NEWINGTON	$	707,300
NEWTOWN	$	373,986
NORFOLK	$	25,226
NORTH BRANFORD	$	118,412
NORTH CANAAN	$	31,833
NORTH HAVEN	$	739,822
NORTH STONINGTON	$	65,533
NORWALK	$	3,457,511
NORWICH	$	1,287,022
OLD LYME	$	139,173
OLD SAYBROOK	$	381,787
ORANGE	$	583,069
OXFORD	$	150,826
PLAINFIELD	$	261,583
PLAINVILLE	$	564,665
PLYMOUTH	$	187,730
POMFRET	$	30,371
PORTLAND	$	247,314
PRESTON	$	53,173
PROSPECT	$	213,624
PUTNAM	$	207,595
REDDING	$	153,237
RIDGEFIELD	$	451,022
ROCKY HILL	$	596,897
ROXBURY	$	31,450
SALEM	$	48,998
SALISBURY	$	350,140
SCOTLAND	$	5,355
SEYMOUR	$	461,084
SHARON	$	225,894
SHELTON	$	1,262,307
SHERMAN	$	71,291
SIMSBURY	$	541,849
SOMERS	$	186,519
SOUTH WINDSOR	$	1,225,007
SOUTHBURY	$	620,615
SOUTHINGTON	$	900,862
SPRAGUE	$	7,547
STAFFORD	$	155,502
STAMFORD	$	3,095,148
STERLING	$	73,596
STONINGTON	$	518,136
STRATFORD	$	1,201,592
SUFFIELD	$	307,948
THOMASTON	$	231,690
THOMPSON	$	104,574
TOLLAND	$	186,778
TORRINGTON	$	544,304
TRUMBULL	$	976,786
UNION	$	6,655
VERNON	$	804,832
VOLUNTOWN	$	16,007
WALLINGFORD	$	1,711,183
WARREN	$	18,182
WASHINGTON	$	63,443
WATERBURY	$	2,564,395
WATERFORD	$	712,645
WATERTOWN	$	681,598
WEST HARTFORD	$	1,759,097
WEST HAVEN	$	973,100
WESTBROOK	$	107,610
WESTON	$	171,697
WESTPORT	$	817,835
WETHERSFIELD	$	569,343
WILLINGTON	$	44,021
WILTON	$	534,538
WINCHESTER	$	186,134
WINDHAM	$	757,611
WINDSOR	$	1,208,398
WINDSOR LOCKS	$	609,139
WOLCOTT	$	233,090
WOODBRIDGE	$	215,951
WOODBURY	$	199,769
WOODSTOCK	$	73,585

* Based on 2010 data. All figures are approximate and may vary due to rounding. This does not include incentives for ISO-NE Load Response program participants.

Summary of Energy Savings by Customer Sector
(in millions of dollars)

	Annual Savings 2010			Lifetime Savings 2010		
Customer Sector	Electric	Natural Gas	Oil	Electric	Natural Gas	Oil
Limited-Income	3.08	0.76	2.24	27.00	11.19	32.20
Residential (Non Limited-Income)	43.52	1.29	3.02	261.53	25.56	59.84
Commercial & Industrial	24.55	0.81	0.00	315.52	10.69	0.00
Totals	71.15	2.86	5.26	604.04	47.44	92.04

2010-2011 Budget Summaries

Conservation and Load Management Fund Programs	2010 Actuals Electric	2011 Plan Electric	2010 Actuals Natural Gas	2011 Plan Natural Gas
RESIDENTIAL				
Residential Retail Products	$ 11,194,953	$ 7,701,913	$ —	$ —
Appliance Rebate	4,490,920	—	$ —	$ —
Total - Consumer Products	**$ 15,685,873**	**$ 7,701,913**	**$ —**	**$ —**
Residential New Construction	1,210,637	1,675,464	956,278	1,150,000
Home Energy Solutions (HES)	27,756,100	14,350,683	3,975,196	4,600,000
Home Energy Solutions - Income Eligible (HES-IE)	12,338,151	12,926,043	2,807,784	2,681,575
Water Heating	—	—	193,537	363,000
Subtotal Residential	**$ 56,990,761**	**$ 36,654,103**	**$ 7,932,796**	**$ 8,794,575**
COMMERCIAL & INDUSTRIAL				
C&I LOST OPPORTUNITY				
Energy Conscious Blueprint	$ 13,303,304	$ 11,934,133	$ 2,352,356	$ 3,670,000
Total - Lost Opportunity	**$ 13,303,304**	**$ 11,934,133**	**$ 2,352,356**	**$ 3,670,000**
C&I LARGE RETROFIT				
Energy Opportunities	23,224,314	15,810,100	901,215	2,480,000
O&M (Service, RetroCx & BSC)	1,478,851	4,719,407	145,969	400,000
Prime	532,931	574,095	—	—
Total - C&I Large Retrofit	**$ 25,236,096**	**$ 21,103,602**	**$ 1,047,184**	**$ 2,880,000**
Small Business	15,073,749	13,048,527	—	—
Subtotal C&I	**$ 53,613,149**	**$ 46,086,262**	**$ 3,399,540**	**$ 6,550,000**
OTHER - EDUCATION				
Smart Living Center/Museums	$ 621,725	$ 859,246	$ —	$ —
EE Communities	1,132,547	1,026,822	—	—
EE Smarts/K-8 Education	677,610	626,825	—	—
Subtotal Education	**$ 2,431,882**	**$ 2,512,893**	**$ —**	**$ —**
OTHER - PROGRAMS/REQUIREMENTS				
Institute for Sustainable Energy (ECSU)	$ 500,000	$ 500,000	$ —	$ —
Other Funding Requests	372,325	—	—	—
Residential Loan Program (Including CHIF)	18,997,722	3,739,087	172,653	420,000
C&I Loan Program	204,898	525,000	—	150,000
C&LM Loan Defaults	186,197	185,000	—	—
Subtotal Programs/Requirements	**$ 20,261,142**	**$ 4,949,087**	**$ 172,653**	**$ 570,000**
OTHER - LOAD MANAGEMENT				
ISO Load Response Program	2,864,833	3,000,000	$ —	$ —
Subtotal Load Management	**$ 2,864,833**	**$ 3,000,000**	**$ —**	**$ —**
OTHER - RD&D				
Research, Development & Demonstration	$ 296,311	$ 325,000	$ —	$ —
Subtotal RD&D	**$ 296,311**	**$ 325,000**	**$ —**	**$ —**

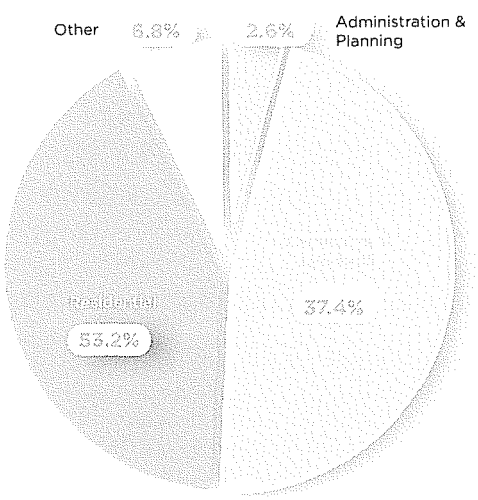
Conservation and Load Management Fund Programs	2010 Actuals Electric	2011 Plan Electric	2010 Actuals Natural Gas	2011 Plan Natural Gas
OTHER - ADMINISTRATIVE & PLANNING				
Administration	$ 1,577,412	$ 1,546,635	$ —	$ —
Planning and Evaluation	2,587,346	3,188,819	191,140	811,000
Information Technology	2,091,360	1,943,000	80,557	95,000
EEB	673,247	610,000	30,240	49,500
Performance Management Fee	6,972,510	5,015,290	—	—
General Awareness	74,992	100,000	—	—
Admin/Planning Expenditures	**$ 13,976,867**	**$ 12,403,744**	**$ 301,937**	**$ 955,500**
PROGRAM SUB-TOTALS				
Residential	**$ 78,129,504**	**$ 42,608,869**	**$ 8,105,449**	**$ 9,214,575**
C&I	**$ 57,234,930**	**$ 50,193,476**	**$ 3,399,540**	**$ 6,700,000**
Other	**$ 15,070,511**	**$ 13,128,744**	**$ 301,937**	**$ 955,500**
TOTAL C&LM BUDGET	**$ 150,434,945**	**$ 105,931,089**	**$ 11,806,927**	**$ 16,870,075**
Docket 05-07-14 PH01 EIA programs				
ISO Load Response Programs (Load Curtailment & Emer. Gen)	$ (604,983)	$ —	$ —	$ —
Subtotal Docket 05-07-14PH01 EIA Programs	$ (604,983)	$ —	$ —	$ —
Total C&LM and EIA Programs	**$ 149,829,962**	**$ 105,931,089**	**$ 11,806,927**	**$ 16,870,075**

Budget summaries reflect actual 2010 expenditures.

Totals vary due to rounding.

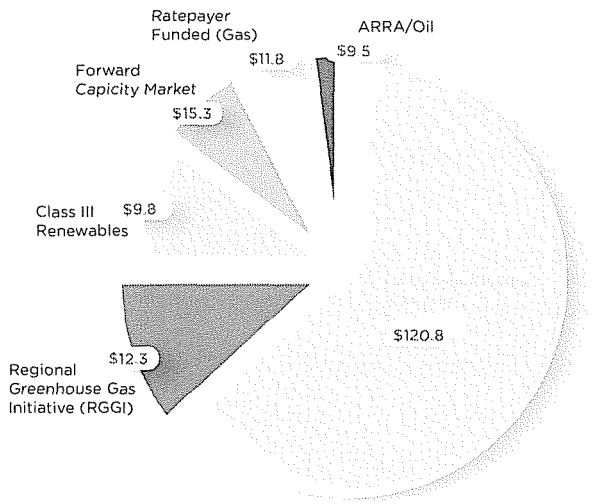
2010 Actuals: Budget Allocations

Energy Efficiency Fund programs are administered to maximize the cost-effectiveness and impacts of energy-efficiency and load management activities. Only 2.6 percent of the total Fund budget was allocated to administrative expenses in 2010.



2010 Efficiency Program Funding

Funding for energy efficiency programs comes from many sources. Funding reflects 2010 revenues received. (In Millions)



Connecticut Municipal Electric Energy Cooperative

Background

The Connecticut Municipal Electric Energy Cooperative (CMEEC), a joint action supply and transmission agency established by the state's municipal electric utilities, is owned by the Cities of Groton and Norwich, the Borough of Jewett City, and South and East Norwalk. In addition, CMEEC provides all power requirements to these participating utilities: Town of Wallingford Department of Public Utilities, Bozrah Light and Power Company, and the Mohegan Tribal Utility Authority.

Energy use and its cost continue to be of critical importance to all Connecticut residents and businesses. In 2010, CMEEC utilities continued their proactive work and active partnerships with their municipalities, commercial and industrial businesses, residents and limited-income customers. By supporting the energy supply, transmission and distribution needs of all customer sectors, CMEEC utilities serve as integrated energy managers helping to reduce and reshape energy use and helping the entire spectrum of customers to lower monthly bills.

In 2010, CMEEC's utilities realized annual savings of 18,730,000 million kilowatt-hours and peak demand savings of 6.3 megawatts. These savings were achieved through the delivery of a full array of efficiency programs.

Smart Grid Project

CMEEC's Smart Grid project, initiated in 2009 with a significant American Recovery and Reinvestment Act (ARRA) grant, continued to be a major focus for the CMEEC utilities in 2010. The project involves deploying advanced two-way meters for the majority of commercial customers as well as many residential accounts. The utilities will utilize data from these meters to enable time-differentiated rates over discrete time intervals. Thus, customers will have the opportunity to reduce their electric bills by reducing electricity usage and shifting usage away from peak-demand times. As the project proceeds over the next year, energy efficiency program efforts will be integrated with Smart Grid capabilities. Taken together, these two programs offer exciting opportunities to serve customers better and help them use energy even more efficiently.

Renewable Projects

In 2010 CMEEC completed a master program management agreement with the Connecticut Clean Energy Fund to coordinate solar photovoltaic installations on member systems. Several systems were installed with the largest being a 75 kilowatt system in Wallingford.

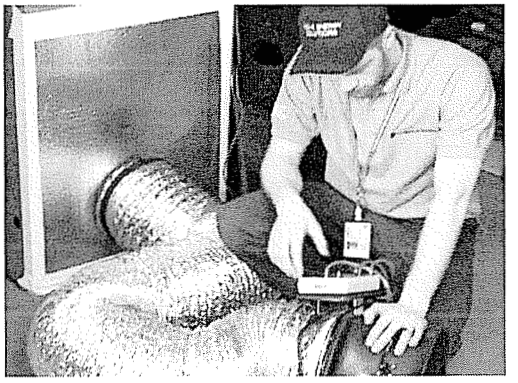


Photo credit Jonathan Gorham

Serving Residential Customers

The CMEEC systems delivered a full array of energy efficiency programs in 2010. Residential program efforts were centered on CMEEC's Home Energy Savings program. The Home Energy Savings program provides comprehensive whole-house retrofit services with a number of consumer incentives to residential and limited income customers. Program measures include blower door testing and air leak sealing, duct testing and sealing, installation of compact fluorescent light bulbs (CFLs), as well as water and hot water efficiency devices and pipe insulation. CMEEC's authorized contractors and local utility personnel assist customers with the procurement of attic insulation and provide quality control and program governance. Efforts are coordinated locally with incentive offers from the natural gas and oil supply companies. In 2010, CMEEC provided Home Energy Savings services to 4,382 homes or residential housing units.

A pilot loan program was also initiated in 2010 at one of the CMEEC systems. Residential customers may access low or no-interest loans for major energy saving measures. Plans are to expand the program to additional systems in 2011, as well as seeking additional capital sources.

In 2010 CMEEC systems continued the distribution of CFLs using a variety of avenues. The systems employed direct distribution through local service centers and other available community activities and organizations as well as direct mail offers. The Home Energy Savings program provides and installs CFLs at customer locations as a major component. CMEEC also continued the Negotiated Cooperative Purchase program, utilizing major chain stores and local retailers. CMEEC utilities distributed 131,630 CFLs in 2010, bringing the total distribution to 709,380 since the program's inception in 2006.

Commercial & Industrial Advances

CMEEC's commercial and industrial initiatives include both prescriptive and custom elements and offer customers incentives for retrofit and new construction projects. Rebates for commercial and industrial customers included lighting, motor replacements, heating, ventilation and air conditioning (HVAC) units and special efforts to engage small businesses. CMEEC also works closely with its largest customers on load response efforts. In 2010 commercial and industrial programs resulted in energy savings of 5,020,000 million kilowatt-hours and peak demand reduction of one megawatt.

Community Education

In 2010 CMEEC provided a grant to the Institute for Sustainable Energy (ISE) to provide extensive outreach in the CMEEC communities. The purpose of the grant was to encourage the participation of town and city agencies and officials in energy efficiency-related activities and educational programs provided by the ISE. The arrangement will provide comparable programs and parity with what is currently offered throughout the state. Specific programs include Energy Star Portfolio Manager Benchmarking, Keep Connecticut Cool: the Climate Challenge, building code updates and training, Green Schools, and K-12 school/municipal building operators training.

Connecticut Municipal Electric Energy Cooperative

2010 CMEEC Program Highlights

Customers Served
19,400

CO_2 Emissions Reduced
10,165 Tons (Annual)

Energy Savings
kWh Annual
19 Million
kWh Lifetime
338 Million

Annual Savings
$3.4 Million

Lifetime Savings
$31 Million

CMEEC Assistance to Customers
(Rounded to Nearest Dollar)

This table details the incentives and rebates provided to CMEEC residential and commercial and industrial customers in 2010.

	$ 73,000
	$ 1,213,000
	$ 26,000
	$ 167,000
	$ 160,000
	$ 1,280,000
	$ 1,570,000

2010 CMEEC Budget Summary

Program	Program Budget 2010	Actual Utility Costs 2010	% of Budget Spent	Proj Annual Savings (kWh)	Annual Energy Savings (kWh)	% of Annual kWh Saved	Lifetime Savings (kWh)	2010 Proj. kW Impact	kW Impact	% of kW Impact Achieved
Residential										
Home Energy Savings Program	$ 1,127,000	$ 2,542,678	226%	1,540,000	9,878,727	641%	150,581,694	296	2,532	855%
Efficient Products										
Lighting	$ 350,000	$ 387,434	111%	3,102,000	3,783,458	122%	18,306,521	246	2,396	974%
Appliances	$ 129,000	$ 341,021	264%	188,000	48,368	26%	589,882	27	377	1396%
Subtotal - Residential	**$ 1,606,000**	**$ 3,271,133**	**204%**	**4,830,000**	**13,710,552**	**284%**	**169,478,097**	**569**	**5,304**	**932%**
Commercial										
Commercial New Construction	$ 80,000	$ 2,416	3%	85,000	0	0%	0	29	0	0%
Prescriptive Equipment Replacement	$ 260,000	$ 12,842	5%	660,000	6,190	1%	95,326	209	3	2%
Existing Facility Retrofit /Custom Equip. Repl.	$ 1,659,000	$ 1,202,312	72%	9,874,000	5,013,173	51%	69,285,366	1,522	962	63%
Subtotal - Commercial	**$ 1,999,000**	**$ 1,217,571**	**61%**	**10,619,000**	**5,019,364**	**47%**	**69,380,692**	**1,760**	**965**	**55%**
Total - All Programs	**$3,605,000**	**$4,488,704**	**125%**	**15,449,000**	**18,729,916**	**121%**	**238,858,789**	**2,329**	**6,269**	**269%**

Notes: 1. Data for the Limited Income Customers is included under the Home Energy Savings Program.
2. ARRA and RGGI funds are included under Actual Utility Costs
3. HES Savings include the kWh conversion of BTU reductions from weatherization measures.

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Connecticut Energy Efficiency Fund

Activities in 2010 Produced Substantial Economic and Environmental Benefits for Residents, Businesses and Municipalities

Customers Served

Number of Households Served
848,058

Number of Businesses Served
4,599

CO_2 Emissions Reduced

CO_2	2.4 Million Tons (Lifetime)
SO_x	3,031 Tons (Lifetime)
NO_x	1,044 Tons (Lifetime)

Energy Savings

kWh Annual	**CCF Annual**	**Gallons Annual**
423 Million	2.6 Million	1.7 Million
kWh Lifetime	**CCF Lifetime**	**Gallons Lifetime**
3.7 Billion	41.1 Million	29.9 Million

Dollars Saved

Annual	$79 Million
Lifetime	$744 Million

Connecticut Light & Power
A Northeast Utilities Company

CONNECTICUT ENERGY EFFICIENCY FUND
www.CTEnergyInfo.com

The United Illuminating Company

CNG

Southern Connecticut Gas
Service First!

Yankee Gas
A Northeast Utilities Company

Energy Key
Connecticut's Municipal Utilities

Connecticut's Energy Efficiency Programs are funded by a charge on customer energy bills. The Programs are designed to help customers manage their energy usage and cost.

Energy Efficiency Board
c/o Connecticut Department of Public Utility Control
10 Franklin Square New Britain, CT 06051
www.CTEnergyInfo.com

Connecticut Department of Public Utility Control
10 Franklin Square New Britain, CT 06051
www.ct.gov/dpuc

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REQEUST 1-2

Attachment 2

Synapse
Energy Economics, Inc.

The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date

Kenji Takahashi and David A. Nichols

The 2008 ACEEE Summer Conference
August 20, 2008

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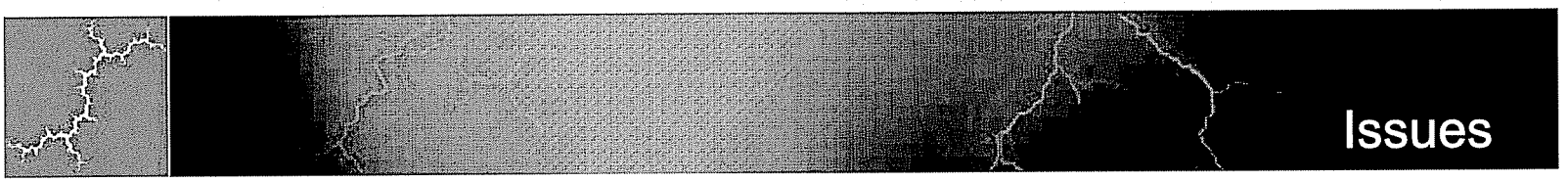

Issues

- High Annual Electric Energy Savings through Energy Efficiency Programs
- Sustainability of High Energy Savings
- Conservation Supply Curve
- Trend in Cost of Saved Energy (CSE)

High Annual Electric Energy Savings through Energy Efficiency Programs

Jurisdiction or Entity	Annual Savings (%)	Year(s)	Source
Interstate Power & Light (IPL) (MN)	3.0	2001	Garvey, E. 2007. "Minnesota's Demand Efficiency Program."
San Diego Gas & Electric (SDG&E) (CA)	2.1	2005	SDG&E 2006. Energy Efficiency Programs Annual Summary
Minnesota Power	1.9	2005	Garvey, E. 2007
Sacramento Municipal Utility District (SMUD) (CA)	1.9	1994	Data provided by SMUD
Vermont	1.8	2007	Efficiency Vermont 2008. 2007 Preliminary Results and Savings Estimate Report
Southern California Edison (SCE)	1.7	2005	SCE 2006. Energy Efficiency Annual Report
Western Mass. Electric Co. (MA)	1.6	1991	MA Dept. of Telecommunications & Energy (DTE) 2003. Electric Utility Energy Efficiency Database
Pacific Gas & Electric (PG&E) (CA)	1.5	2005	PG&E 2006. Energy Efficiency Programs Annual Summary
Massachusetts Electric Co.	1.3	2005	MECo 2006. 2005 Energy Efficiency Annual Report Revisions
Connecticut IOUs	1.3	2006	CT Energy Conservation Management Board (ECMB). 2007
Commonwealth Electric (MA)	1.2	1990	MA DTE 2003.
Cambridge Electric (MA)	1.1	2000	MA DTE 2003.
Seattle City Light (WA)	1.0	2001	Seattle City Light 2006. Energy Conservation Accomplishments: 1977-2005
Eastern Edison (MA)	1.0	1994, 1998	MA DTE 2003.

Examples of High Energy Savings

	Mass. Electric	SMUD	W. Mass. Electric
1991	1.00%	0.70%	1.60%
1992	0.70%	1.30%	1.00%
1993	0.70%	1.10%	1.30%
1994	1.00%	1.90%	0.80%
1995	1.00%	1.60%	0.70%
1996	0.90%	0.90%	0.80%
1997	1.00%	0.40%	1.00%
1998	0.80%	0.40%	0.80%
1999	0.90%	0.30%	0.70%
2000	0.70%	0.30%	1.00%
2001	0.80%	0.70%	0.90%

	CT IOUs	Efficiency Vermont	IPL	SDG&E
2000	0.90%	0.40%		0.80%
2001	1.10%	0.70%	2.40%	1.10%
2002	0.90%	0.80%	2.50%	1.10%
2003	0.40%	1.00%	2.50%	0.70%
2004	1.00%	0.90%	2.50%	1.20%
2005	1.10%	1.00%	2.30%	2.00%
2006		1.00%	2.90%	
2007		1.80%		

Cost of Saved Energy (CSE)

- Levelized CSE: The present value of the total cost of energy savings over the measure economic lives, converted to equal annual payments per kWh savings.
- Levelized CSE = Measure Costs x CRF / First Year kWh Savings
  - Capital Recovery Factor (CRF) = $i (1 + i)^n /\{(1 + i)^n - 1\}$
  - i = real discount rate
  - n = useful measure life (years)

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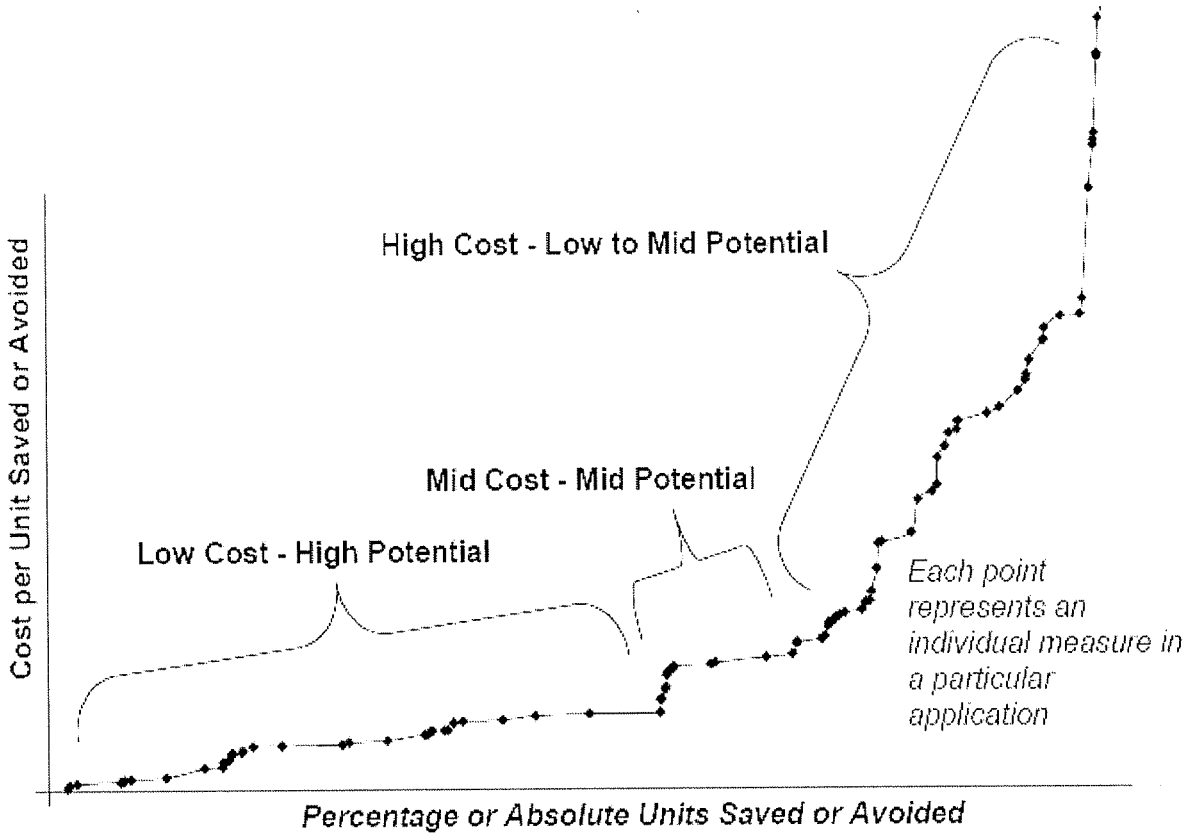
Conservation Supply Curve



Limitting Factors

- Includes only demonstrated and currently well-understood measures.
- Program and measure cost reductions are not considered
- Costs associated with marketing, administration, and M&V are not included.
- Actual program design is often a portfolio of various measures and does not follow the CSC.

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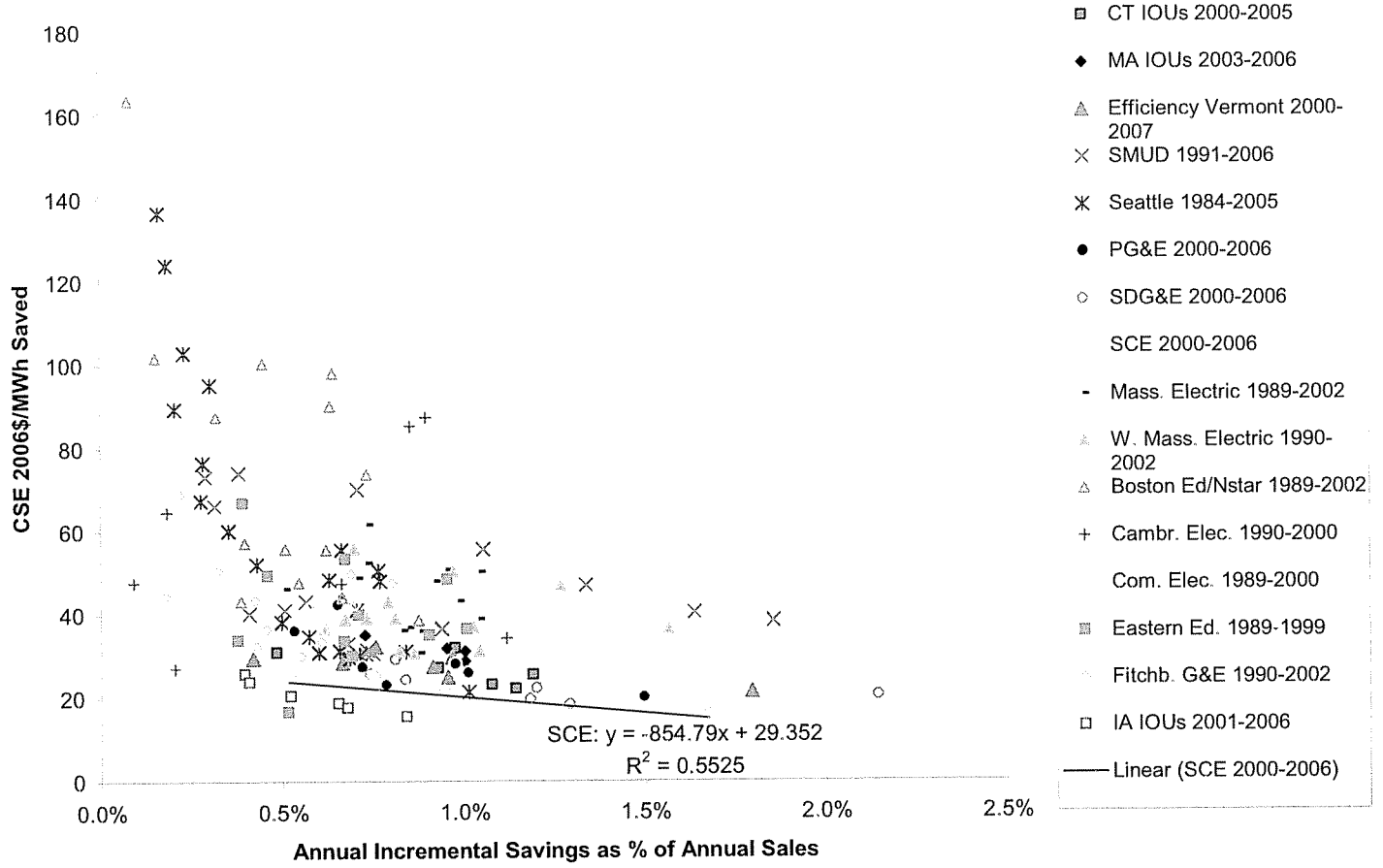
Utility Cost of Saved Energy (2006$/MWh) vs. Annual Incremental Savings as % of Sales



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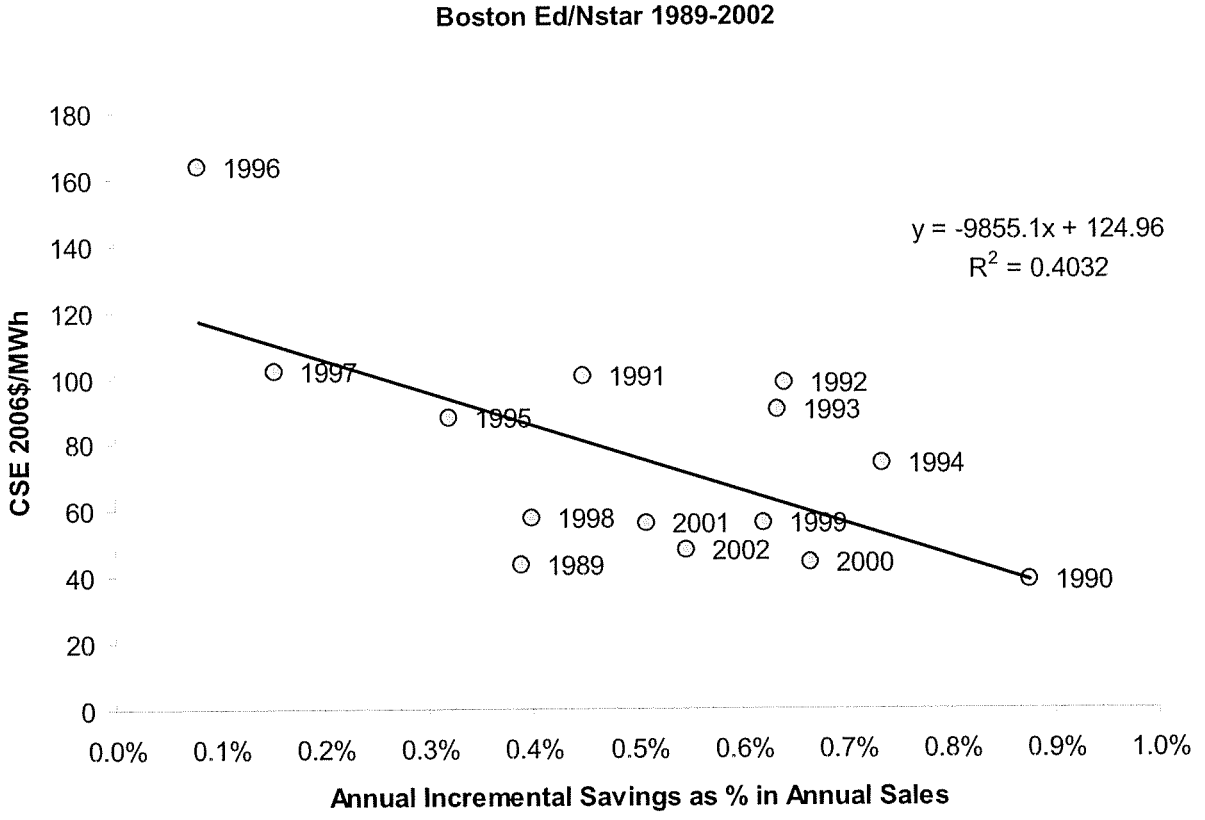
Example- Boston Edison/NStar



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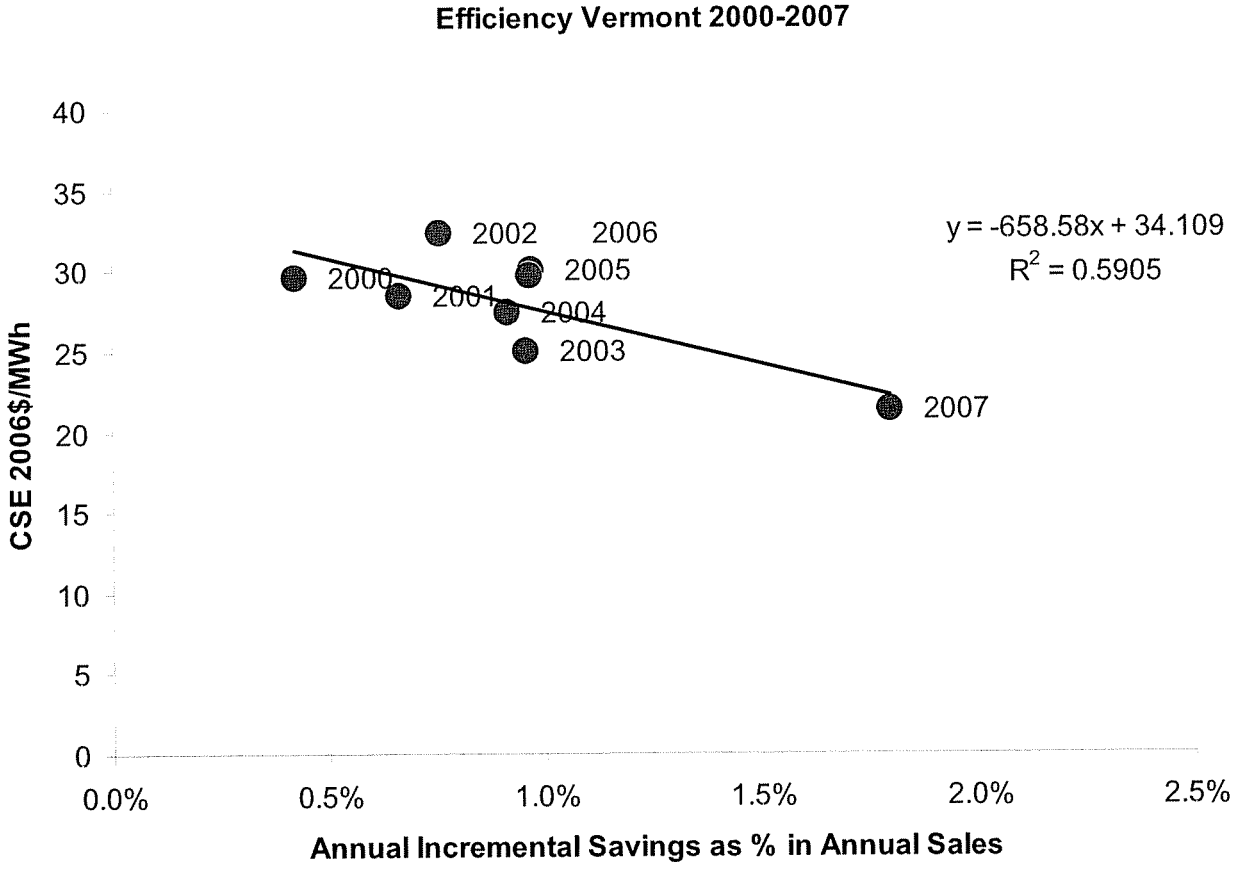
Example- Efficiency Vermont



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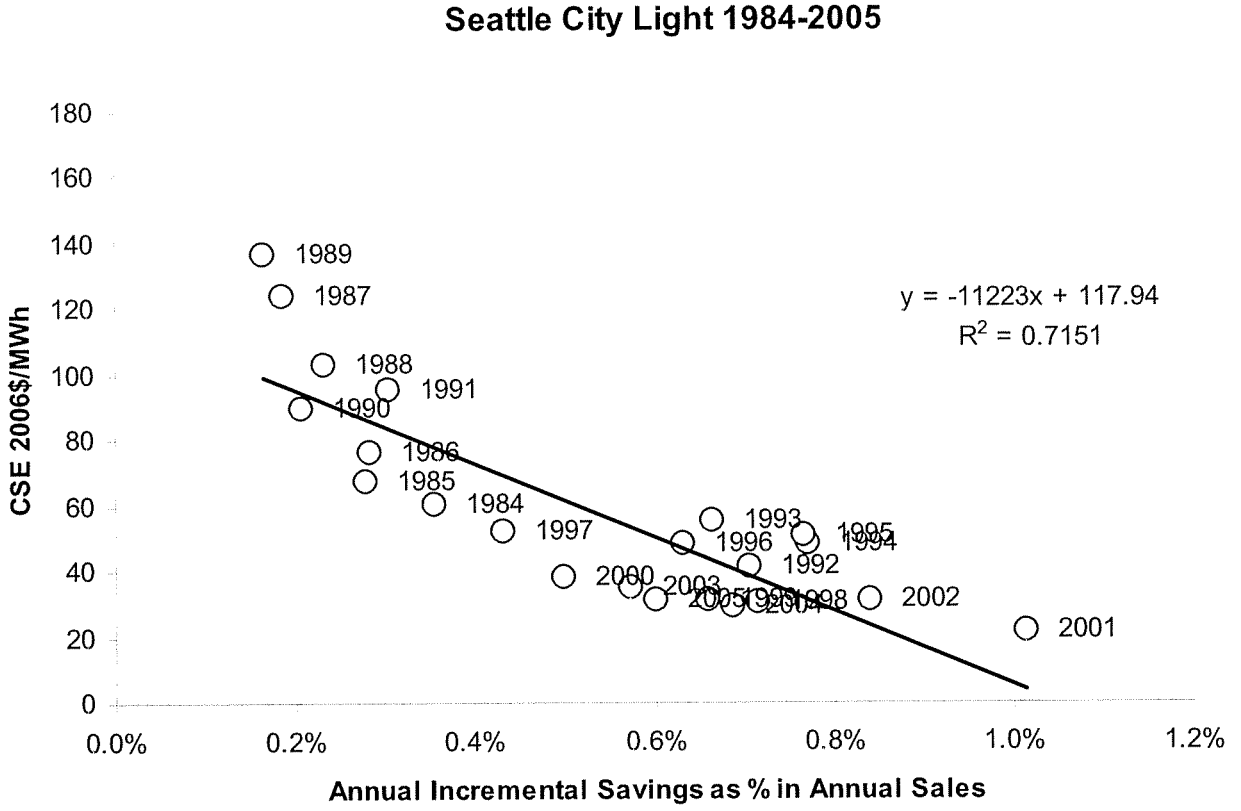
Example- Seattle City Light



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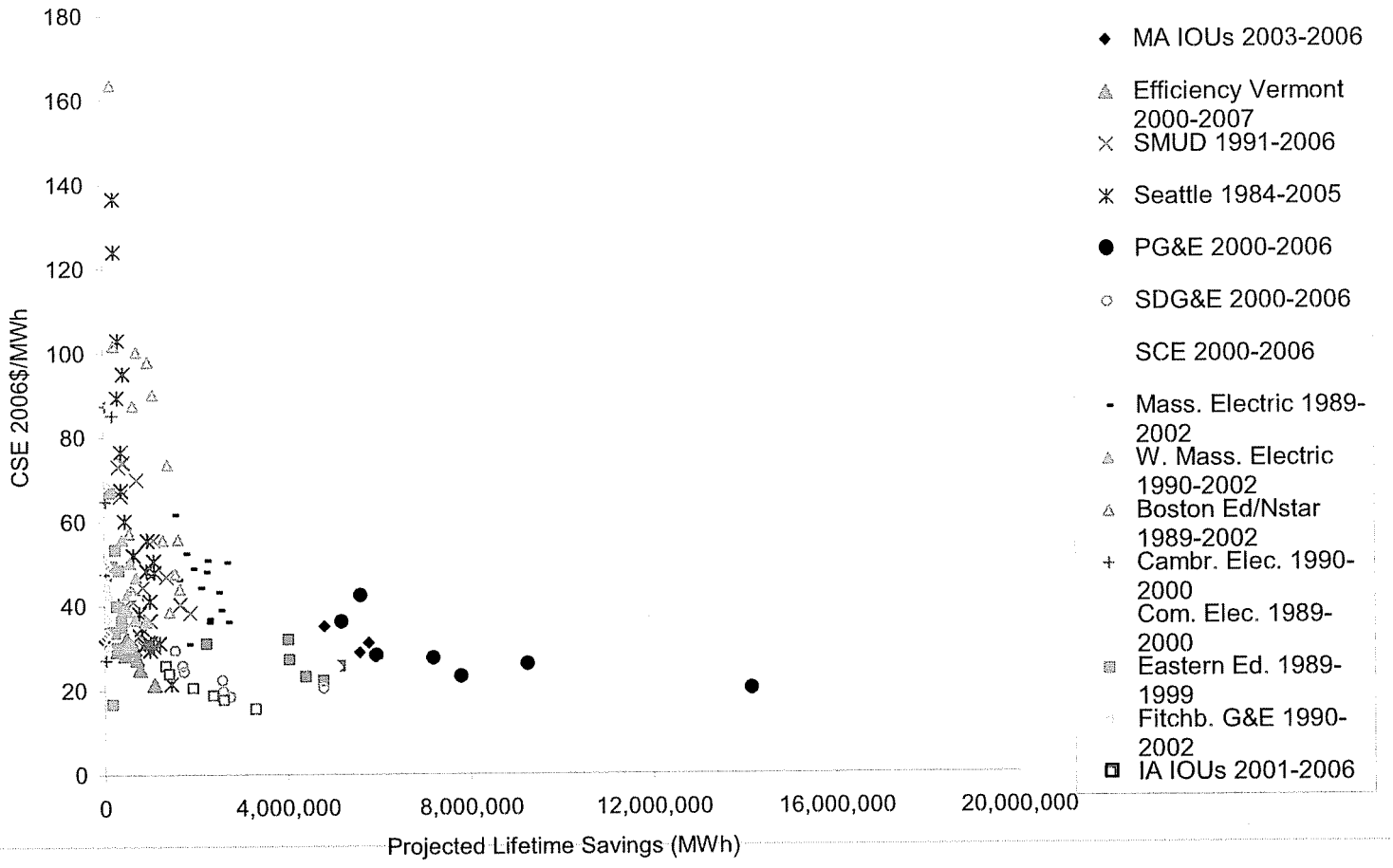
Utility Cost of Saved Energy (2006$/MWh) vs. Annual Incremental Savings as % of Sales

Data	Coefficient	R-square
CT IOUs 2000-2005	-1073	0.462
MA IOUs 2003-2006	-1798	0.834
Efficiency Vermont 2000-2007	-659	0.591
SMUD 1991 - 2006	-1257	0.136
Seattle 1984 - 2006	-11223	0.715
PG&E 2000-2006	-1747	0.526
SDG&E 2000-2006	-506	0.400
SCE 2000-2006	-771	0.553
Mass. Electric 1989-2002	-1185	0.050
W. Mass. Electric 1990-2002	-220	0.006
Boston Ed/Nstar 1989-2002	-9855	0.403
Cambr. Elec. 1990-2000	-48857	0.271
Com. Elec. 1989-2000	-8189	0.213
Eastern Ed. 1989-1999	-858	0.020
Fitchb. G&E 1990-2002	-1903	0.125
Iowa IOUs 2001-2006	-2189	0.943

Utility Cost of Saved Energy (2006$/MWh) vs. Projected Lifetime Savings



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Utility Cost of Saved Energy (2006$/MWh) vs. Projected Lifetime Savings

Data	Coefficient	R-square
CT IOUs 2000-2005	-2.695E-06	0.457
MA IOUs 2003-2006	-4.950E-06	0.676
Efficiency Vermont 2000-2007	-1.135E-05	0.658
SMUD 1991 - 2006	-1.590E-05	0.207
Seattle 1984 - 2006	-7.680E-05	0.731
PG&E 2000-2006	-1.841E-06	0.552
SDG&E 2000-2006	-2.249E-06	0.420
SCE 2000-2006	-6.484E-07	0.591
Mass. Electric 1989-2002	-9.022E-06	0.168
W. Mass. Electric 1990-2002	-8.284E-06	0.026
Boston Ed/Nstar 1989-2002	-4.542E-05	0.454
Cambr. Elec. 1990-2000	-1.747E-03	0.183
Com. Elec. 1989-2000	-1.390E-04	0.186
Eastern Ed. 1989-1999	-2.854E-05	0.034
Fitchb. G&E 1990-2002	-1.760E-04	0.078
Iowa IOUs 2001-2006	-5.021E-06	0.948

Possible Reasons for Cost Variation

(1) economies of scale are at work (e.g., allocating marketing and administration costs over more EE savings, achieving lower unit costs for program measures);

(2) economies of scope are at work (e.g., exploiting synergies among different measures);

(3) administrators become smarter and more organized in designing and developing EE programs (e.g., less incentive to get the same level of savings); or

(4) administrators have more credibility or more resources available for quality program design and development, etc.

Key Finding

Among all of the datasets that we have collected, all of the slope coefficients of the linear trend lines are negative. This strongly suggests that per-unit cost of energy efficiency (EE) decreases as the amount of EE savings increases. It is important to emphasize that this finding contradicts the generally accepted theory that costs of EE increase when EE savings amounts increase.

The fact that the coefficient is negative in every case is particularly striking. While there exists a possibility that unit costs might begin to increase at much higher levels of EE program savings, this evidence suggests that current program savings levels have not yet approached any such point.

 |

Further Research Needs

- Adding data for additional utilities and regions to the analysis.
- Investigation of CSE by type of programs or sector (e.g. residential versus non-residential).
- Explicit analysis of the share of administrative and marketing costs to total program costs as a function of program impact, to test one of the hypotheses about economies of scale.
- And many more…

 |

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Minnesota's Demand Efficiency Program

Edward Garvey,
Deputy Commissioner for
Energy & Telecommunications,
Minnesota Department of Commerce

June 21, 2007

Gov. Pawlenty's Guiding Energy Policy

- **Reliable,**
- **Low-Cost,**
- **Community-Benefiting, and**
- **Environmentally-Superior**
- **Energy Systems**

Gov. Pawlenty's Next Generation Energy Initiative

"We cannot, as a strategic plan for the future, just experience the cost crisis, the environmental impacts, and the supply questions that flow from embracing the status quo. We need a different and better energy future."

- From November 29, 2005 address to the U of MN Renewable Energy Symposium

Gov. Pawlenty's Next Generation Energy Initiative

- **More Renewables**
- **More Efficiency**
- **Less Carbon**
- **Decreasing fossil fuel use**
  - **Governor Pawlenty announced a goal of reducing per capita energy consumption by 15% by 2015.**
  - **To achieve this goal, both aggressive renewable *and* energy efficiency policies are needed.**

MORE EFFICIENCY--
2007 CIP Legislative Changes

Next Generation Energy Act of 2007

2007 Minnesota Session Laws,
Chapter 136—Article 2

Overview of the Demand Efficiency Program

- **Shifts focus from spending to energy savings.**
- **Sets annual energy savings goal of 1.5% of retail energy sales.**
- **Ensures programs are available to low-income customers.**
- **Creates mechanism to conduct research and development projects.**
- **Requires Commerce to provide additional technical assistance to utilities**

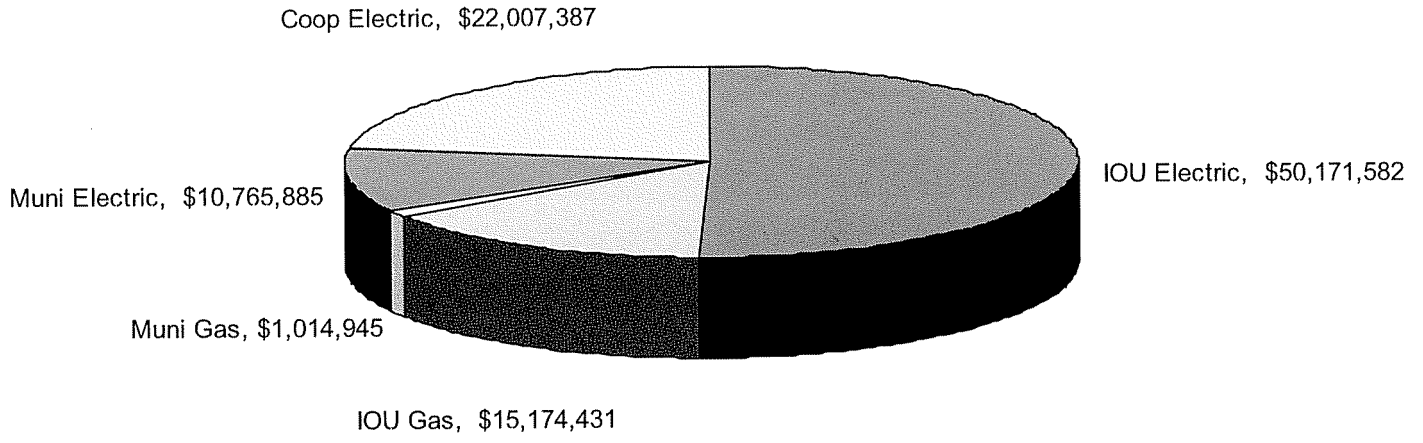
Background: "Old CIP Law"

CIP Requirements

- **Electric utilities: minimum spending requirement of 1.5% of gross operating revenue (GOR) from sales to retail customers. Xcel Energy must spend 2% of GOR.**
- **Gas utilities: minimum spending requirements of 0.5% of GOR.**
- **Serve a wide range of customer classes**
- **Maintain cost-effective programs**
- **Provide programs targeting low-income customers**

CIP 2005 Spending Totals

In 2005, utilities invested approximately $99 million in the Conservation Improvement Program.



CIP 2005 Spending By Utility

Electric

Xcel Energy	$42,553,160
Cooperatives	$22,007,387
Municipal	$10,765,885
Minnesota Power	$3,573,852
Interstate Power and Light	$2,454,159
Otter Tail	$1,590,411
Total Electric	$82,944,854

Natural Gas

CenterPoint Energy	$7,803,848
Xcel Energy	$4,672,048
MERC-PNG	$1,545,299
Municipal	$1,014,945
MERC-NMU	$464,181
Interstate Power and Light	$446,284
Great Plains	$231,271
Greater Minnesota Gas	$11,500
Total Gas	$16,189,376

Old CIP Cost Recovery

- **IOUs are allowed to recover prudent investments and expenditures for CIP.**

- **Cost recovery is authorized by Minn. Stat. 216B.16, subd. 6b (2005).**

- **Municipal and cooperative utilities are not rate-regulated, so each governing board determines how CIP expenditures will be recovered.**

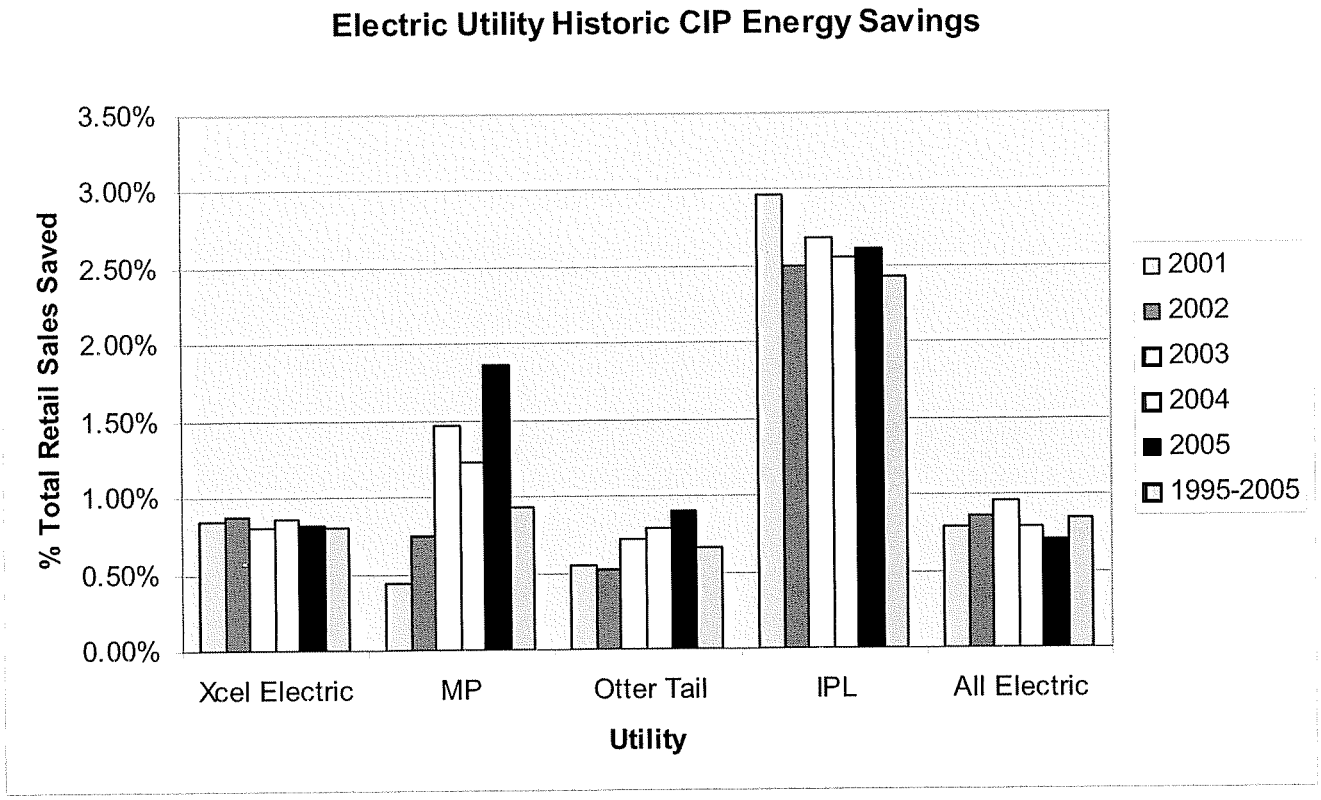
OLD CIP Shared-Savings Incentive

- **IOUs are eligible to receive a financial incentive (up to 30% of CIP spending or approved budget, whichever is less) for meeting and exceeding energy savings goals.**

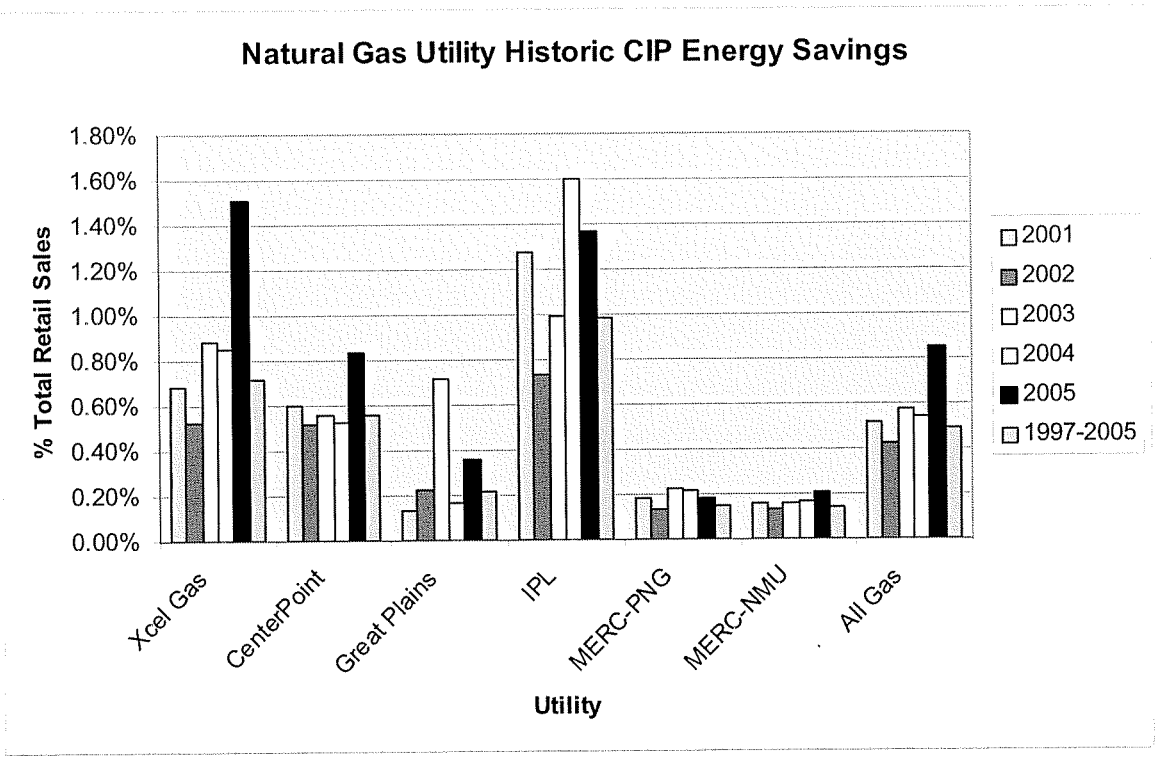
- **The incentive is based on a percentage of actual net benefits from the utility's CIP.**

- **The financial incentive is authorized by Minn. Stat. 216B.16, subd. 6c (2006).**

CIP Historic Energy Savings: Electric IOUs



CIP Historic Energy Savings: Natural Gas IOUs



CIP Historic Energy Savings Investor-owned utilities

Table 1: Electric utility CIP energy savings as a percentage of total annual retail sales

	Xcel Electric	MP	Otter Tail	IPL	All Electric
2001	0.85%	0.43%	0.56%	2.96%	0.79%
2002	0.88%	0.74%	0.53%	2.49%	0.86%
2003	0.80%	1.47%	0.72%	2.68%	0.97%
2004	0.86%	1.23%	0.79%	2.55%	0.80%
2005	0.81%	1.87%	0.90%	2.61%	0.71%
1995-2005	0.80%	0.93%	0.66%	2.43%	0.85%

Table 2: Natural gas utility CIP energy savings as a percentage of total annual retail sales

	Xcel Gas	CenterPoint	Great Plains	IPL	MERC-PNG	MERC-NMU	All Gas
2001	0.68%	0.60%	0.13%	1.27%	0.18%	0.16%	0.52%
2002	0.52%	0.52%	0.23%	0.74%	0.14%	0.14%	0.42%
2003	0.89%	0.56%	0.71%	0.99%	0.22%	0.16%	0.57%
2004	0.85%	0.53%	0.17%	1.60%	0.22%	0.17%	0.54%
2005	1.51%	0.84%	0.36%	1.37%	0.18%	0.20%	0.85%
1997-2005	0.71%	0.56%	0.22%	0.98%	0.15%	0.14%	0.49%

DEMAND EFFICIENCY— Energy Savings Goal

- **1.5% of Minnesota retail energy sales**
- **Investment only required if cost-effective**
- **Utilities may petition to lower goal of 1%**

DEMAND EFFICIENCY-- Technical Assistance

Dept. of Commerce will develop:

1. Statewide energy savings assumptions
2. Tool to evaluate cost-effectiveness
3. Inventory of effective programs

DEMAND EFFICIENCY— Low Income Programs

Electric utilities are required to spend:

- **0.10% of residential revenues annually until 2010**
- **0.20% annually thereafter**

Utilities have the option of administering low income programs locally or authorizing Commerce to administer programs on behalf of the utility

DEMAND EFFICIENCY-- Research and Development

- **Commerce may assess utilities up to $3.6 million annually for CIP R&D projects**

- **Utilities and other stakeholders will have an opportunity to suggest high priority projects**

- **R&D projects focused on helping utilities identify ways to meet energy savings goals**

DEMAND EFFICIENCY-- Facilities Energy Efficiency

- **Goal of 1,000 ENERGY STAR and 100 LEED or Green Globes commercial buildings by 2010.**
- **Updates the sustainable building guidelines**
- **Enhances existing benchmarking tool to allow public buildings to track energy saved through efficiency**

ENERGY STAR Buildings

Eligible Building Types

Offices, general
Offices, financial center
Offices, bank branch
Offices, courthouse
K-12 Schools
Hospitals
Hotels and Motels
Medical Offices
Supermarkets
Residence halls/dormitories
Warehouses

Calculating the DEMAND EFFICIENCY Goal-- First reporting period

- **Due date – June 1, 2008**
  - ***Average Energy Sales (based on '05, '06, '07)***
  - ***Example: 100,000 kWh***
- **Goal - 1,500 kWh savings**
- **Applicable to 2010 & 2011**

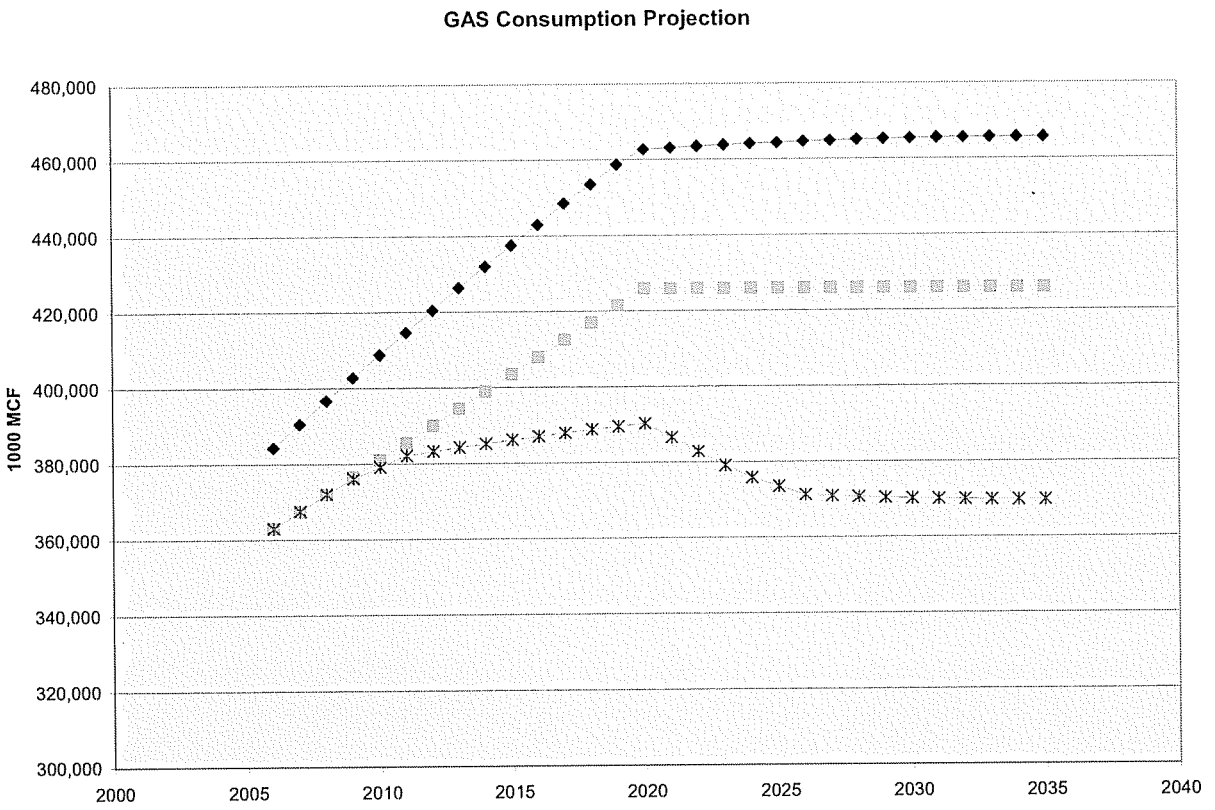
Calculating the DEMAND EFFICIENCY Goal— Second reporting period

- **Due date – June 1, 2011**
  - ***Average Energy Sales (based on '08, '09, '10)***
  - ***Example: 103,000 kWh***
- **Goal - 1,545 kWh savings**
- **Applicable to 2012 to 2014**

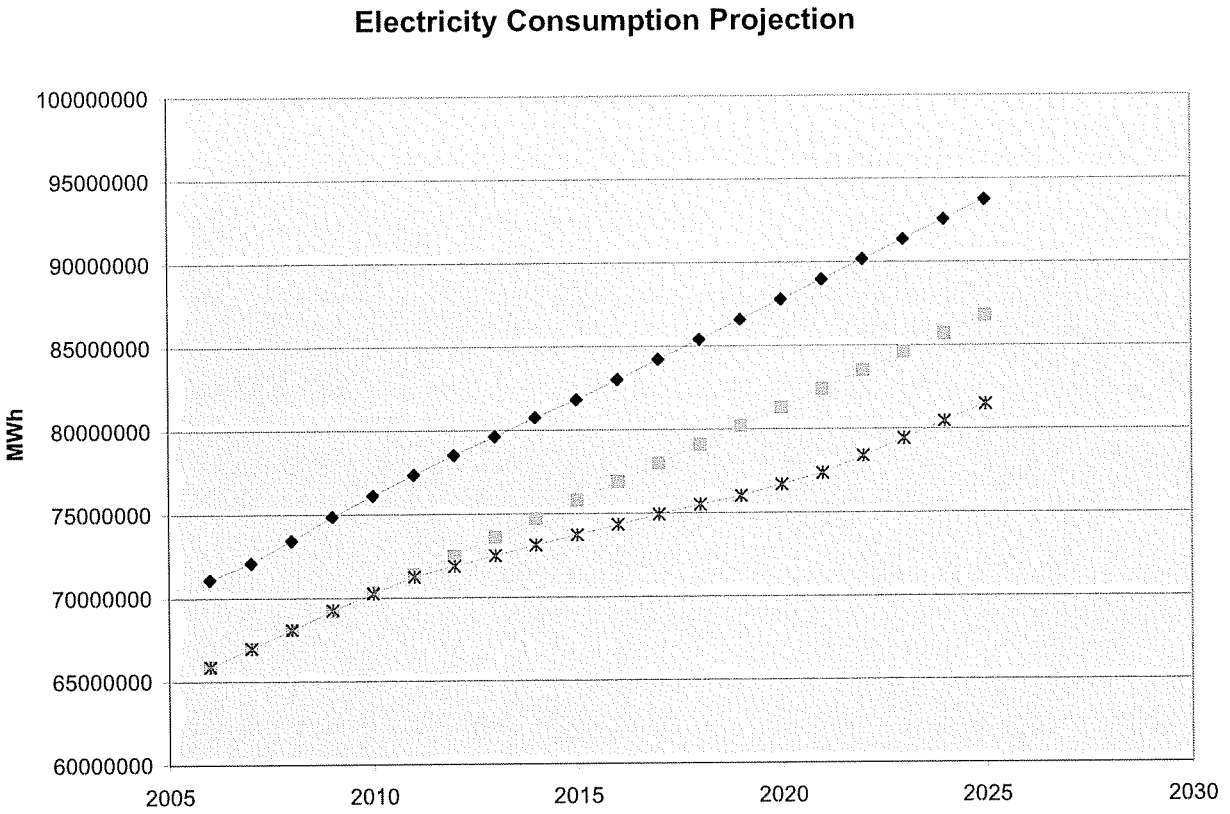
Calculating the DEMAND EFFICIENCY Goal-- Second reporting period – Alt 2

- **Due date – June 1, 2011**
  - ***Average Energy Sales (based on '08, '09, '10)***
  - ***Example: 98,500 kWh***
- **Goal - 1,478 kWh savings**
- **Applicable to 2012 to 2014**

Effect of Increased DEMAND EFFICIENCY Savings on Gas



Effect of Increased DEMAND EFFICIENCY Savings on Electricity



Resources

- **DEMAND EFFICIENCY/CIP Website**
  - **Basic program information**
  - **Program evaluation from the Office of the Legislative Auditor**
  - **www.commerce.state.mn.us, then click>>Energy Info Center>>Utility Conservation**

- **Utility filings -- www.eDockets.state.mn.us**

- **CIP.info@state.mn.us**

Minnesota's Demand Efficiency Program

THANK YOU

QUESTIONS?

Edward Garvey,
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Minnesota Department of Commerce
Edward.Garvey@State.mn.us
651-296-9325

2011 Savings Claim

April 1, 2012

128 Lakeside Avenue, Suite 401
Burlington, Vermont 05401
888-921-5990

www.efficiencyvermont.com

This report is submitted April 1, 2012, to the Vermont Public Service Board and to the Vermont Department of Public Service, in fulfillment of the regulatory requirement for submitting Efficiency Vermont's annual savings claim for 2011.

2011 Efficiency Vermont Savings Claim
TABLE OF CONTENTS

1.1 Savings Claim Summary

1.1 SAVINGS CLAIM SUMMARY

Overview

Efficiency Vermont helps Vermonters save money and energy in their homes and businesses by providing comprehensive energy efficiency services. These services, offered for both electric and thermal efficiency, include technical assistance and financial incentives to support investments in energy efficiency.

Efficiency Vermont operates under a performance-based model and is regulated by the Vermont Public Service Board. The year 2011 marked the conclusion of Efficiency Vermont's 2009-2011 performance period. **Table 1** presents Efficiency Vermont's key results for that period.

Table 1. Key results (approximated) for Efficiency Vermont, 2009 - 2011

	2009	2010	2011	2009 – 2011 Total
Energy savings	85,000 MWh	111,000 MWh	108,000 MWh	304,000 MWh
Total Resource Benefits[1]	$101.4 million	$112 million	$101.5 million	$314.9 million
Efficiency as a share of Vermont's electric energy needs[2]	1.6%	1.95%	1.91%	N/A
CO_2 emissions avoided through efficiency	540,000 tons	805,000 tons	790,000 tons	2,135,000 tons

This performance demonstrates a trend of improved results across the period, particularly in the context of Vermont's economic recovery during the ongoing national recession. As **Table 1** depicts, benefits can be seen in energy savings, economic value, and environmental gains. After a challenging start to the performance period in 2009, both 2010 and 2011 reflect valuable progress in these three indicators of efficiency program success.

[1] 2009 dollars.

[2] To reflect the relationship between energy efficiency programs and the state's overall electricity requirements, this figure includes savings from efficiency measures installed by the Burlington Electric Department and via the Green Mountain Power Energy Efficiency Fund.

Figure 1. Annualized MWh savings, by year, since 2000

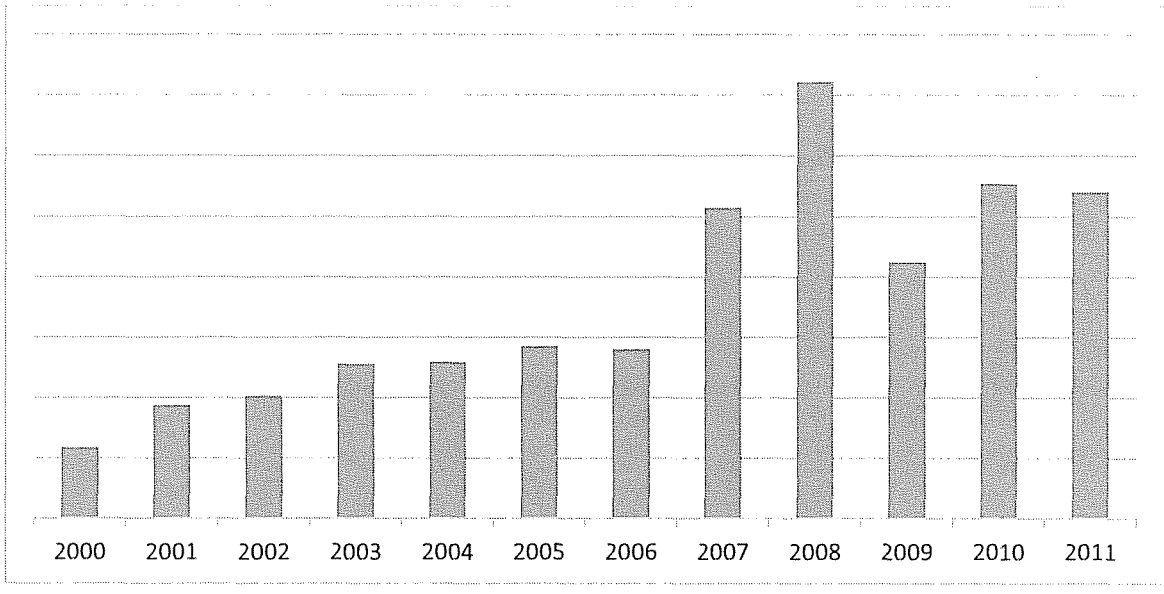


Figure 1 presents a comparison of MWh savings, annualized, since the year 2000.

In addition to providing its established services for Vermont residential and business ratepayers, Efficiency Vermont also responded to broader state priorities, notably the rapid implementation of special services to aid victims of Tropical Storm Irene. These services were designed to help Vermonters "rebuild better" with energy efficiency and safety in mind.

In total, Efficiency Vermont coordinated with contractors to perform free moisture assessment and air sealing services to approximately 180 homes; provided financial incentives to customers for the installation of 200 energy-efficient water heaters and heating systems; and worked with partners to provide low-cost lighting replacement for some 60 businesses. Efficiency Vermont partnered in the development and promotion of special "Button Up After the Flood" workshops, and provided free technical support to 675 Vermont callers seeking advice on how to rebuild safely and energy efficiently.

The final year of the current performance period, 2011, marked the first year of Efficiency Vermont's operation under the new, franchise-like Order of Appointment structure. Under this structure, Efficiency Vermont is regulated in a manner comparable to that of other Vermont utilities. This transition has resulted in a significant change in regulatory processes related to Efficiency Vermont's budgets and performance goals. Notably, the inaugural Demand Resources Plan Proceeding continued throughout the year. This proceeding is an extensive and multi-pronged process that encompasses planning efforts such as forecasting Efficiency Vermont's

energy savings goals for the next 20 years, consistent with the time horizon for the state's Long-Range Transmission Plan.

Economic Value for Vermont

Efficiency Vermont continues to provide a good economic value for Vermont ratepayers. In 2011, the benefit-to-cost ratio of Efficiency Vermont services was 2.2 to 1, as shown in **Table 2.**

Table 2. Net lifetime economic value of energy efficiency investments in 2011

Benefits	$101,500,000	Total Resource Benefits
	$25,500,000	Operations and maintenance savings
Minus costs	$40,200,000	Efficiency Vermont costs
	$18,000,000	Costs paid for by participants and third-party investments
	$58,200,000	Total costs
Equals net benefits	$68,800,000	Net lifetime economic value to Vermont

Total Resource Benefits for each major market served by Efficiency Vermont were as follows:

- Business New Construction: $6.8 million
- Existing Business: $47.3 million
- Residential New Construction: $8.2 million
- Retail Efficient Products: $29.6 million
- Existing Homes: $9.7 million

Efficiency continued to be an excellent value compared to the costs of other sources of energy: Efficiency Vermont delivered energy efficiency in 2011 at 4.3 cents / kWh. Taking into account participating customers' additional costs and savings, the levelized net resource cost of saved electric energy in 2011 was 1.4 cents / kWh. By contrast, the cost of comparable electric supply in 2011 was 12.1 cents / kWh.

Investments in energy efficiency continue to bring economic benefits not just to Vermont ratepayers, but also to the private-sector partners who deliver services on behalf of Efficiency Vermont. For instance, Efficiency Vermont's Home Performance

with ENERGY STAR® contractor partners completed 800 projects worth $6 million in 2011.[3] That network of contractor partners now totals 78 contractors throughout the state.

Efficiency Vermont also supports a growing network of retailers and distributors throughout the supply chain. On the retail side alone, Efficiency Vermont now works with more than 250 retailers, helping them promote and sell efficient products. This collaboration contributes to those retailers' bottom lines. In 2011, sales of energy-efficient appliances, lighting, and consumer electronics promoted by Efficiency Vermont totaled approximately $15.8 million.

Energy Savings

Energy savings resulting from efficiency measures installed in 2011 provided an estimated 1.91% of Vermont's overall electric energy requirements for the year.

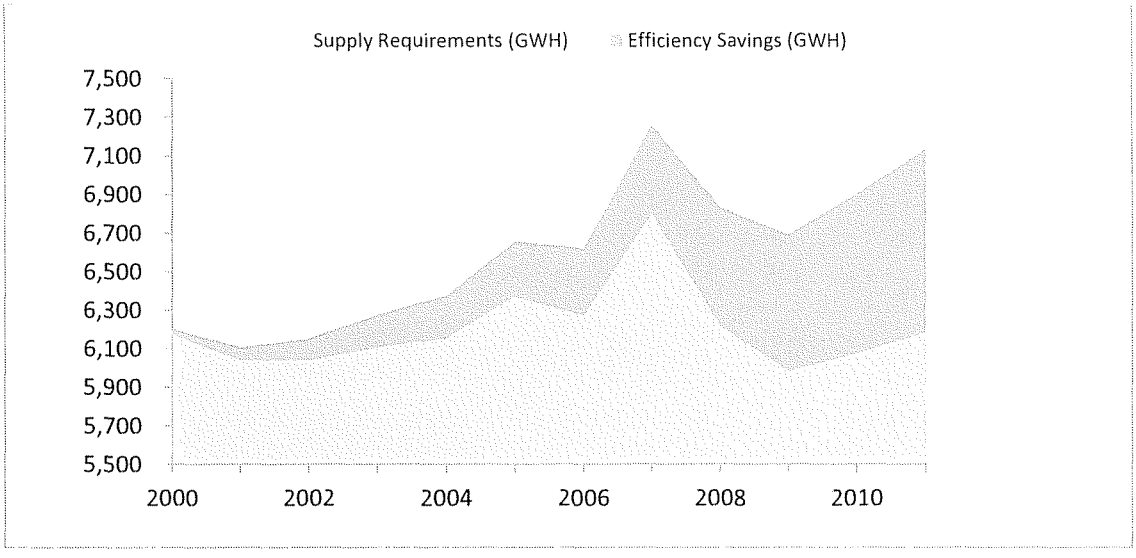
Figure 2 indicates a year-by-year comparison of electric savings as a percentage of statewide retail electric resource sales.

Figure 2. Savings from efficiency, compared to statewide electric resource requirements since 2000

Cumulatively, efficiency measures installed since 2000 provided 11% of the state's electric energy requirements in 2011. **Figure 3** shows the cumulative impact of energy efficiency on the state's electric resource requirements.

[3] To provide a comprehensive overview of the economic impact of this program, these figures also include work completed with support from Green Mountain Power's Energy Efficiency Fund.

Figure 3. Cumulative impact of efficiency on growth in statewide annual electric supply requirements, by year



Efficiency Vermont's mandate also includes reductions in peak demand. A summary of that activity for the 2009 – 2011 performance is shown in **Table 3.**

Table 3. Comparison of Efficiency Vermont peak demand reductions, 2009 - 2011

Type of demand reduction	2009	2010	2011
Summer peak	12.9	16.3	14.9
Winter peak	14.9	20.2	19.7
Summer Geographic Targeting peak	5	5.6	3.8
Winter Geographic Targeting peak	5.1	6.7	5.2

In addition to electricity savings, Efficiency Vermont must also address heating and process fuels efficiency as well, allowing for a comprehensive approach to energy savings. Efficiency Vermont savings for heating and process fuels efficiency totaled 49,000 MMBtu in 2011. Services used to deliver these savings include Home Performance with ENERGY STAR, which provides incentives of up to $2,500 per project for comprehensive residential energy efficiency upgrades; Building Performance, which provides similar incentives for small businesses; and custom incentives for high-efficiency heating systems for businesses.

These services are funded through a combination of revenues from the State's participation in the Regional Greenhouse Gas Initiative and from the Vermont Energy Investment Corporation's participation on behalf of Vermont ratepayers in the regional grid's Forward Capacity Market. Although these resources are not sufficient to meet Vermont's statutory goals for energy efficiency in buildings, Efficiency Vermont has sought innovative ways to maximize the impact of the limited funds available.

Support for Vermont Businesses and Institutions

Savings in the Business New Construction and Existing Business markets for 2011 totaled 6,000 MWh and 50,000 MWh, respectively, delivering Total Resource Benefits of $54 million. Savings through efficiency continue to provide an important financial benefit for Vermont businesses, particularly as the economy continues its recovery. The average return on investment for efficiency improvements made by business customers in 2011 was 70%.

Efficiency Vermont unveiled an initiative for Vermont's largest energy users in 2011: the Energy Leadership Challenge. Under this challenge, customers were asked to commit to saving 7.5% of their energy use over a two-year period beginning July 2011. As of the end of 2011, over 20% of the top 300 energy users in Vermont had committed to the challenge. Efficiency Vermont also began to develop long-term energy plans with all of its large customers.

In 2011, Efficiency Vermont hosted the first Customer Advisory Group meeting, bringing together leaders of a dozen large commercial and industrial customers to provide formalized feedback on Efficiency Vermont services. Efficiency Vermont also co-hosted three events at customer sites to provide information sharing and networking opportunities for groups of customers who share similar interests.

For large and small commercial customers alike, Efficiency Vermont continued to offer services through 15 different targeted market initiatives. For instance, Efficiency Vermont has a market initiative for agriculture and dairy farms, with specific incentives and energy-saving measures tailored to the needs of that market. Efficiency Vermont participated in several annual farm shows, conducted direct phone outreach to agricultural partners such as farm vendors, and created targeted marketing materials. In addition, Efficiency Vermont offered farmers free timers to control engine block heaters used in cold weather on farm vehicles. Efficiency Vermont invested $4.3 million in 2011 in financial incentives and technical assistance for a variety of energy-saving measures that support this critical part of Vermont's economy and heritage.

Within the commercial buildings context, Efficiency Vermont also supports public-serving institutions, such as schools. Efficiency Vermont launched the Whole School Energy Challenge pilot program at five K-12 schools, with a goal of having each school reduce its overall energy use by 10% by May 2012. For institutions of higher education, Efficiency Vermont worked with the High Meadows Fund and the Sustainable Energy Institute to launch the Green Revolving Fund. This fund encourages using alumni donations and endowment resources to capitalize revolving loan funds that can be invested on an ongoing basis in energy efficiency.

Efficiency Vermont also provided comprehensive thermal efficiency services to business customers, delivered through its Building Performance service. This service, modeled after Home Performance with ENERGY STAR, provides energy efficiency incentives of up to $7,500 per project for qualifying small businesses to improve their building performance. In 2011, 39 projects were completed, through a growing network of private-sector contractors.

Retail Efficient Products

Efficiency Vermont provides incentives and other promotional support for a range of energy-efficient consumer products. This support can take the form of rebates, cost buydowns at the distribution level, and point-of-purchase display materials. In 2011, electricity savings from retail efficient products amounted to 48,000 MWh.

Compact fluoresecent lightbulb (CFL) products remain a significant focus in this sector. In 2011, Efficiency Vermont continued its successful promotion of speciality CFL products, such as three-way and dimmable bulbs. These products provide significant opportunities for savings in uses where traditional CFLs are not suitable. Efficiency Vermont's 99-cent promotion of many specialty CFL products has resulted in a significant increase in the sales of these units, as well as in the composition of the Vermont's CFL market overall.

In 2011, sales of specialty CFL products totaled 407,000 units, resulting in 33,000 MWh in savings. Specialty CFLs made up 55% of total CFL sales for 2011, compared with 40% in 2010. Sales of standard CFLs totaled 750,000 units, resulting in 9,000 MWh in savings.

Efficiency Vermont expanded its incentive offerings for light-emitting diode (LED) products. LEDs represent the next generation in lighting technology, with higher levels of energy efficiency, high-quality light, and no mercury disposal issues. Efficiency Vermont now offers incentives for more than 60 LED products, including screw-based LEDs for 2011. As prices have continued to fall on these products, they have become increasingly cost-effective for both residential and business uses.

The success of Efficiency Vermont's retail initiatives is, to a significant degree, a reflection of partnerships with Vermont's retail establishments. The Efficiency Vermont Business and Consumer Electronics program, launched in 2010, grew in 2011 and now has 31 retail partners.

Efficiency Vermont continued its support for the Vermont Foodbank in 2011, providing 76,000 CFLs for distribution to low-income Vermonters throughout the state. New in 2011, Efficiency Vermont provided 2,000 advanced power strips to the Foodbank for distribution to its clients. These devices help reduce "phantom load" from home electronics such as television and game consoles that otherwise would constantly draw low levels of electricity, even when not in use or on stand-by.

Savings for Residential Customers

Efficiency Vermont savings for residential customers totaled 4,500 MWh in 2011. Savings for heating and process fuels efficiency totaled 29,000 MMBtu, up 55% from 2010.

In Residential New Construction, Efficiency Vermont launched a significant initiative to accommodate improvements to the state energy code and the ENERGY STAR Homes standard. Under the initiative, support for newly built homes falls into two tiers: one to support builders in meeting and exceeding the requirements of the new residential building energy standards, and one to support builders in meeting the more stringent requirements of the ENERGY STAR Homes standard.

For exisiting homes, Efficiency Vermont's comprehensive Home Performance with ENERGY STAR service grew in 2011. This service provides incentives of up to $2,500 per homeowner to improve the home's energy efficiency for both electricity and heating fuels. The number of completed projects in 2011 expanded to approximately 575, a 160% increase over 2010.[4] This high level of participation enabled Efficiency Vermont to exceed its 2009–2011 performance indicator for heating and process fuels energy reduction (MMBTUs) by more than 25%.

As with other Efficiency Vermont services, Home Performance with ENERGY STAR is delivered to customers through a network of private service providers and other partners. In 2011, this service was supported by 78 building contractors, an increase of 10% compared with 2010. Efficiency Vermont also worked closely with other marketplace partners such as NeighborWorks® of Western Vermont, a nonprofit housing organization. NeighborWorks is using the Home Performance with ENERGY STAR service as the foundation for a U.S. Department of Energy

[4] This number reflects Efficiency Vermont projects only. Projects funded through the Green Mountain Power Energy Efficiency Fund bring the 2011 statewide total to 800.

grant it received to increase participation in residential retrofit services in Rutland County.

A significant initiative launched by Efficiency Vermont in 2011 was the biomass heating system incentive. Prior to 2011, Efficiency Vermont had provided incentives of $500 for fossil fuel heating systems as part of its comprehensive efforts. In cooperation with Governor Peter Shumlin and state legislators, Efficiency Vermont expanded equipment eligibility for this incentive in late 2011 to include biomass-fueled central heating systems.

Following statutory direction for this offering, the incentive for biomass equipment was set at the higher level of $1,000. Unlike other heating system incentives, it does not require comprehensive energy improvements to be made. Initial results for this offering were promising, with incentives provided for 16 residential and 2 commercial biomass heating systems. Efficiency Vermont also offered incentives in 2011 to help low-income customers replace inefficient outdoor wood boilers. This limited offering involved a collaboration with the Air Pollution Control Division of the Agency of Natural Resources.

Finally, Efficiency Vermont enhanced its services to low-income Vermonters in 2011 with the launch of the Major Appliance Replacement Service (MARS). MARS is delivered by Vermont's Weatherization Assistance Programs, and provides no-cost replacement of inefficient older appliances with ENERGY STAR appliances (primarily refrigerators and clothes washers) to qualifying low-income Vermonters.

Although the primary objective of this service is to save energy, customers are reporting significant non-energy benefits as well. For instance, Efficiency Vermont received feedback from several customers that their old refrigeration equipment had been incapable of safely storing their food and medicine, but with the new equipment provided through MARS, they are now able to keep those items safely in their homes.

The success of MARS and other low-income services enabled Efficiency Vermont to exceed by 10% its performance standard for investments directed to benefit that segment of the population.

Geographic Targeting

As directed by the Public Service Board, Efficiency Vermont continues to target additional investments in specific geographic areas where significant transmission or distribution constraints exist. In 2011, Efficiency Vermont savings with regard to Geographic Targeting performance indicators were strong, with summer peak demand reductions of 3.1 MW, and winter peak demand reductions of 1.1 MW in

those regions. Overall, summer peak demand was reduced by 3.8 MW and winter peak demand by 5.2 MW in 2011.

In the business sector, Efficiency Vermont sought deeper savings primarily through its account management services for large customers, which provided technical assistance and financial incentives to these customers. For residential customers, Efficiency Vermont primarily sought to promote deeper levels of energy efficiency through additional targeted promotion of retail efficient products, in particular the 99-cent specialty CFL promotion.

Other Activities

Throughout 2011, Efficiency Vermont engaged in activities beyond direct energy savings (resource acquisition activities). Under the Order of Appointment structure, many of these activities have been budgeted and will be reported under the label, Non-Resource Acquisition. Highlights for 2011:

- The 2011 Better Buildings by Design conference, which brought together contractors, design professionals, and Efficiency Vermont partners for training and continuing education from world-renowned energy efficiency experts. As in recent years, the conference sold out, attracting more than 1,100 attendees.
- Participation in the ISO New England Forward Capacity Market (FCM), in which energy efficiency savings are bid in as a resource for the regional grid. VEIC met its commitments to deliver savings from Efficiency Vermont activity in the FCM in both the first and second delivery periods that occurred in 2011, delivering 39 MW and 49 MW of capacity, respectively. Commitments increase to 55 MW in June 2012, 72 MW in June 2013, and 84 MW in June 2014.
- Participation in the statewide Smart Grid collaboration. Supported by carryover funds from 2008 Energy Efficiency Utility activity and by federal funding to the State, Efficiency Vermont participated in planning processes that involved customer communications, rates, and the overall steering committee leadership. Efficiency Vermont was also an active participant in regulatory activity related to this area, with the resumption of Docket 7307 (Investigation into Vermont Electric Utilities' Use of Smart Metering and Time-Based Rates) and considerations of important smart grid policy issues such as privacy and cyber-security.
- Launch of an entirely revamped website, www.efficiencyvermont.com, designed to make it easier for customers to find information that would lead them to take steps toward improving the energy efficiency of their homes and businesses.

- Support for the process of implementing the State's residential and commercial building energy codes, in collaboration with the Vermont Department of Public Service and other relevant stakeholders. Efficiency Vermont also participated in stakeholder discussions related to building energy code compliance.
- Continued development and refinement of financing models for energy efficiency improvements to buildings. Property assessed clean energy (PACE) mechanisms will allow Vermonters in participating communities to finance investments in energy efficiency and renewable energy through their municipalities.

2.1 Efficiency Vermont Services and Initiatives Results

2.1.1 Overall Summary

Services	Total Efficiency Vermont Services and Initiatives	Heating and Process Fuels Services and Initiatives	EEC Funded Services and Initiatives
Costs			
Year to Date Costs	$37,658,833	$5,427,760	$32,231,073
* Annual Budget Estimate	$38,281,200	$5,483,500	$32,797,700
Unspent Annual Budget Estimate	$622,367	$55,740	$566,627
% Annual Budget Estimate Unspent	2%	1%	2%
Other Costs and Commitments			
Participant Costs Year to Date	$16,524,619	$5,005,174	$11,519,445
Third Party Costs Year to Date	$1,471,727	$197,952	$1,273,775
Committed Incentives	$184,655	nap	$184,655
Savings Results			
MWh Year to Date	107,965	337	107,627
MWh cumulative starting 1/1/09	303,660	307	303,353
Winter Peak Coincident kW Savings Results			
Winter Coincident Peak kW Year to Date	19,684	141	19,543
Winter Coincident Peak kW Starting 1/1/09	55,147	160	54,987
Summer Peak Coincident kW Savings Results			
Summer Coincident Peak kW Year to Date	14,946	5	14,941
Summer Coincident Peak kW Starting 1/1/09	44,868	21	44,847
TRB Savings Results			
TRB Year to Date	$101,537,860	$12,882,536	$88,655,324
TRB Starting 1/1/09	$314,981,184	$22,922,054	$292,059,130
MMBtu Savings Results			
MMBtu Year to Date	66,722	49,206	17,516
MMBtu Starting 1/1/09	194,044	85,623	108,421
Participation			
Partic.w/ installs Year to Date	33,437	1,657	31,780
Partic.w/ installs cumulative starting 1/1/09	106,327	3,034	103,293

* Annual projections are estimates only and provided for informational purposes.

2.1.2 Budget Summary[1]

	Budget Current Year 2011	Actual Current Year 2011	Budget 2009-2011	Actual 2009-2011
RESOURCE ACQUISITION				
Electric Efficiency Funds Activities				
Business Sector	$ 22,899,100	$ 21,216,670	$ 59,245,055	$ 58,405,198
Residential Sector	$ 9,898,600	$ 11,014,403	$ 29,022,864	$ 29,552,554
Total Electric Efficiency Funds Activities	$ 32,797,700	$ 32,231,073	$ 88,267,919	$ 87,957,752
Heating and Process Fuels Funds Activities				
Business Sector	$ 1,453,400	$ 1,168,318	$ 2,154,950	$ 1,404,956
Residential Sector	$ 4,030,100	$ 4,259,442	$ 6,639,736	$ 6,448,456
Total Heating and Process Fuels Funds Activities	$ 5,483,500	$ 5,427,760	$ 8,794,686	$ 7,853,412
TOTAL RESOURCE ACQUISITION	$ 38,281,200	$ 37,658,833	$ 97,062,605	$ 95,811,164
NON-RESOURCE ACQUISITION				
Information Technology	$ 757,600	$ 612,461	$ 2,325,659	$ 2,174,790
General Administration[2]	$ 397,900	$ 311,890	$ 799,088	$ 911,861
ISO-NE Regional Capacity Activities	$ 377,700	$ 298,597	$ 1,087,677	$ 850,129
Demand Resource Planning Process	$ 141,200	$ 534,656	$ 279,279	$ 816,314
Smart Grid	$ 831,600	$ 766,158	$ 889,598	$ 784,738
TOTAL NON-RESOURCE ACQUISITION	$ 2,506,000	$ 2,523,760	$ 5,381,300	$ 5,537,832
Sub-Total Prior to Performance-Based Fee	$ 40,787,200	$ 40,182,593	$ 102,443,904	$ 101,348,997
Performance-Based Fee	$ 1,007,000	$ -	$ 2,697,000	$ 2,596,418
TOTAL ESTIMATED COSTS INCLUDING PERFORMANCE-BASED FEE	$ 41,794,200	$ 40,182,593	$ 105,140,904	$ 103,945,415

[1] The values in this report are un-audited and represent preliminary results for the annual and 2009-2011 Performance Period

[2] Beginning in 2010, the DPS requested VEIC report operations fees on electric efficiency incentives in the General Administration totals. For the 2009-11 period, that amount totaled approximately $321,000 which should not be counted toward the 2009-11 General Administrative cap of $944,200 as outlined in the Process and Administration document item 33 on page 18.

2.1.3 2009-2011 Electric Minimum Performance Requirements

MPR#	Name	Minimum Requirement	1/1/09 To Date
1	Minimum Electric Benefits	Total electric benefits divided by total EEU costs is greater than 1.2	2.5
2	Threshold (or minimum acceptable) Level of Participation by Residential Customers	Total residential sector spending is greater than $19,700,000	$29,648,138
3	Threshold (or minimum acceptable) Level of Participation by Low-Income Households	Spending for low-income single and multifamily services is greater than $6,307,000	$6,919,057
4	Threshold (or minimum acceptable) Level of Participation by Small Non-Residential Customers	Number of total non-residential accounts with annual electric use of 40,000 kWh/yr or less that have savings is greater than 700	3,146
5	Geographic Equity	TRB for each county is greater than values shown in table below	
	County	**3-Year Minimum TRB Goal**	**1/1/09 To Date**
	Addison	$4,251,387	$14,382,185
	Bennington	$5,725,127	$18,535,703
	Caledonia	$2,928,436	$11,350,967
	Chittenden	$13,528,705	$72,142,350
	Essex/Orleans	$3,051,759	$13,040,097
	Franklin	$5,181,847	$27,071,881
	Grand Isle	$359,531	$2,043,514
	Lamoille	$2,691,770	$13,677,093
	Orange	$2,442,011	$7,102,005
	Rutland	$9,117,465	$34,570,700
	Washington	$6,880,168	$32,369,438
	Windham	$7,293,624	$22,343,555
	Windsor	$7,056,592	$16,850,104

2.1.4 2009-2011 Heating and Process Fuels Minimum Performance Requirements and Performance Indicators

2009-2011 Heating and Process Fuels Minimum Performance Requirements			
MPR#	Name	Minimum Requirement	Target to Date
1	Threshold (or minimum acceptable) Level of Participation by Small Non-Residential Customers	Total residential sector spending is greater than 62.5% of the total Heating and Process Fuels (HPF) Fund expenditures	82%

2009-2011 Heating and Process Fuels Performance Indicators			
PI#	Name	Minimum Requirement	Target to Date
1	Thermal & Mechanical Energy Efficiency Savings[1]	Annual incremental net MMBTU savings is at least 67,600	85,623
2	Residential single family comprehensiveness	a. Average air leakage reduction per project is at least 34%[2]	33%
		b. Percent of projects with at least 1,500 total square feet of insulation added is at least 44%[3]	65%
		c. Percent of projects with both shell measures and heating system measures installed is at least 16%[4]	11%

Footnotes	
1	The Performance Indicator metric is based on six services considered for delivery. One of those services involves a collaboration with the Vermont Fuel Efficiency Partnership. The collaboration agreement is not finalized as of 1/1/2010. If the final collaboration agreement results in substantive changes from the current service offerings, this Performance Indicator target will recalculated.
2	Projects are defined as a work project completed by a Home Performance with Energy Star (HPwES) contractor in a single family (1-4 units). All single family homes in which HPF-funded incentives are provided through HPwES will be included in the average, regardless of whether or not air infiltration reduction is achieved.
3	The total shall include all insulation that is installed in the home, including attic and ceiling insulation, wall insulation, floor insulation, foundation insulation, etc.
4	Significant heating system measures will include system replacements, distribution improvements such as duct sealing or installing improved or right-sized ductwork, burner replacements, etc. with a cost of at least $200 per reported job. Neither setback thermostats nor clean and tunes shall count as significant heating system measures for this Performance Indicator. Shell measures include any measures that reduce conductive losses through the building shell (typically insulation measures) as well as air infiltration reductions.

2.1.5 Electric Services and Initiatives Summary

	Totals				Business Energy Services		Residential Energy Services			Other
Services	All Services and Initiatives Including CC	EVT Services and Initiatives	Subtotal Business Energy Services	Subtotal Residential Energy Services	Business New Construction	Business Existing Facilities	Residential New Construction	Efficient Products	Existing Homes	Customer Credit Program
Costs										
Year to Date Costs	$32,231,073	$32,231,073	$21,216,670	$11,014,403	$1,533,067	$19,683,603	$2,041,813	$5,967,262	$3,005,328	$0
* Annual Budget Estimate	$32,797,700	$32,797,700	$22,899,100	$9,898,600	$3,023,500	$19,875,600	$2,082,000	$6,116,500	$1,700,100	$0
Unspent Annual Budget Estimate	$566,627	$566,627	$1,682,430	($1,115,803)	$1,490,433	$191,997	$40,187	$149,238	($1,305,228)	$0
% Annual Budget Estimate Unspent	2%	2%	7%	-11%	49%	1%	2%	2%	-77%	0%
Savings Results										
MWh Year to Date	107,627	107,627	55,535	52,092	6,050	49,485	1,486	47,927	2,680	0
MWh cumulative starting 1/1/09	303,353	298,751	152,686	146,066	23,778	128,908	4,542	133,262	8,261	4,601
3-Year MWh Goal	nap	359,700	225,900	133,800	29,142	196,758	6,263	116,912	10,625	nap
% of 3-Year MWh Goal	nap	83%	68%	109%	82%	66%	73%	114%	78%	nap
Winter Coincident Peak kW Year to Date	19,543	19,543	8,358	11,185	913	7,445	346	10,320	519	0
Winter Coincident Peak kW cumulative starting 1/1/09	54,987	54,616	22,098	32,517	3,280	18,818	1,019	29,801	1,697	371
3-Year Winter Coincident Peak kW Goal	nap	54,000	14,200	39,800	2,300	11,900	1,000	35,800	3,000	nap
% of 3-Year Winter Coincident Peak kW Goal	nap	101%	156%	82%	143%	158%	102%	83%	57%	nap
Summer Coincident Peak kW Year to Date	14,941	14,941	9,273	5,669	1,072	8,201	151	5,247	271	0
Summer Coincident Peak kW cumulative starting 1/1/09	44,847	44,095	27,092	17,003	4,151	22,941	546	15,678	780	752
3-Year Summer Coincident Peak kW Goal	nap	51,200	22,300	28,900	3,500	18,800	1,000	27,000	900	nap
% of 3-Year Summer Coincident Peak kW Goal	nap	86%	121%	59%	119%	122%	55%	58%	87%	nap
Associated Benefits										
MMBtu Year to Date	17,516	17,516	6,124	11,392	2,419	3,705	18,825	(7,063)	(370)	0
MMBtu cumulative starting 1/1/09	108,421	107,546	58,411	49,136	38,141	20,269	60,690	(21,624)	10,069	874
Participation										
Partic.w/ installs Year to Date	31,774	31,774	2,840	28,934	131	2,709	789	23,900	4,245	0
Partic.w/ installs cumulative starting 1/1/09	103,293	103,292	6,061	97,231	610	5,451	2,444	83,250	11,537	1

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.6 Electric Services and Initiatives including Customer Credit

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09	Cumulative starting 3/1/00
# participants with installations	42,405	31,780	nap	103,293	306,990
Services and Initiatives Costs					
Operating Costs					
Administration	$265,771	$311,890	$397,900	$911,861	$2,213,230
ISO-NE Regional Capacity Activities	$269,985	$298,597	$377,700	$850,129	$1,233,767
Smart Grid	$18,581	$766,158	$831,600	$784,738	$784,738
DRP & DRPP	$281,658	$534,656	$141,200	$816,314	$816,314
Services and Initiatives	$5,377,959	$4,023,176	$3,159,800	$14,397,033	$39,722,726
Program Planning	nap	nap	nap	nap	$1,006,327
Marketing/Business Development	$5,295,601	$4,299,707	$5,319,400	$13,483,883	$32,479,867
Information Systems	$735,832	$612,461	$757,600	$2,174,790	$6,129,121
Subtotal Operating Costs	$12,245,386	$10,846,643	$10,985,200	$33,418,749	$84,386,091
Incentive Costs					
Incentives to Participants	$15,439,559	$18,838,351	$18,217,100	$43,546,173	$97,774,975
Incentives to Trade Allies	$84,986	$75,367	$63,100	$246,003	$501,214
Subtotal Incentive Costs	$15,345,281	$18,913,718	$18,280,200	$43,792,176	$98,276,189
Technical Assistance Costs					
Services to Participants	$5,818,661	$4,830,465	$5,845,800	$16,790,755	$41,960,955
Services to Trade Allies	$136,698	$164,006	$192,500	$558,536	$2,989,289
Subtotal Technical Assistance Costs	$5,955,359	$4,994,472	$6,038,300	$17,349,290	$44,950,243
Total Efficiency Vermont Costs	$33,546,026	$34,754,833	$35,303,700	$94,560,215	$227,612,523
Total Participant Costs	$17,523,587	$11,519,445	nav	$48,438,760	$153,788,955
Total Third Party Costs	$1,213,600	$1,273,775	nav	$3,314,937	$8,489,296
Total Services and Initiatives Costs	$52,283,213	$47,548,053	nav	$146,313,912	$389,890,774
Annualized MWh Savings	110,872	107,627	nap	303,353	868,481
Lifetime MWh Savings	1,155,989	1,109,895	nap	3,182,264	9,863,151
TRB Savings (2009 $)	$102,780,275	$88,655,324	nap	$292,059,130	$815,736,112
Winter Coincident Peak kW Savings	20,277	19,543	nap	54,987	145,322
Summer Coincident Peak kW Savings	16,363	14,941	nap	44,847	123,901
Annualized MWh Savings/Participant	2.615	3.387	nap	2.937	2.829
Weighted Lifetime	10	10	nap	10	11
Committed Incentives	$554,405	$184,655	nap	nap	nap

Annualized MWh Savings (adjusted for measure life)	728,842
Winter Coincident Peak kW Savings (adjusted for measure life)	129,454
Summer Coincident Peak kW Savings (adjusted for measure life)	106,591

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.7 Electric Services and Initiatives excluding Customer Credit

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09	Cumulative starting 3/1/00
# participants with installations	42,404	31,780	nap	103,292	306,991
Services and Initiatives Costs					
Operating Costs					
Administration	$265,771	$311,890	$397,900	$911,861	$2,213,230
ISO-NE Regional Capacity Activities	$269,985	$298,597	$377,700	$850,129	$1,233,767
Smart Grid	$18,581	$766,158	$831,600	$784,738	$784,738
DRP & DRPP	$281,658	$534,656	$141,200	$816,314	$816,314
Services and Initiatives	$5,377,959	$4,023,176	$3,159,800	$14,393,330	$39,563,035
Program Planning	nap	nap	nap	nap	$977,110
Marketing/Business Development	$5,295,601	$4,299,707	$5,319,400	$13,483,883	$32,479,867
Information Systems	$735,832	$612,461	$757,600	$2,174,790	$6,129,121
Subtotal Operating Costs	$12,245,386	$10,846,643	$10,985,200	$33,415,045	$84,197,182
Incentive Costs					
Incentives to Participants	$15,081,031	$18,838,351	$18,217,100	$42,490,254	$91,453,679
Incentives to Trade Allies	$84,986	$75,367	$63,100	$246,003	$501,213
Subtotal Incentive Costs	$15,166,017	$18,913,718	$18,280,200	$42,736,257	$91,954,892
Technical Assistance Costs					
Services to Participants	$5,818,661	$4,830,465	$5,845,800	$16,785,747	$41,931,109
Services to Trade Allies	$136,698	$164,006	$192,500	$558,536	$2,989,289
Subtotal Technical Assistance Costs	$5,955,359	$4,994,472	$6,038,300	$17,344,283	$44,920,398
Total Efficiency Vermont Costs	$33,366,762	$34,754,833	$35,303,700	$93,495,585	$221,072,472
Total Participant Costs	$17,499,376	$11,519,445	nav	$48,166,093	$152,039,207
Total Third Party Costs	$1,213,600	$1,273,775	nav	$3,314,937	$8,489,296
Total Services and Initiatives Costs	$52,079,738	$47,548,053	nav	$144,976,615	$381,600,975
Annualized MWh Savings	110,550	107,627	nap	298,751	837,693
Lifetime MWh Savings	1,151,802	1,109,895	nap	3,115,539	9,435,598
TRB Savings (2009 $)	$102,438,841	$88,655,324	nap	$285,479,594	$781,015,389
Winter Coincident Peak kW Savings	20,213	19,543	nap	54,616	141,885
Summer Coincident Peak kW Savings	16,299	14,941	nap	44,095	118,595
Annualized MWh Savings/Participant	2.607	3.387	nap	2.892	2.729
Weighted Lifetime	10	10	nap	10	11
Committed Incentives	$554,405	$184,655	nap	nap	nap

Annualized MWh Savings (adjusted for measure life)	698,054
Winter Coincident Peak kW Savings (adjusted for measure life)	126,016
Summer Coincident Peak kW Savings (adjusted for measure life)	101,285

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.8 Electric Services & Initiatives - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	1,401	1,871	1,902	30,622	134	566	-517	40	$287,051	$268,369
Cooking and Laundry	4,919	1,637	1,292	22,794	255	191	2,930	60,849	$349,935	$1,799,560
Design Assistance	178	186	176	950	8	5	541	0	$191,215	$72,945
Hot Water Efficiency	1,173	518	478	4,325	65	51	475	4,223	$71,261	-$115,864
Hot Water Fuel Switch	135	444	472	13,326	73	37	-1,539	84	$87,345	$132,204
Industrial Process Eff.	49	6,492	6,594	87,273	1,237	605	1,384	0	$497,095	$1,740,607
Lighting	20,183	78,442	70,649	762,542	15,786	10,720	-24,598	0	$13,306,042	$6,228,931
Monitoring and Metering	2,087	1,562	1,383	8,878	180	151	0	0	$179,951	-$181,994
Motors	214	3,642	3,544	40,798	481	461	1,781	21,751	$500,154	$985,751
Other Efficiency	650	541	483	7,377	116	77	4,454	30	$281,000	-$128,921
Other Fuel Switch	43	81	95	2,416	9	16	-203	0	$14,074	$8,482
Other Indirect Activity	1,493	1,997	2,465	7,829	217	224	-143	0	$480,726	$119,295
Refrigeration	4,544	5,227	5,121	60,224	706	722	0	0	$1,271,919	$679,927
Space Heat Efficiency	578	551	480	12,655	147	17	21,507	110	$70,963	$380,799
Space Heat Fuel Switch	7	279	308	5,444	48	2	-1,104	0	$10,386	$119,568
Ventilation	811	4,156	3,751	42,442	82	1,095	12,548	0	$1,413,044	-$590,216
Totals		107,627	99,194	1,109,895	19,543	14,941	17,516	87,087	$18,838,351	$11,519,445

2.1.9 Electric Services & Initiatives - Utility Breakdown

Utility	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Barton	150	224	207	2,654	43	26	-35	331	$80,958	$28,168
Burlington	25	313	308	2,775	48	74	-20	0	$68,017	$7,862
CVPS	13,337	44,183	41,257	475,378	8,051	6,389	9,819	50,783	$8,571,563	$6,214,400
Enosburg Falls	186	880	777	9,727	176	116	-103	346	$213,734	$69,068
Green Mountain	9,053	40,554	37,144	393,401	7,374	5,356	6,944	21,035	$5,567,898	$3,985,051
Hardwick	368	860	780	8,894	144	134	367	982	$214,591	$33,825
Hyde Park	128	497	420	4,039	94	54	-70	277	$81,619	-$569
Jacksonville	48	29	25	261	7	4	-1	66	$5,219	$2,037
Johnson	159	409	370	4,629	106	44	267	137	$73,561	$169,415
Ludlow	150	420	356	3,412	84	50	-100	313	$52,128	$24,822
Lyndonville	515	1,758	1,639	18,290	306	249	-614	763	$410,867	$210,695
Morrisville	389	1,532	1,382	14,483	291	181	-329	650	$215,338	$116,685
Northfield	201	330	305	2,966	65	47	-75	410	$53,477	$17,544
Orleans	105	151	130	1,323	31	15	-16	108	$33,859	$1,101
Readsboro	14	4	4	40	1	0	1	12	$1,042	$306
Rochester	28	7	6	52	2	1	0	0	$779	$15
Stowe	360	1,338	1,357	13,834	218	222	-232	501	$238,807	$90,426
Swanton	310	1,801	1,649	21,708	283	276	-429	661	$325,522	$218,771
VT Electric Coop	4,595	10,890	9,784	118,050	1,917	1,524	1,593	7,225	$2,506,628	$253,449
VT Marble	94	125	123	1,543	21	25	-49	243	$34,407	$37,279
Washington Electric	1,559	1,323	1,172	12,436	281	155	600	2,243	$262,150	$39,094
Totals	31,780	107,627	99,194	1,109,895	19,543	14,941	17,516	87,087	$18,838,351	$11,519,445

2.1.10 Electric Services & Initiatives - County Breakdown

County	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Addison	1,764	6,321	5,831	72,639	1,053	919	4,481	3,280	$1,682,313	$329,088
Bennington	1,554	7,401	6,847	76,632	1,302	1,236	6,598	2,998	$1,097,344	$1,125,088
Caledonia	1,490	5,383	4,932	56,120	932	777	-1,082	24,211	$1,171,782	$634,100
Chittenden	6,291	29,503	26,892	282,976	5,349	4,009	1,582	16,080	$3,929,166	$2,576,378
Essex	276	704	677	7,056	135	54	-38	543	$134,213	$29,883
Franklin	2,367	10,790	9,924	127,906	1,746	1,485	-1,132	4,832	$2,632,199	$1,209,637
Grand Isle	508	685	638	7,289	126	103	125	962	$178,786	$40,159
Lamoille	1,615	4,467	4,161	43,348	845	602	-167	2,923	$744,695	$427,609
Orange	1,663	3,290	2,948	33,544	664	414	647	2,720	$646,336	$208,261
Orleans	1,851	4,496	3,982	48,557	818	669	658	2,546	$1,163,088	$116,191
Rutland	3,565	9,410	8,886	90,774	1,805	1,304	3,781	8,326	$1,960,681	$1,588,161
Washington	3,765	10,828	10,075	104,149	2,033	1,344	2,393	6,262	$1,454,052	$1,250,054
Windham	2,273	8,225	7,751	96,654	1,631	1,096	74	5,730	$1,217,801	$1,185,780
Windsor	2,792	6,125	5,650	62,249	1,104	930	-402	5,673	$999,707	$799,055
Totals	31,780	107,627	99,194	1,109,895	19,543	14,941	17,516	87,087	$18,838,351	$11,519,445

2.1.11 Electric Services & Initiatives - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$73,778,747
Fossil Fuel Savings (Costs)	$312,130	$7,598,305
Water Savings (Costs)	$652,049	$7,278,443
Total	$964,179	$88,655,324

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	99,194	96,184	107,627
Winter on peak	38,522	37,390	42,437
Winter off peak	27,655	26,753	30,573
Summer on peak	18,407	17,870	17,870
Summer off peak	13,867	13,437	14,873
Coincident Demand Savings (kW)			
Winter	18,924	17,766	19,543
Shoulder	0	0	0
Summer	14,228	13,522	14,941

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	81,325	87,087	1,113,198
Annualized fuel savings (increase) MMBtu	17,845	17,516	526,733
LP	12,342	12,659	296,632
NG	1,795	2,755	78,435
Oil/Kerosene	(5,920)	(7,619)	(5,032)
Wood	8,979	8,655	149,789
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$2,560,052	$2,698,642	$23,031,789

Net Societal Benefits	$79,937,437

2.1.12 Electric Business Energy Services Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	2,876	2,846	nap	6,061
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$2,843,643	$1,592,982	$1,288,400	$7,275,508
Marketing/Business Development	$2,920,988	$2,684,270	$3,384,800	$7,649,899
Subtotal Operating Costs	$5,764,631	$4,277,252	$4,673,200	$14,925,407
Incentive Costs				
Incentives to Participants	$10,679,801	$13,407,145	$13,059,500	$30,008,937
Incentives to Trade Allies	$8,775	$59,364	$54,600	$77,676
Subtotal Incentive Costs	$10,688,576	$13,466,509	$13,114,100	$30,086,613
Technical Assistance Costs				
Services to Participants	$4,970,143	$3,472,909	$5,111,800	$13,393,179
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$4,970,143	$3,472,909	$5,111,800	$13,393,179
Total Efficiency Vermont Costs	$21,423,350	$21,216,670	$22,899,100	$58,405,198
Total Participant Costs	$12,633,950	$9,087,111	nav	$31,294,274
Total Third Party Costs	$402,054	$176,957	nav	$820,866
Total Services and Initiatives Costs	$34,459,353	$30,480,738	nav	$90,520,338
Annualized MWh Savings	55,857	55,535	nap	152,686
Lifetime MWh Savings	731,384	710,389	nap	1,983,315
TRB Savings (2009 $)	$58,034,028	$48,956,709	nap	$161,443,713
Winter Coincident Peak kW Savings	8,155	8,358	nap	22,098
Summer Coincident Peak kW Savings	10,030	9,273	nap	27,092
Annualized MWh Savings/Participant	19.422	19.513	nap	25.191
Weighted Lifetime	13	13	nap	13
Committed Incentives	$554,405	$184,655	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.13 Electric Business Energy Services - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	115	1,704	1,712	27,993	122	482	-517	40	$248,365	$241,415
Cooking and Laundry	4	57	57	742	8	6	403	695	$2,106	$18,320
Design Assistance	81	186	176	950	8	5	541	0	$168,604	$72,945
Hot Water Efficiency	25	162	150	1,622	24	21	36	46	$44,849	$17,267
Industrial Process Eff.	49	6,492	6,594	87,273	1,237	605	1,384	0	$497,095	$1,740,607
Lighting	2,496	34,315	33,260	458,810	5,663	5,985	-15,176	0	$9,821,978	$5,645,273
Motors	141	3,611	3,517	40,296	472	458	1,781	21,751	$496,427	$975,439
Other Efficiency	656	541	483	7,377	116	77	4,454	30	$281,000	-$128,921
Other Fuel Switch	2	8	8	228	0	10	-26	0	$352	$776
Other Indirect Activity	21	986	1,184	3,785	108	69	-143	0	$257,072	$274,908
Refrigeration	133	3,148	2,945	34,227	464	469	0	0	$333,047	$508,005
Space Heat Efficiency	33	84	82	1,398	33	9	4,496	110	$13,319	$259,798
Space Heat Fuel Switch	4	264	293	4,978	40	2	-933	0	$9,378	$97,862
Ventilation	134	3,978	3,589	40,709	62	1,075	9,824	0	$1,366,588	-$636,583
Totals		55,535	54,049	710,389	8,358	9,273	6,124	22,672	$13,407,145	$9,087,111

2.1.14 Electric Residential Energy Services Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	39,528	28,934	nap	97,231
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$2,534,315	$2,430,194	$1,871,400	$7,117,822
Marketing/Business Development	$2,374,613	$1,615,437	$1,934,600	$5,833,984
Subtotal Operating Costs	$4,908,929	$4,045,631	$3,806,000	$12,951,806
Incentive Costs				
Incentives to Participants	$4,401,231	$5,431,206	$5,157,600	$12,481,317
Incentives to Trade Allies	$76,211	$16,003	$8,500	$168,327
Subtotal Incentive Costs	$4,477,442	$5,447,210	$5,166,100	$12,649,644
Technical Assistance Costs				
Services to Participants	$848,518	$1,357,556	$734,000	$3,392,569
Services to Trade Allies	$136,698	$164,006	$192,500	$558,536
Subtotal Technical Assistance Costs	$985,216	$1,521,563	$926,500	$3,951,104
Total Efficiency Vermont Costs	$10,371,586	$11,014,403	$9,898,600	$29,552,554
Total Participant Costs	$4,865,426	$2,432,334	nav	$16,871,819
Total Third Party Costs	$811,547	$1,096,818	nav	$2,494,072
Total Services and Initiatives Costs	$16,048,558	$14,543,555	nav	$48,918,445
Annualized MWh Savings	54,693	52,092	nap	146,066
Lifetime MWh Savings	420,418	399,506	nap	1,132,225
TRB Savings (2009 $)	$44,404,813	$39,698,616	nap	$124,035,880
Winter Coincident Peak kW Savings	12,059	11,185	nap	32,517
Summer Coincident Peak kW Savings	6,269	5,669	nap	17,003
Annualized MWh Savings/Participant	1.384	1.800	nap	1.502
Weighted Lifetime	8	8	nap	8
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.15 Electric Residential Energy Services - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	1,286	167	190	2,629	12	84	0	0	$38,686	$26,954
Cooking and Laundry	4,915	1,580	1,235	22,052	247	185	2,527	60,154	$347,829	$1,781,240
Design Assistance	97	0	0	0	0	0	0	0	$22,612	$0
Hot Water Efficiency	1,148	357	328	2,703	40	30	439	4,177	$26,412	-$133,131
Hot Water Fuel Switch	135	444	472	13,326	73	37	-1,539	84	$87,345	$132,204
Lighting	17,687	44,127	37,390	303,732	10,123	4,735	-9,421	0	$3,484,063	$583,658
Monitoring and Metering	2,087	1,562	1,383	8,878	180	151	0	0	$179,951	-$181,994
Motors	73	31	28	502	8	4	0	0	$3,726	$10,312
Other Fuel Switch	41	73	87	2,188	8	6	-178	0	$13,722	$7,706
Other Indirect Activity	1,472	1,011	1,281	4,044	109	155	0	0	$223,655	-$155,613
Refrigeration	4,411	2,079	2,176	25,996	242	253	0	0	$938,873	$171,922
Space Heat Efficiency	545	467	398	11,257	114	7	17,011	0	$57,644	$121,002
Space Heat Fuel Switch	3	16	15	466	8	0	-171	0	$1,008	$21,706
Ventilation	677	178	162	1,732	20	20	2,724	0	$46,455	$46,367
Totals		52,092	45,145	399,506	11,185	5,669	11,392	64,415	$5,431,206	$2,432,334

2.1.16 Heating and Process Fuels Services and Initiatives Summary

				Business Energy Services		Residential Energy Services		
Services	EVT Services and Initiatives	Subtotal Business Energy Services	Subtotal Residential Energy Services	Business New Construction	Business Existing Facilities	Residential New Construction	Efficient Products	Existing Homes
Costs								
Year to Date Costs	$5,427,760	$1,168,318	$4,259,442	$96,645	$1,071,673	$10,361	$0	$4,249,081
* Annual Budget Estimate	$5,483,500	$1,453,400	$4,030,100	$83,300	$1,370,100	$11,600	$0	$4,018,500
Unspent Annual Budget Estimate	$55,740	$285,082	($229,342)	($13,345)	$298,427	$1,239	$0	($230,581)
% Annual Budget Estimate Unspent	1%	20%	-6%	-16%	22%	nap	nap	-6%
Savings Results								
MMBtu Year to Date	49,206	20,645	28,561	1,819	18,826	877	nap	27,684
MMBtu cumulative starting 1/1/09	85,623	34,597	51,026	9,687	24,910	957	nap	50,068
3-Year MMBTu Goal	67,600	22,475	45,125	4,200	18,275	160	nap	44,965
% of 3-Year MMBTu Goal	127%	154%	113%	231%	136%	598%	nap	111%
Associated Electric Benefits								
MWh Year to Date	337	39	298	(1)	40	0	nap	298
MWh cumulative starting 1/1/09	307	(207)	515	(255)	48	0	nap	515
Winter Coincident Peak kW Year to Date	141	19	122	3	16	0	nap	122
Winter Coincident Peak kW cumulative starting 1/1/09	160	(46)	206	(65)	19	0	nap	206
Summer Coincident Peak kW Year to Date	5	4	1	4	0	0	nap	1
Summer Coincident Peak kW cumulative starting 1/1/09	21	17	5	16	0	0	nap	5
Participation								
Partic.w/ installs Year to Date	1,657	176	1,481	28	148	6	nap	1,475
Partic.w/ installs cumulative starting 1/1/09	3,034	259	2,775	60	199	14	nap	2,761

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.17 Heating and Process Fuels Services and Initiatives

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	1,011	1,657	nap	3,034
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$135,538	$1,585,698	$121,500	$1,758,095
Marketing/Business Development	$137,493	$1,062,706	$215,300	$1,367,119
Subtotal Operating Costs	$273,031	$2,648,404	$336,800	$3,125,214
Incentive Costs				
Incentives to Participants	$762,073	$1,787,270	$4,143,600	$2,696,081
Incentives to Trade Allies	$19,600	$114,192	$0	$133,792
Subtotal Incentive Costs	$781,673	$1,901,462	$4,143,600	$2,829,873
Technical Assistance Costs				
Services to Participants	$825,104	$877,895	$1,003,100	$1,898,325
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$825,104	$877,895	$1,003,100	$1,898,325
Total Efficiency Vermont Costs	$1,879,808	$5,427,760	$5,483,500	$7,853,412
Total Participant Costs	$2,986,589	$5,005,174	nav	$8,293,580
Total Third Party Costs	$3,253	$197,952	nav	$201,205
Total Services and Initiatives Costs	$4,869,650	$10,630,887	nav	$16,348,197
Annualized MMBtu Savings	32,459	49,206	nap	85,623
Lifetime MMBtu Savings	616,579	880,682	nap	1,552,938
TRB Savings (2009 $)	$9,215,874	$12,882,536	nap	$22,922,054
Annualized MMBtu Savings/Participant	32.106	29.696	nap	28.221
Weighted Lifetime	19	18	nap	18
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.18 Heating and Process Fuels Services & Initiatives - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Cooking and Laundry	19	0	0	0	0	0	0	0	$0	$1,880
Hot Water Efficiency	291	16	16	222	2	1	2,689	1,438	$147,210	$73,695
Hot Water Fuel Switch	1	1	1	26	0	0	-3	0	$0	$640
Industrial Process Eff.	2	0	0	0	0	0	10,479	0	$87,108	$311,189
Motors	29	0	0	0	0	0	42	0	$0	$3,231
Other Indirect Activity	109	0	0	0	0	0	0	0	$0	$10,710
Space Heat Efficiency	1,405	257	254	4,668	121	0	34,845	1	$1,553,735	$4,271,965
Space Heat Fuel Switch	22	64	71	960	15	0	166	0	$22,440	$197,958
Ventilation	179	-1	-1	-20	3	4	988	0	$9,771	$133,906
Totals		337	340	5,856	141	5	49,206	1,439	$1,787,270	$5,005,174

2.1.19 Heating and Process Fuels Services and Initiatives - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$295,269
Fossil Fuel Savings (Costs)	$971,478	$12,493,778
Water Savings (Costs)	$10,763	$93,486
Total	$982,241	$12,882,533

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	340	299	337
Winter on peak	153	134	152
Winter off peak	180	158	203
Summer on peak	4	4	4
Summer off peak	4	3	4
Coincident Demand Savings (kW)			
Winter	144	128	141
Shoulder	0	0	0
Summer	5	4	5

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	1,599	1,439	12,960
Annualized fuel savings (increase) MMBtu	55,297	49,206	880,682
LP	10,214	9,550	190,272
NG	5	4	58
Oil/Kerosene	42,185	36,747	648,103
Wood	2,895	2,905	42,248
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$209,773	$167,819	$2,517,109

Net Societal Benefits	$16,447,999

2.1.20 Heating and Process Fuels Business Energy Services Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	84	176	nap	259
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$2,606	$269,925	$30,500	$279,556
Marketing/Business Development	$0	$298,423	$53,800	$298,637
Subtotal Operating Costs	$2,606	$568,348	$84,300	$578,193
Incentive Costs				
Incentives to Participants	$126,422	$354,138	$1,043,000	$480,560
Incentives to Trade Allies	$2,400	$8,500	$0	$10,900
Subtotal Incentive Costs	$128,822	$362,638	$1,043,000	$491,460
Technical Assistance Costs				
Services to Participants	$97,972	$237,332	$326,100	$335,303
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$97,972	$237,332	$326,100	$335,303
Total Efficiency Vermont Costs	$229,400	$1,168,318	$1,453,400	$1,404,956
Total Participant Costs	$643,628	$1,006,492	nav	$1,650,119
Total Third Party Costs	$0	$1,593	nav	$1,593
Total Services and Initiatives Costs	$873,028	$2,176,403	nav	$3,056,668
Annualized MMBtu Savings	13,952	20,645	nap	34,597
Lifetime MMBtu Savings	286,227	362,409	nap	648,636
TRB Savings (2009 $)	$4,810,573	$5,084,219	nap	$9,894,792
Annualized MMBtu Savings/Participant	166.099	117.301	nap	133.580
Weighted Lifetime	21	18	nap	19
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.21 Heating and Process Fuels Business Energy Services - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Hot Water Efficiency	29	0	0	0	0	0	2,043	0	$119,403	$29,277
Industrial Process Eff.	2	0	0	0	0	0	10,479	0	$87,108	$311,189
Space Heat Efficiency	140	40	40	803	16	0	7,183	0	$144,380	$591,962
Space Heat Fuel Switch	1	0	0	3	0	0	13	0	$1,020	$19,313
Ventilation	9	-1	-1	-20	3	4	928	0	$9,310	$54,751
Totals		39	39	786	19	4	20,645	0	$354,138	$1,006,492

2.1.22 Heating and Process Fuels Residential Energy Services Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	927	1,481	nap	2,775
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$132,931	$1,315,773	$91,000	$1,478,539
Marketing/Business Development	$137,493	$764,283	$161,500	$1,068,482
Subtotal Operating Costs	$270,424	$2,080,056	$252,500	$2,547,021
Incentive Costs				
Incentives to Participants	$635,652	$1,433,131	$3,100,600	$2,215,521
Incentives to Trade Allies	$17,200	$105,692	$0	$122,892
Subtotal Incentive Costs	$652,852	$1,538,823	$3,100,600	$2,338,413
Technical Assistance Costs				
Services to Participants	$727,132	$640,563	$677,000	$1,563,021
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$727,132	$640,563	$677,000	$1,563,021
Total Efficiency Vermont Costs	$1,650,408	$4,259,442	$4,030,100	$6,448,456
Total Participant Costs	$2,342,962	$3,998,683	nav	$6,643,461
Total Third Party Costs	$3,253	$196,359	nav	$199,612
Total Services and Initiatives Costs	$3,996,623	$8,454,484	nav	$13,291,529
Annualized MMBtu Savings	18,507	28,561	nap	51,026
Lifetime MMBtu Savings	330,352	518,273	nap	904,302
TRB Savings (2009 $)	$4,405,301	$7,798,317	nap	$13,027,262
Annualized MMBtu Savings/Participant	30.051	164.952	nap	86
Weighted Lifetime	43	42	nap	42
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

2.1.23 Heating and Process Fuels Residential Energy Services - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Cooking and Laundry	19	0	0	0	0	0	0	0	$0	$1,880
Hot Water Efficiency	262	16	16	222	2	1	646	1,438	$27,806	$44,417
Hot Water Fuel Switch	1	1	1	26	0	0	-3	0	$0	$640
Motors	29	0	0	0	0	0	42	0	$0	$3,231
Other Indirect Activity	109	0	0	0	0	0	0	0	$0	$10,710
Space Heat Efficiency	1,265	217	214	3,865	105	0	27,662	1	$1,409,355	$3,680,004
Space Heat Fuel Switch	21	64	71	957	15	0	153	0	$21,420	$178,645
Ventilation	170	0	0	0	0	0	60	0	$462	$79,155
Totals		298	301	5,070	122	1	28,561	1,439	$1,433,132	$3,998,683

3.1 Efficiency Vermont Detailed Services and Initiatives Results

3.1.1 Electric Business New Construction Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	276	131	nap	610
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$320,662	$205,115	$368,200	$865,990
Marketing/Business Development	$344,083	$189,741	$288,500	$819,564
Subtotal Operating Costs	$664,745	$394,856	$656,700	$1,685,555
Incentive Costs				
Incentives to Participants	$1,201,190	$591,000	$1,488,400	$2,647,928
Incentives to Trade Allies	$2,700	$8,093	$11,600	$12,984
Subtotal Incentive Costs	$1,203,890	$599,093	$1,500,000	$2,660,912
Technical Assistance Costs				
Services to Participants	$627,324	$539,117	$866,800	$1,785,324
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$627,324	$539,117	$866,800	$1,785,324
Total Efficiency Vermont Costs	$2,495,959	$1,533,067	$3,023,500	$6,131,791
Total Participant Costs	$2,593,524	$1,130,761	nav	$6,031,481
Total Third Party Costs	$47,963	$47,963	nav	$158,389
Total Services and Initiatives Costs	$5,137,445	$2,711,790	nav	$12,321,661
Annualized MWh Savings	9,128	6,050	nap	23,778
Lifetime MWh Savings	136,621	81,200	nap	344,517
TRB Savings (2009 $)	$13,411,289	$6,062,554	nap	$34,523,248
Winter Coincident Peak kW Savings	1,273	913	nap	3,280
Summer Coincident Peak kW Savings	1,545	1,072	nap	4,151
Annualized MWh Savings/Participant	33.072	46.185	nap	38.980
Weighted Lifetime	15	13	nap	14
Committed Incentives	$61,840	$43,000	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.2 Electric Business New Construction - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	33	274	247	3,913	9	91	0	0	$43,901	$74,901
Design Assistance	8	0	0	2	0	0	28	0	$17,801	-$434
Hot Water Efficiency	3	20	19	192	4	7	14	0	$758	$3,198
Industrial Process Eff.	2	1,264	1,119	18,957	197	198	0	0	$34,027	$136,654
Lighting	121	2,946	2,701	41,569	439	430	-1,201	0	$365,973	$559,918
Motors	21	299	269	3,593	51	46	571	0	$29,261	$53,302
Other Efficiency	3	17	15	227	5	1	10	13	$8,529	$6
Other Indirect Activity	1	1	1	3	1	0	0	0	$126	$75
Refrigeration	14	1,102	1,016	11,324	191	273	0	0	$64,732	$201,453
Space Heat Efficiency	9	15	14	258	5	8	1,423	0	$2,195	$55,270
Ventilation	24	112	104	1,165	11	19	1,575	0	$28,131	$46,419
Totals		6,050	5,504	81,200	913	1,072	2,419	13	$591,000	$1,130,761

3.1.3 Electric Business New Construction - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$5,666,876
Fossil Fuel Savings (Costs)	$35,784	$394,192
Water Savings (Costs)	$100	$1,487
Total	$35,884	$6,062,554

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	5,504	5,363	6,050
Winter on peak	2,126	2,074	2,354
Winter off peak	1,456	1,416	1,589
Summer on peak	1,150	1,122	1,122
Summer off peak	773	751	832
Coincident Demand Savings (kW)			
Winter	853	830	913
Shoulder	0	0	0
Summer	1,002	970	1,072

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	13	13	268
Annualized fuel savings (increase) MMBtu	2,499	2,419	42,930
LP	682	655	7,810
NG	1,507	1,468	29,779
Oil/Kerosene	244	237	4,436
Wood	63	59	905
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$34,582	$33,627	$467,613

Net Societal Benefits	$4,802,116

3.1.4 Electric Business Existing Facilities Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	2,600	2,709	nap	5,451
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$2,522,981	$1,387,867	$920,200	$6,409,518
Marketing/Business Development	$2,576,905	$2,494,529	$3,096,300	$6,830,334
Subtotal Operating Costs	$5,099,886	$3,882,396	$4,016,500	$13,239,852
Incentive Costs				
Incentives to Participants	$9,478,611	$12,816,145	$11,571,100	$27,361,009
Incentives to Trade Allies	$6,075	$51,271	$43,000	$64,692
Subtotal Incentive Costs	$9,484,686	$12,867,416	$11,614,100	$27,425,700
Technical Assistance Costs				
Services to Participants	$4,342,819	$2,933,792	$4,245,000	$11,607,855
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$4,342,819	$2,933,792	$4,245,000	$11,607,855
Total Efficiency Vermont Costs	$18,927,391	$19,683,603	$19,875,600	$52,273,407
Total Participant Costs	$10,040,426	$7,956,350	nav	$25,262,793
Total Third Party Costs	$354,091	$128,994	nav	$662,477
Total Services and Initiatives Costs	$29,321,908	$27,768,947	nav	$78,198,677
Annualized MWh Savings	46,729	49,485	nap	128,908
Lifetime MWh Savings	594,763	629,189	nap	1,638,797
TRB Savings (2009 $)	$44,622,739	$42,894,155	nap	$126,920,465
Winter Coincident Peak kW Savings	6,882	7,445	nap	18,818
Summer Coincident Peak kW Savings	8,486	8,201	nap	22,941
Annualized MWh Savings/Participant	17.973	18.267	nap	23.648
Weighted Lifetime	13	13	nap	13
Committed Incentives	$492,565	$141,655	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.5 Electric Business Existing Facilities - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	82	1,430	1,465	24,080	113	391	-517	40	$204,464	$166,514
Cooking and Laundry	4	57	57	742	8	6	403	695	$2,106	$18,320
Design Assistance	73	186	175	949	8	5	513	0	$150,803	$73,379
Hot Water Efficiency	22	141	131	1,430	20	15	22	46	$44,091	$14,069
Industrial Process Eff.	47	5,228	5,475	68,316	1,040	407	1,384	0	$463,069	$1,603,953
Lighting	2,375	31,369	30,559	417,242	5,224	5,555	-13,975	0	$9,456,006	$5,085,355
Motors	120	3,312	3,248	36,703	421	411	1,210	21,751	$467,167	$922,137
Other Efficiency	647	525	468	7,150	111	76	4,444	17	$272,470	-$128,927
Other Fuel Switch	2	8	8	228	0	10	-26	0	$352	$776
Other Indirect Activity	20	986	1,183	3,782	107	69	-143	0	$256,946	$274,833
Refrigeration	119	2,046	1,929	22,904	273	196	0	0	$268,315	$306,552
Space Heat Efficiency	24	69	68	1,140	28	1	3,073	110	$11,124	$204,528
Space Heat Fuel Switch	4	264	293	4,978	40	2	-933	0	$9,378	$97,862
Ventilation	110	3,866	3,485	39,545	52	1,057	8,249	0	$1,338,457	-$683,001
Totals		49,485	48,545	629,189	7,445	8,201	3,705	22,658	$12,816,145	$7,956,350

3.1.6 Electric Business Existing Facilities - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$40,106,688
Fossil Fuel Savings (Costs)	$15,063	$1,177,613
Water Savings (Costs)	$169,483	$1,609,744
Total	$184,546	$42,894,045

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	48,545	44,604	49,485
Winter on peak	18,681	17,022	19,320
Winter off peak	12,261	11,210	13,130
Summer on peak	10,049	9,304	9,304
Summer off peak	6,817	6,332	7,010
Coincident Demand Savings (kW)			
Winter	7,425	6,769	7,445
Shoulder	0	0	0
Summer	8,106	7,421	8,201

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	24,154	22,658	229,704
Annualized fuel savings (increase) MMBtu	4,528	3,705	82,601
LP	1,208	1,166	36,643
NG	(4,321)	(3,879)	(58,820)
Oil/Kerosene	(448)	(1,217)	(10,227)
Wood	7,441	7,023	108,098
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$720,563	$688,335	$8,353,041

Net Societal Benefits	$34,390,860

3.1.7 Electric Residential New Construction Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	927	789	nap	2,444
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$861,670	$726,056	$607,000	$2,443,389
Marketing/Business Development	$266,776	$226,210	$393,000	$822,634
Subtotal Operating Costs	$1,128,446	$952,267	$1,000,000	$3,266,023
Incentive Costs				
Incentives to Participants	$397,237	$354,573	$514,000	$1,179,557
Incentives to Trade Allies	$0	$0	$0	$4,987
Subtotal Incentive Costs	$397,237	$354,573	$514,000	$1,184,543
Technical Assistance Costs				
Services to Participants	$752,876	$734,973	$568,000	$2,189,326
Services to Trade Allies	$172	$0	$0	$27,675
Subtotal Technical Assistance Costs	$753,048	$734,973	$568,000	$2,217,001
Total Efficiency Vermont Costs	$2,278,731	$2,041,813	$2,082,000	$6,667,566
Total Participant Costs	$390,929	$29,676	nav	$711,274
Total Third Party Costs	$207,798	$148,198	nav	$541,620
Total Services and Initiatives Costs	$2,877,458	$2,219,687	nav	$7,920,460
Annualized MWh Savings	1,390	1,486	nap	4,542
Lifetime MWh Savings	22,848	26,479	nap	79,047
TRB Savings (2009 $)	$8,901,755	$7,955,566	nap	$25,084,501
Winter Coincident Peak kW Savings	325	346	nap	1,019
Summer Coincident Peak kW Savings	206	151	nap	546
Annualized MWh Savings/Participant	1.500	1.883	nap	1.859
Weighted Lifetime	16	18	nap	17
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.8 Electric Residential New Construction - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	95	80	76	1,654	12	58	0	0	$6,194	$25,589
Cooking and Laundry	283	49	40	678	9	6	244	2,242	$7,049	$10,201
Hot Water Efficiency	351	2	2	34	0	0	311	511	$14	-$136,223
Lighting	767	700	654	9,832	198	61	-46	0	$122,904	$108,997
Motors	29	15	14	254	4	1	0	0	$1,277	$2,953
Other Fuel Switch	26	57	72	1,715	6	5	-130	0	$6,803	$4,473
Other Indirect Activity	200	0	0	0	0	0	0	0	$150,485	-$158,215
Refrigeration	481	78	70	1,320	9	9	0	0	$7,439	$20,926
Space Heat Efficiency	407	412	349	10,125	97	0	16,882	0	$39,944	$120,015
Ventilation	400	92	80	866	10	10	1,564	0	$15,123	$30,960
Totals		1,486	1,357	26,479	346	151	18,825	2,753	$354,573	$29,676

3.1.9 Electric Residential New Construction - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$1,529,486
Fossil Fuel Savings (Costs)	$400,217	$6,195,138
Water Savings (Costs)	$20,559	$230,942
Total	$420,776	$7,955,567

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	1,357	1,324	1,486
Winter on peak	500	488	554
Winter off peak	535	527	591
Summer on peak	153	146	146
Summer off peak	164	157	174
Coincident Demand Savings (kW)			
Winter	322	314	346
Shoulder	0	0	0
Summer	139	136	151

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	2,583	2,753	35,577
Annualized fuel savings (increase) MMBtu	18,092	18,825	450,539
LP	9,563	9,964	239,221
NG	5,913	6,154	144,170
Oil/Kerosene	988	1,011	24,526
Wood	1,628	1,695	42,620
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$28,010	$25,836	$465,721

Net Societal Benefits	$6,221,621

3.1.10 Electric Efficient Products Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	33,767	23,900	nap	83,250
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$870,519	$909,030	$994,000	$2,440,305
Marketing/Business Development	$1,639,403	$1,095,555	$1,273,900	$3,814,087
Subtotal Operating Costs	$2,509,922	$2,004,585	$2,267,900	$6,254,392
Incentive Costs				
Incentives to Participants	$3,154,788	$3,855,254	$3,681,100	$8,505,176
Incentives to Trade Allies	$7,175	$0	$0	$7,175
Subtotal Incentive Costs	$3,161,963	$3,855,254	$3,681,100	$8,512,351
Technical Assistance Costs				
Services to Participants	$0	$0	$0	$0
Services to Trade Allies	$67,908	$107,423	$167,500	$237,646
Subtotal Technical Assistance Costs	$67,908	$107,423	$167,500	$237,646
Total Efficiency Vermont Costs	$5,739,794	$5,967,262	$6,116,500	$15,004,389
Total Participant Costs	$3,791,921	$2,159,957	nav	$13,406,855
Total Third Party Costs	$394,179	$827,138	nav	$1,540,090
Total Services and Initiatives Costs	$9,925,894	$8,954,358	nav	$29,951,335
Annualized MWh Savings	50,212	47,927	nap	133,262
Lifetime MWh Savings	346,634	330,292	nap	924,216
TRB Savings (2009 $)	$32,050,756	$29,579,563	nap	$89,276,786
Winter Coincident Peak kW Savings	11,083	10,320	nap	29,801
Summer Coincident Peak kW Savings	5,774	5,247	nap	15,678
Annualized MWh Savings/Participant	1.487	2.005	nap	1.601
Weighted Lifetime	7	7	nap	7
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.11 Electric Efficient Products - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	1,164	85	112	930	0	19	0	0	$29,469	$15
Cooking and Laundry	4,429	1,392	1,073	19,482	216	163	2,264	56,135	$228,199	$1,765,380
Lighting	13,910	42,617	36,000	284,511	9,668	4,604	-9,326	0	$3,138,703	$427,759
Monitoring and Metering	1,827	1,534	1,358	8,765	177	148	0	0	$165,223	-$181,994
Motors	3	4	4	42	0	2	0	0	$756	$600
Other Indirect Activity	1,113	1,010	1,281	4,042	109	155	0	0	$72,894	$2,602
Refrigeration	2,347	1,285	1,469	12,521	150	156	0	0	$248,924	$145,594
Totals		47,927	41,295	330,292	10,320	5,247	-7,063	56,135	$3,855,254	$2,159,957

3.1.12 Electric Efficient Products - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$24,607,157
Fossil Fuel Savings (Costs)	($140,825)	($54,430)
Water Savings (Costs)	$420,558	$5,027,118
Total	$279,733	$29,579,845

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	41,295	42,513	47,927
Winter on peak	16,312	16,946	19,233
Winter off peak	12,562	12,796	14,355
Summer on peak	6,689	6,948	6,948
Summer off peak	5,733	5,831	6,452
Coincident Demand Savings (kW)			
Winter	9,832	9,382	10,320
Shoulder	0	0	0
Summer	4,728	4,749	5,247

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	48,892	56,135	787,245
Annualized fuel savings (increase) MMBtu	(6,787)	(7,063)	(14,055)
LP	905	905	14,486
NG	453	453	7,243
Oil/Kerosene	(8,145)	(8,873)	(35,785)
Wood	0	0	0
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$1,758,975	$1,932,443	$13,541,774

Net Societal Benefits	$34,195,051

3.1.13 Electric Existing Homes Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	4,764	4,245	nap	11,537
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$802,126	$795,107	$270,400	$2,234,128
Marketing/Business Development	$468,434	$293,671	$267,700	$1,197,263
Subtotal Operating Costs	$1,270,560	$1,088,779	$538,100	$3,431,391
Incentive Costs				
Incentives to Participants	$849,206	$1,221,379	$962,500	$2,796,585
Incentives to Trade Allies	$69,036	$16,003	$8,500	$156,165
Subtotal Incentive Costs	$918,242	$1,237,383	$971,000	$2,952,750
Technical Assistance Costs				
Services to Participants	$95,642	$622,583	$166,000	$1,203,243
Services to Trade Allies	$68,618	$56,583	$25,000	$293,215
Subtotal Technical Assistance Costs	$164,260	$679,167	$191,000	$1,496,458
Total Efficiency Vermont Costs	$2,353,062	$3,005,328	$1,700,100	$7,880,599
Total Participant Costs	$682,577	$242,701	nav	$2,753,689
Total Third Party Costs	$209,569	$121,482	nav	$412,362
Total Services and Initiatives Costs	$3,245,207	$3,369,510	nav	$11,046,649
Annualized MWh Savings	3,091	2,680	nap	8,261
Lifetime MWh Savings	50,937	42,735	nap	128,961
TRB Savings (2009 $)	$3,452,302	$2,163,486	nap	$9,674,593
Winter Coincident Peak kW Savings	651	519	nap	1,697
Summer Coincident Peak kW Savings	289	271	nap	780
Annualized MWh Savings/Participant	0.649	0.631	nap	0.716
Weighted Lifetime	16	16	nap	16
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.14 Electric Existing Homes - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	27	2	2	45	0	7	0	0	$3,023	$1,350
Cooking and Laundry	203	139	123	1,892	21	16	20	1,778	$112,582	$5,658
Design Assistance	97	0	0	0	0	0	0	0	$22,612	$0
Hot Water Efficiency	797	355	326	2,669	40	30	128	3,666	$26,398	$3,092
Hot Water Fuel Switch	135	444	472	13,326	73	37	-1,539	84	$87,345	$132,204
Lighting	3,010	810	736	9,388	256	70	-49	0	$222,456	$46,901
Monitoring and Metering	260	28	25	113	3	4	0	0	$14,727	$0
Motors	41	12	10	206	4	0	0	0	$1,694	$6,759
Other Fuel Switch	15	16	15	473	2	2	-47	0	$6,920	$3,233
Other Indirect Activity	159	1	0	2	0	0	0	0	$276	$0
Refrigeration	1,583	717	637	12,156	83	87	0	0	$682,509	$5,403
Space Heat Efficiency	138	55	49	1,132	18	7	129	0	$17,700	$987
Space Heat Fuel Switch	3	16	15	466	8	0	-171	0	$1,008	$21,706
Ventilation	277	87	81	867	10	10	1,159	0	$31,333	$15,407
Totals		2,680	2,493	42,735	519	271	-370	5,528	$1,221,379	$242,701

3.1.15 Electric Existing Homes - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$1,868,540
Fossil Fuel Savings (Costs)	$1,892	($114,207)
Water Savings (Costs)	$41,348	$409,152
Total	$43,241	$2,163,485

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	2,493	2,379	2,680
Winter on peak	904	859	975
Winter off peak	842	804	908
Summer on peak	367	350	350
Summer off peak	380	366	405
Coincident Demand Savings (kW)			
Winter	492	472	519
Shoulder	0	0	0
Summer	254	245	271

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	5,683	5,528	60,403
Annualized fuel savings (increase) MMBtu	(486)	(370)	(35,282)
LP	(16)	(31)	(1,528)
NG	(1,758)	(1,441)	(43,936)
Oil/Kerosene	1,441	1,224	12,017
Wood	(153)	(122)	(1,835)
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$17,923	$18,402	$203,639

Net Societal Benefits	$327,789

3.1.16 Heating and Process Fuels Business New Construction Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	33	28	nap	60
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$506	$15,442	$1,800	$15,948
Marketing/Business Development	$0	$17,072	$3,100	$17,072
Subtotal Operating Costs	$506	$32,515	$4,900	$33,020
Incentive Costs				
Incentives to Participants	$23,685	$20,268	$59,700	$43,953
Incentives to Trade Allies	$1,600	$500	$0	$2,100
Subtotal Incentive Costs	$25,285	$20,768	$59,700	$46,053
Technical Assistance Costs				
Services to Participants	$18,717	$43,362	$18,700	$62,079
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$18,717	$43,362	$18,700	$62,079
Total Efficiency Vermont Costs	$44,508	$96,645	$83,300	$141,152
Total Participant Costs	$390,086	$83,026	nav	$473,112
Total Third Party Costs	$0	$0	nav	$0
Total Services and Initiatives Costs	$434,594	$179,671	nav	$614,265
Annualized MMBtu Savings	7,869	1,819	nap	9,687
Lifetime MMBtu Savings	159,023	38,578	nap	197,601
TRB Savings (2009 $)	$2,928,968	$702,347	nap	$3,631,315
Annualized MMBtu Savings/Participant	238.452	64.946	nap	161.457
Weighted Lifetime	20	21	nap	20
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.17 Heating and Process Fuels Business New Construction - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Space Heat Efficiency	25	0	0	0	0	0	1,385	0	$13,791	$45,895
Ventilation	8	-1	-1	-20	3	4	433	0	$6,882	$37,131
Totals		-1	-1	-20	3	4	1,819	0	$20,268	$83,026

3.1.18 Heating and Process Fuels Business New Construction - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$5,682
Fossil Fuel Savings (Costs)	$38,070	$696,665
Water Savings (Costs)	$0	$0
Total	$38,070	$702,347

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	(1)	(1)	(1)
Winter on peak	(1)	(0)	(1)
Winter off peak	(1)	(1)	(1)
Summer on peak	0	0	0
Summer off peak	(0)	(0)	(0)
Coincident Demand Savings (kW)			
Winter	3	3	3
Shoulder	0	0	0
Summer	4	3	4

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	0	0	0
Annualized fuel savings (increase) MMBtu	1,876	1,819	38,578
LP	1,463	1,416	31,951
NG	0	0	0
Oil/Kerosene	413	402	6,627
Wood	0	0	0
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$0	$0	$0

Net Societal Benefits	$666,937

3.1.19 Heating and Process Fuels Business Existing Facilities Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	51	148	nap	199
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$2,101	$254,482	$28,700	$263,608
Marketing/Business Development	$0	$281,351	$50,700	$281,565
Subtotal Operating Costs	$2,101	$535,833	$79,400	$545,172
Incentive Costs				
Incentives to Participants	$102,737	$333,870	$983,300	$436,607
Incentives to Trade Allies	$800	$8,000	$0	$8,800
Subtotal Incentive Costs	$103,537	$341,870	$983,300	$445,407
Technical Assistance Costs				
Services to Participants	$79,255	$193,970	$307,400	$273,224
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$79,255	$193,970	$307,400	$273,224
Total Efficiency Vermont Costs	$184,892	$1,071,673	$1,370,100	$1,263,804
Total Participant Costs	$253,541	$923,466	nav	$1,177,007
Total Third Party Costs	$0	$1,593	nav	$1,593
Total Services and Initiatives Costs	$438,434	$1,996,732	nav	$2,442,404
Annualized MMBtu Savings	6,083	18,826	nap	24,910
Lifetime MMBtu Savings	127,204	323,831	nap	451,035
TRB Savings (2009 $)	$1,881,605	$4,381,872	nap	$6,263,476
Annualized MMBtu Savings/Participant	119.282	127.205	nap	125.175
Weighted Lifetime	21	17	nap	18
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.20 Heating and Process Fuels Business Existing Facilities - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Hot Water Efficiency	29	0	0	0	0	0	2,043	0	$119,403	$29,277
Industrial Process Eff.	2	0	0	0	0	0	10,479	0	$87,108	$311,189
Space Heat Efficiency	115	40	40	803	16	0	5,798	0	$130,589	$546,067
Space Heat Fuel Switch	1	0	0	3	0	0	13	0	$1,020	$19,313
Ventilation	1	0	0	0	0	0	494	0	$2,428	$17,620
Totals		40	40	806	16	0	18,826	0	$333,870	$923,466

3.1.21 Heating and Process Fuels Business Existing Facilities - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$44,084
Fossil Fuel Savings (Costs)	$361,024	$4,337,788
Water Savings (Costs)	$0	$0
Total	$361,024	$4,381,872

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	40	36	40
Winter on peak	16	14	16
Winter off peak	25	22	25
Summer on peak	0	0	0
Summer off peak	0	0	0
Coincident Demand Savings (kW)			
Winter	16	14	16
Shoulder	0	0	0
Summer	0	0	0

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	0	0	0
Annualized fuel savings (increase) MMBtu	22,010	18,826	323,831
LP	1,723	1,689	33,051
NG	0	0	0
Oil/Kerosene	20,320	17,151	290,326
Wood	(33)	(14)	455
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	($54)	($43)	($643)

Net Societal Benefits	$4,329,861

3.1.22 Heating and Process Fuels Residential New Construction Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	8	6	nap	14
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$76	$2,891	$300	$2,967
Marketing/Business Development	$79	$2,180	$500	$2,259
Subtotal Operating Costs	$156	$5,071	$800	$5,226
Incentive Costs				
Incentives to Participants	$413	$4,408	$8,900	$4,821
Incentives to Trade Allies	$0	$0	$0	$0
Subtotal Incentive Costs	$413	$4,408	$8,900	$4,821
Technical Assistance Costs				
Services to Participants	$381	$882	$1,900	$1,263
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$381	$882	$1,900	$1,263
Total Efficiency Vermont Costs	$949	$10,361	$11,600	$11,311
Total Participant Costs	$2,787	$28,920	nav	$31,707
Total Third Party Costs	$0	$0	nav	$0
Total Services and Initiatives Costs	$3,737	$39,281	nav	$43,017
Annualized MMBtu Savings	80	877	nap	957
Lifetime MMBtu Savings	1,999	21,327	nap	23,326
TRB Savings (2009 $)	$37,432	$272,605	nap	$310,037
Annualized MMBtu Savings/Participant	10.000	146.183	nap	68.364
Weighted Lifetime	25	24	nap	24
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.23 Heating and Process Fuels Residential New Construction - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Space Heat Efficiency	6	0	0	0	0	0	817	0	$4,035	$13,372
Ventilation	1	0	0	0	0	0	60	0	$462	$15,547
Totals		0	0	0	0	0	877	0	$4,408	$28,920

3.1.24 Heating and Process Fuels Residential New Construction - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$0
Fossil Fuel Savings (Costs)	$18,200	$272,605
Water Savings (Costs)	$0	$0
Total	$18,200	$272,605

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	0	0	0
Winter on peak	0	0	0
Winter off peak	0	0	0
Summer on peak	0	0	0
Summer off peak	0	0	0
Coincident Demand Savings (kW)			
Winter	0	0	0
Shoulder	0	0	0
Summer	0	0	0

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	0	0	0
Annualized fuel savings (increase) MMBtu	877	877	21,327
LP	163	163	4,064
NG	0	0	0
Oil/Kerosene	715	715	17,263
Wood	0	0	0
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$0	$0	$0

Net Societal Benefits	$270,845

3.1.25 Heating and Process Fuels Efficient Products Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	nap	nap	nap	nap
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	nap	nap	nap	nap
Marketing/Business Development	nap	nap	nap	nap
Subtotal Operating Costs	nap	nap	nap	nap
Incentive Costs				
Incentives to Participants	nap	nap	nap	nap
Incentives to Trade Allies	nap	nap	nap	nap
Subtotal Incentive Costs	nap	nap	nap	nap
Technical Assistance Costs				
Services to Participants	nap	nap	nap	nap
Services to Trade Allies	nap	nap	nap	nap
Subtotal Technical Assistance Costs	nap	nap	nap	nap
Total Efficiency Vermont Costs	nap	nap	nap	nap
Total Participant Costs	nap	nap	nap	nap
Total Third Party Costs	nap	nap	nap	nap
Total Services and Initiatives Costs	nap	nap	nap	nap
Annualized MMBtu Savings	nap	nap	nap	nap
Lifetime MMBtu Savings	nap	nap	nap	nap
TRB Savings (2009 $)	nap	nap	nap	nap
Annualized MMBtu Savings/Participant	nap	nap	nap	nap
Weighted Lifetime	nap	nap	nap	nap
Committed Incentives	nap	nap	nap	nap

3.1.26 Heating and Process Fuels Efficient Products - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Totals	nap	nap	nap	nap	nap	nap	nap	nap	nap	nap

3.1.27 Heating and Process Fuels Efficient Products - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	nap
Fossil Fuel Savings (Costs)	nap	nap
Water Savings (Costs)	nap	nap
Total	nap	nap

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	nap	nap	nap
Winter on peak	nap	nap	nap
Winter off peak	nap	nap	nap
Summer on peak	nap	nap	nap
Summer off peak	nap	nap	nap
Coincident Demand Savings (kW)			
Winter	nap	nap	nap
Shoulder	nap	nap	nap
Summer	nap	nap	nap

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	nap	nap	nap
Annualized fuel savings (increase) MMBtu	nap	nap	nap
LP	nap	nap	nap
NG	nap	nap	nap
Oil/Kerosene	nap	nap	nap
Wood	nap	nap	nap
Solar	nap	nap	nap
Other	nap	nap	nap
Annualized savings (increase) in O&M($)	nap	nap	nap

Net Societal Benefits	nap

3.1.28 Heating and Process Fuels Existing Homes Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	919	1,475	nap	2,761
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$132,855	$1,312,882	$90,700	$1,475,572
Marketing/Business Development	$137,414	$762,103	$161,000	$1,066,223
Subtotal Operating Costs	$270,269	$2,074,985	$251,700	$2,541,795
Incentive Costs				
Incentives to Participants	$635,239	$1,428,723	$3,091,700	$2,210,700
Incentives to Trade Allies	$17,200	$105,692	$0	$122,892
Subtotal Incentive Costs	$652,439	$1,534,415	$3,091,700	$2,333,592
Technical Assistance Costs				
Services to Participants	$726,751	$639,681	$675,100	$1,561,758
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$726,751	$639,681	$675,100	$1,561,758
Total Efficiency Vermont Costs	$1,649,458	$4,249,081	$4,018,500	$6,437,145
Total Participant Costs	$2,340,175	$3,969,763	nav	$6,611,754
Total Third Party Costs	$3,253	$196,359	nav	$199,612
Total Services and Initiatives Costs	$3,992,886	$8,415,203	nav	$13,248,511
Annualized MMBtu Savings	18,427	27,684	nap	50,068
Lifetime MMBtu Savings	328,354	496,946	nap	880,976
TRB Savings (2009 $)	$4,367,869	$7,525,712	nap	$12,717,225
Annualized MMBtu Savings/Participant	20.051	18.769	nap	18.134
Weighted Lifetime	18	18	nap	18
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

3.1.29 Heating and Process Fuels Existing Homes - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Cooking and Laundry	19	0	0	0	0	0	0	0	$0	$1,880
Hot Water Efficiency	262	16	16	222	2	1	646	1,438	$27,806	$44,417
Hot Water Fuel Switch	1	1	1	26	0	0	-3	0	$0	$640
Motors	29	0	0	0	0	0	42	0	$0	$3,231
Other Indirect Activity	109	0	0	0	0	0	0	0	$0	$10,710
Space Heat Efficiency	1,259	217	214	3,865	105	0	26,845	1	$1,405,320	$3,666,631
Space Heat Fuel Switch	21	64	71	957	15	0	153	0	$21,420	$178,645
Ventilation	169	0	0	0	0	0	0	0	$0	$63,608
Totals		298	301	5,070	122	1	27,684	1,439	$1,428,723	$3,969,763

3.1.30 Heating and Process Fuels Existing Homes - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$245,503
Fossil Fuel Savings (Costs)	$554,183	$7,186,720
Water Savings (Costs)	$10,763	$93,486
Total	$564,947	$7,525,709

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	301	264	298
Winter on peak	137	121	137
Winter off peak	156	137	180
Summer on peak	4	4	4
Summer off peak	4	3	4
Coincident Demand Savings (kW)			
Winter	125	111	122
Shoulder	0	0	0
Summer	1	1	1

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	1,599	1,439	12,960
Annualized fuel savings (increase) MMBtu	30,535	27,684	496,946
LP	6,866	6,282	121,206
NG	5	4	58
Oil/Kerosene	20,738	18,479	333,888
Wood	2,929	2,919	41,794
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$209,827	$167,862	$2,517,751

Net Societal Benefits	$11,180,356

4.1 Customer Credit Program

4.1.1 NARRATIVE

The Customer Credit program (CCP) provides an alternative program path for large businesses that meet program eligibility criteria. The program enables customers with the capability and resources to identify, analyze, and undertake efficiency projects, and self-implement energy efficiency measures with financial assistance from Efficiency Vermont. CCP customers can apply for financial incentives for any retrofit or market-driven project that saves electrical energy and passes the Vermont societal cost-effectiveness test. Once a customer elects to participate in CCP, that customer is no longer eligible to participate in other Efficiency Vermont programs.

All projects must be customer-initiated. In addition, the customer or its contractors must complete all technical analysis. Customers can receive cash incentives capped at 90% of their projected three-year contribution to the statewide energy efficiency fund at any time. Customers can draw on contributions from the current year and either the previous or ensuing year. Market-driven projects are eligible for incentives equal to 100% of the incremental measure cost. For retrofit projects, customers can receive incentives that reduce the customer payback time to 12 months.

Eligible Market

To be eligible for CCP, customers must:

- Never have accepted cash incentives from any Vermont utility Demand Side Management (DSM) program;
- Have ISO 14001 certification.

4.1.2 Customer Credit Summary

	Prior Year	Current Year 2011	* Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	1	0	nap	1
Services and Initiatives Costs				
Operating Costs				
Services and Initiatives	$0	$0	$0	$3,703
Marketing/Business Development	$0	$0	$0	$0
Subtotal Operating Costs	$0	$0	$0	$3,703
Incentive Costs				
Incentives to Participants	$179,264	$0	$0	$1,055,920
Incentives to Trade Allies	$0	$0	$0	$0
Subtotal Incentive Costs	$179,264	$0	$0	$1,055,920
Technical Assistance Costs				
Services to Participants	$0	$0	$0	$5,007
Services to Trade Allies	$0	$0	$0	$0
Subtotal Technical Assistance Costs	$0	$0	$0	$5,007
Total Efficiency Vermont Costs	$179,264	$0	$0	$1,064,631
Total Participant Costs	$24,211	$0	nap	$248,456
Total Third Party Costs	$0	$0	nap	$0
Total Services and Initiatives Costs	$203,475	$0	nap	$1,313,087
Annualized MWh Savings	322	0	nap	4,601
Lifetime MWh Savings	4,186	0	nap	66,725
TRB Savings (2009 $)	$341,434	$0	nap	$6,579,536
Winter Coincident Peak kW Savings	64	0	nap	371
Summer Coincident Peak kW Savings	64	0	nap	752
Annualized MWh Savings/Participant	322.201	0.000	nap	4,601
Weighted Lifetime	13	0	nap	15
Committed Incentives	nap	nap	nap	nap

* Annual projections are estimates only and provided for informational purposes.
The Efficiency Vermont contract is based on three-year cumulative budgets and savings goals.

Note: The above budgets include the Customer Credit Net Pay Option Incentive Funds.

4.1.3 Customer Credit - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Totals	0	0	0	0	0	0	0	0	0	0

4.1.4 Customer Credit - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$0
Fossil Fuel Savings (Costs)	$0	$0
Water Savings (Costs)	$0	$0
Total	$0	$0

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	0	0	0
Winter on peak	0	0	0
Winter off peak	0	0	0
Summer on peak	0	0	0
Summer off peak	0	0	0
Coincident Demand Savings (kW)			
Winter	0	0	0
Shoulder	0	0	0
Summer	0	0	0

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	0	0	0
Annualized fuel savings (increase) MMBtu	0	0	0
LP	0	0	0
NG	0	0	0
Oil/Kerosene	0	0	0
Wood	0	0	0
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$0	$0	$0

4.2 Geographic Targeting

4.2.1 Electric Geographic Targeting Regions Combined Summary

	Prior Year	Current Year 2011	Cumulative starting 1/1/09
# participants with installations	8,532	6,649	21,984
Services and Initiatives Costs			
Operating Costs			
Services and Initiatives	$1,704,706	$2,232,479	$5,775,381
Marketing/Business Development	$1,907,488	$2,606,886	$5,982,003
Subtotal Operating Costs	$3,612,194	$4,839,366	$11,757,384
Incentive Costs			
Incentives to Participants	$5,597,600	$4,901,919	$15,059,621
Incentives to Trade Allies	$24,384	$47,981	$92,388
Subtotal Incentive Costs	$5,621,984	$4,949,899	$15,152,010
Technical Assistance Costs			
Services to Participants	$2,058,014	$2,876,965	$7,312,749
Services to Trade Allies	$39,437	$47,356	$152,093
Subtotal Technical Assistance Costs	$2,097,451	$2,924,321	$7,464,842
Total Efficiency Vermont Costs	$11,331,630	$12,713,586	$34,374,236
Total Participant Costs	$5,648,642	$3,859,068	$14,494,094
Total Third Party Costs	$245,626	$66,034	$428,224
Total Services and Initiatives Costs	$17,225,898	$16,638,687	$49,296,553
Annualized MWh Savings	35,826	28,069	93,168
Lifetime MWh Savings	370,433	288,970	989,121
TRB Savings (2009 $)	$30,045,327	$20,838,483	$82,621,955
Winter Coincident Peak kW Savings	6,660	5,162	16,920
Summer Coincident Peak kW Savings	5,629	3,829	14,441
Annualized MWh Savings/Participant	4.199	4.221	4.238
Weighted Lifetime	10	10	11
Committed Incentives	$3,969,270	$329,766	nap

4.2.2 Electric Geographic Targeting Regions Combined - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$19,487,253
Fossil Fuel Savings (Costs)	($66,412)	($25,706)
Water Savings (Costs)	$116,502	$1,377,025
Total	$50,091	$20,838,572

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	26,269	25,036	28,069
Winter on peak	10,012	9,604	10,900
Winter off peak	7,728	7,284	8,172
Summer on peak	4,630	4,460	4,460
Summer off peak	3,757	3,550	3,929
Coincident Demand Savings (kW)			
Winter	5,153	4,693	5,162
Shoulder	0	0	0
Summer	3,640	3,465	3,829

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	13,742	15,552	214,970
Annualized fuel savings (increase) MMBtu	(2,872)	(3,998)	(31,593)
LP	805	732	12,675
NG	(2,976)	(2,467)	(48,919)
Oil/Kerosene	(1,382)	(3,083)	(11,295)
Wood	558	589	14,854
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$849,058	$708,160	$5,933,581

4.2.3 Electric Geographic Targeting Chittenden North Summary

	Prior Year	Current Year 2011	Cumulative starting 1/1/09
# participants with installations	2,468	2,161	6,720
Services and Initiatives Costs			
Operating Costs			
Services and Initiatives	$589,026	$889,233	$2,145,859
Marketing/Business Development	$689,381	$906,077	$2,176,591
Subtotal Operating Costs	$1,278,407	$1,795,310	$4,322,450
Incentive Costs			
Incentives to Participants	$1,815,993	$1,470,340	$4,540,684
Incentives to Trade Allies	$9,795	$16,068	$38,329
Subtotal Incentive Costs	$1,825,788	$1,486,408	$4,579,013
Technical Assistance Costs			
Services to Participants	$626,512	$1,005,799	$2,399,733
Services to Trade Allies	$17,595	$19,729	$69,334
Subtotal Technical Assistance Costs	$644,107	$1,025,528	$2,469,066
Total Efficiency Vermont Costs	$3,748,303	$4,307,245	$11,370,529
Total Participant Costs	$2,252,826	$1,234,770	$5,424,166
Total Third Party Costs	$63,068	$23,785	$139,510
Total Services and Initiatives Costs	$6,064,197	$5,565,801	$16,934,205
Annualized MWh Savings	13,816	11,606	35,661
Lifetime MWh Savings	136,052	112,819	361,233
TRB Savings (2009 $)	$9,830,750	$7,896,962	28,741,478
Winter Coincident Peak kW Savings	2,595	2,109	6,496
Summer Coincident Peak kW Savings	2,153	1,594	5,420
Annualized MWh Savings/Participant	5.598	5.371	5.307
Weighted Lifetime	10	10	10
Committed Incentives	$1,463,175	$182,374	nap

4.2.4 Electric Geographic Targeting Chittenden North - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	105	228	215	4,014	18	54	-621	0	$19,094	$46,786
Cooking and Laundry	410	128	98	1,786	20	15	208	5,147	$20,855	$161,510
Design Assistance	19	134	129	670	0	0	0	0	$29,468	$23,040
Hot Water Efficiency	17	17	15	162	4	1	17	53	$4,192	$217
Hot Water Fuel Switch	71	202	212	6,061	30	15	-709	0	$45,658	$47,229
Industrial Process Eff.	2	647	644	6,469	65	65	-486	0	$1,662	$356
Lighting	1,215	9,053	8,061	79,025	1,799	1,154	-2,760	0	$1,261,386	$724,678
Monitoring and Metering	7	1	1	5	0	0	0	0	$98	$109
Motors	6	122	119	1,571	10	10	232	0	$9,264	$28,864
Other Efficiency	20	0	0	0	0	0	0	0	$6,977	-$6,800
Other Fuel Switch	5	5	5	152	1	1	-15	0	$1,127	$2,386
Other Indirect Activity	1	0	0	0	0	0	0	0	$655	-$800
Refrigeration	392	927	894	10,447	152	240	0	0	$74,647	$178,013
Space Heat Efficiency	64	21	18	385	4	6	409	0	$3,553	$10,241
Space Heat Fuel Switch	2	18	20	546	4	0	-58	0	$1,008	$12,130
Ventilation	8	103	102	1,526	2	33	279	0	$1,726	$6,812
Totals		11,606	10,535	112,819	2,109	1,594	-3,505	5,200	$1,470,340	$1,234,770

4.2.5 Electric Geographic Targeting Chittenden North - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$7,736,371
Fossil Fuel Savings (Costs)	($57,839)	($303,745)
Water Savings (Costs)	$38,959	$464,378
Total	($18,880)	$7,897,004

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	10,535	10,338	11,606
Winter on peak	3,988	3,937	4,468
Winter off peak	3,132	3,053	3,426
Summer on peak	1,866	1,837	1,837
Summer off peak	1,505	1,469	1,625
Coincident Demand Savings (kW)			
Winter	2,078	1,917	2,109
Shoulder	0	0	0
Summer	1,496	1,442	1,594

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	4,538	5,200	72,660
Annualized fuel savings (increase) MMBtu	(3,715)	(3,505)	(45,004)
LP	78	79	1,272
NG	(1,738)	(1,481)	(32,484)
Oil/Kerosene	(2,091)	(2,179)	(14,134)
Wood	0	0	0
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$302,911	$319,127	$2,521,247

4.2.6 Electric Geographic Targeting Saint Albans Summary

	Prior Year	Current Year 2011	Cumulative starting 1/1/09
# participants with installations	2,009	1,571	5,355
Services and Initiatives Costs			
Operating Costs			
Services and Initiatives	$411,093	$496,531	$1,162,803
Marketing/Business Development	$450,924	$575,404	$1,224,372
Subtotal Operating Costs	$862,016	$1,071,934	$2,387,175
Incentive Costs			
Incentives to Participants	$1,070,181	$1,425,968	$3,333,336
Incentives to Trade Allies	$4,500	$10,654	$18,948
Subtotal Incentive Costs	$1,074,681	$1,436,622	$3,352,284
Technical Assistance Costs			
Services to Participants	$542,403	$665,965	$1,506,933
Services to Trade Allies	$6,826	$6,240	$27,801
Subtotal Technical Assistance Costs	$549,229	$672,204	$1,534,734
Total Efficiency Vermont Costs	$2,485,927	$3,180,761	$7,274,192
Total Participant Costs	$1,050,962	$1,070,686	$3,253,382
Total Third Party Costs	$27,181	$24,446	$85,866
Total Services and Initiatives Costs	$3,564,069	$4,275,893	$10,613,441
Annualized MWh Savings	8,348	6,120	20,275
Lifetime MWh Savings	86,645	70,214	217,988
TRB Savings (2009 $)	$6,672,626	$4,794,222	$17,773,737
Winter Coincident Peak kW Savings	1,413	999	3,413
Summer Coincident Peak kW Savings	1,168	795	2,878
Annualized MWh Savings/Participant	2.963	3.896	3.786
Weighted Lifetime	10	11	11
Committed Incentives	$35,005	$71,900	nap

4.2.7 Electric Geographic Targeting Saint Albans - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	97	227	219	5,180	27	33	0	0	$15,443	$6,922
Cooking and Laundry	319	103	79	1,438	16	12	164	4,083	$18,493	$126,750
Design Assistance	3	0	0	0	0	0	0	0	$3,247	-$475
Hot Water Efficiency	18	30	27	278	6	1	4	45	$8,198	$1,148
Hot Water Fuel Switch	12	41	45	1,240	6	3	-144	0	$9,616	$10,315
Industrial Process Eff.	3	477	498	5,830	42	56	0	0	$44,076	$45,879
Lighting	1,032	4,017	3,685	42,251	798	468	-1,031	0	$1,011,489	$943,519
Monitoring and Metering	3	2	2	8	0	0	0	0	$173	$173
Motors	10	302	288	3,313	43	35	0	0	$37,621	$32,008
Other Efficiency	14	32	29	642	4	4	0	0	$5,642	$4,300
Other Fuel Switch	2	2	2	66	0	0	-7	0	$1,817	$0
Other Indirect Activity	4	9	15	44	2	1	0	0	$3,249	$2,975
Refrigeration	190	126	134	1,382	19	18	0	0	$41,719	$9,875
Space Heat Efficiency	12	6	5	115	3	0	81	0	$2,217	-$1,547
Space Heat Fuel Switch	1	195	220	2,929	34	2	-722	0	$7,254	$64,800
Ventilation	18	550	489	5,497	0	161	16	0	$226,410	-$175,955
Totals		6,120	5,737	70,214	999	795	-1,639	4,128	$1,425,968	$1,070,686

4.2.8 Electric Geographic Targeting Saint Albans - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$4,545,256
Fossil Fuel Savings (Costs)	($24,143)	($119,578)
Water Savings (Costs)	$30,927	$368,559
Total	$6,784	$4,794,236

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	5,737	5,465	6,120
Winter on peak	1,979	1,890	2,146
Winter off peak	1,659	1,558	1,748
Summer on peak	1,104	1,064	1,064
Summer off peak	962	919	1,017
Coincident Demand Savings (kW)			
Winter	992	908	999
Shoulder	0	0	0
Summer	759	719	795

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	3,605	4,128	57,664
Annualized fuel savings (increase) MMBtu	(1,913)	(1,639)	(19,939)
LP	29	31	571
NG	(1,273)	(1,022)	(17,026)
Oil/Kerosene	(699)	(709)	(3,673)
Wood	0	0	0
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$302,911	$133,955	$1,298,570

4.2.9 Electric Geographic Targeting Southern Loop Summary

	Prior Year	Current Year 2011	Cumulative starting 1/1/09
# participants with installations	2,250	1,680	5,919
Services and Initiatives Costs			
Operating Costs			
Services and Initiatives	$270,131	$340,402	$938,586
Marketing/Business Development	$290,830	$408,713	$944,528
Subtotal Operating Costs	$560,961	$749,115	$1,883,114
Incentive Costs			
Incentives to Participants	$923,853	$931,829	$2,541,603
Incentives to Trade Allies	$4,846	$7,706	$13,621
Subtotal Incentive Costs	$928,700	$939,535	$2,555,224
Technical Assistance Costs			
Services to Participants	$310,164	$421,530	$1,154,813
Services to Trade Allies	$7,504	$6,825	$26,479
Subtotal Technical Assistance Costs	$317,668	$428,355	$1,181,292
Total Efficiency Vermont Costs	$1,807,328	$2,117,006	$5,619,629
Total Participant Costs	$959,215	$852,516	$2,777,562
Total Third Party Costs	$15,080	$14,284	$45,122
Total Services and Initiatives Costs	$2,781,623	$2,983,805	$8,442,313
Annualized MWh Savings	5,239	5,261	15,269
Lifetime MWh Savings	54,545	60,144	163,115
TRB Savings (2009 $)	$6,183,671	$4,550,530	$15,404,007
Winter Coincident Peak kW Savings	1,083	1,109	3,108
Summer Coincident Peak kW Savings	777	684	2,212
Annualized MWh Savings/Participant	2.328	3.131	2.580
Weighted Lifetime	10	11	11
Committed Incentives	$602,224	$9,640	nap

4.2.10 Electric Geographic Targeting Southern Loop - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	78	52	53	854	0	18	104	0	$5,400	$10,771
Cooking and Laundry	216	73	57	1,027	11	9	109	2,776	$17,288	$83,900
Design Assistance	1	0	0	0	0	0	0	0	$4,685	$0
Hot Water Efficiency	42	18	16	121	2	2	23	253	$1,351	$223
Industrial Process Eff.	7	1,448	1,584	21,702	424	34	0	0	$143,921	$576,854
Lighting	1,255	3,376	3,041	33,306	633	582	-1,366	0	$704,295	$128,392
Monitoring and Metering	11	5	5	22	1	1	0	0	$737	$404
Motors	3	107	107	959	8	17	0	0	$7,526	$20,660
Other Efficiency	24	0	0	0	0	0	0	0	$5,844	-$5,800
Other Indirect Activity	2	4	4	30	1	1	0	0	$1,068	$1,605
Refrigeration	193	132	139	1,462	17	19	0	0	$40,152	$14,548
Space Heat Efficiency	12	20	19	406	9	0	810	0	$882	$12,261
Ventilation	14	25	25	254	3	3	1,159	0	$5,671	$8,698
Totals		5,261	5,050	60,144	1,109	684	839	3,029	$931,829	$852,516

4.2.11 Electric Geographic Targeting Southern Loop - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$4,004,024
Fossil Fuel Savings (Costs)	$16,584	$281,554
Water Savings (Costs)	$22,686	$264,962
Total	$39,270	$4,550,541

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	5,050	4,703	5,261
Winter on peak	2,123	1,979	2,246
Winter off peak	1,538	1,398	1,568
Summer on peak	749	727	727
Summer off peak	601	560	620
Coincident Demand Savings (kW)			
Winter	1,133	1,008	1,109
Shoulder	0	0	0
Summer	647	619	684

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	2,694	3,029	41,197
Annualized fuel savings (increase) MMBtu	990	839	13,305
LP	471	412	6,799
NG	14	15	251
Oil/Kerosene	487	372	6,055
Wood	(14)	(12)	(181)
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$117,586	$123,403	$1,085,674

4.2.12 Electric Geographic Targeting Rutland Summary

	Prior Year	Current Year 2011	Cumulative starting 1/1/09
# participants with installations	1,715	1,237	3,990
Services and Initiatives Costs			
Operating Costs			
Services and Initiatives	$434,457	$506,313	$1,528,133
Marketing/Business Development	$476,353	$716,693	$1,636,513
Subtotal Operating Costs	$910,810	$1,223,006	$3,164,646
Incentive Costs			
Incentives to Participants	$1,787,572	1,073,782	$4,643,998
Incentives to Trade Allies	$5,243	$13,553	$21,491
Subtotal Incentive Costs	$1,792,815	$1,087,335	$4,665,489
Technical Assistance Costs			
Services to Participants	$578,935	$783,671	$2,251,271
Services to Trade Allies	$7,512	$14,562	$28,480
Subtotal Technical Assistance Costs	$586,447	$798,233	$2,279,751
Total Efficiency Vermont Costs	$3,290,072	$3,108,574	$10,109,885
Total Participant Costs	$1,385,639	$701,095	$3,038,984
Total Third Party Costs	$140,298	$3,519	$157,726
Total Services and Initiatives Costs	$4,816,009	$3,813,188	$13,306,594
Annualized MWh Savings	8,423	5,082	21,963
Lifetime MWh Savings	93,192	45,792	246,785
TRB Savings (2009 $)	$7,358,281	$3,596,769	$20,702,733
Winter Coincident Peak kW Savings	1,569	945	3,903
Summer Coincident Peak kW Savings	1,531	757	3,932
Annualized MWh Savings/Participant	4.911	4.109	5.504
Weighted Lifetime	11	9	11
Committed Incentives	$79,290	$65,852	nap

4.2.13 Electric Geographic Targeting Rutland - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	66	64	212	1,122	1	23	0	40	$14,057	$43,307
Cooking and Laundry	211	73	57	1,017	11	9	107	2,707	$15,163	$83,970
Design Assistance	76	0	0	0	0	0	0	0	$5,171	$0
Hot Water Efficiency	60	46	44	355	7	7	19	339	$1,308	-$143
Industrial Process Eff.	3	125	151	1,253	22	23	0	0	$4	$14,396
Lighting	659	3,822	3,457	33,067	787	543	-1,372	0	$668,006	$232,939
Monitoring and Metering	10	1	1	4	0	0	0	0	$552	$0
Motors	9	404	397	4,691	43	89	791	0	$77,396	$165,004
Other Efficiency	10	0	0	0	0	0	0	0	$2,519	-$2,500
Other Fuel Switch	1	3	3	82	0	0	-9	0	$0	$750
Other Indirect Activity	82	328	412	1,436	39	28	0	0	$216,088	$98,545
Refrigeration	346	147	148	1,768	21	16	0	0	$72,001	$12,033
Space Heat Efficiency	5	36	36	555	12	1	554	110	$5,610	$26,101
Ventilation	12	33	31	442	2	19	217	0	$3,961	$26,693
Totals		5,082	4,948	45,792	945	757	307	3,195	$1,073,782	$701,095

4.2.14 Electric Geographic Targeting Rutland - Total Resource Benefits

	2011	Lifetime (Present Value)
Avoided Cost of Electricity	nap	$3,201,601
Fossil Fuel Savings (Costs)	($1,013)	$116,063
Water Savings (Costs)	$23,931	$279,127
Total	$22,918	$3,596,791

	Savings at meter		Savings at Generation
	Gross	Net	Net
Annualized Energy Savings (MWh): Total	4,948	4,530	5,082
Winter on peak	1,923	1,798	2,040
Winter off peak	1,400	1,274	1,430
Summer on peak	912	833	833
Summer off peak	689	602	666
Coincident Demand Savings (kW)			
Winter	950	859	945
Shoulder	0	0	0
Summer	738	685	757

	Gross	Net	Net Lifetime Savings
Annualized Water Savings (ccf)	2,905	3,195	43,449
Annualized fuel savings (increase) MMBtu	1,765	307	20,044
LP	227	210	4,033
NG	21	21	341
Oil/Kerosene	921	(568)	456
Wood	573	601	15,034
Solar	0	0	0
Other	0	0	0
Annualized savings (increase) in O&M($)	$125,650	$131,675	$1,028,089

5.1 Submarket Results

5.1.1 Electric Business New Construction Act 250 Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	61	35	nap	136
Costs				
EVT Incentives	$535,602	$195,056	nap	$1,062,532
Participant Costs	$1,469,552	$540,392	nap	$3,103,617
Third Party Costs	$0	$0	nap	$0
Annualized MWh Savings	4,464	1,974	nap	10,169
Lifetime MWh Savings	67,599	24,252	nap	148,067
TRB Savings (2009$)	$7,874,982	$2,150,650	nap	$17,548,430
Winter Coincident Peak KW Savings	589	320	nap	1,346
Summer Coincident Peak KW Savings	718	436	nap	1,807
Annualized MWh Savings/Participant	73.185	56.386	nap	74.771
Weighted Lifetime	15	12	nap	15
Committed Incentives	$107,118	$64,883	nap	nap

5.1.2 Electric Business New Construction Act 250 - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	15	95	89	1,495	2	54	0	0	$22,787	$34,830
Design Assistance	4	0	0	0	0	0	10	0	$11,196	$166
Hot Water Efficiency	1	18	17	180	2	3	0	0	$668	$2,587
Lighting	33	917	857	12,689	164	149	-491	0	$109,142	$266,603
Motors	13	58	54	780	7	4	232	0	$6,820	$11,559
Other Efficiency	1	0	0	0	0	0	0	0	$2,317	$0
Refrigeration	9	809	756	8,316	135	215	0	0	$36,085	$134,808
Space Heat Efficiency	5	7	7	109	3	4	1,237	0	$1,209	$52,149
Ventilation	14	70	66	683	8	8	760	0	$4,831	$37,690
Totals		1,974	1,845	24,252	320	436	1,748	0	$193,604	$540,392

5.1.3 Electric Business New Construction Non-Act 250 Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	181	73	nap	411
Costs				
EVT Incentives	$545,191	$299,247	nap	$1,339,218
Participant Costs	$1,108,313	$584,941	nap	$2,850,019
Third Party Costs	$0	$0	nap	$14,500
Annualized MWh Savings	4,394	3,744	nap	12,777
Lifetime MWh Savings	64,981	52,259	nap	184,400
TRB Savings (2009$)	$5,238,504	$3,517,419	nap	$15,985,238
Winter Coincident Peak KW Savings	608	541	nap	1,743
Summer Coincident Peak KW Savings	794	602	nap	2,251
Annualized MWh Savings/Participant	24.274	51.284	nap	31.089
Weighted Lifetime	15	14	nap	14
Committed Incentives	$87,680	$72,380	nap	nap

5.1.4 Electric Business New Construction Non-Act 250 - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	19	179	159	2,421	7	36	0	0	$21,565	$39,834
Design Assistance	3	0	0	2	0	0	18	0	$5,138	-$600
Hot Water Efficiency	3	2	2	12	2	4	34	46	$90	$612
Industrial Process Eff.	2	1,264	1,119	18,957	197	198	0	0	$34,027	$136,654
Lighting	67	1,749	1,593	24,817	223	247	-666	0	$187,021	$312,984
Motors	7	220	194	2,487	44	43	339	0	$21,004	$32,669
Other Efficiency	2	17	15	227	5	1	10	13	$167	$6
Other Fuel Switch	1	5	5	146	0	10	-17	0	$352	$26
Other Indirect Activity	1	1	1	3	1	0	0	0	$126	$75
Refrigeration	5	291	259	2,953	58	57	0	0	$26,726	$52,441
Space Heat Efficiency	5	10	9	175	3	5	186	0	$1,187	$3,321
Ventilation	8	6	6	61	1	2	296	0	$1,844	$6,919
Totals		3,744	3,361	52,259	541	602	201	60	$296,758	$584,941

5.1.5 Electric Market Rate Multifamily New Construction Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	127	14	nap	300
Costs				
EVT Incentives	$70,137	$40,310	nap	$178,776
Participant Costs	$134,919	$112,266	nap	$336,929
Third Party Costs	$0	$0	nap	$4,375
Annualized MWh Savings	264	211	nap	749
Lifetime MWh Savings	4,774	3,635	nap	13,321
TRB Savings (2009$)	$617,073	$470,989	nap	$1,856,322
Winter Coincident Peak KW Savings	53	51	nap	162
Summer Coincident Peak KW Savings	27	25	nap	84
Annualized MWh Savings/Participant	2.078	15.055	nap	2.497
Weighted Lifetime	18	17	nap	18
Committed Incentives	$30,000	$20,140	nap	nap

5.1.6 Electric Market Rate Multifamily New Construction - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	0	9	8	133	0	1	0	0	$420	$14,595
Cooking and Laundry	6	3	2	35	0	0	26	123	$1,206	$2,501
Hot Water Efficiency	8	1	1	8	0	0	0	0	$14	$186
Lighting	14	137	125	2,318	38	18	-40	0	$26,130	$42,897
Other Fuel Switch	5	17	22	515	3	2	-59	0	$1,274	$3,586
Refrigeration	14	12	12	212	1	2	0	0	$2,835	$7,161
Space Heat Efficiency	6	14	13	226	6	0	1,273	0	$818	$37,496
Ventilation	9	18	17	189	2	2	165	0	$7,613	$3,843
Totals		211	200	3,635	51	25	1,366	123	$40,010	$112,266

5.1.7 Electric Market Rate Multifamily Retrofit Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	440	478	nap	646
Costs				
EVT Incentives	$51,650	$25,357	nap	$85,618
Participant Costs	$134,859	$22,992	nap	$170,964
Third Party Costs	$0	$0	nap	$0
Annualized MWh Savings	220	101	nap	375
Lifetime MWh Savings	3,102	1,264	nap	5,016
TRB Savings (2009$)	$911,975	$242,259	nap	$1,228,545
Winter Coincident Peak KW Savings	41	20	nap	75
Summer Coincident Peak KW Savings	16	9	nap	29
Annualized MWh Savings/Participant	0.500	0.211	nap	0.581
Weighted Lifetime	14	13	nap	13
Committed Incentives	$10,000	$0	nap	nap

5.1.8 Electric Market Rate Multifamily Retrofit - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Design Assistance	2	0	0	0	0	0	0	0	$101	$0
Hot Water Efficiency	4	1	1	13	0	0	3	42	$13	$12
Lighting	300	49	47	697	14	4	-5	0	$11,702	$10,854
Motors	1	2	2	41	0	0	0	0	$363	$120
Refrigeration	185	5	5	78	1	1	0	0	$3,829	$0
Ventilation	101	44	43	435	5	5	1,159	0	$9,350	$12,006
Totals		101	98	1,264	20	9	1,158	42	$25,168	$22,992

5.1.9 Electric Low Income Multifamily New Construction and Retrofit Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	2,777	2,171	nap	5,615
Costs				
EVT Incentives	$356,033	$332,467	nap	$931,048
Participant Costs	$877,591	$474,717	nap	$1,952,481
Third Party Costs	$164,827	$10,750	nap	$206,727
Annualized MWh Savings	1,664	1,048	nap	4,130
Lifetime MWh Savings	28,855	17,128	nap	67,277
TRB Savings (2009$)	$3,281,018	$2,157,429	nap	$8,195,675
Winter Coincident Peak KW Savings	386	263	nap	930
Summer Coincident Peak KW Savings	169	100	nap	397
Annualized MWh Savings/Participant	0.599	0.483	nap	0.735
Weighted Lifetime	17	16	nap	16
Committed Incentives	$109,740	$60,015	nap	nap

5.1.10 Electric Low Income Multifamily New Construction & Retrofit - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	28	55	49	1,113	12	12	0	0	$5,774	$10,994
Cooking and Laundry	38	15	13	158	2	2	89	370	$2,243	$12,158
Design Assistance	95	0	0	0	0	0	0	0	$22,511	$0
Hot Water Efficiency	215	76	75	683	9	4	197	1,839	$2,946	$1,066
Hot Water Fuel Switch	25	65	57	1,937	17	9	-216	84	$12,425	$11,717
Lighting	1,586	581	535	8,574	176	51	-51	0	$128,811	$74,030
Motors	69	25	22	419	8	1	0	0	$2,608	$9,592
Other Fuel Switch	21	40	51	1,201	3	2	-72	0	$5,529	$887
Other Indirect Activity	159	1	0	2	0	0	0	0	$276	$0
Refrigeration	838	99	88	1,675	11	12	0	0	$93,567	$18,467
Space Heat Efficiency	140	35	31	854	18	0	3,012	0	$26,286	$300,788
Ventilation	289	57	51	512	6	6	1,399	0	$29,492	$35,017
Totals		1,048	972	17,128	263	100	4,359	2,294	$329,992	$474,717

5.1.11 Electric Low Income Multifamily New Construction Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	336	206	nap	710
Costs				
EVT Incentives	$53,236	$102,707	nap	$262,541
Participant Costs	$84,834	$364,491	nap	$708,681
Third Party Costs	$7,700	$3,750	nap	$40,200
Annualized MWh Savings	255	351	nap	1,116
Lifetime MWh Savings	4,260	6,788	nap	19,583
TRB Savings (2009$)	$526,754	$1,490,499	nap	$3,188,609
Winter Coincident Peak KW Savings	49	88	nap	239
Summer Coincident Peak KW Savings	31	37	nap	116
Annualized MWh Savings/Participant	0.760	1.704	nap	1.572
Weighted Lifetime	17	19	nap	18
Committed Incentives	$37,000	$28,375	nap	nap

5.1.12 Electric Low Income Multifamily New Construction - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	28	55	49	1,113	12	12	0	0	$5,774	$10,994
Cooking and Laundry	2	1	1	9	0	0	70	162	$252	$6,500
Hot Water Efficiency	66	0	0	0	0	0	89	479	$0	$341
Lighting	201	186	184	3,358	56	17	-6	0	$54,049	$37,822
Motors	28	14	13	239	4	1	0	0	$1,047	$2,181
Other Fuel Switch	21	40	51	1,201	3	2	-72	0	$5,529	$887
Refrigeration	182	24	22	412	3	3	0	0	$4,317	$13,195
Space Heat Efficiency	99	17	15	376	9	0	2,821	0	$24,230	$260,954
Ventilation	113	14	12	80	2	2	1,399	0	$7,509	$31,617
Totals		351	345	6,788	88	37	4,301	641	$101,942	$364,491

5.1.13 Electric Low Income Multifamily Retrofit Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	2,462	1,136	nap	4,449
Costs				
EVT Incentives	$302,797	$122,598	nap	$561,164
Participant Costs	$792,757	$103,035	nap	$1,236,608
Third Party Costs	$157,127	$6,400	nap	$165,927
Annualized MWh Savings	1,408	465	nap	2,781
Lifetime MWh Savings	24,595	7,309	nap	44,640
TRB Savings (2009$)	$2,754,263	$468,230	nap	$4,807,008
Winter Coincident Peak KW Savings	337	124	nap	640
Summer Coincident Peak KW Savings	138	41	nap	259
Annualized MWh Savings/Participant	0.572	0.410	nap	0.625
Weighted Lifetime	17	16	nap	16
Committed Incentives	$72,740	$31,640	nap	nap

5.1.14 Electric Low Income Multifamily Retrofit - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Cooking and Laundry	35	14	13	148	2	2	19	201	$1,201	$5,658
Design Assistance	90	0	0	0	0	0	0	0	$22,491	$0
Hot Water Efficiency	38	30	29	267	3	2	58	557	$0	$534
Hot Water Fuel Switch	1	44	39	1,306	14	7	-139	84	$7,388	$10,717
Lighting	930	293	261	4,257	85	24	-44	0	$61,537	$35,177
Motors	41	11	9	181	4	0	0	0	$1,561	$7,412
Refrigeration	163	15	14	262	2	2	0	0	$5,713	$7,592
Space Heat Efficiency	17	19	16	478	10	0	126	0	$2,055	$32,434
Ventilation	162	41	36	409	5	5	0	0	$20,653	$3,511
Totals		465	417	7,309	124	41	20	842	$121,685	$103,035

5.1.15 Electric Business Non-Farm Equipment Replacement Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	1,480	516	nap	2,528
Costs				
EVT Incentives	$4,499,055	$2,460,565	nap	$10,528,949
Participant Costs	$2,120,060	$1,797,080	nap	$5,908,553
Third Party Costs	$0	$0	nap	$0
Annualized MWh Savings	17,116	8,950	nap	41,473
Lifetime MWh Savings	216,826	114,703	nap	529,828
TRB Savings (2009$)	$15,153,815	$10,259,476	nap	$44,444,053
Winter Coincident Peak KW Savings	2,785	1,338	nap	6,255
Summer Coincident Peak KW Savings	3,562	1,274	nap	8,264
Annualized MWh Savings/Participant	11.565	17.344	nap	16.405
Weighted Lifetime	13	13	nap	13
Committed Incentives	$2,042,676	$85,235	nap	nap

5.1.16 Electric Business Non-Farm Equipment Replacement - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	17	177	316	3,251	21	25	-621	0	$18,571	$76,461
Cooking and Laundry	1	0	0	1	0	0	4	51	$102	$1,400
Design Assistance	3	0	0	0	0	0	0	0	$3,664	$133
Industrial Process Eff.	8	762	728	11,003	114	114	0	0	$73,576	$275,437
Lighting	457	5,323	5,031	71,493	931	837	-1,699	0	$2,108,767	$507,444
Motors	19	396	409	4,952	53	37	838	21,751	$49,709	$289,110
Other Efficiency	3	31	28	381	4	5	106	20	-$3,486	$10,097
Other Indirect Activity	5	310	551	1,550	35	35	0	0	$28,339	$152,374
Refrigeration	37	1,204	1,144	13,327	142	117	0	0	$111,773	$164,752
Space Heat Efficiency	2	4	4	73	2	0	2,122	0	$3,361	$35,062
Space Heat Fuel Switch	1	50	52	1,493	0	0	-150	0	$1,329	$7,072
Ventilation	7	694	651	7,180	38	105	8,035	0	$64,860	$277,739
Totals		8,950	8,912	114,703	1,338	1,274	8,635	21,822	$2,438,753	$1,797,080

5.1.17 Electric Business Non-Farm Retrofit Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	1,140	713	nap	1,960
Costs				
EVT Incentives	$4,762,992	$3,337,624	nap	$9,608,145
Participant Costs	$8,609,429	$4,022,419	nap	$18,782,235
Third Party Costs	$224,696	$0	nap	$275,043
Annualized MWh Savings	30,849	16,874	nap	66,504
Lifetime MWh Savings	393,906	216,143	nap	844,490
TRB Savings (2009$)	$30,418,172	$13,783,317	nap	$66,639,052
Winter Coincident Peak KW Savings	4,206	2,277	nap	9,017
Summer Coincident Peak KW Savings	5,152	3,080	nap	11,383
Annualized MWh Savings/Participant	27.061	23.667	nap	33.931
Weighted Lifetime	13	13	nap	13
Committed Incentives	$1,543,746	$347,337	nap	nap

5.1.18 Electric Business Non-Farm Retrofit - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	13	136	135	2,220	7	48	-59	0	$32,516	$31,473
Cooking and Laundry	1	0	0	4	0	0	7	13	$202	$1,800
Design Assistance	35	0	0	0	0	0	0	0	$71,342	$26,470
Hot Water Efficiency	3	29	29	347	1	8	0	0	$1,325	$3,058
Industrial Process Eff.	12	2,081	2,073	22,601	264	207	1,384	0	$120,769	$392,481
Lighting	641	12,230	12,498	162,760	1,740	2,540	-8,219	0	$2,747,720	$2,892,645
Motors	29	1,575	1,567	18,071	175	211	468	0	$208,203	$462,574
Other Efficiency	289	123	112	1,708	14	4	5,185	0	$88,844	-$70,000
Other Fuel Switch	1	3	3	82	0	0	-9	0	$0	$750
Other Indirect Activity	4	148	133	443	11	6	0	0	$28,426	$33,047
Refrigeration	7	212	200	2,619	23	21	0	0	$23,211	$62,501
Space Heat Efficiency	5	12	12	185	4	1	1,040	0	$2,131	$96,930
Space Heat Fuel Switch	2	208	234	3,322	35	2	-764	0	$8,262	$76,130
Ventilation	5	119	117	1,781	3	32	561	0	$4,675	$12,562
Totals		16,874	17,112	216,143	2,277	3,080	-407	13	$3,299,597	$4,022,419

5.1.19 Electric Market Rate Single Family Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	1,036	617	nap	2,834
Costs				
EVT Incentives	$144,354	$143,870	nap	$502,658
Participant Costs	$117,155	$121,776	nap	$1,870,304
Third Party Costs	$23,645	$32,310	nap	$55,955
Annualized MWh Savings	731	598	nap	2,183
Lifetime MWh Savings	14,257	13,402	nap	42,278
TRB Savings (2009$)	$551,801	$438,067	nap	$3,550,562
Winter Coincident Peak KW Savings	154	119	nap	487
Summer Coincident Peak KW Savings	63	60	nap	188
Annualized MWh Savings/Participant	0.705	0.969	nap	0.770
Weighted Lifetime	20	22	nap	19
Committed Incentives	nap	nap	nap	nap

5.1.20 Electric Market Rate Single Family - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	27	2	2	45	0	7	0	0	$3,023	$1,350
Hot Water Efficiency	99	43	43	260	5	5	27	27	$4,086	$2,355
Hot Water Fuel Switch	104	354	393	10,627	52	27	-1,238	0	$56,521	$114,400
Lighting	385	149	147	1,449	50	13	0	0	$69,692	$27
Other Fuel Switch	7	7	7	208	1	1	-21	0	$705	$3,233
Space Heat Efficiency	89	36	33	654	8	7	0	0	$8,836	-$14,090
Space Heat Fuel Switch	2	5	6	159	3	0	-139	0	$1,008	$14,500
Totals		598	631	13,402	119	60	-1,370	27	$142,672	$121,776

5.1.21 Electric Low Income Single Family Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	997	1,236	nap	3,294
Costs				
EVT Incentives	$415,490	$841,598	nap	$1,700,174
Participant Costs	$14,009	$7,236	nap	$25,012
Third Party Costs	($12,095)	($120)	nap	($15,597)
Annualized MWh Savings	936	1,312	nap	3,240
Lifetime MWh Savings	12,898	18,071	nap	43,904
TRB Savings (2009$)	$550,522	$856,406	nap	$2,069,168
Winter Coincident Peak KW Savings	176	213	nap	567
Summer Coincident Peak KW Savings	95	141	nap	333
Annualized MWh Savings/Participant	0.939	1.062	nap	0.984
Weighted Lifetime	14	14	nap	14
Committed Incentives	nap	nap	nap	nap

5.1.22 Electric Low Income Single Family - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Cooking and Laundry	167	125	110	1,743	19	15	0	1,570	$110,590	$0
Hot Water Efficiency	546	237	210	1,731	27	21	0	2,270	$19,588	$0
Hot Water Fuel Switch	6	25	23	761	4	2	-85	0	$18,399	$6,087
Lighting	986	239	212	2,316	79	22	0	0	$75,552	$0
Monitoring and Metering	260	28	25	113	3	4	0	0	$14,727	$0
Other Fuel Switch	8	9	8	265	1	1	-26	0	$6,214	$0
Refrigeration	758	639	568	10,835	74	78	0	0	$589,719	$700
Space Heat Efficiency	9	0	0	0	0	0	0	0	$6,808	-$6,758
Space Heat Fuel Switch	1	10	9	307	5	0	-33	0	$0	$7,206
Totals		1,312	1,165	18,071	213	141	-144	3,840	$835,333	$7,236

5.1.23 Electric Large Industrial Summary

	Prior Year	Current Year 2011	Projected Year 2011	Cumulative starting 1/1/09
# participants with installations	70	61	nap	100
Costs				
EVT Incentives	$1,046,298	$1,388,046	nap	$3,062,666
Participant Costs	$2,825,251	$2,887,334	nap	$8,612,884
Third Party Costs	$0	$0	nap	$14,332
Annualized MWh Savings	11,568	9,966	nap	30,000
Lifetime MWh Savings	141,411	124,170	nap	377,962
TRB Savings (2009$)	$13,501,705	$10,574,746	nap	$36,060,403
Winter Coincident Peak KW Savings	1,485	1,644	nap	4,227
Summer Coincident Peak KW Savings	1,374	1,010	nap	3,677
Annualized MWh Savings/Participant	165.261	163.374	nap	300.002
Weighted Lifetime	12	12	nap	13
Committed Incentives	nap	nap	nap	nap

5.1.24 Electric Large Industrial - End Use Breakdown

End Use	# of Participants	Net MWH Saved	Gross MWH Saved	Net Lifetime MWH Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBTU	Net Water CCF Saved	Participant Incentives Paid	Participant Costs
Air Conditioning Eff.	5	239	379	5,416	27	36	0	40	$17,464	$44,402
Design Assistance	16	41	37	123	6	0	18	0	$56,805	$10,277
Hot Water Efficiency	1	2	2	12	0	0	0	0	$222	$180
Industrial Process Eff.	14	4,176	4,409	57,675	944	234	1,870	0	$418,779	$1,554,781
Lighting	39	2,691	2,492	35,829	357	403	-1,694	0	$424,526	$418,454
Motors	21	1,762	1,741	19,268	192	268	991	21,751	$201,016	$608,730
Other Efficiency	6	115	104	1,474	13	4	5,185	0	$4,556	$11,800
Other Indirect Activity	9	822	1,027	3,044	84	53	-170	0	$250,713	$202,416
Refrigeration	3	83	83	832	10	10	0	0	$8,255	$16,258
Space Heat Efficiency	1	33	33	498	11	0	-74	110	$5,408	$19,401
Ventilation	1	0	0	1	0	0	0	0	$302	$635
Totals		9,966	10,307	124,170	1,644	1,010	6,125	21,900	$1,374,247	$2,887,334

5.1.25 Electric Cumulative Distributions by Customer Sector

	Total Resource Benefits starting 01/01/09		Annualized MWh Energy Savings starting 01/01/09		Year 2009-2011 PSB Approved Budgets
	Total	%	Total	%	%
Business Energy Services	$168,023,250	58%	157,287	52%	61%
Residential Energy Services	$124,035,880	42%	146,066	48%	39%
Total	$292,059,130	100%	303,353	100%	100%

Data in this table includes Customer Credit Program results.

5.2 List of Support Documents by Service

5.2.1 LIST OF SUPPORT DOCUMENTS BY SERVICE

EXISTING HOMES SERVICES

Implementation and Procedure Modifications

Subject	Document Type	Initiator	Addressee	Date of PIP
N/A				

BUSINESS NEW CONSTRUCTION SERVICES

Implementation and Procedure Modifications

Subject	Document Type	Initiator	Addressee	Date of PIP
N/A				

BUSINESS EXISTING FACILITIES

Implementation and Procedure Modifications

Subject	Document Type	Initiator	Addressee	Date of PIP
N/A				

RETAIL EFFICIENT PRODUCTS

Implementation and Procedure Modifications

Subject	Document Type	Initiator	Addressee	Date of PIP
N/A				

EFFICIENCY VERMONT CROSS-SECTOR

Implementation and Procedure Modifications

Subject	Document Type	Initiator	Addressee	Date of PIP
#46 - Average Retail Electricity and Fuel Costs Calculations Annual Revision	Program Implementation Procedure	Bill Fisher	TJ Poor	Original 1/1/2006; Revised 1/1/2011

6.1 Definitions and End Notes

6.1 DEFINITIONS AND END NOTES

6.1.1 DATA TABLES OVERVIEW

1 – Section **6.1.2** presents a list of definitions for items in the data tables. Section **6.1.3** presents notes for specific items in the tables. Section **6.1.4** provides a guide to the re-mapping of multifamily projects and savings into new markets.

2 –Items for which data are not available are labeled "nav." Data items for which data are not applicable are labeled "nap."

3 – Except where noted, data in this report for Efficiency Vermont expenditures were incurred during the period January 1, 2011, through December 31, 2011. Similarly, measure savings are for measures installed during the period January 1, 2011, through December 31, 2011.

4 – Efficiency Vermont costs include an operations fee of 0.75%. The operations fees are reported in all Services and Initiative Costs line items, where applicable, with one exception: The operations fees for Incentives to Participants are reported with the Administration costs.

5 – Data for Incentives to Participants in Tables **2.1.6, 2.1.7, 2.1.12, 2.1.14, 2.1.17, 2.1.20, 2.1.22, 3.1.1, 3.1.4, 3.1.7, 3.1.10, 3.1.13, 3.1.16, 3.1.19, 3.1.22, 3.1.25, 3.1.28,** and **4.1.2** are based on financial data from Vermont Energy Investment Corporation's (VEIC's) accounting system. Participant Incentives Paid on all other tables are based on data entered in Efficiency Vermont's Knowledge-based Information Technology Tool (KITT) tracking system.

6 – The following indicators in Table 2.1.6 and Table 2.1.7 are provided for reference only: Annualized MWh Savings (adjusted for measure life), Winter Coincident Peak kW Savings (adjusted for measure life), and Summer Coincident Peak kW Savings (adjusted for measure life) These data exclude savings for measures that have reached the end of their specified lifetimes.

7 – Program planning costs have been rolled into Services and Initiatives for years 2003–2010. For years 2000–2002, program planning costs were reported as a separate line item. In Tables **2.1.6** and **2.1.7**, program planning costs under "Cumulative Starting 3/1/00 contain data reported prior to 2003.

8 – For years 2003–2005, Multifamily program costs and savings are reported in the Business Energy Services section. For all other contract years, Multifamily costs and savings are reported in the Residential Energy Services section. See Section **6.1.4,** Multifamily Reporting Changes.

6.1.2 DEFINITIONS AND REPORT TEMPLATE

The table templates that appear in the 2011 Efficiency Vermont Savings Claim Summary / Annual Report were developed collaboratively by Efficiency Vermont, the Vermont Department of Public Service, and Burlington Electric Department. Note that there are two major table formats, one for the markets and services summary and the other for breakdowns by end use, county, and utility savings.

The definitions of the data reported in these tables are referred to by numbers in parentheses in the table on the next page. These footnoted definitions are listed by number beginning on the page following the table labeled X.X.X Breakdown Report.

		Prior Year (1)	Current Year 2011 (2)	Projected Year 2011 (3)	Cumulative Starting 1/1/09 (4)	Cumulative Starting 3/1/00 (5)
# participants with installations	(6)					
Services and Initiatives Costs						
Operating Costs						
Administration	(7)					
Services and Initiatives	(8)					
Program Planning	(9)					
Marketing / Business Development	(10)					
Information Systems	(11)					
Subtotal Operating Costs	(12)					
Incentive Costs						
Incentives to Participants	(13)					
Incentives to Trade Allies	(14)					
Subtotal Incentive Costs	(15)					
Technical Assistance Costs						
Services to Participants	(16)					
Services to Trade Allies	(17)					
Subtotal Technical Assistance Costs	(18)					
Total Efficiency Vermont Costs	(19)					
Total Participant Costs	(20)					
Total Third-Party Costs	(21)					
Total Services and Initiatives Costs	(22)					
Annualized MWh Savings	(23)					
Lifetime MWh Savings	(24)					
TRB Savings (2009$)	(25)					
Winter Coincident Peak kW Savings	(26)					
Summer Coincident Peak kW Savings	(27)					
Annualized MWh Savings / Participant	(28)					
Weighted Lifetime (years)	(29)					
Committed Incentives	(30)					
Annualized MWh Savings (adjusted for measure life)	(31)					
Winter Coincident Peak kW Savings (adjusted for measure life)	(32)					
Summer Coincident Peak kW Savings (adjusted for measure life)	(33)					

X.X.X. Breakdown Reports

End Use or Utility or County	# of Participants	Net MWh Saved	Gross MWh Saved	Net Lifetime MWh Saved	Net Winter KW Saved	Net Summer KW Saved	Net Other Fuel MMBtu	Net Water CCF	Participant Incentives Paid	Participant Costs
	(34)	(35)	(36)	(37)	(38)	(39)	(40)	(41)	(42)	(43)

Footnotes for the report table templates:

(1) Activity for the prior reporting year.

(2) Activity for the current reporting year. For savings, the figure reported is estimated savings for measures actually implemented for the current reporting period. Savings are reported in MWh, at generation and net of all approved adjustment factors, except as otherwise noted.

(3) Projected costs for the current reporting period are estimates only and are provided for reference. The Efficiency Vermont contract contains three-year cumulative budgets and savings goals.

(4) Data reported for the contract period starting January 1, 2009 and continuing through December 31, 2011.

(5) Data reported for all contract periods starting March 1, 2000, and continuing through December 31, 2011.

(6) Number of customers with installed measures. The "# participants with installations" is counted by summing unique physical locations (sites) where efficiency measures have been installed for the reporting period. For the Multifamily market, the "# of participants with installations" is counted by summing the number of individual units. Under Cumulative Starting 1/1/09 and Cumulative Starting 3/1/00, customers are counted once, regardless of the number of times the customer participates in Efficiency Vermont services throughout the period 2000–2011. Whenever Efficiency Vermont works in collaboration with other providers of efficiency services, the same participants may be counted and reported by more than one organization. As a result, total statewide participation might be less than the sum of all the organizations' reported participants.

(7) Costs include general management, budgeting, financial management, and Efficiency Vermont contract management. These costs are not broken out by market. This cost category is presented only in Tables **2.1.6** and **2.1.7**. Administration costs prior to 2009 do not include the incentives operations fee. For 2009 and all years thereafter, the operations fee is included.

(8) Management and other management-related costs directly associated with market implementation work.

(9) Costs related to program design, planning, screening, and other similar functions. Program Planning costs refer to data reported prior to 2003.

(10) Costs related to marketing, outreach, customer service, and business development.

(11) Costs related to information systems development and maintenance. These costs are not broken out by market. This cost category is presented only in **Tables 2.1.6** and **2.1.7**.

(12) Subtotal of all operating costs detailed in the cost categories above: (7) + (8) + (9) + (10) + (11).

(13) Direct payments to participants to defray the costs of specific efficiency measures. Prior to 2009, participant incentive costs included the operations fee.

(14) Incentives paid to manufacturers, wholesalers, builders, retailers, and other non-customer stakeholders that do not defray the costs of specific efficiency measures. Prior to 2009, trade ally incentive costs included the operations fee.

(15) Subtotal reflecting incentive cost categories: (13) + (14).

(16) Costs related to conducting analyses, preparing packages of efficiency measures, contract management, and project follow-up.

(17) Costs related to educational or other support services provided to entities other than individual participants: trade allies, manufacturers, wholesalers, builders, architects, etc.

(18) Subtotal reflecting total technical assistance cost categories: (16) + (17).

(19) Total costs incurred by Efficiency Vermont. All costs are in nominal dollars: (12) + (15) + (18).

(20) Total costs incurred by participants and related to Efficiency Vermont or utility activities. This category includes the participant contribution to the capital costs of installed measures and to specific services related to demand side management (DSM). These might include technical assistance or energy ratings.

(21) Total costs incurred by third parties (i.e., entities other than Efficiency Vermont, utilities, and participants) and directly related to Efficiency Vermont or utility DSM activities. This category includes contributions by third parties to the capital costs of installed measures and to specific DSM-related services, such as technical assistance or energy ratings.

(22) Total cost of services and initiatives: (19) + (20) + (21).

(23) Annualized MWh savings at generation, net of all approved adjustment factors (e.g., free ridership, spillover effects, line losses) for measures installed during the current reporting period.

(24) Lifetime estimated MWh savings for measures installed during the current reporting year, at generation and net of all approved adjustment factors. (Typically, this value is calculated by multiplying estimated annualized savings by the lifetime of the measure.)

(25) Total Resource Benefits (TRB) savings for measures installed during the current reporting year. TRB are gross electric benefits, fossil fuel savings, and water savings. TRB are stated in 2009 dollars throughout the report. Whenever Efficiency Vermont works in collaboration with other providers of efficiency services, the same savings might be counted and reported by more than one organization. As a result, the total statewide savings might be less than the sum of all the organizations' reported savings.

(26) Estimated impact of measures at time of winter system peak, at generation, net of adjustment factors.

(27) Estimated impact of measures at time of summer system peak, at generation, net of adjustment factors.

(28) Annualized MWh savings per participant, net at generation: (23) ÷ (6).

(29) Average lifetime, in years, of measures, weighted by savings: (24) ÷ (23).

(30) Incentives that have not yet been paid to a customer but where there is a signed contract as of December 31, 2011, for projects that will be completed after December 31, 2011.

(31) Adjusted annualized MWh savings at generation and net of all approved adjustment factors (e.g., free ridership, spillover effects, line losses) for measures installed during the current reporting period. These data include savings for measures that have not yet expired during the reporting period, and exclude savings for measures that have reached the end of their specified lifetimes.

(32) Adjusted impact of measures at time of winter system peak, at generation, net of adjustment factors. These data include savings for measures that have not yet expired during the reporting period, and exclude savings for measures that have reached the end of their specified lifetimes.

(33) Adjusted impact of measures at time of summer system peak, at generation, net of adjustment factors. These data include savings for measures that have not yet expired during the reporting period, and exclude savings for measures that have reached the end of their specified lifetimes.

Items 34-43 refer to installed measures for the current reporting period, presented in the Breakdown reports by End Use, Utility, and County.

(34) Number of participants with installed measures for the End Use, Utility, or County breakdown. Whenever Efficiency Vermont works in collaboration with other providers of efficiency services, the same participants may be counted and reported by more than one organization. As a result, total statewide participation might be less than the sum of all the organizations' reported participants.

(35) Annualized MWh savings at generation, net of all approved adjustment factors (e.g., free ridership, spillover effects, line losses) for measures installed during the current reporting period. This is the same number as that reported in the line item containing footnote (23).

(36) Annualized MWh savings, gross at the customer meter.

(37) Lifetime estimated MWh savings for measures installed during the current reporting period, at generation and net of all approved adjustment factors. This is the same number as that reported in the line item containing footnote (24).

(38) Estimated impact of measures at time of winter system peak, at generation, net of adjustment factors. This is the same number as that reported in the line item containing footnote (26).

(39) Estimated impact of measures at time of summer system peak, at generation, net of adjustment factors. This is the same number as that reported in the line item containing footnote (27).

(40) MMBtu estimated to be saved (positive) or used (negative) for alternative fuels as a result of measures installed in the end use.

(41) Water saved (positive) or used (negative) as a result of measures installed in the end use.

(42) Incentives paid by Efficiency Vermont to participants for measures installed during the current reporting period. This is the same number as that reported in the line item containing footnote (13).

(43) Costs incurred by participants and related to Efficiency Vermont or utility activities. This is the same number as that reported in the line item containing footnote (20).

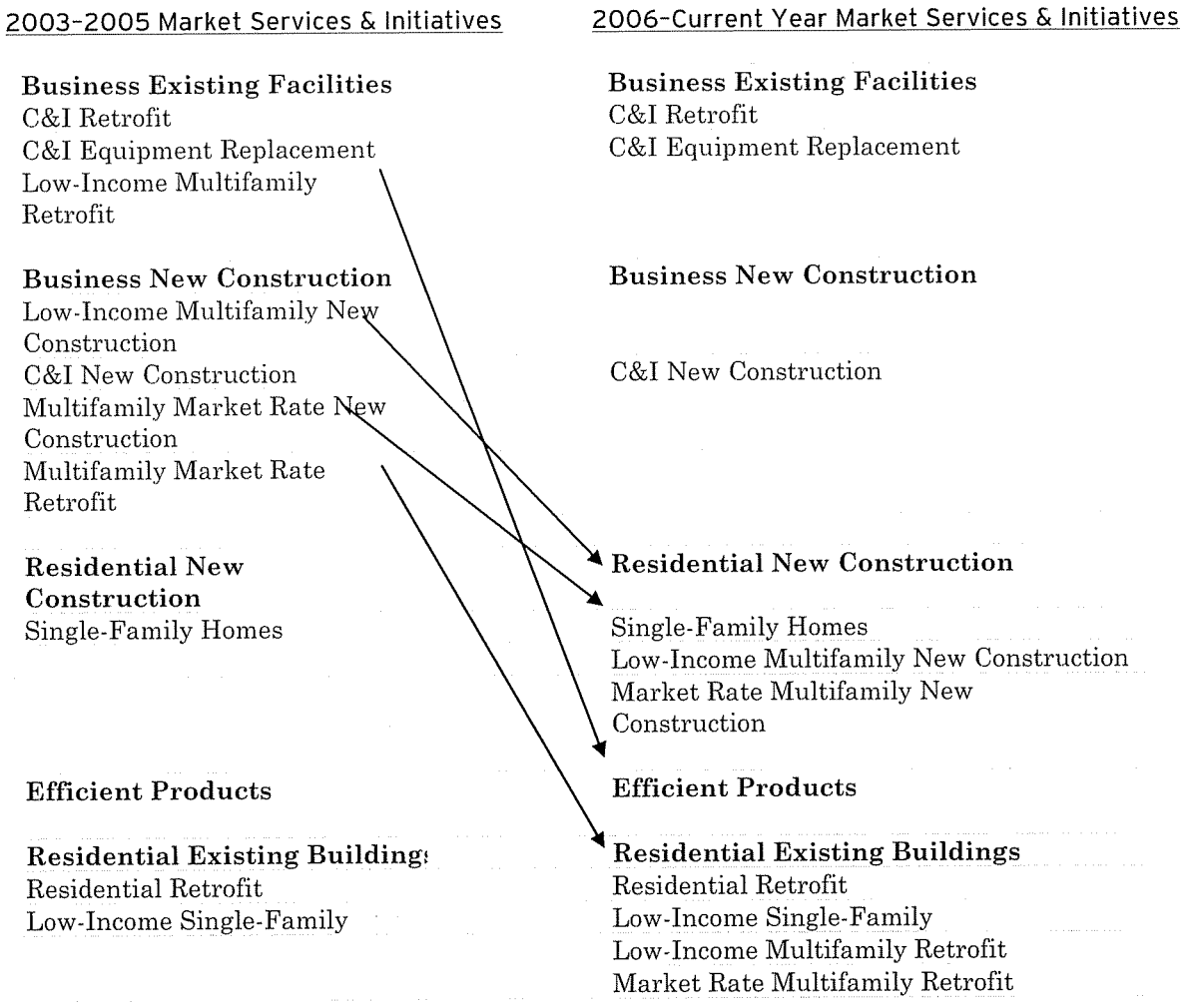
6.1.3 TABLE END NOTE

2.1.11 Electric Services & Initiatives - Total Resource Benefits
Net lifetime water savings is the net annual water savings associated with a measure, multiplied by the measure's lifetime. *Net lifetime fossil fuel savings* is the net annual fossil fuel savings associated with the measure, multiplied by the measure's lifetime.

6.1.4 MULTIFAMILY REPORTING CHANGES

Throughout this report, all multifamily projects are reported in the Business Energy Services section for years 2003–2005, and in the Residential Energy Services section for all other years.

Following is a diagram of the 2003–2005 Market Services and Initiatives and the 2006–Current Year Market Services and Initiatives, showing the re-mapping of Multifamily projects and savings under the subsequently developed markets.



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BURLINGTON ELECTRIC DEPARTMENT

2011 Energy Efficiency Annual Report

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1 Introduction & Summary

The Burlington Electric Department (BED) is pleased to submit the following report to the Burlington Electric Commission, the Vermont Public Service Board and the Vermont Department of Public Service, summarizing the implementation of energy efficiency programs in the City of Burlington for the year 2011. BED remains committed to offering its customers high quality and affordable energy services and a secure, environmentally sound supply of electricity into the future. Energy efficiency continues to play a major role in achieving this goal, and is the cornerstone of the BED resource acquisition strategy that is described in its 2008 Integrated Resource Plan.

Energy efficiency has been clearly shown to be Vermont's least expensive future energy supply resource over time, and is every day a greater environmental imperative. The Burlington Electric Department is owned by all the citizens of Burlington, who have been unequivocally clear that the option for future supply that they prefer above all others is the pursuit of additional cost-effective energy efficiency.

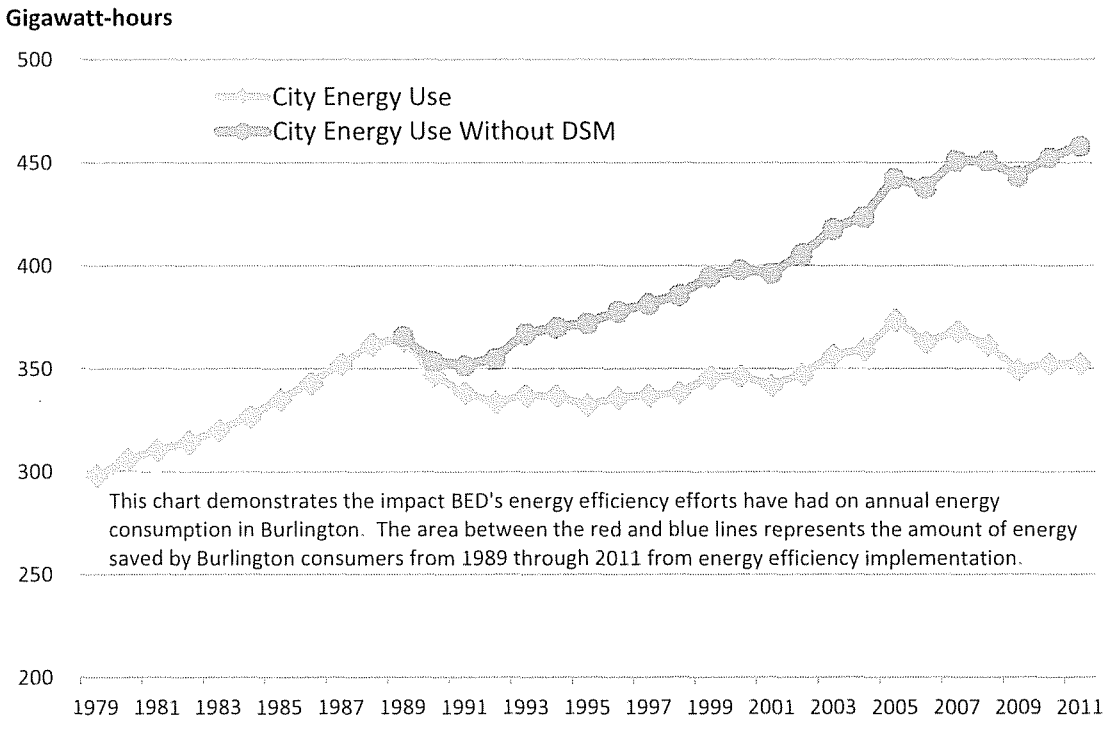
Burlington voters in 1990 approved an 11.3 million dollar bond to fund energy efficiency programs that supported successful program activities through 2002. Since 2003, BED customers (like all other Vermont electric customers) pay a small monthly charge that supports these "Energy Efficiency Utility" programs. When these funding sources are considered along with customers' direct investment, $38.3 million has been invested in energy efficiency efforts sponsored by BED over the last 22 years. This is comprised of about $17.6 million spent by BED on all of its energy efficiency efforts during that period, combined with another $20.7 million in matching expenditures by its customers. The willingness to invest their private funds in these investments is a testament to the value that BED customers place on these services.

As Figure 1 indicates, the overall effect has been dramatic. Annual electricity consumption in 2011 was about 4.7% lower than in 1989. During the same period, statewide use of electricity increased by 8.3%. It is important to recognize that

population growth was similar for Burlington and the state (8% v. 11% respectively), but statewide job growth was greater than Burlington's (17% v. 5%) which can explain some portion of the variance. However, consistent energy efficiency services have helped to meet the needs of a growing local economy over the last 22 years with less electricity than was used then! As a result, energy efficiency investments save Burlington consumers about $10 million of retail electric costs annually.

Energy efficiency expenditures are made almost entirely locally, typically in the form of professional services, skilled trades employment, and equipment purchases. Not only is the value of the City's building and energy-using equipment improved, but locally-retained dollars are "multiplied" many times over by subsequent consumer spending. Absent these energy efficiency expenditures, these funds would have gone towards the purchase of electricity and enhanced infrastructure to satisfy increased demands on the City's electrical system. Most of these dollars would have been exported out of state, and many out of the country. Energy Efficiency is a win-win situation for the city of Burlington through increased local economic activity, and through the avoidance of increasingly costly electricity purchases, their associated infrastructure growth and capital expenses, and their environmental impacts.

Figure 1: Impact of DSM on Total City Energy Use



During 2011 alone, BED saved 8,239 Megawatt hours (MWh) of energy from efficiency measures installed, which will result in 70,900 MWh of savings over the useful life of the installed measures (2011 measures have a weighted average lifetime of 9 years). This is equivalent to providing energy to about 1,560 average Burlington residential customers for 9 years. During 2011, total BED program spending was $2,061,883 and participating customers spent an additional $1,020,850 of their own to fund energy efficiency investments in their homes and facilities.

Harder to quantify, but of increasing importance to the ratepayers of Burlington are the environmental impacts avoided by decreasing the need for electricity. Thanks to the energy savings (8,239 MWh) generated by energy efficiency programs in 2011 alone, Burlington will have avoided the release of about 53,798 tons of carbon dioxide (CO2); the equivalent of removing about 1,560 cars from U.S. highways each year for the next 9 years.

Considering the difficult economic conditions our customers have been experiencing over the past few years, BED is encouraged that it met 101% of savings projections in 2011. BED projected 8,160 MWh savings and achieved 8,240 MWh. BED's projected budget for 2011 was $2,244,113 and $2,061,883 was spent, about 10% less than projected. BED's cost for saved energy was less than projections. BED estimated it would spend $275 per annualized MWh saved, and instead spent $250 per annualized MWh. BED's administrative costs as a percentage of total program costs remained consistent with historical performance; about 16% of the budget was used to defray program operation costs. This amount includes BED's program marketing efforts, most of which are produced in cooperation with Efficiency Vermont.

Annual fluctuations in any energy efficiency program's performance depend on a variety of human and business cycle dimensions that are hard to quantify and even harder to predict with precision. The decision to move forward with an energy efficiency project is ultimately the individual customer's. Customers consider a wide variety of factors in their decision-making process, including their perceptions of local and national economic conditions and trends, their availability of funds and competing interests for the use of those funds, fluctuations in their business functions and volumes, and the opinion of off-site consultants and decision makers. The decision to move forward with an energy efficiency project is ultimately the individual customer's. Given the small size of BED's system, the loss of only a few new construction projects can have a dramatic impact on its annual budgets and savings estimates.

Year-to-year fluctuations in program results reflect the relative unpredictability of energy efficiency program timing, and support the notion that *annual* projections are no more than rough estimates. In the long run, the performance of BED's energy efficiency programs continues to meet the expectations laid out in BED's Integrated Resource Plan of 2008 and prior planning documents dating back more than 20 years.

This report includes coverage of BED's program activities related to the twelfth year of operation of the State's – and the nation's – first Energy Efficiency Utility (EEU). Statewide energy efficiency programs are today operated by the non-profit service

provider "Efficiency Vermont" (EVt). Thanks to a long history of successful program implementation, BED serves as the City's own EEU and delivers the majority of these programs within the City of Burlington, continuing to build on its past success in helping Burlington's consumer-owners achieve energy efficient electric use.

Since the inception of the EEU concept in 2000, BED has shared planning and program design work with (EVt). This relationship has helped to shape a seamless and transparent set of programs to the mutual benefit of both organizations and Vermont ratepayers. BED and EVt annually update a detailed coordination plan that seeks to maximize the benefits of synergism to both organizations. The marketing and outreach power of Efficiency Vermont over the past twelve years has helped to heighten the awareness of energy efficiency and building performance issues among all Vermonters, including Burlingtonians.

BED recognizes that much of its success comes from effective working relationships not only with EVt, but also with its partners Vermont Gas Systems (VGS) and the Champlain Valley Weatherization Service (CVWS). A very cooperative relationship with the VGS has helped to develop a complete suite of thermal energy efficiency measures available to Burlington customers, and VGS's willingness to work with BED to promote electrical energy efficiency programs to its natural gas customers has been a noteworthy strength of its joint energy efficiency program offerings. BED looks forward to continuing this partnership in 2012 and beyond. CVWS continues to successfully and cooperatively provide a comprehensive set of energy efficiency services to their customer base. BED and VGS plan to work closely with CVWS in the coming years to gain more program participation from the private landlord rental market, which comprises a large percentage of low-income housing in the Burlington area.

BED also continues to perform substantial analysis of energy efficiency and demand response impacts on its system as part of the BED Integrated Resource planning and reporting process. BED updates all of its energy efficiency and demand response planning assumptions on a 3-year basis. BED is responsible for reacting with

appropriate program design modifications to the changing market conditions that impact customers' decisions about undertaking energy efficiency upgrades.

The difficult economic conditions that our customers have been facing over the past few years have presented BED with challenges that have required modifications to program incentives in particular. BED (often in collaboration with EVT) began to increase incentives for mostly commercial custom projects in 2010 to encourage higher levels of overall participation and deeper savings per project. Given the uncertainty of a return to more "normal" market conditions, BED estimates that higher incentives will be necessary in 2012, and potentially beyond, in order to approach savings targets.

BED will continue to test all program design assumptions and pursue all strategies to make programs as cost-effective as possible, however, BED estimates that yield rates will be declining in coming years. Baselines are increasing due to more stringent state energy codes and federal standards. This results in declining increments of potential savings to pursue through advanced technology upgrades driven by program activities.

BED is also continuing the focus on summer peak demand reduction using the Public Service Board approved additional incremental increases in Burlington Electric Department (BED)'s service-territory specific EEC funds. The charge to BED in spending these funds is to reduce its growing summer air-conditioning peak load, a phenomenon that has increasingly absorbed the attention of BED's own power planners. In response to the Board's order, BED will continue to focus those increased efforts on measures that address this load growth in the City. In 2011, BED was able to achieve 1,378 KW of summer coincident-peak demand reduction, about 9% higher than the projected target of 1,262 KW. Over the 2009-2011 EEU three-year program cycle, BED was able to achieve 3,203 KW of summer coincident-peak demand reduction, about 4% higher than the projected target of 3,087 KW.

In addition to traditional energy efficiency measures that focus on reducing peak demand, BED initially engaged in 2007 in demand response (DR) efforts supported by the New England Independent System Operator (ISO-NE). ISO-NE offers customers

ongoing financial incentives to reduce peak electric use through load curtailment and the use of on-site generation during its peak load periods. BED continues to work in partnership with a demand services provider, EnerNoc, Inc., to help enroll key customers in the ISO-NE program. To date, this partnership has enrolled 17 BED accounts for about 3.0 MW of potential load reduction capability.

BED is also pleased to see a growing amount of photo-voltaic (PV) systems in Burlington as this technology can also help to alleviate the summer peak issues. Currently, there is about 900 KW of installed PV capacity through net-metering, standard offer or direct purchase power agreements. We currently have five customers taking advantage of BED's solar rider tariff that was approved by the PSB in November 2011.

In 2011, BED continued with efforts, in collaboration with VEIC and other stakeholders, to develop financing tools for customers to encourage both higher levels of participation and more comprehensive savings per project.

Both organizations, along with other stakeholders, will continue to work together on launching Property Assessed Clean Energy **(PACE)** programs in the 2012-2014 that allows residential customers to finance eligible efficiency and renewable energy products on the property tax bill.

In 2009, BED collaborated with VEIC and a coalition of energy efficiency advocates statewide to secure legislation enabling what in Vermont is now called PACE Districts. Through voter establishment of such districts, municipalities are empowered to secure funds which they can then lend property-owners to pay for eligible energy efficiency and renewable improvements. Property owners then repay the municipality through a special assessment on their property tax bill. The assessment can be transferred should the building be sold before the full special assessment is repaid. The assessment period can be up to twenty-years which can help to align the periodic energy savings with the periodic assessment payment amount.

PACE is an exciting development and BED is hopeful that this unique funding mechanism will increase customer participation in all energy efficiency services and encourage property-owners to invest more comprehensively in improving the overall energy performance of buildings. Equally important these efforts will allow investments from the state's energy efficiency funds to blend with and help to leverage much greater levels of investment by property owners in energy efficiency projects, and address the full range of potential energy retrofit measures, well beyond cost-effective electricity savings alone.

BED was originally able to research the program concept and develop the program design with help from an American Public Power Association (APPA) Demonstration of Energy Efficiency Developments (DEED) grant competitively awarded to BED in 2008. BED enlisted VEIC to assist with research and design work and assist with the legislative effort. This collaboration continues today and the results should be beneficial to the entire state as many other Vermont communities are actively exploring implementing PACE programs.

BED is also investigating other financing options for all customers. In 2012, BED will continue to explore an **"on-the-electric bill"** financing service for eligible electric energy efficiency measures. A financing tool like this could be helpful in meeting savings goals by helping customers overcome the "out-of-pocket" expense barrier. The loan would be structured so that the customer sees monthly positive cash-flow; monthly energy savings are greater than the monthly loan payment.

For over a decade, BED offered customers the Smartlight CFL lease program where customers could lease screw-in CFL's from BED with no out-of-pocket expense and the monthly lease fee would appear as a separate line item on the bill. The lease structure created monthly positive cash-flow and the program was very successful especially with commercial customers. BED is exploring the idea of using aspects of the Smartlight concept to offer a financing tool for a variety of electric measures that would have many of the same characteristics as Smartlight.

Advanced metering infrastructure (AMI), smart grid and a new realm of potential customer energy use empowerment tools will be deployed over 20012 and 2013 in most of Vermont. BED is excited to explore the extensive possibilities for enhanced interaction with its customers and the potential benefits and capabilities AMI technology will bring them.

BED has also been working collaboratively with several other Vermont electric utilities and Efficiency Vermont on a statewide customer education campaign and researching customer web presentment software packages. Web presentment software includes engaging looks at energy usage details and energy efficiency related technical advice for customers and clear guidance on how to best take advantage of available energy services and incentives.

Over 2012 BED will also continue working with UVM's Engineering School on a consumer behavior study stemming from advanced meter deployment. The goal of this experiment (known as **Energy Minder**) is to evaluate the utility of an energy efficiency social network in which energy efficiency models are derived from interactions (questions and answers) among participants within a web-based social network.

Social networks are known to be an important driver of behavior change. The advent of internet-tools for social networking has had some impact on behavior, but much of their use is currently limited to leisure activities. Social pressure has been shown to have some impact on energy efficiency, but has not been extensively evaluated as a means of meeting energy efficiency goals. The goal of this task is to develop and test a new social networking tool for sharing energy consumption information among customers and to test the hypothesis that a web-based social network can assist electricity consumers in identifying relationships between energy consumption and information exchanged within the social network.

Long lasting energy efficiency benefits created by the smart-grid investments are largely unknown at this early stage by are clearly worth pursuing. **Energy Minder** is 3-year

collaboration between UVM and BED to integrate the social networking tool with BED's meter data management and web presentment systems.

The remaining pages on this report provide details on BED's delivery of the following EEU services in 2011:

- Business New Construction
- Business Existing Facilities
- Residential New Construction
- Existing Homes
- Efficient Products

Table 1: All Business & Residential DSM History

Participants				Costs					Savings				
	Install	Audits	Audit + Instlall	Admin	Services	Incentive	Evaluation	Participant	Program Total	Mwh	Lifetime Mwh	Winter Kw	Summer Kw
1991	391	95	0	$356,563	$0	$273,437	$6,015	$1,091,190	$1,727,205	3,703	52,103	1,224	0
1992	330	424	0	$334,066	$0	$264,615	$14,711	$1,104,050	$1,717,442	3,595	72,723	1,385	0
1993	1,343	1,130	517	$344,326	$0	$501,991	$107,646	$2,052,045	$3,006,008	9,198	133,079	2,634	0
1994	734	367	333	$367,600	$0	$197,054	$46,172	$927,802	$1,538,628	3,304	32,558	991	0
1995	827	66	193	$255,770	$0	$149,865	$16,666	$1,584,811	$2,007,112	6,764	31,402	1,650	0
1996	774	18	140	$215,329	$0	$118,006	$44,318	$500,363	$878,016	2,285	38,654	0	358
1997	735	35	80	$143,184	$0	$122,189	$6,011	$848,380	$1,119,764	2,665	39,091	0	714
1998	692	7	75	$204,588	$0	$107,140	$353	$731,707	$1,043,788	3,202	43,971	0	822
1999	675	26	68	$214,782	$0	$101,224	$1,529	$331,985	$649,520	1,300	14,174	0	358
2000	1,364	36	29	$334,762	$97,067	$148,162	$0	$761,673	$1,341,664	3,130	37,211	443	387
2001	1,410	240	238	$425,123	$129,955	$208,178	$59,637	$609,115	$1,432,008	3,094	41,258	398	341
2002	1,824	323	312	$469,263	$192,143	$407,057	$2,352	$1,178,695	$2,249,510	4,438	63,159	444	520
2003	1,897	190	187	$305,283	$365,691	$236,762	$19,006	$538,589	$1,465,331	3,346	56,332	346	361
2004	1,484	233	203	$253,037	$302,017	$271,856	$19,067	$638,819	$1,484,796	3,500	46,856	625	557
2005	1,977	237	208	$242,385	$351,009	$260,806	$5,904	$970,437	$1,830,541	4,948	69,570	630	630
2006	2,188	515	377	$221,862	$352,886	$381,706	$42,057	$702,575	$1,701,086	6,254	83,951	813	891
2007	2,045	361	324	$255,856	$375,480	$441,352	$52,025	$1,353,651	$2,478,364	9,679	128,022	1,206	1,158
2008	6,392	317	241	$447,867	$412,037	$578,245	$65,159	$1,187,671	$2,690,979	7,299	72,402	1,178	889
2009	1,181	239	232	$317,257	$371,233	$452,901	$67,667	$1,959,977	$3,169,035	5,481	63,115	715	795
2010	1,638	470	460	$378,153	$339,569	$1,102,597	$54,283	$781,528	$2,656,130	6,462	72,586	1,061	1,078
2011	1,027	283	273	$310,536	$381,043	$1,372,682	$69,742	$1,020,842	$3,154,845	8,239	70,900	1,539	1,377
Total	30,928	5,612	4,490	$6,397,592	$3,670,130	$7,697,825	$700,320	$20,875,905	$39,341,772	101,886	1,263,117	17,282	11,237

(Note: All tables in this report reflect a 10% reduction in 2006 MWh savings claims as a result of the VT-DPS savings verification of 2006 projects)

Table 2: All Business DSM History

	Participants			Costs						Savings			
	Install	Audits	Audit + Instlall	Admin	Services	Incentive	Evaluation	Participant	Program Total	Mwh	Lifetime Mwh	Winter Kw	Summer Kw
1991	3	17	0	$130,784	$0	$1,849	$0	$2,157	$134,790	31	93	30	0
1992	16	117	0	$149,138	$0	$119,535	$4,063	$454,104	$726,840	246	24,388	227	0
1993	164	190	105	$162,366	$0	$305,473	$35,559	$1,308,524	$1,811,922	5,587	72,218	1,421	0
1994	104	85	116	$238,153	$0	$163,733	$21,690	$630,639	$1,054,215	2,242	14,970	626	0
1995	163	30	47	$199,835	$0	$142,342	$9,480	$1,368,954	$1,720,611	6,137	21,386	1,615	0
1996	151	15	36	$151,409	$0	$50,423	$28,498	$355,217	$585,547	1,233	16,150	0	334
1997	160	31	44	$78,321	$0	$96,959	$5,612	$757,774	$938,666	2,300	33,565	0	669
1998	164	3	20	$141,258	$0	$65,048	$50	$615,144	$821,500	2,767	37,930	0	734
1999	162	6	17	$150,772	$0	$71,501	$0	$270,056	$492,329	1,051	10,895	0	338
2000	145	11	8	$176,552	$56,070	$80,108	$0	$613,597	$926,327	2,438	28,712	309	334
2001	127	6	6	$255,082	$99,310	$84,729	$43,248	$384,763	$867,132	2,064	26,581	240	240
2002	113	0	0	$284,826	$112,447	$238,866	$252	$912,280	$1,548,671	2,888	43,183	224	392
2003	144	0	0	$154,937	$243,386	$148,306	$9,503	$254,905	$811,037	2,193	32,975	122	162
2004	142	98	68	$115,796	$192,327	$140,234	$3,928	$507,253	$959,538	2,505	35,419	335	394
2005	133	82	53	$133,542	$208,860	$202,143	$0	$814,001	$1,358,546	3,751	57,787	342	397
2006	150	115	89	$112,917	$240,425	$261,310	$24,533	$575,467	$1,214,652	5,094	73,084	503	652
2007	151	100	90	$125,761	$244,030	$280,213	$33,320	$977,132	$1,660,456	6,530	104,174	482	763
2008	115	97	64	$113,641	$250,666	$304,252	$43,576	$904,640	$1,616,775	3,264	48,407	386	386
2009	105	19	17	$173,789	$224,900	$305,352	$44,608	$1,743,182	$2,491,831	3,781	51,336	336	555
2010	228	36	35	$168,765	$249,094	$849,801	$35,630	$458,549	$1,761,839	4,015	54,285	535	702
2011	220	9	7	$162,357	$277,034	$972,032	$47,704	$335,095	$1,794,222	2,787	37,955	420	519
Total	2,860	1,067	822	$3,380,001	$2,398,549	$4,884,209	$391,254	$14,243,433	$25,297,446	62,904	825,493	8,153	7,571

Table 3: All Residential DSM History

	Participants			Costs						Savings			
	Install	Audits	Audit + Install	Admin	Services	Incentive	Evaluation	Participant	Program Total	Mwh	Lifetime Mwh	Winter Kw	Summer Kw
1991	388	78	0	$225,779	$0	$271,588	$6,015	$1,089,033	$1,592,415	3,672	52,010	1,194	0
1992	314	307	0	$184,928	$0	$145,080	$10,648	$649,946	$990,602	3,349	48,335	1,158	0
1993	1,179	940	412	$181,960	$0	$196,518	$72,087	$743,521	$1,194,086	3,611	60,861	1,213	0
1994	630	282	217	$129,447	$0	$33,321	$24,482	$297,163	$484,413	1,062	17,588	365	0
1995	664	36	146	$55,935	$0	$7,523	$7,186	$215,857	$286,501	627	10,016	35	0
1996	623	3	104	$63,920	$0	$67,583	$15,820	$145,146	$292,469	1,052	22,504	0	24
1997	575	4	36	$64,863	$0	$25,230	$399	$90,606	$181,098	365	5,526	0	45
1998	528	4	55	$63,330	$0	$42,092	$303	$116,563	$222,288	435	6,041	0	88
1999	513	20	51	$64,010	$0	$29,723	$1,529	$61,929	$157,191	249	3,279	0	20
2000	1,219	25	21	$158,210	$40,997	$68,054	$0	$148,076	$415,337	692	8,499	134	53
2001	1,283	234	232	$170,041	$30,645	$123,449	$16,389	$224,352	$564,876	1,030	14,677	158	101
2002	1,711	323	312	$184,437	$79,696	$168,191	$2,100	$266,415	$700,839	1,550	19,976	220	128
2003	1,753	190	187	$150,346	$122,305	$88,456	$9,503	$283,684	$654,294	1,153	23,357	224	199
2004	1,342	135	135	$137,241	$109,690	$131,622	$15,139	$131,566	$525,258	995	11,437	290	163
2005	1,844	155	155	$108,843	$142,149	$58,663	$5,904	$156,436	$471,995	1,197	11,783	288	233
2006	2,038	400	288	$108,945	$112,461	$120,396	$17,524	$127,108	$486,434	1,160	10,867	310	239
2007	1,894	261	234	$130,095	$131,450	$161,139	$18,705	$376,519	$817,908	3,149	23,848	724	395
2008	6,277	220	177	$334,226	$161,371	$273,993	$21,583	$283,031	$1,074,204	4,035	23,995	792	503
2009	1,076	220	215	$143,468	$146,333	$147,549	$23,059	$216,795	$677,204	1,700	11,779	379	240
2010	1,410	434	425	$209,388	$90,475	$252,796	$18,653	$322,979	$894,291	2,447	18,301	526	376
2011	807	274	266	$148,179	$104,009	$400,650	$22,038	$685,747	$1,360,623	5,452	32,945	1,119	858
Total	28,068	4,545	3,668	$3,017,591	$1,271,581	$2,813,616	$309,066	$6,632,472	$14,044,326	38,982	437,624	9,129	3,666

2 Overview of EEU Electric Services Results

Like 2010, 2011 proved to be a challenge for achieving savings goals in all markets but overall we achieved a 101% of the total annual MWh goal. The slow economy impacted some customer decision making as BED experienced reduced activity levels, especially in commercial and residential new construction. BED projected 8,160 annualized MWh savings and achieved 8,239 annualized MWh. BED projected 1,262 coincident-peak summer KW savings and achieved 1,378 KW, 109% of the annual summer goal.

BED spent $2,061,883 in 2011, which is about 10% less than the projected budget of $2,244,113. In total, BED's EEU Services implementation saved 8,239 MWh of energy annually from installed measures that will result in 70,900 MWh savings over the equipment's useful life; 2011 measures have a weighted lifetime of 9 years.

In the first twelve years of the Vermont Energy Efficiency Utility both organizations have exceeded savings estimates in most years and have done so at a lower cost per MWh than anticipated. Energy efficiency is now being delivered at a total utility cost of about $.03 per kilowatt-hour statewide. When compared with other energy sources, energy efficiency remains the state's best bargain for future supply and the expenditures stay largely in the Vermont economy. Avoiding electric generation also avoids the associated air emissions and other environmental impacts that impact Vermont and the region.

BED looks forward to continuing work in 2012 with the DPS on the challenges and rewards that the ISO-NE Forward Capacity Market presents to Vermont. The on-site metering for savings verification has been an invaluable learning lesson for all parties and should lead to a higher level of accuracy with measures savings calculations.

2011 brings to a close the end of the 2009-2011 three-year EEU program cycle. As part of BED's bilateral agreement with the VT-DPS to implement certain EEU programs, BED and the VT-DPS established performance standards for the 2009-2011 program cycle. The following chart describes the standards and BED's results:

Table 4: BED EEU Electric Services Implementation Minimum Performance Indicators by end 2009-2011

					12/31/2011
1	Meet Estimated Annual MWh goals	Three year target is 22,354 MWh's	A predetermined target helps to ensures that all cost effective energy efficiency resources are being aggressively pursued by BED	NA	Total three-year savings of 19,917 MWh, 89% of goal
2	Meet a minimum electric benefits standard	Total electric benefits divided by total costs is greater than 1 2	This requirement is intended to ensure that BED produces at least enough electricity resource savings to cover contributions by BED's consumer-owners Also, to ensure that resources are being obtained cost effectively and at or below market power costs.	NA	Total electric benefit ratio of 4 1 was achieved over the three-year period
3	Threshold (or minimum acceptable) level of participation by low-income households	10% of program spending to be for low-income single and multifamily services	Equity for low-income customers	Assuring that a minimum level of BED's overall efficiency efforts, as reflected in spending, will be dedicated to low-income households	4 3% of all program spending was for low-income single and multifamily services (13 8% of total three-year residential spending was for low-income customers)
4	Threshold (or minimum acceptable) level of participation by small non-residential customers	40% of total non-residential accounts with savings are accounts with annual electric use of 40,000 kWh/yr or less	Equitable share of service to smaller non-residential customers	Offsets potential incentive to concentrate on larger non-residential customers, where BED's cost per kWh is lower	Over the 3 year period, 64% of non-residential accounts with savings are accounts with annual electric use of 40,000 kWh/yr or less
5	Cumulative summer net peak demand savings	3,086 CP-KW cumulative by end of 2011	Designed to encourage BED to achieve high levels of peak summer demand savings in addition to annual energy savings and total resource benefits	Leveraging project implementation to maximize summer peak demand savings	3,221 CP-KW cumulative was achieved, 104% of the three-year goal
6	Cumulative winter net peak demand savings	3,649 CP-KW cumulative by end of 2011	Designed to encourage BED to achieve high levels of peak winter demand savings in addition to annual energy savings and total resource benefits	Leveraging project implementation to maximize winter peak demand savings	3,286 CP-KW cumulative was achieved, 90% of the three-year goal
7	Meet Minimum Cost Benefit on Total Resource Benefit (TRB) savings	TRB total divided by BED total EEU operating costs is equal to or greater than 3 3 over the 3-year period	Designed to encourage BED to maximize energy-related and other resource benefits in implementing energy-efficiency measures and projects during their economic lifetime	Leveraging project implementation to maximize TRB	TRB total divided by BED's total EEU operating costs over the 3-year period was 4 0

Table 5: EEU Business & Residential - Total Resource Benefits

Avoided costs of Electricity	$7,326,403.73
Fossil Fuel Savings	($434,014.29)
Water Savings	$358,906.50
TRB Total	$7,251,295.82

	Annualized	Lifetime
Meter MWh	7,510	66,478
Generation MWh	8,240	70,900
Meter Demand Kw	4,559	40,595
Generation Peak Summer Kw	1,378	12,083
Generation Peak Winter Kw	1,538	13,758
Water Savings	4,203	55,391
Fuel Increase	-5,691	-56,976
O+M Savings	$211,137	$1,826,851

Table 6: EEU Business & Residential - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	1,632	1,027	1,752	1,752	30,912
Audits	474	294			5,677
Audits with Installation	456	273			4,486
— Program Costs —					
BED Administration Costs					
General	$217,088	$249,867			$3,367,559
Implementation	$55,935	$3,853			$1,952,120
Planning	$12,162	$11,166			$105,062
Marketing	$81,887	$39,426			$747,238
IT	$11,140	$6,224			$211,957
	$378,212	**$310,536**			**$6,383,936**
BED Service Costs					
Participants	$339,570	$378,664			$3,653,936
Trade Allies	$0	$0			$11,761
	$339,570	$378,664			**$3,665,095**
BED Incentive Costs					
Participants	$1,002,214	$1,368,497			$4,166,001
Trade Allies	$3,565	$4,185			$10,300
	$1,005,779	**$1,372,682**			**$4,176,301**
BED Total Costs	**$1,723,561**	**$2,061,883**			**$14,225,32**
Evaluation Costs	**$54,283**	**$69,651**			**$700,229**
Participant Costs	**$863,115**	**$1,020,851**			**$24,356,205**
Total Program Costs	**$2,640,960**	**$3,152,384**	**$2,244,113**	**$1,879,931**	**$39,281,766**
— Benefits —					
Annualized mWh	6,290	8,239	8,160	7,259	101,709
Lifetime mWh	70,658	70,900			1,261,023
Winter peak Kw	1,037	1,539			17,254
Summer Peak Kw	1,049	1,377			11,207
mWh / Participant	4	8	5	4	3
Weighted Lifetime	11	9			12

Table 7: EEU Business & Residential - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Air Conditioning	161	98 15	102 43	1,772 95	12 01	23 34	0 00	0 00
Clothes Drying	8	7 82	7 60	106 44	1 58	1 19	-26 64	0 00
Clothes Washing	503	106 78	138 50	1,939 05	19 55	14 73	45 28	3,509 20
Consumer Electronics	1506	196 39	225 01	1,260 72	24 66	19 18	0 00	0 00
Dishwashing	4	0 12	0 14	1 83	0 02	0 01	0 48	4 60
Hot Water	135	305 30	204 30	2,773 06	84 25	52 65	-1,004 08	689 20
Lighting	861	5,680 21	6,497 15	50,686 51	1,281 73	1,173 38	-2,540 03	0 00
Motors	3	13 46	14 97	224 59	2 03	1 18	0 00	0 00
Other Efficiency	1	0 22	0 13	1 26	0 02	0 05	0 00	0 00
Refrigeration	690	714 06	619 60	5,927 36	71 23	74 25	0 00	0 00
Space Heating	22	36 68	34 49	656 17	28 43	1 28	38 85	0 00
Ventilation	35	350 59	395 18	5,549 62	12 50	16 31	0 00	0 00
Total		7,509 80	8,239 50	70,899 57	1,538 01	1,377 56	-3,486 14	4,203 00

2.1 Business Services Overview

Overall, 2011 results in business services did not meet savings projections. BED projected 4,100 megawatt-hour (MWh) savings in 2011 while achieving actual annual energy savings of 2,787 MWh, 32% below projections. BED's cost to deliver EEU business services in 2011 was $1,409,524, below the budgeted amount of $1,511, 854 by 7%. Considering the weak national and statewide economic conditions, the 2009-2011 program period results were relatively positive as BED achieved 92% of the three-year MWh goal and exceeded the summer cpKW goal by 7%.

As reported in 2009 and 2010, the new construction market in Burlington was not as active as we originally estimated in 2008 as several projects were delayed or postponed and we continued to see a steady decline in the number of new permit application through Burlington's Planning and Zoning Department. However, Business Existing Facilities was active in 2010 and 2011 largely due to a joint effort by BED and EVt on special commercial lighting incentives.

It is often difficult to forecast savings and expenses in the C&I sector in Burlington. This is due to the potential for completion of a few large unexpected projects by one or two customers, dramatically exceeding projections and budgets. On the other hand, savings goals may just as unpredictably be missed due to delays or cancellations of planned significant projects.

As we look at the 2012-2014 period, commercial lighting technologies continue to improve. Higher quality LED products are becoming more widely available and cost-effective wireless lighting control systems are also emerging.

This section of the report contains information on BED's Business EEU Services: Business New Construction and Business Existing Facilities (Market Opportunities & Retrofit).

Table 8: EEU Business - Total Resource Benefits

Avoided costs of Electricity	$3,537,641.00
Fossil Fuel Savings	($252,563.02)
Water Savings	$0.00
TRB Total	$3,285,077.85

	Annualized	Lifetime
Meter MWh	2,484	33,926
Generation MWh	2,787	37,955
Meter Demand Kw	715	10,213
Generation Peak Summer Kw	519	7,501
Generation Peak Winter Kw	420	5,872
Water Savings	0	0
Fuel Increase	-2,360	-34,040
O+M Savings	$71,492	$1,002,658

Table 9: EEU Business - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	223	219	122	122	2,851
Audits	33	9			1,048
Audits with Installation	32	7			819
— Program Costs —					
BED Administration Costs					
General	$99,994	$139,689			$1,741,753
Implementation	$24,130	$1,301			$1,220,679
Planning	$7,646	$6,646			$61,169
Marketing	$30,349	$10,457			$233,231
IT	$7,630	$4,263			$145,169
	$169,748	**$162,357**			**$3,402,001**
BED Service Costs					
Participants	$249,095	$275,135			$2,387,213
Trade Allies	$0	$0			$6,780
	$249,095	$275,135			**$2,393,993**
BED Incentive Costs					
Participants	$745,006	$971,732			$2,792,103
Trade Allies	$200	$300			$1,475
	$745,206	**$972,032**			**$2,793,578**
BED Total Costs	**$1,164,048**	**$1,409,524**			**$8,589,572**
Evaluation Costs	**$37,178**	**$47,704**			**$479,585**
Participant Costs	**$547,259**	**$335,095**			**$15,504,681**
Total Program Costs	**$1,748,486**	**$1,792,322**	**$1,511,854**	**$1,351,770**	**$24,573,838**
— Benefits —					
Annualized mWh	3,842	2,787	4,100	4,068	62,731
Lifetime mWh	52,358	37,955			823,557
Winter peak Kw	511	420			8,129
Summer Peak Kw	673	519			7,542
mWh / Participant	17	13	34	33	22
Weighted Lifetime	14	14			13

Table 10: EEU Business - End-Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Air Conditioning	17	50 85	48 69	733 26	0 38	18 20	0 00	0 00
Hot Water	1	52 24	58 77	881 60	8 11	13 86	0 00	0 00
Lighting	458	1,960 25	2,213 30	29,877 73	391 33	464 25	-238 39	0 00
Motors	3	13 46	14 97	224 59	2 03	1 18	0 00	0 00
Other Efficiency	1	0 22	0 13	1 26	0 02	0 05	0 00	0 00
Refrigeration	17	61 66	62 91	753 01	6 06	6 12	0 00	0 00
Ventilation	2	345 02	388 58	5,483 70	11 76	15 57	0 00	0 00
Total		2,483 69	2,787 36	37,955 16	419 70	519 23	-238 39	0 00

2.1.1 Business New Construction

Program Description

This service helps commercial and industrial builders and developers incorporate the most energy efficient products and systems possible when building or renovating. It is designed to help customers exceed the City of Burlington's required Guidelines for Energy Efficient Construction (which adopted the statewide CBES energy code as of January 1, 2007). By working directly and early in the process with designers and owners, BED assists in the choice of energy efficient systems and construction techniques that meet business and energy needs.

The program offers prescriptive and custom tracks for Act 250 and non-Act 250 projects, providing financial incentives for the installation of cost effective efficiency measures. This includes a minimum package of efficiency criteria including lighting, motors and HVAC systems that all customers must include to be eligible to participate. Eligible participants gain technical assistance, verification services and financial incentives to help with efficient equipment costs. BED's Business New Construction service addresses all energy (especially electricity) consuming equipment, components or practices, including motors, lighting, heating, ventilation and air-conditioning (HVAC).

Natural gas is almost universally available in Burlington. To insure comprehensiveness in building and system designs, BED coordinates with Vermont Gas Systems (VGS) on all projects. The two utilities notify each other when projects are identified or when major changes are considered by the developers or the design teams. This partnership is mutually beneficial to both organizations and the ratepayers.

BED maximizes the adoption of energy efficient systems and techniques through proactive outreach and recruitment. As both an electric distribution utility and a municipal department with a role in the City's design review process, BED is in a unique position to identify new construction and major renovation before significant design efforts begin. BED coordinates this effort with other city agencies including the city's

Planning & Zoning Department and its Department of Public Works. See the Design Review Guide (Attachment A) for an example of our coordinated efforts.

BED continues to support enforcement and provide administration of the Guidelines for Energy Efficient Construction for the City of Burlington, VT (adopted CBES), the energy code for all new construction and renovation in the City. The benefits of the Business New Construction program have evolved into a very important facet of the city's economic development efforts. Because BED is involved in the very earliest stages of project development, the benefits of energy efficiency are packaged along with other attractive elements that entice businesses to locate facilities in the city, enhancing employment growth and economic development in Burlington.

Project Highlights and Program Results

The expansion of Dealer.com's headquarters, on Pine Street, was the largest completed project in 2011. BED worked successfully with the project team to install high efficiency HVAC equipment and a very efficient lighting system.

2011 results in this program did not meet BED projections as was anticipated in our 2010 Annual Report and new permitting applications were very slow throughout 2010 and into 2011. The annualized megawatt-hour (MWh) savings for 2011 were 148, about 66% lower than the projection of 1,100 MWh. Total BED program costs were $138,598, 28% of the budgeted amount of $494,503.

Variance Discussion

As stated in other parts of this report, the economic conditions impacted new construction starts again in 2011. We began to see this trend in 2009 as new permit applications through the Burlington Planning and Zoning approval process had declined rapidly. BED's 2009-2011 projections, made in 2008, were partly based on historical projections along with plans for one private apartment building and two dormitory projects at Champlain College and UVM that were postponed.

Customers make business decisions independent of BED's program budgeting efforts, and we fully anticipate that year to year efforts will be "lumpy", and show dramatic swings in performance. Long-term average results are a better indicator of what can be expected on an annual basis than any given year's data.

In 2012, BED does not envision any major program changes but sees the revisions to the Commercial Building Energy Standard (CBES) as a fresh opportunity to educate and inform design professionals and contractors about the code but also about the technical assistance and incentives available through BED and VGS.

Table 11: EEU Business New Construction - Total Resource Benefits

Avoided costs of Electricity	$199,747.91
Fossil Fuel Savings	($15,245.33)
Water Savings	$0.00
TRB Total	$184,502.58

	Annualized	Lifetime
Meter MWh	131	1,968
Generation MWh	148	2,223
Meter Demand Kw	39	578
Generation Peak Summer Kw	28	423
Generation Peak Winter Kw	22	323
Water Savings	0	0
Fuel Increase	-138	-2,066
O+M Savings	$15	$218

Table 12: EEU Business New Construction - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	7	5	7	7	146
Audits					69
Audits with Installation					83
— Program Costs --					
BED Administration Costs					
General	$25,819	$52,145			$275,112
Implementation	$12,449	$1,222			$126,485
Planning	$1,225	$2,097			$15,642
Marketing	$16,903	$3,306			$147,568
IT	$749	$419			$14,255
	$57,145	**$59,189**			**$579,061**
BED Service Costs					
Participants	$48,371	$58,164			$774,006
Trade Allies	$0	$0			$0
	$48,371	**$58,164**			**$774,006**
BED Incentive Costs					
Participants	$68,806	$21,245			$389,956
Trade Allies	$0	$0			$375
	$68,806	**$21,245**			**$390,331**
BED Total Costs	**$174,323**	**$138,598**			**$1,743,398**
Evaluation Costs	**$3,651**	**$4,684**			**$47,093**
Participant Costs	**$209,603**	**$19,395**			**$3,741,895**
Total Program Costs	**$387,576**	**$162,677**	**$494,503**	**$193,977**	**$5,532,386**
— Benefits --					
Annualized mWh	579	148	1,100	439	13,273
Lifetime mWh	8,221	2,223			210,688
Winter peak Kw	53	22			1,037
Summer Peak Kw	76	28			1,588
mWh / Participant	83	30	157	63	91
Weighted Lifetime	14	15			16

Table 13: EEU Business New Construction - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Lighting	6	131 19	148 23	2,223 43	21 50	28 18	0 00	0 00
Total		131 19	148 23	2,223 43	21 50	28 18	0 00	0 00

2.1.2 Business Existing Facilities

(Market Opportunities & Retrofit Services)

Program Description

Business Existing Facilities, Market Opportunity Service (MOP) targets naturally-occurring equipment changeovers to secure energy savings in the equipment replacement market. Targeted equipment includes lighting, heating, ventilation, cooling, water heating, refrigeration, motors and drives, controls and industrial process applications. This program offers prescriptive and custom tracks, with technical assistance and financial incentives that encourage the adoption of cost effective, high efficiency alternatives to standard efficiency equipment.

BED and EVt offer prescriptive incentives (fixed incentives for specific eligible measures) for building lighting, refrigeration economizers and controls, motors, unitary HVAC equipment and dual enthalpy economizers for unitary HVAC units. BED and EVt also participate jointly in the Northeast Energy Efficiency Partnership to further the market transformation of motors, lighting and HVAC equipment. Incentives for above-average energy efficient equipment are supplied to wholesalers, contractors, and customers at the time of equipment replacement.

Non-prescriptive cost-effective measures or combinations of measures are eligible for custom incentives. Custom incentives are designed to capture as many potential lost opportunity resources as possible, while maximizing program delivery resources. BED staff and trade allies serving Burlington (including: equipment vendors, manufacturers, suppliers, contractors, architects and engineers) market the program to potential participants.

As natural gas is the predominant heating fuel in Burlington, BED works closely with Vermont Gas Systems (VGS) to encourage a comprehensive approach to energy savings. BED and VGS staff is committed to bringing appropriate projects to each other's

attention. This partnership is mutually beneficial to both organizations and our mutual ratepayers.

Business Existing Facilities, Retrofit Service offers energy efficiency services that have been provided by BED staff for well almost two decades. Building retrofit entails BED staff and/or trade allies examining customer buildings and systems to identify energy efficiency opportunities for the customer. When promising projects are identified, BED staff prepares analyses for the customer showing the costs and benefits of potential energy efficiency measures. This service is offered to all business customers – from the smallest retail store to the largest commercial and industrial facility. Given BED's long history of delivering this service, the program has reached a high level of maturity and customer acceptance. Facility managers have learned to rely on the program benefits and the technical assistance offered by BED staff.

Business Existing Facilities (MOP & Retrofit) Highlights and Program Results. The annualized megawatt-hour (MWh) savings for 2011 were 2,639, about 12% lower than the projection of 3,000 MWh. Total BED program costs were $1,270,926, 25% over the budgeted amount of $1,017,351.

The Business Existing Facilities 2011 End-Use Activity table shows diversity in the end use savings but lighting and controls was once again the leader. Commercial lighting measures are strongly coincident with summer loads and thus provide significant avoided peak energy costs to BED. BED projected 570 coincident-peak KW savings and achieved 491 KW, 86% of the goal for 2011. For the 2009-2011 program period, the three-year MWh goals were exceed by 12% and the summer cp-KW goal by 34%.

Variance Discussion

Overall, the Business Existing Facilities services performed fairly well in 2009-2011 period considering the weak economy.

Table 14: EEU Business Existing Facilities - Total Resource Benefits

Avoided costs of Electricity	$3,337,893.09
Fossil Fuel Savings	($237,317.69)
Water Savings	$0.00
TRB Total	$3,100,575.28

	Annualized	Lifetime
Meter MWh	2,353	31,958
Generation MWh	2,639	35,732
Meter Demand Kw	677	9,635
Generation Peak Summer Kw	491	7,078
Generation Peak Winter Kw	398	5,549
Water Savings	0	0
Fuel Increase	-2,222	-31,974
O+M Savings	$71,477	$1,002,440

Table 15: EEU Business Existing Facilities - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	216	214	115	115	2,705
Audits	33	9			979
Audits with Installation	32	7			736
— Program Costs —					
BED Administration Costs					
General	$74,175	$87,544			$1,474,504
Implementation	$11,681	$79			$1,094,194
Planning	$6,421	$4,549			$45,526
Marketing	$13,446	$7,152			$85,663
IT	$6,881	$3,844			$130,914
	$112,603	**$103,168**			**$2,722,940**
BED Service Costs					
Participants	$200,723	$216,971			$1,613,207
Trade Allies	$0	$0			$6,780
	$200,723	**$216,971**			**$1,619,987**
BED Incentive Costs					
Participants	$676,200	$950,487			$2,402,147
Trade Allies	$200	$300			$1,100
	$676,400	**$950,787**			**$2,403,247**
BED Total Costs	**$989,726**	**$1,270,926**			**$6,846,173**
Evaluation Costs	**$33,528**	**$43,020**			**$432,492**
Participant Costs	**$337,657**	**$315,700**			**$11,762,786**
Total Program Costs	**$1,360,910**	**$1,629,645**	**$1,017,351**	**$1,157,793**	**$19,041,453**
— Benefits —					
Annualized mWh	3,263	2,639	3,000	3,629	49,458
Lifetime mWh	44,137	35,732			612,869
Winter peak Kw	458	398			7,092
Summer Peak Kw	597	491			5,954
mWh / Participant	15	12	26	32	18
Weighted Lifetime	14	14			12

Table 16: EEU Business Existing Facilities - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Air Conditioning	17	50 85	48 69	733 26	0 38	18 20	0 00	0 00
Hot Water	1	52 24	58 77	881 60	8 11	13 86	0 00	0 00
Lighting	452	1,829 06	2,065 07	27,654 30	369 83	436 07	-238 39	0 00
Motors	3	13 46	14 97	224 59	2 03	1 18	0 00	0 00
Other Efficiency	1	0 22	0 13	1 26	0 02	0 05	0 00	0 00
Refrigeration	17	61 66	62 91	753 01	6 06	6 12	0 00	0 00
Ventilation	2	345 02	388 58	5,483 70	11 76	15 57	0 00	0 00
Total		2,352 51	2,639 14	35.731 73	398 20	491 05	-238 39	0 00

2.2 Residential Service Overview

2009-2011 economic conditions proved to be challenging in meeting annual savings projections in residential services but a combination of increased marketing efforts, along with an improving economy over 2011, allowed us to exceed saving projections for the year. BED projected 3,720 annualized MWh savings in 2011 while achieving annual energy savings of 5,452 MWh or 46% above the projected goal. Residential Existing Homes exceeded the MWh goals by 27%, Retail Efficient Products exceeded the MWh goals by 37%, however, Residential New Construction met only 20% of the MWH goal. BED's cost to deliver residential services in 2011 was $652,840 which was 11% under budget for the year's projected spending of $732,259.

This section of the report contains information on BED's Residential EEU Electric Services: Residential New Construction, Existing Homes and Efficient Products services.

Table 17: EEU Residential - Total Resource Benefits

Avoided costs of Electricity	$3,788,762.73
Fossil Fuel Savings	($181,451.27)
Water Savings	$358,906.50
TRB Total	$3,966,217.97

	Annualized	Lifetime
Meter MWh	5,026	32,552
Generation MWh	5,452	32,944
Meter Demand Kw	3,844	30,383
Generation Peak Summer Kw	858	4,582
Generation Peak Winter Kw	1,118	7,887
Water Savings	4,203	55,391
Fuel Increase	-3,331	-22,937
O+M Savings	$139,646	$824,193

Table 18: EEU Residential - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	1,409	808	1,630	1,630	28,061
Audits	441	285			4,629
Audits with Installation	424	266			3,667
— Program Costs --					
BED Administration Costs					
General	$117,094	$110,178			$1,625,806
Implementation	$31,806	$2,551			$731,441
Planning	$4,516	$4,521			$43,893
Marketing	$51,539	$28,969			$514,007
IT	$3,510	$1,961			$66,788
	$208,464	**$148,180**			**$2,981,935**
BED Service Costs					
Participants	$90,476	$104,010			$1,266,121
Trade Allies	$0	$0			$4,981
	$90,476	**$104,010**			**$1,271,102**
BED Incentive Costs					
Participants	$257,208	$396,765			$1,373,898
Trade Allies	$3,365	$3,885			$8,825
	$260,573	**$400,650**			**$1,382,723**
BED Total Costs	**$559,513**	**$652,840**			**$5,635,760**
Evaluation Costs	**$17,105**	**$21,947**			**$220,644**
Participant Costs	**$315,856**	**$685,756**			**$8,851,524**
Total Program Costs	**$892,474**	**$1,360,543**	**$732,259**	**$528,161**	**$14,707,928**
— Benefits --					
Annualized mWh	2,448	5,452	4,060	3,191	38,978
Lifetime mWh	18,300	32,945			437,466
Winter peak Kw	526	1,119			9,125
Summer Peak Kw	376	858			3,665
mWh / Participant	2	7	2	2	1
Weighted Lifetime	7	6			11

Table 19: EEU Residential - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Air Conditioning	144	47 30	53 73	1.039 69	11 63	5 14	0 00	0 00
Clothes Drying	8	7 82	7 60	106 44	1 58	1 19	-26 64	0 00
Clothes Washing	503	106 78	138 50	1.939 05	19 55	14 73	45 28	3.509 20
Consumer Electronics	1506	196 39	225 01	1.260 72	24 66	19 18	0 00	0 00
Dishwashing	4	0 12	0 14	1 83	0 02	0 01	0 48	4 60
Hot Water	134	253 06	145 53	1.891 46	76 14	38 80	-1,004 08	689 20
Lighting	403	3.719 96	4,283 85	20,808 78	890 40	709 14	-2,301 64	0 00
Refrigeration	673	652 40	556 69	5,174 36	65 17	68 13	0 00	0 00
Space Heating	22	36 68	34 49	656 17	28 43	1 28	38 85	0 00
Ventilation	33	5 58	6 59	65 91	0 74	0 74	0 00	0 00
Total		5,026 11	5,452 14	32,944 41	1,118 31	858 33	-3,247 75	4,203 00

2.2.1 Residential New Construction

Program Description

This service aims to improve the efficiency of all new homes, and buildings undergoing substantial renovation. This includes single-family homes, multi-family homes and low-income multi-family projects. It addresses all major end uses: space heating, water heating, central cooling (if applicable), ventilation, major appliances and lighting for high use areas. Residential New Construction (RNC) encourages builders and consumers to build to the Vermont Energy Star Home standard. This standard specifies that homes meet the Energy Star performance standard (representing over 20% savings in heating, cooling and hot water consumption relative to the Vermont Residential Building Energy Standard (RBES).

The Vermont Energy Star Homes (VESH) standard is promoted to developers, architects, builders, building supply centers, equipment suppliers and consumers through a combination of marketing, technical assistance to builders, provision of energy ratings, and a package of incentives for efficient lighting fixtures, major appliances and ventilation equipment.

EVt and Vermont Gas Systems have done a great job over the years promoting VESH which has had direct benefits to BED. As most of the trade allies mentioned above build inside and outside of Burlington it has been helpful to have a joint program with identical participation requirements.

BED uses several additional methods to encourage participation in this sometimes difficult to influence market. These include:

BED staff attends local monthly Technical Review meetings where all new construction and virtually all substantial renovation projects are introduced to the Burlington Planning and Zoning Department staff as part of the City's local project approval process. At these meetings BED explains the RNC program to the permit applicant and gives them program literature. BED then forwards the project information to **Vermont**

Wise Energy Services to follow-up with the customer. For larger multi-family projects BED staff (in partnership with Vermont Gas Systems) work directly with the property owner.

- BED receives monthly "Development Case Load" updates from the Department of Planning and Zoning that track the progress of each of the development projects in Burlington.

- New and revised electric service and line extension applications help us track smaller renovation projects that may have bypassed the City's permit approval process. All "ability to serve" letters from BED include information about energy efficiency services.

- BED receives a weekly electronic report from the Department of Public Works-Building Inspection Division (DPW) listing all trades permits issued.

- The Burlington DPW refers projects to BED to help them ensure compliance with RBES (and CBES) and to assess opportunities for exceeding requirements. DPW requires a compliance memo from BED Energy Services before issuing the building permit.

Program Highlights

In 2011, a majority of RNC savings came from major gut rehabilitation projects. There were five projects in 2011 consisting of 3 single-family gut-rehabs and 2 single-family new construction projects. In many years, Burlington sees more gut-rehab type of building activity than brand new construction projects. BED, EVT and VGS have collaborated over the years to address this market more successfully.

Variance Discussion

The RNC service achieved 15 MWh in annualized electricity savings for the year, about 20% of the projected 80 MWh goal. At $37,318, spending was 30% of projected spending of $124,365.

As we reported in the 2010 Annual Report, 2011 was not looking promising for RNC in terms of new permit applications as the poor economic conditions continued.

BED's original 2009-2011 RNC savings projections, developed in 2008, were based on historical trends and information we receive from Burlington's Planning and Zoning Review process. Unfortunately, some of the proposed projects did not start during the 2009-2011 period and new construction starts were well below historical trends. As of April 2012, residential single-family building activity remains slow but multi-family activity is increasing and we have over a 100 units o f housing enrolled at this time.

Program Changes

In 2012, BED, EVT and VGS will continue to assist the residential market with exceeding RBES and will also promote low-load and net-zero building practices. RNC now offers three paths for projects to participate in that recognize different levels of builders in terms of their experience with energy efficiency practices:

Base Tier - Energy Code Plus - RBES was updated in 2011 to bring the state into compliance with the 2009 International Energy Conservation Code. The Energy Code Plus service provides builders with free technical assistance to meet or exceed all code requirements, as well as a Home Energy Rating Certificate, Residential Building Energy Standards Certificate, and the opportunity for financial incentives.

Middle Tier - ENERGY STAR Homes - A new federal ENERGY STAR Homes specification - ENERGY STAR Version 3 - was launched in 2011-2012. This specification expands on the previous Version 2 requirements to provide increased energy efficiency, durability, and comfort to homeowners. The new specification includes detailed criteria

addressing high-quality insulation and air sealing details, efficient lights and appliances, HVAC design and installation, and building durability. Efficiency Vermont helps Vermont builders earn the ENERGY STAR Homes label by offering free technical assistance and home energy ratings. Builders participating in the ENERGY STAR tier also have additional opportunities for incentives based on the Home Energy Rating Score, and receive a Home Energy Rating Certificate, Residential Building Energy Standards Certificate, and ENERGY STAR Home label when qualifications are met.

Highest Tier – Net-Zero-Ready - The highest tier service is under development and will launch in 2013 to support builders in reaching a Passive House or net-zero-ready level of performance.

Table 20: EEU Residential New Construction - Total Resource Benefits

Avoided costs of Electricity	$16,084.78
Fossil Fuel Savings	($7,809.87)
Water Savings	$1,499.84
TRB Total	$9,774.75

	Annualized	Lifetime
Meter MWh	14	165
Generation MWh	15	177
Meter Demand Kw	19	245
Generation Peak Summer Kw	1	17
Generation Peak Winter Kw	4	42
Water Savings	17	233
Fuel Increase	-126	-704
O+M Savings	($11)	($252)

Table 21: EEU Residential New Construction - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	13	13	35	35	367
Audits	13	18			206
Audits with Installation	11	10			113
— Program Costs —					
BED Administration Costs					
General	$11,550	$8,617			$179,488
Implementation	$9,643	$0			$96,638
Planning	$456	$262			$11,063
Marketing	$4,510	$1,678			$76,883
IT	$200	$112			$3,810
	$26,359	**$10,669**			**$367,882**
BED Service Costs					
Participants	$15,916	$10,498			$407,692
Trade Allies	$0	$0			$2,700
	$15,916	**$10,498**			**$410,392**
BED Incentive Costs					
Participants	$4,983	$16,100			$90,226
Trade Allies	$0	$50			$50
	$4,983	**$16,150**			**$90,276**
BED Total Costs	**$47,259**	**$37,318**			**$868,550**
Evaluation Costs	**$976**	**$1,252**			**$12,585**
Participant Costs	**$3,434**	**$8,098**			**$410,042**
Total Program Costs	**$51,668**	**$46,668**	**$124,365**	**$59,481**	**$1,291,177**
— Benefits —					
Annualized mWh	24	15	80	33	954
Lifetime mWh	416	177			15,582
Winter peak Kw	6	4			258
Summer Peak Kw	2	1			193
mWh / Participant	2	1	2	1	3
Weighted Lifetime	17	12			16

Table 22: EEU Residential New Construction - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Clothes Drying	2	1 95	1 54	21 60	0 30	0 23	-6 66	0 00
Clothes Washing	2	0 38	0 49	6 86	0 07	0 05	0 16	12 40
Dishwashing	4	0 12	0 14	1 83	0 02	0 01	0 48	4 60
Lighting	14	10 39	11 69	119 15	2 75	0 76	-159 00	0 00
Refrigeration	4	0 47	0 53	8 95	0 06	0 06	0 00	0 00
Space Heating	3	0 79	0 88	18 35	0 31	0 22	38 85	0 00
Total		14 10	15 27	176 73	3 51	1 34	-126 17	17 00

2.2.2 Existing Homes

Program Description

This service aims to improve the efficiency of all existing residential buildings including low-income single family, market-rate single-family and all multi-family projects (market-rate and low-income). BED offers the same existing homes service as Efficiency Vermont (EVt) and also works closely with Vermont Gas Systems (VGS) and the Champlain Valley Weatherization Service (CVWS) on many of its projects.

Low-income buildings are addressed by a partnership with the state's Low-income Weatherization Assistance Program (WAP). This partnership provides electric efficiency measures (including fuel switching of electric hot water and electric space heating) to Burlington's low-income electricity consumers. Electrical efficiency measures are delivered to income-eligible electric customers at the time they receive thermal shell, space heating and water heating improvements from CVWS.

This service also works closely with high usage households for energy efficiency improvements that can significantly reduce their energy bills. On-site energy audits, customer education, appliance meter loans, technical assistance, project management and cash incentives are all part of this service. In some cases, the high usage is driven by electric domestic hot water and\or electric resistance space heating. The opportunity to convert to natural gas is available to the owners of some of these housing units, providing significant energy and cost savings.

Over the past several years, BED and EVt have been trying to work more successfully in the private (market-rate) rental housing market (customers not eligible for low-income energy services) to increase both participation and the depth of savings per participant. Traditionally, renters have not been strong participants and the same holds true for property-owners where the tenants pay the energy bills directly.

The "Rental Properties Owners" service offers free tank wraps (electric tanks only), pipe insulation, water saving devices, enhanced rebates for the early retirement of eligible

refrigerators, incentives for improving mechanical ventilation along with up to fifteen free screw-in CFL's per apartment.

This service provides savings directly to the tenant but also water savings, and potentially maintenance savings via ventilation fans to the property owner. This service allows us the opportunity to develop long-lasting relationships with property-owners to help identify further savings from refrigeration replacements, common area lighting and laundry equipment improvements, weatherization and ventilation.

BED continues to offer a robust energy education service for customers that includes on-site energy audits, lending of appliance meters and custom billing history analysis. BED also continues to provide energy efficiency information in a variety of forums. BED staff also visited several classrooms in the Burlington School District to discuss energy efficiency with faculty and schoolchildren.

Also, starting in 2009 and continuing today, BED contracted with VGS to install CFL's and collect potential electrical energy efficiency savings information while perform normal VGS energy audits.

Heating and Process Fuels Activity

BED continues to work with EVt on the Home Performance with ENERGY STAR (HPES) service. BED offers the same contractor and customer incentives that are available through EVt. There were seven residential unregulated fossil fuel HPES completions in 2011 with total savings of 188 MMBTU's. BED worked with one oil heated commercial customer that decided to convert to natural gas and use Vermont Gas's energy efficiency services. BED will begin to include all residential and commercial heating and process fuel activity in the 2012 regular monthly reports as we now have approved budgets, savings goals and minimum performance indicators for the 2012-2014 program cycle.

Program Highlights

In 2011 alone, 86 fuel switch projects were completed. 76 electric hot water tanks were switched to natural gas, 4 dwellings replaced electric heat with natural gas space heating equipment and 6 electric clothes dryers were switched to natural gas units. 15 customers and their contractors took advantage of rebates for ENERGY STAR furnace fans and 4 more customers took advantage of incentives for ENERGY STAR central AC systems. 56 refrigerators were retired early and replaced with ENERGY STAR models and571 CFL's were provided (515 through the landlord program 46 through CVWS).

BED and EVt offer incentives to the contractor and the building owner to install this equipment. Vermont Gas Systems offers additional incentives to install high efficiency space and water heating equipment along with thermal shell upgrades.

Variance Discussion

The Existing Homes service achieved 331 MWh in annualized electricity savings for the year, about 27% higher than the projected 260 MWh. At $270,374 spending was 5% higher than BED's projected spending of $256,452.

The market- rate rental property owner program has been beneficial as we have been able to access a greater number of rental units. We plan to continue with the campaign as about 60% of BED's residential customers live in rental housing and about 85% pay their electric and heating costs directly. About 85% to 90% of BED's residential rental customers use natural gas for space heating and domestic hot water.

It is worth noting that electric resistance space and water heating is a disappearing market along with the savings from screw-in CFL's. In 2011, these measures accounted for about 80% of the total savings. BED will continue to work with EVT and VGS on developing services that leverage as much cost-effective total resource benefit as possible in an increasingly challenging market.

BED will also continue working with UVM's office of off-campus services. BED and VGS conducted energy workshops for students, staff and faculty living off-campus in 2011 and they will be offered again in 2012.

VGS energy specialists will continue to install CFL's and collect potential electrical energy efficiency savings information for BED while performing VGS energy audits.

Table 23: EEU Residential Existing Homes - Total Resource Benefits

Avoided costs of Electricity	$790,655.43
Fossil Fuel Savings	($117,088.66)
Water Savings	$46,420.85
TRB Total	$719,987.63

	Annualized	Lifetime
Meter MWh	426	5,899
Generation MWh	331	4,635
Meter Demand Kw	522	7,303
Generation Peak Summer Kw	55	756
Generation Peak Winter Kw	134	1,935
Water Savings	708	6,463
Fuel Increase	-1,108	-15,576
O+M Savings	$4,379	$25,208

Table 24: EEU Residential Existing Homes - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
-- Participants —					
Installations	418	279	95	95	14,411
Audits	426	267			4,406
Audits with Installation	411	256			3,537
— Program Costs --					
BED Administration Costs					
General	$61,669	$59,818			$1,122,470
Implementation	$10,468	$2,551			$544,547
Planning	$3,130	$3,402			$18,370
Marketing	$4,467	$10,925			$305,425
IT	$1,460	$816			$27,776
	$81,192	**$77,512**			**$2,018,588**
BED Service Costs					
Participants	$74,559	$93,458			$537,447
Trade Allies	$0	$0			$0
	$74,559	**$93,458**			**$537,447**
BED Incentive Costs					
Participants	$123,552	$95,568			$603,540
Trade Allies	$3,365	$3,835			$8,675
	$126,917	**$99,403**			**$612,215**
BED Total Costs	**$282,669**	**$270,374**			**$3,168,250**
Evaluation Costs	**$7,114**	**$9,128**			**$91,762**
Participant Costs	**$68,663**	**$77,450**			**$5,646,228**
Total Program Costs	**$358,445**	**$356,951**	**$256,452**	**$260,325**	**$8,906,240**
— Benefits --					
Annualized mWh	440	331	260	409	20,056
Lifetime mWh	6,137	4,635			310,531
Winter peak Kw	158	134			5,507
Summer Peak Kw	59	55			852
mWh / Participant	1	1	3	4	1
Weighted Lifetime	14	14			15

Table 25: EEU Residential Existing Homes - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Air Conditioning	4	0 30	0.30	5 40	0 00	0 90	0 00	0 00
Clothes Drying	6	5 86	6 06	84 85	1 28	0 96	-19 98	0 00
Clothes Washing	3	0 38	0 49	6 86	0 07	0 05	0 24	18 60
Hot Water	134	253 06	145 53	1,891 46	76 14	38 80	-1,004 08	689 20
Lighting	99	76 74	84 01	1,023 66	20 82	5 76	0 00	0 00
Refrigeration	59	48 05	54 07	919 19	6 63	6 93	0 00	0 00
Space Heating	19	35 90	33 61	637 82	28 12	1 06	0 00	0 00
Ventilation	33	5 58	6 59	65 91	0 74	0 74	0 00	0 00
Total		425 86	330 66	4,635 16	133 78	55 19	-1,023 82	707 80

2.2.3 Retail Products

Program Description

The Efficient Products Program (EP) aims to increase sales of DOE\EPA ENERGY STAR® qualified lighting products, Compact Fluorescent (CFL) screw-in bulbs, CFL hardwired fixtures, and ENERGY STAR® appliances such as clothes washers, refrigerators, freezers, and ceiling fans with lights, room air conditioners, dehumidifiers and televisions. Over recent years, EP also promotes advanced power strips for home entertainment centers, controls for computer internal power supplies and ultra efficient LCD computer monitors. This is accomplished primarily through retail stores with on-site and mail-in consumer rebates, but also by arranging retailer buy-downs and manufacturer mark-downs for products.

The program pursues this objective with extensive outreach to retailers, such as efforts to encourage Vermont lighting showrooms to increase the number and variety of energy efficient fixtures stocked and displayed.

EP uses a variety of marketing and promotion efforts in addition to its prominently displayed in-store rebate coupons including a catalog, and an on-line purchase web site in order to build consumer awareness and participation in the program.

Program Highlights

In 2011 alone, BED customers purchased 74,219 CFL bulbs, 512 CFL or LED lighting fixtures, 561 ENERGY STAR® clothes washers, 166 ENERGY STAR® refrigerators, 454 second refrigerators/freezers were retired, 52 ENERGY STAR® dehumidifiers, 178 internal power supply units, 278 ultra efficient LCD computers monitors and 1,049 efficient televisions.

Variance Discussion

As the economy appeared to improve slightly over 2011, and with an increased marketing effort for specialty CFL's over the year, the program exceeded savings

projections in 2011. Savings of 5,106 annualized MWh exceeded the projection of 3,720 annualized MWh for 2011 by 37%. Annual expenditures were $345,148 which is about 2% lower than of the projected budget of $351,442. BED believes that the large disparity in savings and costs from year to year can be attributed to the turbulent economic conditions over the 2009-2011 period. BED and EVT discussed the statewide slowdown starting in 2009, and BED greatly appreciates EVT's strong efforts with a more robust marketing effort over the period. BED also continued to increased customer educational efforts with bill messages, articles in local papers and in our quarterly new letters.

Program Changes

The VT-DPS, EVT and BED continue to discuss the impact on savings claims for standard CFL's with the approaching 2012 Federal standard which will begin to phase out many inefficient light sources. Market research continues to show rapid market transformation with standard CFL's so the DPS, EVT and BED agreed to start reducing savings claims for standard CFL's. BED and EVT will continue to jointly focus on promoting specialty bulbs not impacted by the 2012 Federal standard and also keep a close watch on emerging LED technologies and other non-lighting products and opportunities.

2012 will see a focus on promoting appliances that are the most efficient within the ENERGY STAR rating. These products include: refrigerators, clothes washers, dehumidifiers, and two-speed and variable-speed pool pumps. New for 2012 will be a statewide pilot promotion of heat pump water heaters beginning in 2012 and super-efficient clothes dryers in 2013-2014.

Table 26: EEU Efficient Products - Total Resource Benefits

Avoided costs of Electricity	$2,982,022.52
Fossil Fuel Savings	($56,552.74)
Water Savings	$310,985.81
TRB Total	$3,236,455.59

	Annualized	Lifetime
Meter MWh	4,586	26,489
Generation MWh	5,106	28,133
Meter Demand Kw	3,302	22,835
Generation Peak Summer Kw	802	3,809
Generation Peak Winter Kw	981	5,910
Water Savings	3,478	48,695
Fuel Increase	-2,098	-6,657
O+M Savings	$135,278	$799,238

Table 27: EEU Efficient Products - Summary

	Prior Year 2010	Current 2011	(Projected) 2011	(Projected) 2012	Program to date
— Participants —					
Installations	n/a	n/a	n/a	n/a	n/a
Audits	2				17
Audits with Installation	2				17
— Program Costs —					
BED Administration Costs					
General	$43,875	$41,742			$323,848
Implementation	$11,695	$0			$90,256
Planning	$930	$857			$14,460
Marketing	$42,562	$16,365			$131,699
IT	$1,850	$1,034			$35,202
	$100,913	**$59,998**			**$595,465**
BED Service Costs					
Participants	$0	$53			$320,982
Trade Allies	$0	$0			$2,281
	$0	**$53**			**$323,263**
BED Incentive Costs					
Participants	$128,673	$285,097			$680,132
Trade Allies	$0	$0			$100
	$128,673	**$285,097**			**$680,232**
BED Total Costs	**$229,586**	**$345,148**			**$1,598,960**
Evaluation Costs	**$9,015**	**$11,568**			**$116,296**
Participant Costs	**$243,760**	**$600,208**			**$2,795,254**
Total Program Costs	**$482,361**	**$956,925**	**$351,442**	**$208,355**	**$4,510,511**
— Benefits —					
Annualized mWh	1,984	5,106	3,720	2,749	17,968
Lifetime mWh	11,747	28,133			111,353
Winter peak Kw	362	981			3,360
Summer Peak Kw	315	802			2,620
Weighted Lifetime	6	6			6

Table 28: EEU Efficient Products - End Use Summary

Description	Participants	Gross Mwh	Net Mwh	Lifetime Net	Winter Net Kw	Summer Net Kw	MMBTU	CCF
Air Conditioning	140	47 01	53 43	1,034 29	11 63	4 24	0 00	0 00
Clothes Washing	498	106 03	137 52	1,925 32	19 41	14 63	44 88	3,478 20
Consumer Electronics	1506	196 39	225 01	1,260 72	24 66	19 18	0 00	0 00
Lighting	290	3,632 83	4,188 16	19,665 98	866 83	702 62	-2,142 64	0 00
Refrigeration	610	603 89	502 09	4,246 21	58 48	61 14	0 00	0 00
Total		4,586 15	5,106 21	28,132 52	981 01	801 80	-2,097 76	3,478 20

3 Appendix

3.1 Definition and End Notes

Tables 29 and 30 are templates to help explain the appropriate footnotes for each program and summary table throughout this report.

Table 29: Summary Report Table Template

	Prior Year	Current Year 2011 (1)	Projected Year 2011 (2)	Projected Year 2011	Program To Date (3)
Participants					
Installation	(4)				
Audits	(5)				
Audits with Installation	(7)				
Program Costs					
BED Administration Costs	(9)				
General	(10)				
Implementation	(11)				
Planning	(12)				
Marketing	(13)				
IT Development	(14)				
BED Service Costs	(15)				
Service to Participants	(16)				
Service to Trade Allies	(17)				
BED Incentive Costs	(18)				
Participants	(19)				
Trade Allies	(20)				
BED Total Costs	(8)				
Evaluation Costs	(23)				
Participant Costs	(21)				
Total Program Costs	(26)				
Benefits					
Annualized MWh	(27)				
Lifetime MWh	(28)				
Winter Peak KW	(29)				
Summer Peak KW	(30)				
MWh/Participant	(31)				
Weighted Lifetime	(32)				

Table 30: End Use Report Table Template

Description	Participants	Gross MWh	Net MWh	Lifetime MWh	Winter Net KW	Summer Net KW	MMBTU	CCF
	(33)	(35)	(36)	(34)	(37)	(38)	(39)	(40)

Footnotes for the report table templates:

(1) Verified activity for the current reporting year. For savings this figure will be the estimated savings for measures actually implemented and verified for the current report period. Savings should be reported in MWH, at generation and net of all approved adjustment factors, except as otherwise noted.

(2) Estimated portion of the three-year savings and costs projected for the current report year. This footnote should identify the source of the projections. Projections for categories footnoted (4) to (7), (21) to (26) and (28) to (32) will be provided if available.

(3) Program to date activity. For participation [(4) to (7)], the program to date column should count each customer (premise) only once, regardless of participation in previous years. The executive summary should count each customer (premise) only once, even if a customer was served by more than one program.

(4) Number of customers with verified installations during the current report period. Customer is defined as a unique premise as defined by the utility, with one exception. For master-metered, multifamily buildings, customer is defined as a dwelling unit.

(5) Number of customers who had analyses or audits completed during the current report period.

(7) Number of customers who had analyses or audits during the current report period and have completed one or more installations during the current report period. The number of customers reported in this category should be a subset of the customers counted in (5) above. The program to date column should reflect activity related to all participants with analyses/audits, regardless of when the analysis was conducted.

(8) Total costs incurred by Burlington Electric Department during the current report period. All costs in nominal dollars, (9) + (15) + (18).

(9) Subtotal of all administrative costs detailed in the categories below, (10) + (11) + (12) + (13) + (14).

(10) Costs include general management, budgeting, financial management and legal costs directly associated with program implementation (such as contract review).

(11) Implementation management and administrative costs include costs related to business development and customer service, data management, and other program administrative costs directly related to implementation.

(12) Costs related to program design and planning, program screening and other similar functions.

(13) Costs related to marketing and outreach.

(14) IT development and maintenance costs do not need to be broken out by program, i.e., this category may be filled in only on the executive summary page.

(15) Subtotal reflecting total implementation costs, (16) + (17).

(16) Costs related to conducting audits or analyses, preparing the package of efficiency measures, contract management and post project follow up.

(17) Costs related to educational or other support services provided to entities other than individual program participants, such as trade allies, manufacturers, wholesalers, builders, and architects.

(18) Subtotal reflecting total incentive costs, (19) + (20).

(19) Direct payments made to participants to defray the costs of specific efficiency measures. If a program employs a shared savings mechanism or loan system, this category should include the utility share of the measure and carrying costs projected over the payment period, net of all projected participant payments.

(20) Incentives paid to manufacturers, wholesalers, builders, or other stakeholders.

(21) Total costs incurred by participants related to BED activities during the current report period. This category includes the participant contribution to the capital costs of installed measures and to specific DSM-related services, such as technical assistance or energy ratings.

(23) Evaluation costs, excluding tracking and reporting expenditures.

(24) Total program costs, (8) + (21) + (22) + (23).

(26) Total expenditures associated with the delivery of direct services to participants and trade allies, including all BED, participant and third party costs.

(27) Annualized MWH savings at generation and net of all approved adjustment factors (e.g., free riders, spill over) for measures installed and verified during the current report period.

(28) The lifetime estimated MWH savings for measures installed and verified during the current reporting year, at generation and net of all approved factors. (Estimated annualized savings times the life of the measure).

(29) Estimated impact of measures at time of winter system peak, at generation, net of adjustment factors.

(30) Estimated impact of measures at time of summer system peak, at generation, net of adjustment factors.

(31) Annualized MWH savings per participant, net at generation, i.e., (27) / (4).

(32) Average lifetime, in years, of measures in the program weighted by savings, i.e., (28)/(27).

(33) Number of customers with verified installations of measures within the end use, utility grouping.

(34) The total annualized MWH saved, at generation, net of adjustment factors, should add up to the savings reported in the line item footnoted as (27).

(35) The total lifetime MWH saved, at generation, net of adjustment factors, should add up to the savings reported in the line item footnoted as (28).

(36) The total annualized MWH saved, gross at the customer meter.

(37) The total winter coincident KW, at generation, net of adjustment factors, should add up to the savings reported in the line item footnoted as (29).

(38) The total summer coincident KW, at generation, net of adjustment factors, should add up to the savings reported in the line item footnoted as (30).

(39) Total MMBtu estimated to be saved (positive) or used (negative) for alternative fuels as a result of measures installed in the end use.

(40) Total water saved (CCF) (positive) or used (negative) due to measures installed in the end use.

3.2 Design Review Guide

Burlington
Planning and Zoning

◦DESIGN◦REVIEW◦GUIDE◦

Energy Efficient Construction

Burlington is well known as a community with a high quality of life, small and cohesive neighborhoods, a vibrant downtown and waterfront – all within a spectacular setting on the shores of Lake Champlain. This deserving reputation is due in part to the City's small size, entrepreneurial spirit, civic-minded citizens and activist government. One of the many factors that makes Burlington such a great place to live, work and visit is the community's attention to detail, and respect for its setting, heritage and quality urban design.

Burlington's Design Review process strives to protect the city's unique qualities and strong sense of place by carrying out citywide development and design objectives. The purpose of this *Design Review Guide* is to help applicants in preparing projects to be reviewed by the City's Design Advisory Board and Development Review Board. Through materials such as this, the Department of Planning & Zoning seeks to make information available well before the final design of a project, saving the applicant and the city, time and money.

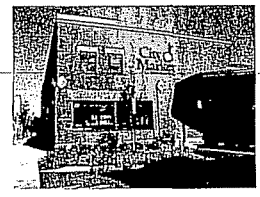
Did you know that the initial cost of building construction represents only 1% to 2% of the total cost to build, own and operate a building over a thirty-year life? In addition, buildings are major energy users: the energy needed to heat, cool, light and ventilate buildings represents over 35% of the total national energy usage and 60% of total electricity production.

A well-planned construction project - including careful attention to energy efficiency and worker comfort - can pay dividends over time. Research indicates that buildings with energy efficient features like day-lighting and good ventilation can improve people's attitudes and productivity. Even slight gains in productivity will more than pay for the incremental cost of energy efficient design.

The City of Burlington is committed to promoting energy efficiency in buildings throughout the City. Energy-efficient buildings:

- benefit the owners and tenants by lowering costs,
- improve the lives of citizens by saving consumers money,
- lessen our demand for fossil fuels,
- decrease the need for new power generation,
- reduce pollution and,
- strengthen the local, state and national economy.

It is much cheaper to build efficiency into a new building than to retrofit an existing building later. Burlington's "Energy Efficiency Guidelines for New Construction" describes a minimum level of energy efficiency that must be designed into all new construction.



Energy Efficient Construction Guidelines

In 1991 the Burlington City Council established an ordinance that requires that all commercial and residential construction and applicable new equipment be in compliance with the "Guidelines for Energy Efficient Construction for the City of Burlington, Vermont". (Art. VI, Energy Conservation, Sec. 8, Burlington Code of Ordinances)

Any new building, addition, renovation or equipment replacement project must meet the energy efficiency criteria of the Guidelines. The Guidelines adopt a national standard as the model energy code for Burlington. This standard is amended to suit Burlington's climate and special needs. The Guidelines contain criteria for the building's roof, exterior walls, and floors/ foundations; and the mechanical, lighting, and power systems.

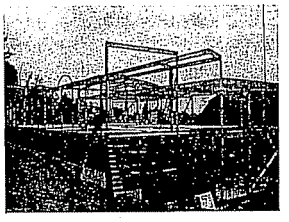
Residential Construction

All residential construction must comply with the current edition of the Vermont Residential Building Energy Standard (RBES) and Sec. 21 V.S.A. § 266 of Vermont law as referenced in the Guidelines. The Guidelines amend RBES in Burlington to maintain application to renovation and any covered building component of RBES regardless of size and scope.

As is the case with all other development in Burlington, the Inspection Division of the Dept of Public Works (DPW) is the enforcement authority for compliance with the Guidelines. However, the BED Energy Services staff helps to administer the Guidelines and assists the Inspection Division and applicants with Guidelines applicability, interpretation and construction plan review. The Inspection Division will typically require a letter of approval from BED prior to issuing a building permit.

Steps to Compliance:

- Obtain a copy of the Guidelines by visiting www.burlingtonelectric.com or calling BED, Energy Services at 802-865-7342.
- Contact the DPW Inspection Division (863-9094) and BED Energy Services staff early in your planning process to discuss the project scope and compliance with the Energy Efficiency Guidelines.
- Request free consultation from BED Energy Services staff for ideas to best meet the Guidelines and cost effective design improvements that go beyond the Guidelines.
- Provide a set of design documents to BED Energy Services staff and request a Guidelines plan review and a letter of approval for DPW. This is a free service and BED will act quickly to review your project.
- BED will advise you of any building components that do not meet the Guidelines and how to make necessary design improvements.



Financial Incentives

BED has a long history in helping owners, builders and developers incorporate energy efficient equipment, systems and techniques. BED will work with you to produce innovative, creative building designs that are efficient, cost effective and durable.

If you're planning a new construction project or building renovation, contact BED for assistance from permitting through inspection and occupancy. BED offers:

- technical assistance with building design and Guidelines compliance
- funding for your design team to evaluate various building system options exceeding the Guidelines
- funding assistance for third-party commissioning
- cash incentives for highly efficient equipment and systems.

BED will tailor its program to meet your individual needs - from incremental improvements in energy efficient equipment to advanced building designs incorporating energy efficiency, renewable energy systems and green building design.

Additional Information

assistance with Burlington's Energy Efficiency Guidelines

- **Burlington Electric Dept.**
  585 Pine St., Burlington, VT 05401
  BED Residential Services - 802.865.7337
  BED Commercial Services - 802.865.7342
  www.burlingtonelectric.com
- **Energy Code Assistance Center**
  255 South Champlain St., Burlington, VT 05401
  888.373.2255

general information regarding city zoning permits

- **Burlington Dept. of Planning & Zoning**
  149 Church St., Burlington, VT 05401
  802.865.7188 www.ci.burlington.vt.us/planning/

general information regarding city building permits

- **Burlington Dept. of Public Works, Inspection Services**
  645 Pine St., Burlington, VT 05401
  802.863.9094 www.dpw.ci.burlington.vt.us/

In accordance with the Americans with Disabilities Act (ADA) of 1992, it is the policy of the City of Burlington not to discriminate on the basis of disability in offering benefits, services, programs, and activities.

This information can be made available in alternative media forms for people with disabilities. Reasonable accommodation shall be made upon request to insure that all benefits, services, programs, and activities offered by the City are fully accessible to all individuals. For information, call 865-7188 (865-7144 TTY). EOE

Prepared by the Burlington Department of Planning & Zoning, 2004

Energy Efficiency Resource Standards: A Progress Report on State Experience

Michael Sciortino, Seth Nowak, Patti Witte,
Dan York, and Martin Kushler

June 2011

Report Number U112

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CONTENTS

EXECUTIVE SUMMARY

Inspired by the economic and environmental benefits of energy efficiency, over half the states now embrace specific energy efficiency savings goals, known as Energy Efficiency Resource Standards (EERS). An EERS requires utilities (or related organizations in states where the programs are administered by non-utility entities) to save a certain amount of energy each year, typically expressed as a percentage of annual retail energy sales or as specific energy savings amounts set over a long-term period. The first EERS passed in Texas over a decade ago and since then, utilities, regulators, and consumers across the country have embraced this type of policy to catalyze the implementation of energy efficiency programs to reduce electricity and natural gas consumption in homes and businesses.

The report includes legislative and regulatory background for every state where an EERS policy has been in place for over two years and examines the progress these states have made achieving their goals. Tracking actual energy savings and comparing these results with the required targets, the analysis develops a comprehensive portrait of the performance of twenty states, noting important trends influencing the outcomes thus far.

Across the country, state EERS policies are driving energy efficiency investments and energy cost savings to unprecedented levels, lowering utility bills, improving building comfort, and reducing strains on the utility grid. Overall, the performance of states in comparison to the targets set in EERS policies has been encouraging; most states are meeting or are on track to meet energy savings goals.

The report finds that states' performance meeting energy savings targets is driven by issues such as the clarity and appropriateness of the regulatory framework, the length of time allowed for program administrators to ramp-up programs, and the overall commitment of all parties to invest the proper resources to meet targets. States must overcome these barriers in order to successfully meet EERS targets and states considering the adoption of an EERS should carefully consider these issues in the policymaking process.

ACKNOWLEDGMENTS

The authors would like to thank their many contacts at utilities, commissions, state governments, and nonprofit organizations, as listed below. These contacts participated in interviews and shared their knowledge and insights on state performance meeting energy efficiency resource standards.

We are grateful for the thorough reviews given by Rebecca Stanfield, Natural Resources Defense Council; Sam Krasnow and Derek Murrow, Environment Northeast; and Greg Ehrendreich, Midwest Energy Efficiency Alliance.

Thank you also to ACEEE colleagues Steven Nadel, Glee Murray, Maggie Molina, Max Neubauer, Suzanne Watson, Patrick Kiker, and Eric Schwass for their assistance in the research, review, production, and release of the report. Finally, many thanks to Renee Nida for her work editing this report.

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Sam Krasnow Derek Murrow	Environment Northeast
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Estrella Seese Christian Whitney	Hawaii Department of Business, Economic Development, and Tourism
Mike Messenger	Itron
Walt Auburn	Maryland Energy Administration
Rick Leuthauser	MidAmerican Energy
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Rebecca Stanfield	Natural Resources Defense Council
Jeff Primm	New Mexico Public Regulatory Commission
Carlene Pacholczak	New York Department of Public Service
Sarah Osgood	New York Energy Research and Development Authority (NYSERDA)
Paul Quinlan	North Carolina Sustainable Energy Association
Jack Floyd	North Carolina Utilities Commission
Danielle Dixon Kim Drury	NW Energy Coalition
Daniel Sawmiller	Ohio Consumer Counsel
Nolan Moser	Ohio Environmental Council
Megan Good	Pennsylvania Public Utilities Commission
Nick Ucci	Rhode Island Public Utilities Commission
John Wilson	Southern Alliance for Clean Energy
Howard Geller	Southwest Energy Efficiency Project
George Twigg	Vermont Energy Investment Corporation
Deborah Reynolds	Washington Utilities and Transportation Commission

ENERGY EFFICIENCY RESOURCE STANDARDS (EERS)

A majority of states now have policies in place that establish specific energy savings targets that utilities or related organizations must meet through customer energy efficiency programs. These policies—called "energy efficiency resource standards" (EERS)—are analogous to "renewable portfolio standards," also in place in a majority of the states. An EERS sets multi-year electric or natural gas efficiency targets (e.g., 2% incremental savings per year or 20% cumulative savings by 2020), measured against a baseline of retail sales.[1] Energy efficiency savings are typically measured by the first-year savings of energy-efficient measures installed. EERS policies accelerate and expand the scale of energy savings achieved through utility and related energy efficiency programs.

Historically, energy efficiency program requirements tended to focus on spending levels rather than specific energy savings levels. Energy savings amounts were more of an outcome of the process—a function of initial program budgets, cost-effectiveness screening of measures and programs, and finally the implementation of the programs. Rather than basing policy and program planning on the desired level of energy efficiency savings, the process of planning around budgets resulted in uncertain commitments to actual energy efficiency and often lower savings levels than might have been achievable.

The shift to EERS represents a significant evolution in the treatment of energy efficiency in the utility system. Rather than view energy efficiency in the context of spending requirements to meet some "customer service" obligation, the use of an EERS strategy—with its explicit focus on quantifiable energy savings results—helps directly reinforce the expectation that energy efficiency is a real utility system "resource," and helps utility system planners more clearly anticipate and project the effect of energy efficiency programs on utility system loads and resource needs.

Moreover, EERS targets are generally set at levels that push programs to achieve higher savings than they would have targeted prior to enactment. EERS policies maintain strict requirements for cost-effectiveness so that programs are insured to provide overall benefits to customers. Not only does an EERS drive utilities and program administrators to achieve greater levels of savings, but it also helps ensure a long-term commitment to energy efficiency as a resource, building essential customer engagement as well as the workforce and market infrastructure necessary to sustain high savings levels.

Key Distinctions of EERS Policies

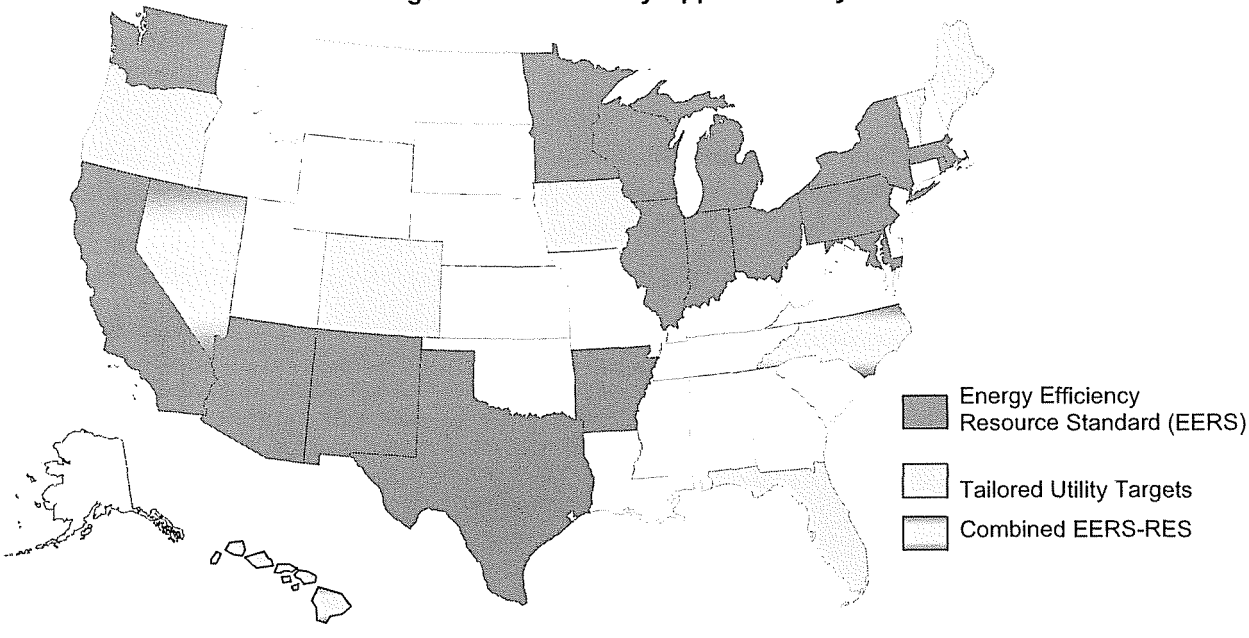
This review finds that EERS policies currently encompass three distinct types of policy approaches, all of which accomplish the same outcome—setting binding, long-term targets for energy efficiency savings from utility programs. The three approaches are a statewide Energy Efficiency Resource Standard, long-term energy savings targets set by utility commissions tailored to each utility and incorporating energy efficiency as an eligible resource in renewable portfolio standards (RPS). While the latter two options may not technically be considered a "standard" in the traditional sense, ACEEE has defined all three approaches as an EERS to avoid confusion and draw focus to the key similarity of all these policies—establishing binding, long-term energy savings targets. In practice, RPS policies that include efficiency have not thus far resulted in aggressive goals, but the policy approach itself has the potential to produce results comparable to the other two mechanisms if properly designed. Tailored utility targets and statewide EERS policies have each been very effective at driving aggressive energy efficiency savings in the states. In addition, certain states such as Massachusetts, Rhode Island, Washington, California, and others have a statewide EERS that operates in the following manner: (1) state law broadly requires utilities to procure all cost-effective efficiency resources ("an efficiency procurement requirement"); and (2) planning processes between the utilities, stakeholder efficiency councils, and public utility commissions (PUCs) then establish the specific percentage savings targets the utilities are required to meet to effectuate the all cost-effective

[1] "Multi-year" is defined as three or more years for the purpose of this report. EERS policies may also set specific gigawatt-hour (GWh) energy savings targets without consideration of percentage of prior-year sales, or as a percentage of load growth.

efficiency procurement requirement.[2] These states have set increasingly aggressive—and fully funded—efficiency savings targets.

Statewide EERS	Tailored Utility Target	Combined EERS–RPS
Typically set by state legislatures and codified by utility commissions, the statewide EERS calls for all eligible utilities to achieve a prescribed level of savings. In efficiency procurement states, the state legislatures have required utilities to invest in all cost-effective efficiency and the specific targets are then set by stakeholder councils and PUCs.	Initiated in a variety of ways, long-term energy efficiency targets in these states are tailored to each specific utility. In each case, law or regulation calls for the establishment of multi-year (3-year+) specific energy savings targets.	Energy efficiency may be accepted as an eligible resource in state renewable energy standards (RPS). In these cases, energy efficiency is measured on a cumulative, rather than annual, incremental basis.

Figure 1: EERS Policy Approaches by State



OBJECTIVES AND METHODOLOGY

Of the twenty-six states with an EERS, only seven were in effect before 2008. While the effects of an EERS have been estimated in numerous ACEEE state policy studies (Neubauer et al. 2011), and ACEEE has examined the results of energy efficiency programs and the potential for meeting aggressive targets (Molina et al. 2010; Kushler et al. 2009), ACEEE has not comprehensively examined states' performance meeting the energy savings targets since 2006 (Nadel 2007). The primary purpose of this report is to track the actual energy savings in states with EERS policies and compare these results with the required targets. The analysis covers every state with an EERS in effect for two or more years, or twenty of the twenty-six EERS states (see Figure 2 for list of states). The report provides a "progress report" profile for every state that includes legislative and regulatory background of the EERS policy, energy savings achieved, and a brief summary of the trends in the state influencing the outcomes thus far.

[2] In some cases, broad goals are set in stage 1 along with the efficiency procurement requirement. For example, Washington's EERS law requires utilities to base their targets on the Northwest Power and Conservation Council methodology, which aims for approximately 1.5% annual savings. The binding targets, however, are set in a separate planning process.

While the report does not detail the broader economic, environmental, and electricity reliability impacts of EERS policies, it should be noted that existing literature confirms that energy efficiency is a well-documented strategy to improve economic productivity, reduce harmful pollutant emissions, and strengthen energy reliability and security (Laitner et al. 2010; National Academy of Sciences 2010). Numerous studies have overwhelmingly portrayed a significant amount of cost savings and indirect economic benefit that would result through cost-effective improvements in energy efficiency of our buildings and industries (McKinsey & Company 2009). Properly implemented EERS policies drive states to realize this potential.

Methodology

The findings of this report are based on extensive primary research and interviews with stakeholders in the states. ACEEE made a good-faith effort to interview at least two stakeholders in each state with knowledge of utility targets and performance. Research was completed May 3, 2011, and while the peer review process did provide updates in some states, the findings of this report should be assumed to be accurate up to this date.

The savings data presented in this report is derived from publicly available utility and commission data, which is reported in varying ways across states. When available, verified net savings are presented, but in some cases, states report gross savings or unverified savings. Because they inhibit reliable comparisons of energy savings, the differences among states' EM&V protocols is an issue that deserves further research. A forthcoming ACEEE report will take on the issue.

A Companion Report

ACEEE is simultaneously releasing a new report, *Energy Efficiency Resource Standards: State and Utility Strategies for Higher Energy Savings,* which thoroughly examines how several states are ramping up energy efficiency programs and policies to achieve aggressive EERS targets. That report focuses on twelve states and offers insight into the policy and programmatic strategies states are implementing to achieve high savings levels. Aside from covering a broader range of states, this report's primary purpose is to track savings levels compared to targets and discuss general trends affecting states' performance. The two reports are complementary and can be separated by the primary research questions asked: Are states meeting EERS targets; how can states ramp-up to and sustain aggressive savings levels?

A Note about Natural Gas

While the primary focus of this report is on electricity EERS policies, general information is included on every state natural gas EERS in effect. When information is readily available, we have included progress meeting goals, but the main focus of the report is to track progress towards meeting electricity efficiency goals.

EERS Policy Status

As of the writing of this report, twenty-six states have an electricity EERS in effect. Thirteen states have a natural gas EERS. The standards and their underlying authorities, listed in order of highest approximate electric annual savings goals to lowest, are summarized below:

Figure 2: Summary of State EERS Policies

☐ States in grey rows have not been in effect for two or more years and are not examined in this report.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Massachusetts[3] 2009 Electric and Natural Gas EERS	Electric: 1.4% in 2010, 2.0% in 2011; 2.4% in 2012 Natural Gas: 0.63% in 2010, 0.83% in 2011; 1.15% in 2012	Electric: D.P.U. Order 09-116 through 09-120) Natural Gas: D.P.U. Order 09-121 through 09-128
Vermont 2000 Electric Tailored Utility Targets (Efficiency Vermont)	~6.75% cumulative savings from 2009 to 2011	30 V.S.A. § 209; VT PSB Docket 5980; PSB Contract[4]
Arizona 2009 Electric EERS	2% annual savings beginning in 2014., 22% cumulative savings by 2020	Docket Nos. RE-00000C-09-0427, Decision No. 71436
Illinois 2007 Electric and Natural Gas EERS	Electric: 0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter Natural Gas: 8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019)	S.B. 1918 Public Act 96-0033 § 220 ILCS 5/8-103
New York 2008 Electric and Natural Gas EERS	Electric: 15% Cumulative savings by 2015 Natural Gas: ~14.7% Cumulative savings by 2020	Electric: NY PSC Order, Case 07-M-0548 Natural Gas: NY PSC Order, Case 07-M-0748
Minnesota 2007 Electric and Natural Gas EERS	Electric: 1.5% annual savings beginning in 2010 Natural Gas: 0.75% annual savings from 2010-2012; 1.5% annual savings in 2013	Minn. Stat. § 216B.241
Iowa 2009 Electric and Natural Gas Tailored Utility Targets	Electric: Varies by utility from 1-1.5% annually by 2013 Natural Gas: Varies by utility from 0.74-1.2% annually by 2013	Senate Bill 2386 and Iowa Code § 476

[3] The underlying statute, Mass. General Laws c. 25 § 21, requires gas and electric efficiency program administrators to procure "all energy efficiency and demand reduction resources that are cost effective or less expensive than supply."
[4] Goals for 2009 and 2010 were combined. Efficiency Vermont also set goals in previous years in three-year intervals.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Rhode Island 2006 Electric and Natural Gas Tailored Utility Targets	Electric: ~1.3% in 2010; 1.5% in 2011; Council proposed 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014 Natural Gas: ~0.4% of sales in 2011; Council proposed 0.75% in 2012, 1.0% in 2013, and 1.2.% in 2014	R.I.G.L § 39-1-27.7
Ohio 2008 Electric EERS	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019)	ORC 4928.66 et seq. S.B. 221
Indiana 2009 Electric EERS	0.3% annual savings in 2010, increasing to 1.1% in 2014, and leveling at 2% in 2019.	Cause No. 42693, Phase II Order
Maryland[5] 2008 Electric EERS	15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (10% by utilities, 5% achieved independently)	Md. Public Utility Companies Code § 7-211
Maine 2010 Electric and Natural Gas Tailored Utility Targets (Efficiency Maine)	Electricity: Annual energy savings of ~1% in FY2011, ramping up to 1.4% in FY2013. Natural Gas: 130 BBtu annually by FY2013	Efficiency Maine Trust: Triennial Plan
Colorado 2007 Electric and Natural Gas Tailored Utility Targets	Electric: PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011 and increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019 Natural Gas: Savings targets commensurate with spending targets (at least 0.5% of prior year's revenue)	Colorado Revised Statutes 40-3.2-101, et seq.; COPUC Docket No. 08A-518E; Docket 10A-554EG
Wisconsin 2010 Electric and Natural Gas EERS	Electric: 0.75% in 2011, ramping up to 1.5% in 2014. Natural Gas: 0.5% in 2011, ramping up to 1% in 2013	Order, Docket 5-GF-191
Connecticut[6] 2005 Electric	~1% annual savings 2008-2011	Public Act 07-242 of 2007

[5] The 15% per-capita electricity use reduction goal translates to around 17% cumulative savings over 2007 retail sales.

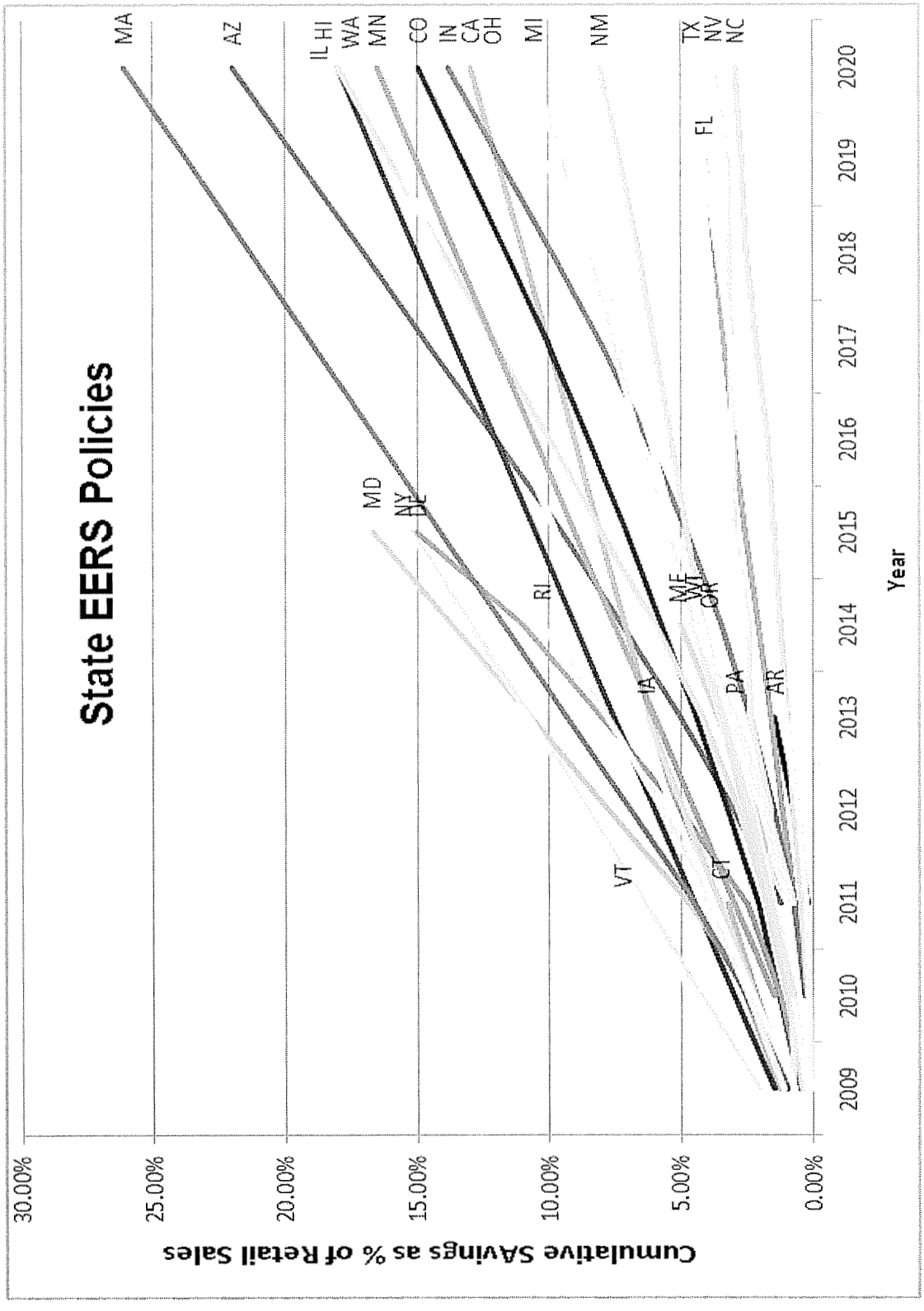
State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
California[7] 2004 and 2009 Electric and Natural Gas EERS	Electric: ~1% annual savings through 2020 Natural Gas: 150 gross MMTh by 2012	CPUC Decision 04-09-060; CPUC Decision 08-07-047; CPUC Decision 09-09-047
Washington 2006 Electric EERS	Biennial and Ten-Year Goals vary by utility. Law requires savings targets to be based on the Northwest Power Plan, which estimates potential savings of about 1.5% savings annually through 2030 for Washington utilities.	Ballot Initiative I-937 WAC 480-109 WAC 194-37
Michigan 2008 Electric and Natural Gas EERS	Electric: 0.3% annual savings in 2009, ramping up to 1% in 2012 and thereafter Natural Gas: 0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter	M.G.L. ch. 25, § 21; Act 295 of 2008
Oregon 2010 Electric and Natural Gas Tailored Utility Targets (Energy Trust of Oregon)	Electric targets are equivalent to 0.8% of 2009 electric sales in 2010, ramping up to 1% in 2013 and 2014. Natural Gas: 0.2% of sales in 2010 ramping up to 0.4% in 2014	Energy Trust of Oregon 2009 Strategic Plan
Pennsylvania 2004 and 2008 Electric EERS	3% cumulative savings by 2013	66 Pa C.S. § 2806.1; PUC Order Docket No. M-2008-2069887
Arkansas 2010 Electric and Natural Gas EERS	Annual reduction of 0.25% of total electric kilowatt hour (kWh) sales to 0.75% of total electric kWh sales over the next three years (slightly less for natural gas).	Order No. 17, Docket No. 08-144-U; Order No. 15, Docket No. 08-137-U
New Mexico 2008 Electric EERS	5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020	N.M. Stat. § 62-17-1 et seq.

[6] Connecticut does not currently have long-term energy efficiency savings goals that can be defined as an EERS. It is included in this report because it has very recent experience with an EERS policy.

[7] California's goals presented as gross savings. A rough estimate of California's goal as net savings can be achieved by converting gross savings to net savings using the 2009 net to gross conversion factor of 61% (CPUC 2011). Net goals are approximately 0.8% annual savings for the period 2010-2013, dropping to 0.55% from 2014-2020. California's evaluation and attribution methods are some of the strictest in the country, however, which partly explains the low net to gross conversion factor.

State Year Enacted Electric/Natural Gas Policy Type	Energy Efficiency Resource Standard	Reference
Nevada 2005 and 2009 Electric RPS - EERS	20% Renewable energy by 2015 and 25% by 2025—energy efficiency may meet a quarter of the standard in any given year, or 5% cumulative savings by 2015 and 6.25% by 2025.	NRS 704.7801 et seq.
Hawaii[8] 2004 and 2009 Electric RPS - EERS and EERS	Renewable Portfolio Standards include 15% electrical energy savings through 2015. Starting in 2015 all electric utility savings will count towards Hawaii's Energy Efficiency Portfolio Standards (EEPS). EEPS long-term goal is 4,300 GWh reduction by 2030, or 30% of sales.	HRS §269-91, 92, 96
North Carolina 2007 Electric RPS - EEERS	Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Investor-owned: 12.5% by 2021 and thereafter. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.	N.C. Gen. Stat. § 62-133.8 04 NCAC 11 R08-64, et seq.
Texas 1999 and 2007 Electric EERS	20% Incremental Load Growth in 2011 (equivalent to ~0.10% annual savings); 25% in 2012, 30% in 2013+	Senate Bill 7; House Bill 3693; Substantive Rule § 25.181
Florida 2009 Electric Tailored Utility Targets	3.5% energy savings over 10 years.	Docket Nos. 080407-EG – 080413-EG; Order No. PSC-09-0855-FOF-EG
Delaware Pending Electric and Natural Gas EERS	Electricity: 15% electricity cumulative savings by 2015 Natural Gas: 10% cumulative savings by 2015.	SB 106

[8] Although Hawaii does not currently have a mandated annual goal for energy efficiency, ACEEE estimates that the current 30% goal will result in 1.5% annual savings through utility programs.


State EERS Policies
Cumulative SAvings as % of Retail Sales
Year
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
MA
AZ
IL HI WA MN
CO IN CA OH
MI
NM
TX NV NC
FL
MD NY DE
RI
VT
IA
ME WI OR
CT
PA
AR

As the figure above illustrates, eleven geographically dispersed states have committed to long-term targets to achieve over 10% cumulative annual savings by 2020. Because some state tailored utility targets are set in three-year intervals, the figure shows many states with EERS ramp-ups that only reach 2011, 2013, or 2015. While some states, such as Vermont, expect to extend EERS policies out to another three years, it is unclear whether Connecticut will re-establish long-term utility targets. Below, annual savings targets are drawn out to 2020 and presented as a cumulative total to demonstrate how current state policies, if maintained, would compare.

Table 1: Cumulative Electricity Savings of State EERS Policies Extrapolated to 2020[9]

State	Cumulative 2020 Target	State	Cumulative 2020 Target
Vermont*	27.00%	**Wisconsin***	13.50%
Maryland*	26.70%	**Maine***	13.40%
New York*	26.50%	**Connecticut***	13.14%
Massachusetts	26.10%	**California**	12.94%
Rhode Island*	25.26%	**Ohio**	12.13%
Arizona	22.00%	**Michigan**	10.55%
Illinois	18.00%	**Oregon***	10.40%
Hawaii*	18.00%	**Pennsylvania***	9.98%
Washington	17.24%	**New Mexico**	8.06%
Minnesota	16.50%	**Arkansas***	6.75%
Iowa*	16.10%	**Texas**	4.60%
Delaware	15.00%	**Florida**	4.06%
Colorado	14.93%	**Nevada**	3.76%
Indiana	13.81%	**North Carolina**	2.92%

*Savings beginning in 2009 extrapolated out to 2020 based on final year of annual savings required

RESULTS

Across the country, state EERS policies are driving energy efficiency investments and energy cost savings to unprecedented levels. State utility commissions, utilities, and other program administrators have made impressive progress over the last three years implementing EERS policies. This review finds that most states are meeting or on track to meet energy savings targets.

Overall Savings

States with an EERS are achieving significant energy efficiency savings from utility programs, benefitting electric and natural gas customers by lowering utility bills, improving building comfort, and reducing strains on the utility grid. Nine states achieved 1.2% of annual sales or more in their latest reporting year of either 2009 or 2010, an impressive accomplishment considering in 2006 only one state achieved over 1.2% (Molina et al. 2008).[10] Following this group of leading states, an encouraging number of states with an EERS have climbed close to or above 0.5% savings, including states that only recently adopted full-scale utility energy efficiency programs in the Midwest and Southwest.

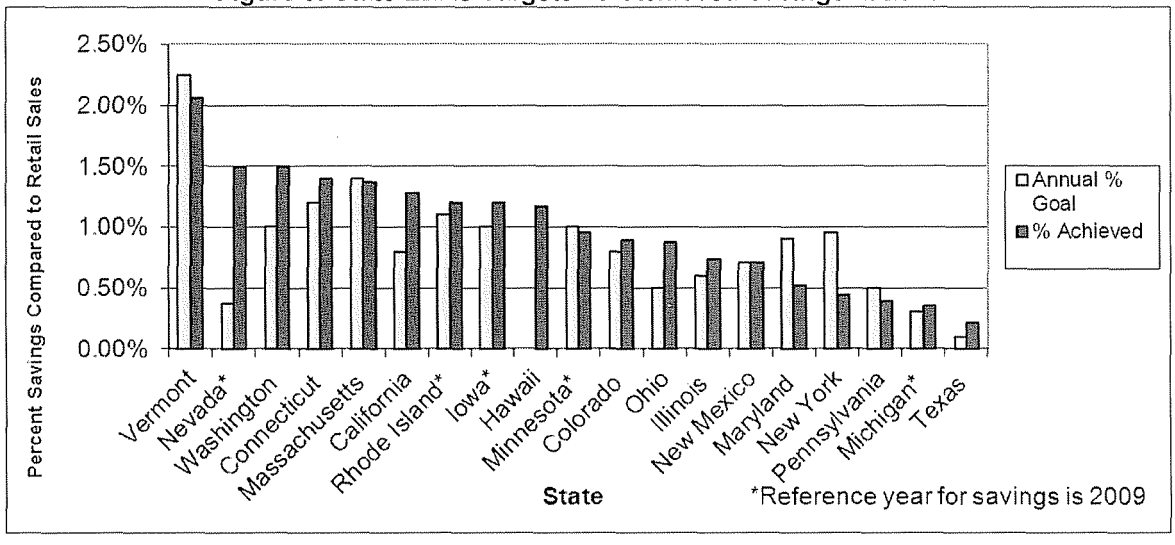
Savings Compared to Targets

Overall, the performance of states in comparison to the targets set in EERS policies has been encouraging; most states are meeting or are on track to meet energy saving goals. Thirteen of the

[9] Colorado savings for PSCo only. Delaware is in the process of formulating rules for its EERS. ACEEE does not extrapolate the goal out to 2020. Other assumptions noted in footnotes of EERS summary table.
[10] Of the nine achieving >1.2%, Nevada, Iowa, and Rhode Island have a reference year of 2009.

twenty states with EERS policies in place for over two years are achieving 100% or more of their goals, three states are achieving over 90% of their goals, and only three states are realizing savings below 80% of their goals.[11]

Figure 3: State EERS Targets vs. Achieved Savings in 2010[12]



While the figure above positively portrays states currently meeting goals, the hard work has yet to come. Targets in many states are still increasing and sustaining aggressive savings levels will be a challenge for states. In states where EERS policies are still ramping up and have low annual savings goals for 2010, such as Ohio, Illinois, and Michigan, meeting goals in the coming years will be challenging and deserves ongoing attention and analysis. Ramping up to high levels of savings in a short period of time is a difficult task, even for states with demonstrated success in energy efficiency program administration. States such as Massachusetts and Minnesota, which are achieving slightly less savings than their targeted goals, are in the midst of major program ramp-ups. Low savings levels during the program ramp-up period have also caused Pennsylvania to fall short of its goals thus far.

Another reason some states are falling below target levels in 2010 is that some EERS policies set long-term goals, which place emphasis on long-term, rather than annual achievements. Pennsylvania and Vermont, for example, set two- and three-year savings targets for 2011, respectively. Past experiences in Vermont and California have demonstrated that it is common for states to make a major push in the final year to make up for lower savings in prior years.[13] This trend seems to be continuing in Pennsylvania, where savings in the first two quarters of its second program year far outpaced levels of its first.

In New York and Maryland, the only states currently achieving less than 80% of their near-term targets, shortfalls can be attributed both to new administrators ramping-up programs as well as the effect of long-term EERS. As explained in further detail below, the combination of delays in program approval and low savings as programs ramp-up has resulted in savings levels, which, if continued, would result in savings below the levels needed to meet long-term goals. New York has approved

[11] While its policy has been in place for over two years, North Carolina has not recorded energy efficiency savings and is thus not included in this tally. Currently, Hawaii's RPS goals allow electrical energy savings to count through 2014. Starting in 2015, electrical energy savings will count towards Hawaii's Energy Efficiency Portfolio Standards.

[12] California gross savings and targets adjusted to net savings using 61% of conversion factor. California savings include partial savings from advanced codes and standards adopted in the state. California, Iowa, and Washington savings and targets based on IOUs reporting savings as of 2010 only. New York based on NYSERDA and utility program administrators only. Colorado includes only PSCo. Ohio does not include First Energy.

[13] Vermont exceeded three year targets for 2006-2008 due to 2008 savings that made up for shortfalls in the prior two years. California came close to meeting 2004-2008 goals due to 2008 savings that made up for shortfalls in the prior two years.

funding, expertise, and an established market that inspire confidence among stakeholders in the state that they can make up for the initial shortfall in the years between now and the long-term target year of 2015. In Maryland, it is less likely utilities will be able to make up the lost ground. The Maryland PSC has not approved utility targets or funding levels sufficient to meet goals set in the EmPOWER Maryland Act. Lacking a strong mandate from the PSC, Maryland utilities have shown uneven commitment to meeting the goals, failing to invest the necessary financial and human resources.

OBSERVATIONS

Aside from the most prominent observation of this report, that states are generally on track to meet or exceed EERS goals, a number of general trends have emerged as states gain experience with EERS policies, which may help states in the varying stages of the policy process.

- Establishing an EERS lays a foundation for increased levels of energy efficiency savings, regardless of prior experience with energy efficiency programs.
- Available data indicates the benefits of programs administered under an EERS substantially exceed the costs.[14]
- Meeting EERS targets requires fair and clear regulation, meaning targets for utilities unaccustomed to energy efficiency must be gradual and the evaluation method for savings clear.
- All parties must be committed to meeting targets. Utilities need to devote proper resources to ensure successful EE programs and Commissions should approve sufficient levels of funding and complementary policies such as cost recovery, performance incentives, and decoupling.
- Ramping-up savings to aggressive levels and sustaining these levels requires programmatic excellence. Tried and true program models work to meet lower goals, but innovative programs reaching all sectors are necessary to achieve deeper savings.

EERS Drives Savings for States of All Types

The EERS policy has driven higher levels of savings in states with established energy efficiency program infrastructure as well as in states without energy efficiency program experience. In Washington and Iowa, for instance, energy efficiency had long been recognized by the major utilities and customers as having significant value. The two states consistently scored well in the ACEEE Scorecard Report, and achieved energy efficiency savings of around 0.6–0.8% of sales from utility programs (Molina et al 2010). EERS policies went into effect in Iowa and Washington in 2009 and 2010, and both states realized a significant boost in savings over previous years. Iowa and Washington achieved 1.2% and ~1.5% savings in 2009 and 2010, respectively.[15] Targets mandated by an EERS policy allow utilities to justify higher spending levels on cost-effective energy efficiency measures. The long-term nature of the goals also provides market certainty regarding the utility commitment to energy efficiency services and technologies, improving the business case for energy efficiency companies in the private sector. States with established energy efficiency programs may have utilities with varying commitment to energy efficiency. The EERS policy can serve to "raise the floor" and drive program development from utilities historically reluctant to offer robust efficiency programs.

States without significant existing energy efficiency programs also benefit from establishing savings targets. In states such as North Carolina, Michigan, and Illinois, the adoption of an EERS prompted utilities to develop and implement programs to benefit customers of all market segments. Without the strong mandate of an EERS, states that have yet to develop energy efficiency programs are less

[14] This is not surprising, given that repeated analyses have shown that utility sector energy efficiency programs tend to be quite cost-effective. ACEEE's most recent report on this subject found that energy efficiency programs saved electricity at an average cost of 2.5 cents/kWh (Friedrich et al. 2009), about one-third to one-fourth the cost of building, fueling and operating a new power plant.

[15] Washington savings based only on IOUs.

likely to begin such an initiative, depriving utility customers of beneficial programs offered in every region in the country.

The Benefits of EERS Outweigh Costs

Ratepayer-funded energy efficiency programs must undergo cost-effectiveness tests that confirm positive benefit-cost ratios greater than one. The standards for cost-effectiveness as well as the types of tests use vary by state, but the presence of rigorous benefit-cost tests prior to program approval assures that efficiency programs and measures installed will likely be cost-effective.[16]

Available data thus far indicates that the benefits of efficiency programs driven by EERS policies have proven to substantially exceed administrator and customer costs. While this report does not comprehensively analyze the cost-effectiveness of energy efficiency programs, anecdotal evidence from a handful of states confirms that energy efficiency is a net beneficial investment.

- Hawaii Energy, the state's third-party Public Benefits Fee Administrator, collects a percent of each electric utilities' customer's bill and is responsible for carrying out Hawaii's energy efficiency and conservation programs. Hawaii Energy achieved net customer energy savings of 113,159 MWh, meeting 97% and 81% of its residential and commercial targets, respectively. Over the lifetime of these rebated and installed measures, cost savings will yield a 546% return on Hawaii's investment of $46.9 million ($17M/$29.9M Ratepayer/Customer Investment) (Hawaii Energy 2010).

- In Illinois, independent analysis of ComEd's programs in its second program year found portfolio the benefit-cost ratio based on the Illinois Total Resource Cost (TRC) test to be 2.84 (Navigant Consulting 2010). Ameren Illinois met its goals in 2009 cost-effectively and its portfolio scored a 2.78 using a TRC test (Ameren Illinois Utilities 2010).

- In 2010, Efficiency Vermont saved 114 GWh at a cost of 4.1 cents per kilowatt-hour (over the life of the measures). Efficiency Vermont spent $35.4 million on efficiency programs, participants spent $21.7 million, and the overall lifetime benefits equaled $136.1 million (Efficiency Vermont 2011).

- In Colorado, Xcel Energy reports that its electric DSM programs had an overall benefit-cost ratio of 3.3 while the gas DSM programs had a benefit-cost ratio of about 1.6. Xcel Energy spent $54.7 million on electric DSM programs and $16.9 million on gas DSM programs last year. The company estimates that electric programs alone will result in $227 million in net economic benefits for customers over the lifetime of energy efficiency measures installed due to its 2010 DSM programs. Gas DSM programs will result in about $15 million in net economic benefits (Xcel Energy 2010).

Clear and Fair Regulation

Critical to the success of states meeting goals is clear and comprehensive regulation of energy efficiency programs. EERS policies must be developed at a pace that allows all stakeholders to engage, submit comments, and adjust to the impending requirements. A methodical process ensures clarity from all parties on critical elements such as eligible technologies, EM&V requirements, and incentives or penalties for compliance and non-compliance. One particular issue that can cause friction is how Commissions decide to measure savings attributable to the EERS. Regardless of what method is chosen, whether on an annual, annualized, part-year, or life-time basis, clarity in the foundational legislative or regulatory authority is of utmost importance, as the cases in Texas and Ohio illustrate. In both cases, elaborated on in the case studies below, a lack of clarity in how energy

[16] ACEEE will release a detailed analysis of utility cost-effectiveness tests later this year.

savings could qualify to meet EERS targets has led to confusion and contention among utilities on what the policy actually requires.

Regulatory lag inhibits utility program administrators from meeting goals. While state utility Commissions should take time approving programs and policies, there is a hazard in approving energy savings targets and assuming programs will be approved in time to meet initial targets. Utility commissions in Maryland and New York took almost a year to approve programs for utilities after their EERS policies were approved. The EERS legislation can hinder states' ability to properly ramp up programs and meet designated goals. Pennsylvania's EERS, for instance, did not require the Utilities Commission to approve programs until five months into the first of two program years. Rather than having the full two years to meet the 1% cumulative savings target, utilities only have 19 months. Setting realistic timeframes for policy and program approval, therefore, can help lay the groundwork for successful EERS performance.

For states without significant existing energy efficiency programs, a gradual ramp-up of programs has been a successful strategy to gain utility acceptance and achieve significant savings as a result. Particularly in states unfamiliar with energy efficiency program administration, gradual ramp-ups allow utilities to develop and manage program administration and implementation at a realistic pace, allowing time for these utilities to seek advice from experienced professionals in the field. While the targets may be low, utilities and states can tout success meeting targets to build momentum for programs, and if performance incentives are in place, allow utilities to understand the financial benefit of meeting goals.

All Parties Must be Committed to Meeting Targets

Energy efficiency targets can only be met in a sustained fashion if regulators, utilities, and program administrators sincerely pursue cost-effective energy efficiency and treat energy efficiency similarly to supply-side resources. For regulators, this means adopting policies complementary to an EERS that improve the business case for energy efficiency, such as cost recovery, mechanisms to address the link between utility sales and profits (e.g., decoupling or lost-revenue recovery), performance incentives, and loading orders calling for the pursuit of all cost-effective energy efficiency. Regulatory commitment to targets also entails adopting cost-effectiveness tests that accurately measure the full costs and benefits of energy efficiency programs. Commissions must permit utilities to fund energy efficiency programs at the levels necessary to achieve targeted savings levels as well.

Aside from failing to provide complementary policies to ensure success, regulators can also include provisions that inhibit states from achieving intended EERS targets. Rate impact caps, or budget caps, can prohibit utilities from making the necessary, cost-effective energy efficiency investments necessary to achieve EERS requirements. Such caps are present in Texas and North Carolina, where it is uncertain whether the caps will lower cost-effective energy efficiency investment, and in Illinois, where the cap will likely trigger a failure to meet the standard in the next few years unless the General Assembly takes action to raise or eliminate the caps (Nowak et al. 2011). Provisions known as "exit ramps," present in Ohio and New Mexico, allow utilities to request permission to lower goals, which may also limit the effectiveness of an EERS policy. EERS policies that include opt-out provisions for industrial customers, as opposed to provisions that allow industrial to conduct "self-direct" programs tied to spending or savings requirements, raise the chances that states will not achieve their cost-effective energy savings potential.

Regulation can only ensure the proper environment for energy efficiency programs to flourish—utilities or third-party administrators must do the work. Successful utilities and third-party programs administrators devote significant human and capital resources to energy efficiency programs. Regardless of how experienced an administrator is with energy efficiency programs, the importance placed on energy efficiency initiatives from corporate leadership is a critical indicator of how well the utility will perform. If energy efficiency targets are embraced by utility leadership, efforts by energy efficiency division staff to meet goals will be welcomed and rewarded, boosting chances of success.

Questionable commitment from utilities and third-party administrators can lead to delays, underperformance, and threats to the policy. Nowhere is this more clear than in states where utilities have publicly opposed EERS policies, seeking to undermine and repeal the authority. In Ohio, First Energy and Dayton Power and Light have mounted strong opposition to the statewide EERS, claiming that its goals will hinder the state's economic recovery. While other utilities in the state such as Duke Energy have met the goals cost-effectively with ease thus far and claim long-term goals, while challenging, are achievable. First Energy fell far short of its first year target and has received a waiver for targets until 2012. Instead of redoubling its efforts to meet targets, it seems First Energy has shifted to an adversarial stance, threatening to hold Ohio back from being a leader in energy efficiency.

Ramping-Up Savings Requires Programmatic Excellence

Demonstrating the will to succeed is important, but actual energy efficiency savings do not derive from organizational commitment alone, but from program implementation as well. Thus, a third critical element to success is programmatic excellence. An analysis of how utilities are ramping up savings to meet EERS targets will be presented in the forthcoming, companion ACEEE report (Nowak et. al. 2011), which will include discussion and examples of the following strategies:

- Increasing energy efficiency funding levels
- Adopting complementary regulatory policies such as decoupling, performance incentives, and loading orders requiring the consideration of cost-effective energy efficiency in resource planning
- Using non-utility program savings (i.e. building codes) to contribute to contribute towards meeting savings standards
- Creating and sustaining collaborative and stakeholder processes
- Capturing lighting savings early and adding new, higher- efficiency technologies to efficiency portfolios beyond CFL's
- Adopting new program design approaches and strategies, including "Deeper, Then Broader"
- Starting programs for new technologies and new customer market segments
- Promoting participation through upstream rebates, more rebates and enhanced advertising

Conclusions and Recommendations

Energy efficiency savings targets effectively advance the objective of increased, long-term energy savings from cost-effective efficiency programs. The findings of this study show that almost every state with an EERS is on track, meeting, or exceeding goals in 2010. This report finds that states' performance meeting energy savings targets is driven by broader issues such as the clarity and appropriateness of the regulatory framework, the length of time allowed for program administrators to ramp-up programs, and the overall commitment of all parties to invest the proper resources to meet targets. States must overcome these barriers in order to successfully meet EERS targets and states considering the adoption of an EERS should carefully consider these issues in the policymaking process.

CASE STUDIES

The following case studies are presented in chronological order based on the effective date of the EERS policy. Each case study provides a brief summary, regulatory and legislative backgrounds, energy savings vs. targets, and a section outlining factors affecting performance.

Texas

Summary

Electric EERS	20% Incremental Load Growth in 2011; 25% in 2012, 30% in 2013+
Applicable Sector	Investor-owned utilities
Natural Gas EERS	None
Authority 1 Date Enacted	Senate Bill 7 May 1999, subsequently amended
Authority 2 Date Enacted	House Bill 3693 May 2007
Authority 3	Substantive Rule § 25.181

Legislative and Regulatory Background

In 1999, Texas became the first state to establish an energy efficiency resource standard, requiring electric utilities to offset 10% of load growth through end-use energy efficiency.[17] Demand growth is the average growth of the five previous weather adjusted peak demands for each utility. In 2007, after several years of meeting this goal at low costs, the legislature increased the standard to 15% of load growth by December 31, 2008 and 20% of load growth by December 31, 2009.[18] The legislation also required utilities to submit energy savings goals. The Public Utility Commission of Texas (PUCT) approved these rules in March 2008.

While the 2007 legislation required utilities to submit GWh savings goals to ensure they did not overly focus on load management, the PUCT determined that utilities could convert their demand savings goals into corresponding energy savings goals each year using a 0.20 capacity factor.[19] The current practice used by Texas utilities is to interpret the term "capacity factor" to be a direct estimate of the fraction of hours in a year when the average peak savings will occur. Thus, the peak to energy savings multiplier used in Texas is 0.20×8760/1,000 MWh/GWh=1.75. This implies a peak to energy use ratio of 0.575, which is much higher than the actual peak to energy use ratio typically in the range of 0.20 to 0.24, which translates to conversion factors ranging from 3-5.

A preferable alternative to setting goals as a percentage of load growth would be to set savings goals as a percentage of baseline electricity sales and demand, which would produce more achievable and equitable targets (Itron 2008).

Recent Developments

In 2010, the PUCT approved Substantive Rule § 25.181, which increased the goals from 20% of electric demand growth to 25% growth in demand in 2012 and 30% in 2013 and beyond.[20] The rule also establishes customer cost caps to contain costs. Texas law requires all electric transmission and distribution utilities (TDUs) to meet energy efficiency goals. Utilities administer incentive programs and retail electric providers and energy efficiency service providers implement the programs. All programs are designed to reduce system peak demand, energy consumption, and/or energy costs and are available to customers in all customer classes.

Energy Savings Achieved vs. Targeted

While Texas has consistently met its energy efficiency goals, the energy efficiency goals have resulted in only modest electricity savings. Between 1999 and 2009, investor-owned utilities' programs in Texas produced 3,574 GWh of electricity savings, which amounts only to 1% of 2009 sales. The energy savings targets set by utilities are about half of the actual levels achieved.

[17] Texas Senate Bill 7
[18] House Bill 3693
[19] Rule defines capacity factor as "The ratio of the annual energy savings goal, in kWh, to the peak demand goal for the year, measured in KW, multiplied by the number of hours in the year."
[20] http://www.puc.state.tx.us/rules/subrules/electric/25.181/25.181.pdf

Table 2: Texas Energy Efficiency Goals vs. Achieved Savings

Year	Demand Goal (MW)	Demand Savings Achieved (MW)	Energy Savings Goal (GWh)	Energy Savings Achieved (GWh)	Energy Savings Goal as % of Energy Consumption of Nine IOUs	Energy Savings Achieved as % of Energy Consumption of Nine IOUs
2007	136	167	238	427.9	0.09%	0.16%
2008	115	202	201	581	0.08%	0.22%
2009	132	240	231	559.8	0.09%	0.21%
2010	142	301	249	548	0.10%	0.21%
2011 (projected)	143	298	251	539	0.10%	0.21%

Source: Texas utility energy efficiency plans and reports

If the load growth targets were to apply to forecast growth in electric retail sales, meaning utilities would have to offset 30% of growth in sales by 2013, this would amount to about 0.5% savings per year beginning in 2013.

Even though the energy efficiency goals do not apply to them, it should be noted that a handful of Texas municipal electric utilities, particularly Austin Energy, generate impressive amounts of energy efficiency savings. Austin Energy and the City of San Antonio generated 188 GWh alone in incremental energy efficiency savings in 2009 (EIA 2011).

Factors Affecting Performance

Collaboration among Stakeholders

Texas's success meeting energy efficiency goals can be attributed to a number of factors, but a few stand out in particular. Utility programs benefit from the ease of use of standard offer program materials for contractors and long standing relationships with contractors. Program managers cite sound electronic tracking systems and websites as contributing to program success, as well as broad reach and effectiveness of market transformation programs. Others note that while there is an inherent risk of inaccuracy, the programs benefit from a process for deeming energy savings, which reduces the cost of verification and measurement.

The relationship between utilities, the PUCT, and program implementers is characterized by a high-degree of collaboration and consultation, which allows for the dissemination of best practices and common barriers. Stakeholders engage in quarterly Energy Efficiency Implementation Project meetings and Texas IOUs formed a voluntary organization for energy efficiency program managers: The Electric Utility Marketing Managers of Texas (EUMMOT). EUMMOT facilitates coordination among program managers to convey common perspectives on energy efficiency program design and implementation; provides for exchange of information on markets and technologies; and advances understanding and participation in efficiency programs.

Rural vs. Urban Utilities

While the state as a whole consistently meets targets, there is a varying degree of success on a utility-by-utility basis. Rural utilities struggle to meet targets, primarily because of the dearth of energy contractors willing to enter the market in sparsely populated areas. Because goals are set as a percentage of incremental growth, utilities such as El Paso Electric that serve fast-growing areas must ramp up savings targets much faster than those with relatively predictable and stable load growth.

Program Design and Marketing

Program managers and advocates in the state roundly state that regulatory barriers inhibiting utilities' ability to market programs directly to customers is a major weakness to of current energy efficiency programs. Stakeholders also assert that it is difficult to improve upon programs or design new ones due to regulatory rigidity. Looking ahead to increased savings goals, Texas program managers and third-parties echo concerns about rural areas, marketing, and inflexible program designs, and also add the inherent contradiction between energy savings and shareholder value that needs to be addressed with a decoupling mechanism (Itron 2008).

Funding Levels

In total, Texas utility energy efficiency program budgets amounted to 0.3% of their revenues in 2009, while the median state spends 0.7%. An analysis by Good Company Associates found that the increase in the goal from 10% of demand growth to 20% in 2010 and 2011 did little to increase spending. The new goals will not significantly impact energy efficiency spending until the recession years are no longer included in the calculation of the five year average growth in demand. Good Company also concludes the cost-caps should not seriously constrain utilities from meeting goals given the modest savings levels.[21] Many utilities exceed the demand goals, however, and as a result, push the limits of the cost-caps. Some companies have already surpassed the cost-caps and others are very close. Unless the PUCT grants a utility the ability to exceed the cost caps, utilities will have to reduce spending in some manner which could result in less demand reduction and energy savings.

Performance Incentives

A utility that exceeds its demand reduction goal within the prescribed cost limit is awarded a performance bonus. A utility that exceeds its demand reduction goal receives a bonus equal to 1% of the net benefits for every 2% that the utility exceeds its goal. The maximum bonus is equal to 20% of the utility's program costs.

Vermont

Summary

Electric EERS	~6% cumulative savings from 2009 to 2011
Applicable Sector	Third-party administrator
Natural Gas EERS	None
Authority 1	30 V.S.A. § 209

Legislative and Regulatory Background

Vermont pioneered the model of a statewide "energy efficiency utility" (EEU) after Vermont enacted legislation in 1999 authorizing Vermont Public Service Board (PSB) to collect a volumetric charge on all electric utility customers' bills to support energy efficiency programs. Vermont PSB created the EEU, Efficiency Vermont, to use these public benefits funds to provide programs and services that save money and conserve energy. Burlington Electric Department (BED) provides DSM services within its own territory. When Efficiency Vermont was created, BED requested, and was granted, authority to run its own programs. BED reports separately on the costs and savings of its programs.

Vermont does not have traditional EERS legislation with a set schedule of energy-savings percentages for each year. Instead, Vermont law requires EEU budgets to be set at a level that would realize "all reasonably available, cost-effective energy efficiency." Compensation and specific energy-savings levels—not "soft" goals or targets—are then negotiated with EEU contractor Vermont Energy Investment Corporation (VEIC). There is not an explicit penalty for non-performance. However, a portion of the compensation Vermont pays the administrator is contingent on meeting stated goals, subject to a monitoring and verification process. If the administrator does not meet

[21] http://www.goodcompanyassociates.com/files/manager/Summary_PUCT_EE_Rule_8-6-10.pdf

stated goals, the state will withhold compensation, and the administrator potentially will be replaced at the end of the three-year period (DSIRE 2011). Efficiency Vermont's current goal is 360,000 MWh of energy savings during the three-year cycle, equivalent to 6.75% of electricity sales.

Moving forward, the goal-setting process will change due to Vermont's new "order of appointment" franchise-like structure. Every 3 years, a "demand resources plan" proceeding will be held. The proceeding will set budgets and goals for the next 20 years, coinciding with the long-range transmission plan to allow for integration of forecasting.[22]

Energy Savings Achieved vs. Targeted

In 2006, efficiency savings were about 1% of sales and by 2008, Efficiency Vermont achieved unprecedented savings levels equal to 2.5% of annual sales, exceeding its MWh goal for the 3-year period. In 2007 and 2008, savings from energy efficiency measures more than offset the average underlying rate of electricity load growth. Savings dropped slightly to 1.6% in 2009, but rebounded significantly in 2010 as the state once again exceeded 2% annual savings. Judging performance on an annual basis, Vermont almost met over 90% of its goal in 2010, but at 3.7% savings over two years, it will need to make up for lost ground in order to meet the three year of 6.75% savings by the end of 2011.

Table 3: Efficiency Vermont Energy Efficiency Savings Achieved vs. Targets

2006-2008 Achieved (MWh)	2006-2008 Goal (MWh)	Percent Attained	2009 Savings Achieved (MWh)	2010 Savings Achieved (MWh)	2009-2011 Goal (MWh)	Percent of 3-year goal attained over 2 years
311,000	261,700	119%	85,000	114,000	360,000	55%

Sources: Efficiency Vermont, 2009 Annual Report; 2010 Savings Claim; 2011 Annual Plan

Factors Affecting Performance

Funding Levels

Substantial increases to the Energy Efficiency Charge (EEC) included within customer rates drove Vermont's success over the last five years. Even though Vermont already had the highest per-capita investment in electric efficiency of any state in 2004, the state legislature passed Act 61 of 2005, which removed the spending cap on the EEU annual budget. The PSB now has flexibility to determine appropriate funding levels in the context of the integrated resource planning process. The PSB increased energy efficiency funding in 2006 from the previous maximum of $17.5 million to $30 million per year for the next three years. The aggressive electric energy efficiency measures have proven to be consistently cost-effective. In 2010, Efficiency Vermont saved 114 GWh at a cost of 4.1 cents per kilowatt-hour (over the life of the measures). Efficiency Vermont spent $35.4 million on efficiency programs, participants spent $21.7 million, and the overall lifetime benefits equaled $136.1 million.

Third-Party, Performance-Based Program Administrator Model

The EEU structure ensures that as an efficiency program implementer, VEIC does not have conflicting incentives. They are not an investor-owned for-profit utility, have no rate base, and thus, no throughput incentive. VEIC is eligible to receive a performance incentive for meeting or exceeding performance goals established in its contracts, directly tying results to compensation. Along with these performance incentives, VEIC staff attributes much of their success to the alignment between their non-profit structure and their mission: to reduce the environmental and economic costs of energy

[22] EEU Structure (Docket 7466)

use. Efficiency Vermont has a deep culture of innovation and experimentation centered solely on saving energy.[23]

Working under a performance-based "order of appointment" allows Efficiency Vermont the flexibility to allocate funds to where they can buy the most energy savings with each budget dollar. Relative to other program administrators, they do more custom projects, and are not constrained to work off of prescriptive measures and prescriptive projects. This allows for incentives to be entirely negotiated with the customer, with Efficiency Vermont effectively buying down the cost of the project or measure until it becomes an attractive investment for them. Within each three-year performance contract period, Efficiency Vermont has program plans which are updated annually. The 2011 plan builds on 2010's established strategies in five markets: business new construction, business retrofit, residential new construction, residential retrofit, and efficient products.

California

Summary

Electric EERS	Commission-set utility targets; ~1% annual savings
Applicable Sector	Investor-owned utilities
Natural Gas EERS	Yes
Authority 1 Date Effective	CPUC Decision 04-09-060 September 2004
Authority 2 Date Effective	CPUC Decision 08-07-047 7/31/2008
Authority 3 Date Effective	CPUC Decision 09-09-047 September 2009

Legislative and Regulatory Background

California is a long-time leading state for its utility-sector customer energy efficiency programs, which date back to the 1970s and have grown and evolved substantially over three decades. Its programs and related energy efficiency policies have had a significant impact on per capita electricity use, which has remained essentially constant over the past 30 years. Following California's 2001 electricity crisis, the main state resource agencies worked together along with the state's utilities and other key stakeholders and developed the California Integrated Energy Policy Report that included energy savings goals for the state's IOUs. The CPUC formalized the goals in Decision 04-09-060 in September 2004. The goals called for electricity use reductions in 2013 of 23 billion kWh and peak demand reductions of 4.9 million kW from programs operated over the 2004–2013 period. The natural gas goals were set at 67 MMTh per year by 2013.

The California Legislature emphasized the importance of energy efficiency and established broad goals with the enactment of Assembly Bill 2021 of 2006. The bill requires the California Energy Commission (CEC), the California Public Utilities Commission (CPUC) and other interested parties to develop efficiency savings and demand reduction targets for the next 10 years. Having already developed interim efficiency goals for each of the IOUs from 2004 through 2013, the CPUC developed new electric and natural gas goals in 2008 for years 2012 through 2020, which call for 16,300 GWh of gross electric savings over the 9-year period. California's current targets are embedded in the approved 2010-2012 program portfolios and budgets for the state's IOUs, which calls for gross electricity savings of almost 7,000 GWh and natural gas savings of approximately 150 MMTh.[24]

[23] For a more detailed discussion of factors driving success in Vermont, see Nowak et al (2011).

[24] A rough estimate of California's gross savings goal as net savings can be achieved by converting gross savings to net savings using the 2009 net to gross conversion factor of 61% (CPUC 2011). Net goals are approximately 0.8% annual savings for the period 2010-2013, dropping to 0.55% from 2014-2020. California's evaluation and attribution methods are some of the strictest in the country, however, which partly explains the low net to gross conversion factor.

Table 4: Goals and Budgets for the 2010-2012 Program Cycle

	PG&E	SCE	SDG&E	SoCal	Total
2010-2012 Program Cycle Electricity Savings (Gross GWh)	3,100	3,316	539	-	6,965
2010-2012 Program Cycle Natural Gas Savings (Gross MMTh)	48.9	-	11.4	90	150.3
2010-2012 Budgets (millions)	$ 1,338	$ 1,228	$ 278	$ 285	$ 3,129

Energy efficiency is the first priority in California's loading order for energy resources. This was first acknowledged in California's 2003 Final Energy Action Plan I. Under Public Utilities Code Section 454.5(b)(9)(C), investor owned utilities are required to first meet their unmet resource needs through all available energy efficiency and demand reduction resources that are cost effective, reliable, and feasible.

Energy Savings Achieved vs. Targeted

California IOUs' evaluated net savings for the program period between 2004 and 2008 fell slightly short of the Commission's adopted goals, achieving 9,442 GWh of savings, or about 1% annually throughout the program period.[25] The utilities plan to make up for these shortfalls in the 2010-2012 program cycle.

Table 5: 2004-2008 California Achieved Savings vs. EERS Targets

	PG&E	SCE	SDG&E	SoCal	Total
2004-2008 Program Cycle Electricity Target (Net GWh)	4,313	4,788	1,387	-	10,488
Actual Savings (Net GWh)	4,184	4,278	979	-	9,442
2004-2008 Program Cycle Natural Gas Targets (Net MMTh)	64	-	13	77	154
Actual Natural Gas Savings (Net MMTh)	77	-	12	70	159

Source: CPUC, Energy Efficiency 2006-2008 Interim Verification Report. 10/15/2009

The CPUC and the utilities are cautiously optimistic about the utilities meeting the 2010-2012 program savings goals. Saving goals for the California IOU plans must be met over the full 3-year cycle (not annually). Based on non-binding goals for 2010, IOUs are exceeding electricity goals and are close to meeting natural gas goals. [26]

[25] Compared to 2008 IOU retail sales as reported by EIA

[26] Program performance reports to-date for the California IOU programs are posted in a highly usable format at http://eega.cpuc.ca.gov/

Table 6: 2010 California Achieved Savings vs. 2010 Portion of 2010-2012 EERS

	PG&E	SCE	SDG&E	SoCal	Total
2010 Program Cycle Electricity Goal (Gross GWh)	964	1,117	195	-	2,276
2010 Actual Savings (Gross GWh)	1,425	2,000	265	-	3,694
2010 Program Cycle Natural Gas Goal (Gross MMTh)	15.6	-	3.5	28	47.1
2010 Actual Natural Gas Savings (Gross MMTh)	16.9	-	1.1	21.9	39.9

Source: California Energy Efficiency Groupware Application

Factors Affecting Performance

A full discussion of California's programmatic successes can be found in (Nowak et al. 2011). Broadly, California's experience in program planning and customer engagement contributes greatly to its success. Complementary policies such as decoupling and performance incentives also improve the environment for utility energy efficiency programs. Utilities are given program and budget flexibility so that they may shift funding from unsuccessful programs to successful programs, which contributes to the utilities' success in meeting the energy efficiency savings goals.

Hawaii

Summary	
Electric EERS	Starting in 2015 all electric utility savings will count towards Hawaii's Energy Efficiency Portfolio Standards (EEPS). EEPS long-term goal is 4,300 GWh reduction by 2030.
Applicable Sector	One Investor-owned utility with three subsidiaries located on Oahu, Hawaii, and Maui, one rural electric cooperative located in Kauai
Natural Gas EERS	None
Authority 1 Date Enacted Date Enacted	HR 1464 6/25/2009 7/1/2009
Authority 2 Date Effective	HRS §269-91 12/31/2003

Legislative and Regulatory Background

Energy efficiency is included within the definition of "renewable electrical energy" in Hawaii's Renewable Portfolio Standard (RPS), which was codified in HRS §269-91, et seq., and amended in 2006, 2008, and 2009. The RPS requires investor-owned utilities and rural electric cooperative utilities to use "renewable electric energy," which includes energy efficiency measures, to meet 10% of net electricity sales by the end of 2010, 15% by 2015, 25% by 2020, and 40% by 2030. The Public Utilities Commission may assess penalties against a utility for failing to meet the RPS, unless the failure was beyond the reasonable control of the utility. Beginning in 2015, electrical energy savings will no longer be able to count toward Hawaii's RPS, and will instead count towards Hawaii's Energy Efficiency Portfolio Standards.

Recent Developments

Legislation enacted in 2009 (HR 1464) established a formal and separate energy efficiency portfolio standard (EEPS) that sets a goal of a 4,300 GWh reduction by 2030 (equal to about 40% of 2007 electricity sales). The Public Utilities Commission (PUC) must establish interim goals to be achieved by 2015, 2020, and 2025 and may adjust the 2030 standard to maximize cost-effective energy-efficiency programs and technologies. The PUC has yet to establish rules for the stand-alone EEPS, so the current energy efficiency targets in Hawaii are set in its RPS policy.[27]

Shortly before the issuance of the stand-alone EEPS, Hawaii's energy efficiency program administrative structure underwent major changes. In June 2006, the Hawaii State Legislature enacted legislation to create a public benefits fund (PBF) for energy efficiency and demand side management.[28] This legislation granted authority to the Public Utilities Commission (PUC) to develop the details of the third-party administered public benefits fund. In December 2008, the PUC issued an order in Docket No. 2007-0323, outlining the structure of the PBF.[29] In July 2009, the Hawaiian Electric Companies' energy efficiency programs were consolidated into a single program, Hawaii Energy, operated by R.W. Beck, a subsidiary of Science Applications International Corporation (SAIC). Kauai Island Utility Cooperative (KIUC) continues to operate energy efficiency programs independently.

As of the writing of this report, most of the details of Hawaii's EEPS are under consideration by the PUC. The rules that come out of the proceeding will determine interim targets, and of particular importance, whether or not to provide incentives for compliance or penalties for non-compliance. Reducing the overall 4,300 GWh goal is not an option at this time. Hawaii seems committed to energy efficiency and renewable energy, as it recently adopted a statewide goal of reducing its reliance on imported fossil fuels by at least 70% by 2030.

Energy Savings Achieved vs. Targeted

As of 2010, Hawaii utilities achieved 19.0% of its renewable portfolio standard, 8.1% of which derived from cumulative, annualized energy efficiency savings over the policy period, easily meeting the 2010 RPS goal of 10%. In its first year of operation (July 2009-July 2010), Hawaii Energy achieved net customer energy savings of 113,159 MWh, meeting 97% and 81% of its residential and commercial targets, respectively.[30] Over the lifetime of these rebated and installed measures, cost savings will yield a 546% return on Hawaii's investment of $46.9 million ($17M/$29.9M Ratepayer/Customer Investment).

Table 7: Hawaii Energy First Year Program Performance

PY 2009 Target (MWh)	PY 2009 Achieved Net Savings (MWh)	Achieved Savings as % of retail sales*
126,023	113,159	1.17%

*Based on 2009 sales of all HECO companies

The savings levels achieved by Hawaii Energy are impressive compared to the HECO utilities' savings of 57,429 MWh in 2009, which accounted for 0.6% of sales (including Hawaii Energy for the second half of 2009). KIUC reported DSM savings of 19,217 MWh in 2009, or 4.4% of its sales in that year—an impressive achievement. [31]

[27] Docket No. 2010-0037
[28] http://www.capitol.hawaii.gov/hrscurrent/Vol05_Ch0261-0319/HRS0269/HRS_0269-0121.htm
[29] http://www.dsireusa.org/documents/Incentives/HI14R.pdf
[30] Hawaii Energy: Annual Report PY 2009, December 15, 2010
[31] 2010 HECO and KIUC RPS Status Reports, Year Ending 12/31/09. Does not include renewable displacement technologies (i.e. solar hot-water)

Factors Affecting Performance

Decoupling and Performance Incentives

In August 2010, the Hawaii PUC issued its final Decision and Order approving the implementation of the decoupling mechanism for the Hawaiian Electric Company (HECO) companies. Utilities are required to report on their performance of commitments made in the Energy Agreement in their rate cases as the basis for review, modification, continuation or possible termination of the decoupling mechanism.[32]

Hawaii Energy is compensated by the Commission for satisfactory performance of its contract. KIUC has not requested incentives. The most recent bill establishing an Energy Efficiency Portfolio Standard (EEPS) allows the PUC to establish incentives and penalties based on performance in achieving the EEPS.

Connecticut

Summary

Electric EERS	All cost-effective efficiency procurement requirement for electric and natural gas utilities that needs to be implemented. A stakeholder Council called the Energy Conservation Management Board helps to review, provide crucial input into utility proposals to invest in all cost-effective efficiency resources. Combined RPS/EERS 2007-2010 and commission-set utility targets; ~1% annual savings 2008-2011
Applicable Sector	Investor-owned utility, municipal utility
Natural Gas EERS	None
Authority 1 Date Enacted Date Effective	Public Act 07-242 of 2007 June 4, 2007 July 7, 2007

Legislative and Regulatory Background

Connecticut has an all cost-effective efficiency procurement requirement for electric and natural gas utilities that needs to be implemented. It also has a stakeholder Council called the Energy Conservation Management Board comprised of representatives of commercial, industrial, residential, low income, and environmental interests that helps to review, provide crucial input into, and oversee the utilities' efficiency program. Connecticut established a renewable portfolio standard (RPS) several years ago and expanded it in 2005. Specifically, in June 2005, the Connecticut legislature adopted legislation that adds new "Class III" requirements covering energy efficiency and combined heat and power plants (CHP). Under the new Class III requirements, electricity suppliers must meet 1% of their demand through using efficiency and CHP by 2007 and 4% by 2010. No additional Class III resources are required after 2010. Class III resources include: customer-sited CHP systems, with a minimum operating efficiency of 50%, installed at commercial or industrial facilities in Connecticut on or after January 1, 2006; (2) electricity savings from conservation and load management programs that started on or after January 1, 2006; and (3) systems that recover waste heat or pressure from commercial and industrial processes installed on or after April 1, 2007. The revenue from these credits must be divided between the customer and the state Conservation and Load Management Fund, depending on when the Class III systems are installed, whether the owner is residential or nonresidential, and whether the resources received state support.

Distribution utilities and other power distributors are responsible for meeting the goals. Existing energy efficiency programs can be used to help meet the goals, starting in 2006. Third-party providers can also earn savings certificates and sell these to power providers that have Class III

[32] See HI Docket 2008-0274.

obligations. Under the legislation, certificate values can range between $0.01 and $0.031 per kWh of savings.

The 2007 Electricity and Energy Efficiency Act (H.B. 7432) strengthened these requirements by enacting complementary policies, including policies covering energy savings from waste heat recovery. The law also requires utilities to adopt decoupling and enables performance incentives.[33] A key provision of the Act is that it requires utilities to achieve resource needs through "all available energy efficiency resources that are cost-effective, reliable and feasible." The DPUC has interpreted this mandate overly restrictively, however, focusing only on capacity needs, and has not approved funding increases to achieve all cost-effective energy efficiency.[34]

The distribution companies must submit biennial assessments of energy and capacity requirements looking forward three, five and ten years, as well as plans to "eliminate growth in electric demand" and to achieve other demand-side and environmental objectives. The Connecticut Energy Advisory Board (CEAB) reviews the plans before they are submitted to the Department of Public Utility Control (DPUC), along with CEAB comments and analysis. In a separate proceeding, the DPUC reviews the annual Conservation and Load Management (CLM) Plan, which is developed by the utilities with oversight by the Energy Conservation Management Board (ECMB), which is appointed by the DPUC. Connecticut electric utilities adopt savings targets through annual CLM Plans. The ECMB oversees the Connecticut Energy Efficiency Fund (CEEF), which is primarily supported by monthly charges on customers' bills. CEEF was created in 1998 to address increasing energy demand and rising costs. With oversight by the ECMB and its consultants, the utilities administer the energy efficiency programs.

In its 2008 decision approving the combined 2009 CLM Plan submitted by the states' major utilities and the Energy Conservation Management Board, the DPUC ordered that the 2010 plan establish broader, longer-term goals.[35] Connecticut utilities did not include long-term goals in the joint 2010 or 2011 Plans, but goals for programs do exceed 1% annual savings in 2010 and 2011. The 2010 CLM Plan was approved, but the Department expressed concern that long-term goals were not adopted.[36] However, utilities are reluctant to include long-term goals without commitment from the DPUC to increase levels of funding necessary for aggressive long-term energy efficiency goals. The DPUC has shown no indication it will approve additional ratepayer funding for electric programs beyond the current statutorily-mandated ratepayer charge. Recent energy efficiency budget raids described below have fostered uncertainty that limits the utilties' desire to plan out energy efficiency over a long period of time.

Energy Savings Achieved vs. Targeted

Connecticut has been among the national leaders in energy efficiency savings for many years. As the table below illustrates, the state's CEEF-funded programs have been near or above the 1% annual savings for three consecutive years, meeting CLM goals in two of the last three.[37] These figures include programs administered by both IOUs and municipal utilities.[38]

[33] Currently, only United Illuminating uses a full decoupling mechanism. The DPUC has not ordered full decoupling for other gas or electric utilities as of the printing of the report. All utilities are eligible for performance incentives.
[34] Docket 10-02-07
[35] Docket 08-10-03
[36] Docket 09-10-03, Department Order March 17, 2010, pgs 56-58
[37] Since CHP is included in the Class III targets, comparing energy efficiency savings to the RPS goals would not be accurate. Currently, there is no analysis of progress towards meeting Class III RPS targets.
[38] For most recent information on municipal utilities' performance, see Energy Efficiency Services 2009 Annual Report, Connecticut Municipal Electric Energy Cooperative.

Table 8: Connecticut Statewide Energy Efficiency Savings vs. Goals 2008-2011

	2008		2009		2010		2011	
	Goal	Actual	Goal	Actual	Goal	Actual	Goal	Actual
Electric Energy Efficiency Savings (GWh)	250	368	277	237	360	423	325	N/A
As Percent of Sales*	**0.8%**	**1.2%**	**0.94%**	**0.8%**	**1.2%**	**1.4%****	**1.1%**	N/A

Source: 2009, 2010 and 2011 CLM Plans
Note: Data includes Low-income programs
*Based on same year sales
**Based on 2009 Sales

Factors Affecting Performance

Funding Levels

Within the new framework created by the Electricity and Energy Efficiency Act, spending increases have been a major factor enabling and sustaining the attainment of higher energy savings. The utility energy efficiency programs have the infrastructure and capabilities in place to acquire all cost-effective savings, but now these funding increases have been stopped and in some cases reversed.

Program plans—designed by the utilities to meet the explicit legal requirement for all cost effective energy savings—have been approved by ECMB, but funding increases have been blocked at the DPUC. At UI, the efficiency program budget is dropping. Budget changes have been caused by a few factors, including years in which unspent funds were carried over from previous years, sometimes due to DPUC orders to freeze programs for budgetary reasons. Changes also occurred due to influx of stimulus money. Budget decreases have also been caused by the state re-allocating efficiency funds to cut budget deficits. Public Act 10-179 will reallocate approximately $19 million from the Conservation and Load Management Fund in 2012 and $27 million annually from 2013 through 2018 to cut the deficit.[39]

In 2009, electric efficiency program budgets dropped from $104 million to $73 million, which correlated to a savings drop from 354 GWh to 237 GWh. Even as the budgets rebounded in 2010, uncertainty persists about future levels of funding. It is also unclear whether Connecticut will establish a new set of long-term goals. The DPUC did not adopt higher savings goals proposed by the CEAB, utility program administrators, and the Energy Efficiency Board in the last two Integrated Resource Plans (IRPs), which were equivalent to about 20% energy savings over ten years. Since the DPUC has failed to adopt and fund long-term goals in its 2011 CLM plan, Connecticut no longer has a policy that can be characterized as an EERS.

Decoupling and Performance Incentives

Currently, only United Illuminating uses a full decoupling mechanism, adjusted annually. During annual hearings, the Energy Conservation Management Board (ECMB) reviews the past year's results relative to the established goals and determines a performance incentive for the distribution utilities for achieving or exceeding the goals. The incentive, referred to as a "management fee," can be from 1-8% of the program costs before taxes. The threshold for earning the minimum incentive (1%) is 70% of the goal. At 100% of the goal, the incentive would be 5%. At 130% of goals, it would be 8%. Program costs are recovered through rates.

[39] Currently under consideration, SB1157 would restore the funds with surplus anticipated to be announced at the beginning of May.

Nevada

Summary

Electric EERS	Energy Portfolio Standard: 25% Renewable energy by 2025—energy efficiency may meet a quarter of the standard in any given year, or 6.25% *cumulative* savings by 2025.
Applicable Sector	Investor-owned utilities, Retail Suppliers
Natural Gas EERS	None
Authority 1	NRS 704.7801 et seq.
Date Enacted	1997

Legislative and Regulatory Background

In 1997, Nevada established a renewable portfolio standard (RPS) as part of its restructuring legislation. Assembly Bill (AB) 3 of 2005 revised the RPS, increasing the portfolio requirement to 20% by 2015 and allowing the utilities to use energy efficiency to help meet the requirements. Amendments in Senate Bill 358 of 2009 raised the standard to 25% by 2025. Energy efficiency measures qualify if they are subsidized by the electric utility, reduce demand (as opposed to shifting peak demand to off-peak hours), and are implemented or sited at a retail customer's location after January 1, 2005. Energy efficiency savings can meet up to a quarter of the total standard in any given year. AB 1 of 2007 expanded the definition of efficiency resources to include district heating systems powered by geothermal hot water (DSIRE 2011).

The Public Utilities Commission of Nevada (PUCN) established a program to allow energy providers to buy and sell portfolio energy credits (PECs) in order to meet energy portfolio requirements. The number of kWh saved by energy efficiency measures is multiplied by 1.05 to determine the number of PECs. For electricity saved during peak periods as a result of efficiency measures, the credit multiplier is increased to 2.0. PECs are valid for a period of four years.

Since they are cumulative savings goals, the 25% target in 2025 will require only 6.25% of its sales in 2025 to be met with energy efficiency *over a twenty-year period.* The average annual savings goals for periods 2009-2011, 2011-2013, and 2013-2015 will be 0.375%, dropping to 0.25% for the next two five year intervals.

Table 9: Nevada Energy Portfolio Standard Goals

Year	Renewables Requirement (% of sales)	EE Allowed (Total Annual) (% of Sales)
2005	6%	1.25%
2007	9%	2.25%
2009	12%	3.00%
2011	15%	3.75%
2013	18%	4.50%
2015	20%	5.00%
2020	22%	5.50%
2025	**25%**	**6.25%**

Energy Savings Achieved vs. Targeted

Since energy efficiency has been deemed an eligible resource in Nevada's RPS, the state's utilities have ramped up energy efficiency programs to meet the 25% cap in each year. The RPS policy applies to Nevada's two investor-owned utilities (Nevada Power and Sierra Pacific Power) and one retail electricity supplier (Shell Energy). Sierra Pacific and Shell Energy met their full RPS

requirements while Nevada Power achieved 82% of the non-solar resource requirement. Each entity reached the 25% cap for energy efficiency. Nevada's IOUs achieved impressive savings from energy efficiency programs in 2009, substantially exceeding the cap on energy efficiency set in its portfolio standard.

Table 10: 2009 Nevada IOU Energy Efficiency Savings

Utility	2009 Achieved Savings (MWh)	% of Retail Sales (based on 2009 sales)
Nevada Power*	335,816	1.6%
Sierra Pacific**	102,806	1.3%

*Source: NPC 2010 Annual DSM Update Report
** Source: Sierra Pacific Power Company 2010 DSM Update Report

Factors Affecting Performance

Both utilities consider energy efficiency and conservation as the first leg of a "Three-Part Strategy" to meet customer energy needs. The programs offered reach every customer segment and have been thoroughly examined to ensure effectiveness. The latest plans scaled up successful programs and re-designed those in need of support.

Funding Levels

The spending levels proposed by the utilities and approved by the PUCN will produce savings far exceeding those allowed in the Portfolio Standard. Nevada Power will ramp up spending from $47.6 million in 2009 to $76.4 million in 2012. The increased spending will also continue to drive high savings levels, as each utility has demonstrated in their latest DSM plans. The drop in savings in 2012 shown for both utilities is due to the inability of the utilities to claim savings on installations of CFLs because of a Nevada law that eliminates most incandescent lamps from the market, starting in 2012.

Table 11: 2010-2013 Projected Energy Efficiency Savings for Nevada IOUs

Utility	2010	2011	2012	2013
Nevada Power	201,607	215,014	149,609	N/A
Sierra Pacific	N/A	85,380	43,500	44,780

Source: NPC: Docket No. 10-02009 (Approves 2010-2012 DSM Plan) and approved budgets (via SWEEP); SPP: 2011-2013 DSM Plan

Rhode Island

Summary

Electric EERS	A 2006 state law requires the electric distribution utility to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan. After the required review and input by a key stakeholder efficiency council (which included a unanimous 7-0 vote), the Commission approved and fully funded the 2009-2011 Efficiency Procurement Plan which includes electric utility savings targets of 1.12% in 2010; and 1.36% in 2011. The Energy Efficiency Council has proposed savings target of 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014, which are currently being reviewed by the Commission.
Applicable Sector	Investor-owned utilities
Natural Gas EERS	As of 2010, state law newly requires the natural gas utility to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan.

	The Commission has approved natural gas efficiency savings for National Grid of 56,145 Annual MMBtu Savings in 2011 (~0.29% of sales). The Energy Efficiency Council has proposed savings target of 0.75% in 2012, 1.0% in 2013, and 1.2.% in 2014, which are currently being reviewed by the Commission.
Authority 1	R.I.G.L § 39-1-27.7
Date Enacted	2006
Date Updated	2010

Legislative and Regulatory Background

Rhode Island's sole investor-owned utility, Narragansett Electric (National Grid), administers and operates a portfolio of energy efficiency programs for its customers, which account for 99% of statewide sales of electricity. Recent legislation has significantly enhanced energy efficiency's role in planning and meeting resource needs. The Rhode Island legislature unanimously passed sweeping new legislation on June 23, 2006: the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 (R.I.G.L § 39-1-27.7). This act establishes a Least Cost Procurement mandate—requiring utilities to acquire all cost-effective energy efficiency with input and review from the Energy Efficiency and Resource Management Council (EERMC). Under the Least Cost Procurement mandate, National Grid is required to participate in strategic long-term planning and invest in all energy efficiency that is cost-effective and cheaper than supply on behalf of its customers.

The act also established requirements for strategic long-term planning and purchasing of least-cost supply and demand resources. Utilities must submit 3-year and annual energy efficiency procurement plans, which offer program details, as well as spending and savings goals. Hearings are held once a year before the Rhode Island Public Utilities Commission to review program plans. The current 3-year goals are 1.1% in 2009, 1.12% in 2010, and 1.36% in 2011.[40] The EERMC has proposed savings target of 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014, which are currently being reviewed by the Commission.[41]

Rhode Island's EERS policy also includes natural gas targets. On November 1, 2010 National Grid proposed savings targets for 2011 of 173,379 MMBtu and spending goals of $10,715,000. Despite a 2010 legislative mandate to procure all cost-effective natural gas efficiency, the PUC also pointed to a legislative funding provision that it interpreted as setting a funding ceiling. As a result, the Commission approved natural gas efficiency savings for National Grid of 56,145 Annual MMBtu Savings in 2011 (~0.29% of sales).[42] The PUC has indicated that it will promptly reopen the proceeding if the legislative language in question is amended.[43] On May 18, 2011, the Rhode Island House passed legislation to clarify the full funding of all cost-effective natural gas efficiency. The Rhode Island Senate is expected to take up the legislation shortly. The EERMC has proposed savings target of 0.75% in 2012, 1.0% in 2013, and 1.2% in 2014, which are currently being reviewed by the Commission.

The EERMC has a specific legislative mandate and funding to guide, provide input, and oversee the development of 3-year energy efficiency procurement plans and related annual plans an consists of representatives of representing commercial, industrial, residential, low income, and environmental interests . The EERMC is also charged with completing an Energy Efficiency Opportunity Report to identify the size of the character of the cost-effective efficiency resources available in the state. The 3-year and annual energy efficiency procurement plans are developed by the utility with input and oversight of a subcommittee of the EERMC and other key stakeholders, including the Division of

[40] Docket No. 4116, February 8, 2010.(Revised Attachment B)
[41] See http://www.ripuc.org/eventsactions/docket/4202-EERMC-EST-Filing(9-1-10).pdf
[42] Docket 4209, January 21, 2011
[43] See ENE (Environment Northeast), *A Boost for Efficiency in Rhode Island*. Providence 2011; A bill is currently being considered: H 5281 would remove the cap on its natural gas energy efficiency charge and allow for a fully-reconciled funding mechanism.

Public Utilities and Carriers and TEC-RI, a consortium of the state's largest energy users. The full EERMC votes whether to approve the utility's EE plans before they are submitted to the PUC and is present in all related PUC dockets. The EERMC also is charged with evaluating the cost-effectiveness of the EE programs and upon a finding of cost-effectiveness, state laws provide for a fully reconciling funding mechanism to fund the EE program investments.

It is through Rhode Island's underlying economic procurement requirement, stakeholder involvement, and the subsequent PUC Efficiency Procurement Standards and dockets that an energy efficiency savings requirement is established for the electric utility.

Energy Savings Achieved vs. Targeted

National Grid, the state's electric and natural gas distribution utility has been able to meet the EE targets established through the above process. The utility plans to double the amount of savings for its customers, relative to 2008, over the three years from 2009 to 2011 through the implementation of programs that are lower than the cost of supply and are prudent and reliable. The projected cumulative amount of 265,000 net annual MWh savings over the three years is 90% of the "Aggressive Achievable Case" for energy efficiency procurement over the same period presented in an energy efficiency potential study by the consultancy KEMA submitted to the EERMC.[44] In its three-year plan, National Grid emphasized the importance of creating the delivery structure and financing mechanisms to enable the planned program expansion to proceed in a realistic and sustainable manner.[45] The program portfolio for 2011 is projected to have a benefit-cost ratio of 2.86. The Energy Efficiency Council has proposed savings target of 1.7% in 2012, 2.1% in 2013, and 2.5% in 2014, which are currently being reviewed by the Commission.

Table 12: Rhode Island Energy Efficiency Program Performance

	2008	2009	2010	2011
Annual Energy Savings Goal (MWh)	54,268	74,387	88,546	102,627
Goal as % of 2008 Sales	0.8%	1.1%	1.3%	1.5%
Annual Energy Savings Achieved (MWh)	60,053	81,000	NA	NA
Achieved Savings as % of 2008 Sales	0.9%	1.2%	NA	NA

Factors Affecting Performance

Funding Levels

In order achieve these levels of savings, funding increased from $24 million in 2009 to $31 million and $45.6 million in 2010 and 2011. The greater investments are required by Rhode Island's 2010 energy bill which requires full funding for all cost-effective efficiency measures. Funding sources include an energy efficiency program charge, revenue from carbon auction proceeds from the Regional Greenhouse Gas Initiative (RGGI), and the Forward Capacity Market. Investments in this three-year period will generate $281 million in lifetime energy savings for Rhode Island ratepayers.[46] Documented results for 2008-2010 show $345,128,000 in total benefits to electric ratepayers and $120,859,700 in total benefits to natural gas ratepayers. Total utility program cost for 2008-2010 was $66,328,600 for electric and $17,998,500 for natural gas.[47]

[44] See ENE (Environment Northeast), RI Opportunity Report and related information at, http://www.env-ne.org/resources/open/p/id/645/from/339

[45] National Grid Three Year Compliance Plan

[46] See: http://www.env-ne.org/public/resources/pdf/RI_EERMC_AnnualReport_April2011.pdf

[47] RI EERMC. Annual Report to the General Assembly. April 2011.

Least-Cost Procurement Policy

A key factor in Rhode Island's success has been the Least Cost Procurement requirement that the state's utility shall invest in efficiency resources whenever they are cost-effective and cheaper than supply resources. The establishment of the EERMC has also been critical in identifying the potential energy efficiency resource and acting as a guide and evaluator throughout the utility energy efficiency procurement planning process.

Decoupling and Performance Incentives

Rhode Island has also benefited from a newly established state law which removes barriers to investing in cost-effective energy efficiency, a policy known as "revenue decoupling," which breaks the link between a utility's retail electricity sales and revenues. Utilities also may recover the costs for running energy efficiency programs and earn incentives for high performance (ACEEE 2011).

Washington

Summary

Electric EERS	I-937 Energy Efficiency Biennial and Ten-Year Goals: Vary by Utility
Applicable Sector	Investor-owned utilities, Municipal utilities, Public Utility Districts, Co-operatives
Natural Gas EERS	None
Authority 1 Date Enacted	Ballot Initiative I-937 November 2006
Authority 2 Date Effective	WAC 480-109 11/28/07
Authority 3 Date Effective	WAC 194-37 4/18/08

Legislative and Regulatory Background

Washington voters approved ballot initiative 937 in November 2006 which set new renewable energy resource and conservation requirements for large electric utilities to meet. The ballot, codified in Chapter 19.285 RCW, had rules adopted for its implementation in 2007 and 2008.[48] The energy conservation section requires each qualifying utility (those with more than 25,000 customers in Washington) to "pursue all available conservation that is cost-effective, reliable and feasible." Seventeen utilities, both publicly owned and investor owned, currently meet the definition of qualifying utility. "High efficiency cogeneration" is included as part of conservation and the term is defined in the law. The law requires utilities to use the Northwest Power and Conservation Council's (NPCC) methodology to determine their achievable cost-effective conservation potential through 2019, and update that potential assessment every two years for the subsequent ten-year period. Utilities also must establish a biennial acquisition target for 2010-2011, and update that target every two years. If a utility does not meet its conservation goals, it must pay an administrative fine for each MWh of shortfall, starting at $50 and adjusting annually for inflation beginning in 2007.

The three major IOU's submitted reports in 2010 with a biennial conservation target as well as a ten-year achievable conservation potential. The energy efficiency targets Washington's utilities must meet amount to some of the most aggressive in the country. The credit for these ambitious targets is largely due to the law's requirement that utilities follow the NPCC methodology. The NPCC is the regional energy planning entity, established through the 1980 federal "Power Act." The Act codified energy efficiency as a real resource and required the region's largest supplier of electricity, the Bonneville Power Administration (BPA), to acquire energy efficiency that is cost effective, i.e., less expensive from the standpoint of the total cost per unit of energy saved than the next least-expensive

[48] WAC 480-109 for investor owned utilities; and WAC 194-37 for public utilities

available resource. To guide BPA, the Act authorized the NPCC to produce a Northwest energy efficiency and power plan every five years. In its Sixth Power and Conservation Plan released in 2010, the NPCC concludes that energy efficiency can meet 85% of load growth in the region through 2030 at an average cost of 3.6¢/kWh, providing over 5900 average MW (aMW) of new energy efficiency savings (NPCC 2010).[49] While the IOUs and public utilities did not all use the Power Plan to set targets, the document usefully informed the planning process.[50]

Prior to the implementation of its EERS, many of Washington's investor- and publicly-owned utilities had long records of significant investments in energy efficiency. Washington's diverse mix of private and public utilities have long records of offering customer energy efficiency and conservation programs.

Investor-owned utilities account for approximately half the retail electric sales in the state. Washington is a non-restructured state and has no public benefits funding to support programs. Investor-owned utilities recover the costs of energy efficiency programs through tariff riders. Program costs are reported and adjusted annually in proceedings before the Utilities and Transportation Commission.

Energy Savings Achieved vs. Targeted

Entering the second year of the biennial program planning period, Washington's IOUs are on track to meet their goals cost-effectively. Using the Total Resource Cost (TRC) test, PSE's 2010 electric and gas programs performed at 2.15 and 1.22, respectively (3.39 and 2.78 using the Utility Cost Test). The respective TRC figures for Avista in 2009 were 1.68 and 1.08.[51]

Table 13: Washington IOU Energy Savings Achieved vs. Targeted

Utility	2010-2011 Goal (MWh)	Biennial Target as % of 2009 Retail Sales*	2010 Achieved Savings** (MWh)
Avista[52]	128,603	2.4%	86,758
Pacificorp***[53]	74,460	1.8%	N/A
Puget Sound Energy[54]	622,000	2.8%	295,547

*Retail sales reported in EIA 2009
**Savings data reported in utility DSM Annual Business Plans/Report (PSE, Avista)
***Converted from Average MW

Factors Affecting Performance

Collaboration among Stakeholders

The extensive planning process undertaken in 2009 has paid dividends for program performance in 2010 and 2011. The planning process benefited from a Conservation Working Group (CWG), which created a forum for the three utilities and regional stakeholders to share best practices and lessons learned. The CWG was formed in 2011, primarily to aid in providing clarity, certainty, and consistency where possible for IOUs in implementing their I-937 requirements. No similar process exists for the public utilities.

[49] 5900 aMW equals 51,684 GWh. Taking Washington's share of electricity load in the Northwest (~51%), we have calculated the statewide goal in Washington to be 26,358 GWh by 2030, or 1.5% of 2009 retail sales annually.
[50] PSE used its own IRP to set its target; PacifiCorp looked at the 6th Plan and adjusted its "share" generally downwards based on its IRP and key differences between its service territory and the overall region; Avista used its share of the 6th Plan but added fuel switching. Some public utilities used the 5th Power Plan, which identified a lower amount of regional savings than the 6th Plan. Beginning with the next biennium—2012-2013—the 5th Power Plan will no longer be an option.
[51] Assumes 100% net-to-gross ratio
[52] UE-100176
[53] UE-100170
[54] UE-100177

Experience with Energy Efficiency

Washington's initial success staying on track to meet its targets may be partly attributed to the utility program delivery and reporting infrastructure established throughout the past decades, including a Regional Technical Forum that provides utilities with deemed savings for a host of EE measures. Washington's three IOUs have set annual DSM program portfolio savings targets for many years in IRPs, and BPA has required DSM reporting from the public utilities for years. The long-standing commitment to DSM in the region fostered numerous groups, systems, and tools that promote and deliver energy efficiency services. As a result, Washington achieved statewide savings of 0.61% compared to retail sales in 2008 (Molina et al. 2010).

EERS Impacts on an Established Energy Saver

The implementation of the I-937 targets benefits Washington more than if it had maintained the status-quo, however, sending an important lesson to states without a statewide EERS that have energy efficiency programs in place. Aside from spurring a slight ramp-up in savings levels, the statewide EERS provides the state's IOUs certainty that benefits program development. Importantly, the targets have a much greater impact driving higher levels of savings from public and co-operative utilities in Washington, which account for just over half the electric sales in the state and varied greatly in their DSM offerings in the past. Tacoma Power customers will see a major boost in energy efficiency investments as a result of I-937, for example. Most publicly-owned utilities in Washington, including Bonneville Power Administration, Seattle City Light, and Snohomish County Public Utility District, have historically provided funding for energy efficiency programs and services.

The targets also strengthened the system of evaluation, monitoring, and verification of energy efficiency savings from programs. Since the WUCT approves the biennial efficiency targets for investor-owned utilities, Commission staff must base their recommendation for approval on more sufficient evidence than the deemed savings previously submitted by utilities. The targets, therefore, is spurring a transition for some utilities to a system of third-party verified savings and measures installed, resulting in a statewide effort to improve and streamline reporting requirements. PSE, for instance, now relies primarily on third-party EM&V. The increased focus on EM&V will result in more certain savings and prudent energy efficiency investments.

Colorado

Summary

Electric Energy Efficiency Goals	PSCo and Black Hills Energy (BHE) both aim for 0.9% of sales in 2011 and increase to 1.35% (1.0% for BHE) of sales in 2015 and then 1.66% (1.2%) of sales in 2019
Applicable Sector	Investor-owned utilities
Natural Gas Goals	Expenditure targets equal to at least 0.5% of prior year's revenue—savings targets commensurate with spending targets and expressed in terms of gas saved per unit of program expenditure; goals set by gas utilities as part of their gas DSM program plans.
Authority 1	CRS 40-3.2-101, et seq.

Legislative and Regulatory Background

The Colorado legislature passed HB-07-1037 in April 2007, which amended Colorado statutes C.R.S. 40-1-102 and 40-3.2-101-105 by requiring the Colorado Public Utilities Commission (COPUC) to establish energy savings goals for investor-owned electric and gas utilities. The bill also requires the COPUC to provide utilities with financial incentives for implementing cost-effective energy-saving programs. The COPUC must report annually on the progress made by investor-owned natural gas and electric utilities in meeting their demand side management goals.

The EERS statute does not directly set a fixed schedule of statewide percentages of energy savings to be achieved by particular years, nor does it require the acquisition of all cost-effective energy efficiency resources. Instead it sets an overall multi-year statewide goal for investor-owned utilities of at least five percent of the utility's retail MWh energy sales in the base year (2006) to be met by the end of 2018, counting savings in 2018 and including savings from DSM measures installed starting in 2006. The law empowers COPUC to set interim goals for utilities and to modify goals.

Public Service Company Colorado (PSCo) and Black Hills Energy (BHE) together account for more than 80% of the total projected GWh savings and over 58% of retail electricity sales in the state; some municipal utilities and electric co-ops also implement efficiency programs.

In a May 2008 decision, the COPUC set energy savings goals for PSCo for the period 2009-2020. The goals set energy saving targets of 0.53% of retail sales in 2008, ramping up to 1% in 2015, and 1.2% in 2019. The savings would amount to 3,669 GWh over the 12-year period.[55] The Commission accepted modified goals for PSCo for 2009 and 2010 in a Settlement Agreement in Decision R08-1243 in February 2009, which were designed to save approximately 0.6% (176 GWh) in 2009 and 0.8% (237 GWh) in 2010, exceeding the mandated savings in both years.[56] PSCo plans to achieve 255 GWh in 2011.[57]

Black Hills Energy adopted an efficiency plan that aims to save 0.53% of projected sales in 2009 (10,287 MWh), 0.76% in 2010 (15,156 MWh), and 0.80% in 2011 (16,522 MWh).[58] The statutory minimum goal for Black Hills over the ten-year period is 93.9 GWh, based on 2006 sales.[59]

In May 2011, COPUC approved new goals for PSCo for the 2012-2020 period. The goals are approximately 130 percent of the annual goals approved in May 2008, beginning at 1.14% of sales in 2012, ramping up to 1.35% in 2015, and reaching 1.68% in 2020. The goals set out to achieve 3,984 GWh in the nine-year period.[60]

For investor-owned natural gas utilities, the EERS legislation structured the requirement in two parts. First, the natural gas IOU's must set DSM spending targets of more than 0.5% of revenues from customers in the prior year. Energy savings targets are then established by COPUC commensurate with spending and stated in terms of quantity of gas saved per dollar of efficiency program spending.

Energy Savings Achieved vs. Targeted

Leveraging parent company Xcel Energy's years of program delivery experience in Minnesota, PSCo surpassed their planned 2009 and 2010 electricity savings goals, saving 220 GWh in 2009 and 253 GWh in 2010.[61] Black Hills Energy was less successful in the 2009/2010 program period. BHE notes in its 2009/10 Annual Status Report that it received approval of its programs only a month prior to the July 1st, 2009 start date, which did not give the utility enough time to design and execute programs in time for the 2009 Summer. As a result, savings and spending fell below targets for the year. BHE spent $1.4 million and saved 4,554 MWh—58% and 44% of their respective targets.[62]

[55] Docket No. 07A-420E, Decision C08-0560

[56] Based on 2009 retail sales. Xcel Energy/Public Service Company of Colorado 2009/2010 Demand-Side Management Biennial Plan, Electric and Natural Gas, Docket No. 08A-366EG. Originally filed August 2008, revised February 2009. In this profile, Xcel goals and savings are given at the generator level; these values need to be reduced by about 7% to get savings at the customer level.

[57] PSCo 2011 DSM Plan

[58] COPUC Docket No. 08A-518E Decision No. R09-0542,

[59] Public Utilities Commission Report to the Colorado General Assembly on Demand Side Management. April 28, 2009.

[60] Docket No. 10A-554EG, Decision No. C11-0442

[61] Docket No. 08A-366EG. 2009 Savings data from 2009 Demand-Side Management Annual Status Report, 4/5/10; 2010 Savings data from Fourth Quarter Colorado DSM Roundtable Update, 2/15/11.

[62] Black Hills Energy Colorado Electric Annual Status Report Energy Efficiency Programs 2009-2010

Table 14: Colorado Electric Utility Savings Targets as % of Sales

Utility	2009 Target	2009 Achieved	2010 Target	2010 Achieved	2011 Target	2020 (Cumulative 2012-2020)
PSCo	0.6%	**0.8%**	0.8%	**0.9%**	0.9%	13.75%
Black Hills Energy	0.53%	**0.23%***	0.76%	N/A	0.80%	

*Program year beginning July 1, 2009 ending June 30, 2010

For natural gas, PSCo had already budgeted 250% of the minimum spending requirement prior to the EERS, as gas prices had doubled due to suppliers building a pipeline out of the Rocky Mountains. Now that prices have declined again, energy efficiency measures are much less cost effective, many with a total resource cost of 1.1. In 2009, the first year goals took effect and the first year in which PSCo had a complete and comprehensive efficiency plan in place, savings were 308,761 Dth, or 97% of the goal the Commission-approved plan.[63]

Factors Affecting Performance

Funding Levels

One of primary ways utilities are using to achieve greater energy savings has been to invest more money: funding for utility energy efficiency has increased rapidly in Colorado as the PUC sets energy savings goals. According to the revised 2009/2010 Demand-Side Management Biennial Plan, PSCo increased their investment in gas and electric efficiency and demand programs from $63 million in 2009 to $80 million in 2010.

Performance Incentives

Policies complementary to the EERS partly attribute to PSCo's success. COPUC has implemented a performance-based incentive for PSCo, enabling them earn a return of 1-15% of net benefits on its demand-side management expenditures as long as it achieves at least 80% of its energy savings goal in any one year. The incentive is tied to energy savings achieved and the net economic benefits of the programs. The total payment of the performance incentive and a separate pre-tax disincentive is capped at $30 million. Black Hills Energy has adopted the same mechanism.

Meeting Future Goals

With the aggressive savings increases planned over the next three to four years, PSCo will build on its strong residential, commercial and industrial programs, expanding marketing and incentive levels, and possibly adding further market transformation programs. In addition to continuing and expanding existing programs, new directions will be explored, including behavioral programs in the residential sector.

Illinois

Summary

Electric EERS	0.2% annual savings in 2008, ramping up to 1% in 2012, 2% in 2015 and thereafter
Applicable Sector	Investor-owned utilities; retail supplier; Illinois DCEO
Natural Gas EERS	8.5% cumulative savings by 2020 (0.2% annual savings in 2011, ramping up to 1.5% in 2019)
Authority 1	§ 220 ILCS 5/8-103
Authority 2	Public Act 96-0033
Authority 3	S.B. 1918

[63] Docket No. 08A-366EG. 2009 Demand-Side Management Annual Status Report, 4/5/10

Legislative Background

The scope of energy efficiency activity in Illinois began a dramatic expansion in July 2007, when the state legislature passed the Illinois Power Agency Act (IPAA), which includes requirements for energy efficiency and demand response programs. The IPAA establishes an EERS that sets incremental annual electric and natural gas savings targets based on previous year's consumption, beginning on June 1 of that year. The electric savings requirements began at 0.2% in 2008 and ramps up to a requirement of 2% annual savings in 2015 and thereafter. The natural gas goals begin in 2012 with a 0.2% reduction of 2011 sales and ramp up to 1.5% annual savings by 2019.

Table 15: Illinois Electric EERS Savings Goals

2008	2009	2010	2011	2012	2013	2014	2015+
0.20%	0.40%	0.60%	0.80%	1.00%	1.40%	1.80%	2.00%

Investor-owned electric utilities are responsible for roughly 75% of program savings and spending, while the Illinois Department of Commerce and Economic Opportunity (DCEO) administers the remaining 25% of the funds, which are used to for efficiency programs serving government facilities, low-income households, and market transformation-oriented information and training programs.

The rate increase for customers due to energy efficiency is limited by statue to 0.5% of the total 'per kWh' charge in the first year and increasing to 2.0% in 2012. If the rate impact cap is reached, the energy savings goals will be relaxed to the maximum savings that can be achieved within the rate impact cap. If, after 2 years, an electric utility fails to meet the efficiency standard it must make a contribution to the Low-Income Home Energy Assistance Program and transfer the program to the Illinois Power Authority.

Energy Savings Achieved vs. Targeted

Results to date among the major program administrators in Illinois have been mixed. ComEd and Ameren Illinois exceeded savings requirements in its first two program years while DCEO has not met savings goals in either of its first two program years. Independent analysis of ComEd's programs in its second program year found portfolio cost-effectiveness based on the Illinois Total Resource Cost (TRC) test to be 2.84. Ameren Illinois met its goals in 2009 cost-effectively as well as its portfolio scored a 2.78 using a TRC Test.

Table 16: Illinois Electric Efficiency Savings 2008-2010

Utility	2008-2009 (PY 1) Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2009-2010 (PY 2) Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
ComEd	148,842	**163,717**	110%	315,223	**456,151**	145%
Ameren Illinois	62,808	**89,955**	143%	118,288	**142,995**	121%
DCEO	54,572	**27,285**	50%	110,715	**72,331**	65%

Sources: ComEd Year 1 Evaluation Report; ComEd Year 2 Evaluation Report; Ameren Illinois Year 1 Annual Report; Ameren Illinois Final PY2 Monthly Report September 2010; DCEO Program Year 2 Evaluation

Factors Affecting Performance

DCEO claims numerous factors prevented outright success for its public sector and low-income programs, such as the economic downturn and its effect on government and school budgets. DCEO market transformation activities such as training for contractors and technical assistance do not count for any savings during the first three years and public entities also require substantial technical assistance with completing paperwork, which increases the administrative costs of running the programs. Federal funds from the Recovery Act used by municipalities also supplanted, rather than

supplemented, the state government programs, impeding higher levels of savings. In response to these challenges, DCEO adopted new approaches in more recent program years, hiring more contractors to assist government agency customers, and partnering directly with Community Colleges and the State Board of Education to promote DCEO energy efficiency programs. DCEO also partnered with Regional Planning Agencies, which were assisting the administration of municipal-aimed Recovery Act funds (Energy Efficiency Community Block Grants (EECBG)).

Funding Levels

In order to meet the increasing savings goals, Illinois utilities increased energy efficiency budgets. Funding for electric efficiency programs shot up from less than one million in 2007 to $89.9 million in 2009 and then to $107.4 million for 2010 (ACEEE 2011). Natural gas efficiency budgets went from zero in 2007 to over $4 million in 2009. In its 2008-2010 plan, ComEd's spending screens ramp up from $39.4 million to $126.7 million in 2010. In its 2011-2013 plan, its spending screens stabilize around $160 million per year. For Ameren Illinois the limit levels off at $60 million. However, a process is underway in which the Commission will report to the legislature on the impact of the spending caps, and the legislature will have an opportunity to increase or eliminate those caps.

Meeting Future Goals

There is widespread concern among program administrators that when the spending caps are reached, the annual savings goals will not be met. The spending limit stays fixed after it reaches 2% in 2012, but the MWh requirements continue to increase. In the long term, all the program administrators agree that new funding will be required and that there will be an effort to raise the spending limits supported by environmental and consumer stakeholders, who assert that annual savings above 1% can be reached and sustained cost-effectively statewide.

Minnesota

Summary

Electric EERS	1.5% annual savings beginning in 2010 (1% from programs, 0.5% from codes, standards, transmission and generation improvements).
Applicable Sector	Investor-owned utilities; retail suppliers
Natural Gas EERS	0.75% annual savings from 2010-2012; 1.5% annual savings in 2013
Authority 1 Date Enacted Date Effective	Minn. Stat. § 216B.241 2/22/2007 2/22/2007

Legislative Background

Minnesota investor-owned electric and gas utilities are subject to the energy savings requirements of the Next Generation Energy Act (NGEA), passed by the Minnesota Legislature in 2007 (Minnesota Statutes 2008 § 216B.241). Among its provisions, the Act set energy-saving goals for utilities of 1.5% of retail sales each year, commencing with the first triennial plan period that began January 1, 2010. Of the 1.5%, the first 1% must be met with direct energy efficiency energy savings, or conservation improvements. This may include savings from efficiency measures installed at a utility's own facilities. The NGEA also allows savings to be achieved indirectly through energy codes and appliance standards. Up to 0.5% may be met by efficiency enhancements to each utility's generation, transmission, and distribution infrastructure. Electric and natural gas municipal utilities and co-operatives must set energy efficiency spending goals based on a percentage of revenue. Prior to the Next Generation Energy Act going into effect fully in 2010, Minnesota utilities were required to spend a percentage of gross operating revenue (0.5% gas, 1.5% electric) on energy efficiency programs rather than to achieve a set amount of energy savings.

The NGEA allows a utility to request a lower target (based on historical experience, an energy conservation potential study, and other factors), but in no case can that be lower than 1% per year. Lower savings can also be justified if the Commissioner of Commerce determines that additional savings are not cost-effective to ratepayers, the utility, participants, and society. In 2009, the state legislature amended the Act to reduce the mandated level of savings during the first three years for natural gas utilities, establishing an interim average annual savings goal of 0.75 percent over 2010-2012 (Minnesota Session Laws 2009, Ch. 110, Sec. 32).

For the first triennial period 2010-2012, CenterPoint Energy's natural gas energy efficiency plan is to increase savings from 0.73 to 0.78%, averaging the minimum 0.75%. Xcel Energy electric savings goals included in their approved triennial plan are 1.15% in 2010, 1.2% in 2011, and 1.3% in 2012.[64]

Energy Savings Achieved vs. Targeted

Minnesota's utilities achieved increasing levels of efficiency savings over the 2007-2009 period. The Minnesota Office of Energy Security (OES) reported that statewide energy savings in 2009 met around 1.0 percent and 0.6 percent, electric and natural gas respectively, of 2007-2008 retail sales.

Table 17: Minnesota Statewide Electric Savings Achieved from Conservation Improvement Programs, 2006-2009

Year	Statewide Electric Savings Achieved (MWh)	Savings as % of 2007 Sales	IOU Natural Gas Savings (MCF)	Savings as % of Average Sales[65]
2006	411,999	0.60%	N/A	N/A
2007	468,070	0.68%	N/A	N/A
2008	597,288	0.87%	1,534,121	0.54%
2009	648,163	0.95%	1,777,369	0.63%

Source: Minnesota Conservation Improvement Program Energy and Carbon Dioxide Savings Report for 2008-2009, March 23, 2011

Factors Affecting Performance

Funding Levels

Reaching these higher levels of savings necessitated increased funding levels. The $144 million statewide budget for electric efficiency programs in 2009 eclipsed 2008 levels by $42 million. Spending levels will continue to rise as goals ramp-up and programs attempt to reach new sectors and achieve deeper levels of savings. Overall Conservation Improvement Program (CIP) spending by investor-owned utilities is projected to increase from $77 million in 2008 to $127 million in 2010, an increase of 65 percent.

Performance Incentives

In 2010, Minnesota adopted a new "shared savings" model for incentives. This incentive is voluntary (utilities are not required to participate), applies to any utility participating in the Conservation Improvement Program, and will replace existing incentives in 2010.[66] This incentive is designed to help utilities meet the 1.5% savings goal. The percentages are set individually for each utility and are reviewed each year.

[64] Targets presented in: CenterPoint Energy's 2010-2012 Triennial Conservation Improvement Program Plan; Xcel Energy 2010/2011/2012 Triennial Plan Minnesota Electric and Natural Gas Conservation Improvement Program

[65] Based on "average sales" figures presented in CIP Energy and Carbon Dioxide Savings Report for 2007-2008.

[66] Order issued January 27, 2010 in Docket E,G-999/CI-08-133

Experience with Energy Efficiency

Minnesota has a long record of customer energy efficiency programs offered by both investor-owned and publicly-owned utilities. These programs have achieved significant energy savings for well over two decades, without any of the interruption or upheavals that occurred in most other states that restructured their electric utility industries.

Meeting Future Goals

Despite higher spending levels, Minnesota will face several challenges as its utilities attempt to find ways to meet future savings goals. In the case of Xcel Energy, it will strive to meet the electric 1.5% goal over the long term from customer programs, possibly during the next triennial planning period from 2013 to 2015. While some stakeholders in the state argue the goal cannot be achieved over the long-term, others believe that the Minnesota's success thus far doubling and tripling energy savings as utilities ramp up demonstrates the feasibility of aggressive savings in the state.

Impact of Codes and Standards

The impact of higher appliance standards and building codes on utility savings may be a major factor determining the future savings levels for Minnesota utilities, depending on how the Commission addresses the issue in future dockets. Stringent codes and standards that raise baseline conditions for energy efficient equipment result in lower savings attributable to utility efficiency programs, which can reduce a utility's ability to claim savings and reduce the cost effectiveness of program portfolios. Mitigating these effects, Minnesota is one of the few states that permit utilities to get credit for savings from codes and standards.

Collaboration among Stakeholders

Xcel Energy describes their future efficiency program success as dependent on many factors, including the growth of their existing program portfolio, emerging energy efficient equipment technologies, market transformation, and the development of methodologies to quantify savings from nontraditional programs. Two key energy savings areas Xcel is looking at that fit squarely with the 1.5% Energy Efficiency Solutions Project are behavioral programs and codes and standards.

Seeking to address the issue of codes and standards among other potential barriers, the Minnesota Office of Energy Security contracted with the Minnesota Environmental Initiative (MEI) to lead a multi-stakeholder process to find ways to achieve the 1.5% goal. The MEI developed a "1.5% Energy Efficiency Solutions Project" and convened technical working groups to focus on four "policy barrier issue areas": behavioral programs, low income, codes and standards, and utility infrastructure improvements. The Project released its final report in March 2011.[67]

North Carolina

Summary

Electric EERS	Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Investor-owned: 12.5% by 2021 and thereafter. Municipal and co-operative utilities: 10% by 2018. Energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target.
Applicable Sector	Investor-owned utilities, Municipal utilities, Co-operatives
Natural Gas EERS	None
Authority 1 Date Enacted	N.C. Gen. Stat. § 62-133.8 Enacted 8/20/2007 Effective: 1/1/2008

[67] http://mn-ei.org/projects/images/EE1.5/Report/1.5EESolutionsFinalReportwithoutAppendices.pdf

Authority 2	04 NCAC 11 R08-64, et seq.
Date Enacted	2/29/2008
Date Effective	2/29/2008

Legislative Background

North Carolina Senate Bill 3 was finalized in 2008, introducing the state's combined Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Under the REPS, public electric utilities in the state must obtain renewable energy power and energy efficiency savings of 3% of prior-year electricity sales in 2012, 6% in 2015, 10% in 2018, and 12.5% in 2021 and thereafter. For IOUs, energy efficiency is capped at 25% of the 2012-2018 targets and at 40% of the 2021 target. Co-operative and municipal utilities may satisfy their all of their REPS requirements with energy efficiency outside of particular set-asides for solar and other resources. Utilities demonstrate compliance by procuring renewable energy credits (RECs) earned after January 1, 2008. Under NCUC rules, a REC is equivalent to 1 MWh of electricity avoided through an efficiency measure. Since the REPS goals are cumulative, the 12.5% target in 2021 will require 5% of its sales in 2021 to be met with energy efficiency *over the entire 13-year period* in which energy efficiency savings may be counted. Averaged over three years, each target period until 2018 requires annual savings of 0.25%. The final period from 2018 to 2020 will allow annual energy savings of 0.83%. Utilities plan to employ more than the full quarter allowable over the next ten years. Industrial customers may opt-out of utility energy efficiency programs and not bear the costs of new programs if they implement their own programs.

Table 18: REPS Savings Schedule and Eligible Efficiency for North Carolina IOUs

Year	Cumulative Renewables Requirement (% of Sales)	EE Allowed (Total Annual) (% of Sales)
2012	3.00%	0.75%
2015	6.00%	1.50%
2018	10.00%	2.50%
2021	12.5%	5%

Each electric power supplier must file a REPS compliance plan for Commission review as part of its Integrated Resource Planning (IRP) filing on or before September 1 of each year. A utility's IRP filing must include a comprehensive analysis of all resource options considered by the utility, including demand-side management and energy efficiency, which must result in "the least cost mix of generation and demand reduction measures achievable...."[68] According to Commission Rule R8-60, IRP filings must include a 15-year forecast of demand-side resources, among other requirements for the assessment and characterization of the demand-side resource.

EERS Impact on Energy Efficiency Programs

The targets have been effective in prompting utilities to develop energy efficiency programs, bringing substantial benefits to customers. Duke Energy Carolinas introduced energy efficiency programs in mid-2009 and projects savings from these programs will achieve more energy efficiency savings than can be utilized under the REPS for the foreseeable future.[69] Progress Energy had existing programs prior to Senate Bill 3, but developed an expanded portfolio of programs between 2008 and 2010.[70] Duke and Progress estimate cumulative savings to be 4.9% and 6.2% of retail sales, respectively, over the next ten years. Dominion North Carolina Power plans to achieve energy efficiency savings

[68] N.C. Gen. Stat. § 62-2(3a)
[69] Duke IRP, page 16
[70] Progress Energy IRP

beginning in 2011.[71] As these targets are adjusted annually, the next couple of years will be critical as Duke in particular shifts from a program portfolio that emphasizes CFLs towards a more diverse portfolio. As of the writing of the report, no public information is available detailing actual energy savings from energy efficiency programs.

The REPS goals succeeded in pushing North Carolina's utilities to develop programs, with the added benefit of catalyzing programs in South Carolina. While the targets are some of the lowest in the nation, utilities may set savings targets above the allowable REPS goal. In some instances however, such as with Dominion Power, utilities will only seek to save the minimum necessary to meet the REPS goal.

Complementary to the REPS goals, PEC and Duke have also obtained financial structures that promote added achievement.[72] The initial results suggest that Duke has been very aggressive in making sure it achieves as much as possible early in its program deployment. Longer term impacts are less clear. PEC has been less forthcoming about its program impacts and it is not clear that financial structures alone are enough to motivate PEC. It is also unclear whether recently approved lost revenue adjustment mechanisms approved for both utilities will persuade the companies to invest more heavily in demand resources than supply, namely nuclear power, resources. [73]

While prompting utilities to develop energy efficiency program portfolios is a notable achievement, particularly for public and co-operative utilities unlikely to pursue DSM without a policy in place, the paltry 5% cumulative goal energy efficiency goal will not drive annual efficiency savings levels much higher than 0.40% over the next decade—acting more like a business-as-usual baseline than a goal to drive market development and transformation. There is ongoing disagreement among environmental groups and utilities over whether the energy efficiency programs proposed by the IOUs in their latest resource plans are fully harnessing the energy efficiency resource. [74] Adding additional uncertainty to the situation in North Carolina, the N.C. State Legislature also has a bill under consideration that would repeal Senate Bill 3.[75]

Maryland

Summary

Energy Efficiency Goal	15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (10% by utilities, 5% achieved independently)
Applicable Sector	Statewide Goal
Natural Gas EERS	None
Authority 1 Date Enacted: Date Effective	Md. Public Utility Companies Code § 7-211 04/24/2008 06/01/2008

Legislative Background

Although Maryland's utilities ran energy efficiency and demand response programs in the 1980s and early 1990s, most of these efforts were discontinued when the state removed regulations during utility restructuring in the late 1990s. The EmPOWER Maryland Energy Efficiency Act of 2008 directs the Maryland Public Service Commission (PSC) to require electric utilities in the state to provide energy efficiency services to its customers to achieve 10% of the 15% per-capita electricity use reduction goal by 2015 with targeted reductions of 5% by 2011 calculated against a 2007 baseline (Order 82344). The 15% goal is equivalent to approximately 11,206 GWh, or 17% of 2007 retail sales.[76] The Maryland Energy Administration (MEA) and other public and private stakeholders, including the

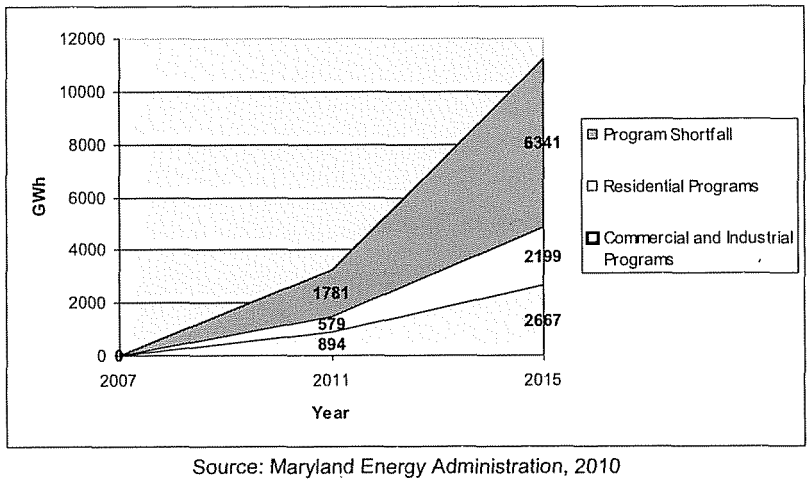
[71] Dominion IRP
[72] Progress: Docket E-2, sub 931; Duke: Docket E-7 sub 831
[73] John Wilson, SACE. Personal e-mail 3/10/11
[74] SACE Comments on Duke and PEC IRP
[75] House Bill 431
[76] Maryland Energy Administration. 2010. Maryland Energy Outlook.

Department of Housing and Community Development (which runs the weatherization program and Department of General Services (runs the public-sector Energy Savings Performance Contracting program) are responsible for achieving the remaining 5% of the overall 2015 electricity savings target. Utility programs must also achieve a reduction in per capita peak demand of at least 5% by end of 2011, 10% by 2013, and 15% by 2015.

Regulatory Background

In late 2008, Maryland's utilities filed energy efficiency and demand reduction plans to achieve the EmPOWER Maryland goals. The "interim" energy efficiency savings goals set in the plans are not sufficient to meet the 2011 or 2015 EmPOWER Maryland goals.[77] Maryland's two largest utilities, Baltimore Gas and Electric (BGE) and Potomac Electric Power Company (PEPCO) set interim goals that fall 40% and 30% short of the EmPOWER Maryland goals for 2015. MEA plans to save 73 GWh for programs in FY11, ramping up from the 64 GWh it saved between 2009 and 2010.[78] As of the end of December 2010, MEA was achieving 97 GWh.[79]

Figure 4: Projected Energy Efficiency Savings from Approved 2008 EmPOWER Maryland Plans



Source: Maryland Energy Administration, 2010

In its 2010 Energy Outlook report, the MEA projects that its programs combined with the approved PSC programs would reduce statewide energy consumption by approximately 4,866 GWh by 2015, which is less than half the overall goal of 11,206 GWh. Nonetheless, this projection would result in around 7% cumulative savings by 2015, or an average of about 1% annual savings, a significant achievement.

Energy Savings Achieved vs. Targeted

The latest DSM reports submitted by Maryland's major IOUs show that while programs are ramping up savings, they have not met their interim goals and will meet neither the interim goals nor the EmPOWER Maryland goals in 2011. The table below outlines the interim targets forecasted by utilities in their 2008 plans, reported savings, and how they compare to the 2011 EmPOWER Maryland Goal.[80]

[77] Allegheny Power: Case 9153, Baltimore Gas & Electric: Case 9154, Potomac Electric Power Company (PEPCO): Case 9155; Delmarva Power & Light: Case 9156; Southern Maryland Electric Cooperative (SMECO): Case 9157

[78] Maryland Energy Administration, EmPOWERing Maryland Clean Energy Programs FY 2011

[79] Walt Auburn, Maryland Energy Administration. Personal Conversation. May 17, 2011.

[80] Yearly numbers are taken from the Full Year tables of each Annual Report and the Program to Date numbers are taken from the 2010 Annual report. The yearly summations for each utility will not equal the respective program to date numbers due to reporting issues or corrections.

Table 19: EmPOWER Maryland Utilties Savings Targets vs. Achieved

Utility		2009 Interim Target (MWh)	2010 Interim Target (MWh)	2011 Interim Target (MWh)	2009-2011 Total Target	2009-2011 EmPOWER Maryland Goal
Allegheny Power	Forecasted	6,757	27,201	46,119	109,955	122,664
	Reported	66	15,068	N/A	32,673	32,673
	Difference	-99%	-45%		-70%	-73%
BGE	Forecasted	295,285	351,735	412,096	1,059,116	2,052,948
	Reported	97,209	274,068	N/A	371,277	371,277
	Difference	-42%	-22%		-65%	-83%
Delmarva Power & Light	Forecasted	34,036	37,321	77,931	149,288	503,202
	Reported	11,035	11,706	N/A	22,925	22,925
	Difference	-68%	-69%		-85%	-96%
Pepco	Forecasted	145,141	163,800	279,687	588,628	1,874,656
	Reported	38,340	68,149	N/A	106,489	106,489
	Difference	-74%	-58%		-82%	-94%
SMECO	Forecasted	24,325	30,923	27,350	82,598	254,827
	Reported	248	18,461	N/A	18,494	18,494
	Difference	-99%	-40%		-78%	-95%
Total	**Forecasted**	**543,884**	**679,129**	**843,183**	**2,096,074**	**4,914,786**
	Reported	**146,898**	**387,452**	**N/A**	**551,858**	**551,858**
	Difference	**-73%**	**-43%**		**-74%**	**-89%**

Source: Maryland Public Service Commission, Annual 2010 EmPOWER Maryland Overall Implementation & EM&V Progress Report, March 22, 2011

Factors Affecting Performance

A recent report from the Maryland Public Interest Research Group (PIRG) issued a detailed account of how Maryland is falling behind on its energy efficiency goals (Maryland PIRG 2011). The report places much of the blame on the PSC for failing to properly initiate and oversee the EmPOWER Maryland initiative. The PSC delayed implementation of the EmPOWER Maryland programs; restricted the types of programs it allows utilities to pursue, namely through its cost-effectiveness test; and did not hold utilities accountable for electricity savings shortfalls. The report also notes that non-utility programs have been weakened because of decreased funding from sources intended for energy efficiency programs. Maryland participates in the Regional Greenhouse Gas Initiative (RGGI), which has brought more than $148 million to the state's Strategic Energy Investment Fund since 1998, nearly half of which was originally allocated for energy efficiency. In 2010, the Governor and General Assembly cut this to 20 percent and diverted funds to assist utility customers pay bills. A similar proposal is in place for 2011 through FY 2014.

While the PIRG report rightly discusses the failure of the PSC, it should be noted that Maryland's utilities faltered in the planning and execution of energy efficiency programs. The utilities lack staff with programmatic experience and failed to exhaust the full range of potential energy efficiency measures in their initial plans. Additionally, while the scale of its effects is hotly debated, there is little doubt that the weakened economy played some role in the lower than expected customer participation rates.

Moving forward, the Maryland PSC commissioned EM&V reports for the completed program period, which should instruct utilities on how to improve upon programs. As Maryland attempts to get on track, the lesson that can be drawn from the past four years is that while aggressive goals send clear signals the future robustness of energy efficiency programs, it must be met with sustained commitment and aligned processes from Commissions and utilities.

Michigan

Summary

Electric EERS	0.3% annual savings in 2009, ramping up to 1% in 2012 and thereafter
Applicable Sector	Investor-owned utilities; co-operatives, municipals
Natural Gas EERS	0.10% annual savings in 2009, ramping up to 0.75% in 2012 and thereafter
Authority 1 Date Effective	Act 295 of 2008 10/6/2008

Legislative Background

Michigan adopted an EERS in October 2008, when the Clean, Efficient, and Renewable Energy Act was signed into law, requiring all types of electric and natural gas utilities to provide "Energy Optimization (EO) Programs." Michigan's EERS requires electric utilities to achieve 0.3% savings in 2009; 0.5% in 2010; 0.75% in 2011; and 1.0% in 2012 and each year thereafter. Percentages are savings relative to the prior year's total retail electricity sales. Natural gas utilities must achieve 0.1% savings in 2009; 0.25% in 2010; 0.5% in 2011; and 0.75% in 2012 and each year thereafter. Percentages are of the prior year's total annual retail natural gas sales in decatherms or equivalent MCFs.

Table 20: Michigan Electric and Natural Gas Energy Efficiency Savings Targets

		2009	2010	2011	2012
Electric	Percent Savings	0.30%	0.50%	0.75%	0.75%
	Savings (MWh)	326,056	502,797	742,451	N/A
Natural Gas	Percent Savings	0.10%	0.25%	0.50%	0.75%
	Savings (Mcf)	551,931	1,370,282	2,489,179	N/A

Source: Michigan PSC, Report on the Implementation of P.A. 295 Utility Energy Optimization Programs, January 2011

Regulated investor-owned utilities are responsible for 88.9 percent of the statewide electric savings targets; municipal utilities represent 7.8 percent of savings; and electric cooperatives, 3.4 percent. Most efficiency programs are administered by the utilities, although some have opted to fund a state-selected program administrator, Efficiency United, through an alternative compliance payment. Although Efficiency United program services are not subject to the statutory savings targets, equivalent contractual targets were imposed by the Commission. Large electric customers, as determined by their peak use, may administer their own programs.

The 66 utilities that did not opt to pay the alternative compliance payment must propose Energy Optimization (EO) Plans to the Michigan Public Service Commission (MPSC). There are limits to how much each utility many collect and spend on energy efficiency programs. In 2011, that spending cap is 1.5% of total retail sales revenues for 2009. In 2012 and thereafter, the spending cap is 2.0% of the total retail sales revenues for the two years preceding.

Energy Savings Achieved vs. Targeted

Overall, Michigan EO program savings for electric and natural gas achieved 129 percent of the statewide target in 2009. IOUs achieved 130 percent of their savings target, while municipal utilities reached 107 percent of their savings targets and electric cooperatives met 17 percent of their target (MPSC 2011). The Commission recently approved EO plans from Detroit Edison and Consumers Energy in which both utilities plan to exceed electric and natural gas savings targets every year through 2015.[81]

Table 21: Michigan Energy Efficiency Savings vs. Targeted

	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2011 Requirement (MWh)
Statewide Electric EO Program Savings	326,056	375,652	129%	502,797	742,451

Factors Affecting Performance

Funding Levels

A major ramp-up in program funding has been critical to the success of EO programs thus far. Aggregate statewide funding (electric and natural gas) for EO programs was $89 million in 2009. Budgets for 2010 and 2011 are $137 million and $191 million, respectively.

Collaboration among Stakeholders

Michigan utilities benefited from a coordinated approach that included a statewide Energy Optimization Collaborative with the mandatory participation of all gas and electric providers. The Collaborative, which also included energy efficiency experts, energy professionals, and other stakeholders, reviewed and improved Energy Optimization plans to maximize their effectiveness. Michigan's utilities quickly planned, designed and launched programs only months after the approval of their EO plans. While the initial programmatic focus was on lighting and other "low-hanging fruit," the major utilities plan to broaden their focus and reach new customers in the commercial and industrial sectors in order to achieve deeper savings.

Decoupling and Performance Incentives

Complementary policies such as revenue decoupling and performance incentives have also improved the business model for utility investments in energy efficiency. The Commission has approved revenue decoupling for Consumers Energy and Detroit Edison as well as for a number of gas utilities. The Commission also permits Detroit Edison to receive a performance incentive for exceeding their annual energy savings target. Performance incentives cannot exceed 15% of the total cost of the energy efficiency programs (MPSC 2011).

New Mexico

Summary

Electric EERS	Energy Efficiency Resource Standard: 5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020
Applicable Sector	Investor-owned electric utilities
Natural Gas EERS	None
Authority 1	N.M. Stat. § 62-17-1 et seq.

[81] DTE: U-15806-EO Amended; MichCon: U-16412 Amended December 2010

Legislative and Regulatory Background

In 2008, New Mexico adopted an amended version of the Efficient Use of Energy Act which: (1) directs utilities to develop and implement cost-effective DSM programs, (2) defines "cost-effectiveness" in terms of the total resource cost test, (3) establishes cost recovery mechanisms for both electric and natural gas utilities, (4) directs the New Mexico Public Regulation Commission to establish rules for integrated resource planning, and (5) directs the Commission to remove financial disincentives for utilities to reduce customer energy use through DSM programs. On February 27, 2008, Governor Bill Richardson signed House Bill 305 into law, amending the Efficient Use of Energy Act to establish energy efficiency targets for the state. Investor-owned utilities are now required to achieve a 5% reduction from 2005 total retail electricity sales by 2014, and a 10% reduction by 2020. A utility that determines it cannot achieve the energy saving requirements shall report to the Commission, explain the shortfall, and propose alternative requirements based on acquiring all cost-effective and achievable energy efficiency and load management resources. If the commission determines that the requirements exceed the achievable amount of energy efficiency and load management available, it may establish lower requirements for the utility.

Distribution cooperative utilities, which are not fully regulated by the PRC, must annually consider self-imposed electricity reduction targets and design demand side management programs to enable them to meet those targets. Each cooperative utility must submit a report to the PRC annually describing their demand side management efforts from the previous year (DSIRE).

Energy Savings Achieved vs. Targeted

Since the adoption of an EERS, New Mexico's investor-owned utilities have developed programs for all customer segments. The electric IOUs suggest in their latest round of reporting that most, if not all, anticipate reaching the 5% cumulative goal by 2014. Experience thus far indicates that utilities can meet goals cost-effectively. In 2009 and 2010, PNM's program portfolio as measured by the Total Resource Cost test was 1.56 and 2.22, respectively. The average cost per kWh of lifetime energy savings from the energy efficiency programs PNM implemented in 2009 and 2010 was 1.76 cents and 1.89 cents, respectively. The latest approved portfolios of programs demonstrate that utilities are learning important lessons on program delivery strategy and customer participation rates, which has led to the expansion and refinement of numerous programs in the last planning period.

Table 22: New Mexico Energy Savings Achieved and Targeted

Year	New Mexico IOU Achieved and Projected Savings 2008-2014 (MWh)		
	PNM	SPS	El Paso Electric
2008	35,200 (includes DR)*	1,279*	855*
2009	39,900*	13,964*	4,667*
2010	58,900*	28,908**	9,474**
2011	58,489	32,436	25,437
2012	69,920	36,979	30,691
2013	79,733	36,979	30,691
2014	77,605***	36,979	30,691
2014 Cumulative Savings (Goal)	**411,000 (411,000)**	**187,689 (187,689)**	**116,025 (75,000)**

* Verified savings
** Estimated savings
***PNM Goals only projected out to 2013. 2014 figure what would be needed to meet 5% goal.

Sources:
PNM: For 2008, see Docket No. 10-00078-UT; 2009 and 2010 savings figures from Energy Efficiency Annual Reports; For 2010-2013 Plan, See PNM 2010 DSM Plan (Docket 10-00280-UT)
SPS: 2010/11 Energy Efficiency and Load Management Plan (Docket 09-00352-UT)
El Paso Electric: Energy Efficiency and Load Management Plan for 2011 (Docket 10-00047-UT)

Factors Affecting Performance

Decoupling and Performance Incentives

The New Mexico PRC adopted rules concerning disincentive removal and performance-based incentives in May 2010. The rules specify amounts the utilities are allowed to collect per kWh and peak KW of verified savings, in addition to program cost recovery. However, the amounts specified in the rules are in the process of being modified utility-by-utility in DSM program plan review dockets subsequent to issuance of the rules. The provision of these disincentive/incentive adders is expected to motivate the utilities to increase DSM budgets and energy savings targets.

New York

Summary

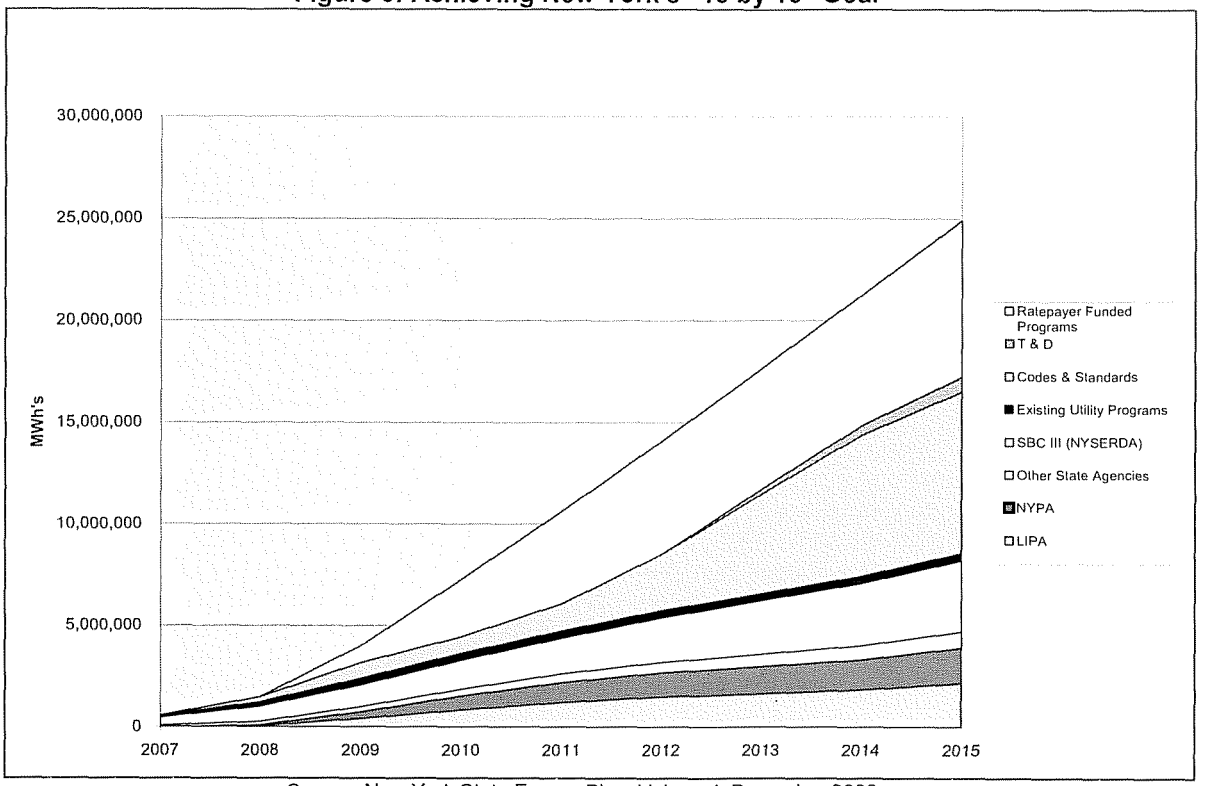
Electric EERS	15% Cumulative savings by 2015
Applicable Sector	Investor-owned utility, natural gas utilities with 14,000 or more customers
Natural Gas EERS	~14.7% by 2020
Authority 1 Date Enacted Date Effective	NY PSC Order, Case 07-M-0548 06/23/2008 06/23/2008
Authority 2 Date Enacted Date Effective	NY PSC Order, Case 07-M-0748 05/19/2009 05/19/2009

Legislative and Regulatory Background

On June 23, 2008, the New York Public Service Commission (NYPSC) issued a decision creating the New York Energy Efficiency Portfolio Standard (EEPS), which aimed to reduce electricity usage by 15% of forecast levels by 2015. NYPSC also approved natural gas efficiency targets in May 2009. The targets aim to save 4.34 Bcf annually through the end of 2011 and 3.45 Bcf annually beyond 2011. The downward revision of the target reflects a likely change in program balance following the exhaustion of federal stimulus funding. Combined with reductions from other sources, this target will result in a 14.7% reduction in estimated gas usage by 2020. New York's EEPS is delivered alongside a broad spectrum of research and development, business development, and market development programs.

New York has an array of program administrators that advance energy efficiency. The New York State Energy Research and Development Authority (NYSERDA) is the largest energy efficiency program administrator, followed by two additional major energy efficiency institutions: The New York Power Authority (NYPA), the largest state public power organization in the U.S., and the Long Island Power Authority (LIPA), which is structured as a non-profit municipal electricity provider and does not own any generation plants on Long Island. New York's investor-owned utilities also administer energy efficiency programs, the largest being Consolidated Edison in New York City and National Grid upstate, through its operating company, the Niagara Mohawk Power Corporation. All of these program administrators contribute to New York's 15x15 goal, as well as savings derived from other state agencies, codes and standards, and improvements to transmission and distribution. LIPA and NYPA, however, are not bound to the EEPS targets by regulation since they are not under the jurisdiction of the NYPSC. Thus while total electricity sales under the 15% by 2015 standard would require savings of roughly 29.4 million MWh annually in 2015, the NYPSC has approved program targets that leave roughly 7.7 million MWh to be achieved by programs outside its jurisdiction.

Figure 5: Achieving New York's "15 by 15" Goal



Source: New York State Energy Plan, Volume I. December 2009.
http://www.nysenergyplan.com/final/New_York_State_Energy_Plan_VolumeI.pdf

As of December 31, 2010, the NYPSC approved 99 energy efficiency programs (48 electric and 51 gas). Energy savings targets are set annually for each program administrator based on its share of the 15x15 goal. The savings targets through December 31, 2010 amount to 1,846,025 Net MWh (about 1% annual savings) and 2,855,811 Dekatherms. NYSERDA is responsible for 62% of electricity savings and 56% of natural gas savings with IOUs responsible for the rest. The approved programs represent a total funding commitment of $1.1 billion, mostly through the end of 2011.

Energy Savings Achieved vs. Targeted

NYSERDA and the investor-owned utilities are performing below the near-term EEPS goals, but trends indicate the state is on track to meet its long-term targets. NYSERDA and the IOUs combined to meet 46.8% of their savings goal through 2010 but spent only 35.9% of what was budgeted for programs. Natural gas programs fared somewhat better, achieving 50.9% of the near-term energy savings goal and spending only 40.9% of the total budget through 2010.

Table 23: Natural Gas and Electric Savings and Spending as Percent of Targets through 12/31/2010, by Program Administrator

Program Administrator	Percent of Net MWh Target Achieved	Percent of Budget Spent
Central Hudson	31.5%	37.2%
Con Edison	22.4%	24.6%
Niagara Mohawk	50.3%	72.2%
NYSEG	13.1%	20.0%
Orange and Rockland	23.9%	22.4%
Rochester Gas & Electric	27.9%	26.9%
NYSERDA	54.2%	29.9%
NEW YORK STATE	**46.8%**	**35.9%**

Program Administrator	Percent of Net Dekatherm Target Achieved	Percent of Budget Spent
Central Hudson	65.4%	74.2%
Con Edison	8.1%	17.4%
Corning	111.2%	106.7%
KED-LI	77.4%	71.1%
KED-NY	28.5%	30.9%
Niagara Mohawk	137.4%	95.0%
NYSEG	127.0%	126.1%
O&R	157.8%	118.0%
RG&E	166.8%	142.6%
St. Lawrence Gas	55.9%	49.8%
NYSERDA	28.0%	25.6%
NEW YORK STATE	**50.9%**	**40.9%**

Source: NYPSC EEEPS Program Implementation Status Through the 4th Quarter of 2010, March 2011

Factors Affecting Performance

Numerous barriers contributed to the slow start. The program approval period took longer than expected as Commission staff carefully examined the operating plans of the utilities, which had not been in the business of delivering efficiency programs for years. Once implemented, the recession negatively impacted program participation. Program administrators also identified market confusion as a concern. Since NYSERDA had been the sole supplier of energy efficiency for so long, customer awareness of the IOU programs is low. When they are aware, having two options makes their decisions more complicated. It is competitive, however, customers in general are not complaining because multiple financial incentive options allow them to choose those that best meet their needs.

New York has the funding, expertise and efficiency potential to meet their energy efficiency portfolio standard goals, and although there have been challenges since the adoption of the EEPS Order in 2008, there have been many initial successes. The programs in place are achieving higher levels of savings than expected, evidenced by the fact that savings levels are greater than spending levels in terms of percentage of expected values. Due to the scale and complexity of utility energy efficiency institutions and programs, one common element linking successful efforts to ramp-up savings is collaboration—especially collaboration across institutions that enables integration, coordination, and standardization. Stakeholders in New York recognize the need to build on these past successes.

Program Administrators state that the outlook for New York to achieve 15 by 2015 EEPS energy savings goals is good. The program plans submitted by electric program administrators supports this claim. Statewide, electric IOUs and NYSERDA forecast electric savings to meet 94% of the 2011 goal. Natural gas program administrators expect to achieve 75% of the statewide 2011 target.

Ohio

Summary

Electric EERS	22% by 2025 (0.3% annual savings in 2009, ramping up to 1% in 2014 and 2% in 2019)
Applicable Sector	Investor-owned utilities
Natural Gas EERS	None
Authority 1 Date Enacted	ORC 4928.66 et seq. 1/1/2009
Authority 2	S.B. 221

Legislative Background

Senate Bill 221, signed into law May 1, 2008, included both an Energy Efficiency Portfolio Standard (EEPS), and Alternative Energy Portfolio Standard (RPS), among other provisions. For efficiency, it requires a gradual ramp up to a cumulative 22 percent reduction in electricity use by 2025. Beginning in 2009, the Act requires electric distribution utilities to implement energy efficiency programs that achieve energy savings equal to at least three-tenths of one per cent of sales. The baseline for which energy savings is calculated against is the average number of total kilowatt hours sold by electric distribution utilities during the preceding three years. The standard ramps up as shown in the table below.

Table 24: Ohio's Energy Efficiency Portfolio Standard

2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020-25
0.30%	0.50%	0.70%	0.80%	0.90%	1.00%	1.00%	1.00%	1.00%	1.00%	2.00%	2.00%

Failure to comply with energy efficiency savings requirements results in forfeiture on the utility. The amount is either that prescribed by the legislature or the existing market value of one renewable energy credit per MWh of undercompliance or noncompliance. Any revenue from forfeiture is credited to the Advanced Energy Fund. The commission may amend the benchmarks if, after application by the electric distribution utility, the commission determines that the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control. Utilities must annually submit energy efficiency status reports and according to Ohio Administrative Code Section 4901:1-39-06(B), Commission Staff is required to review the reports and file its finding and recommendations regarding program implementation and compliance with applicable benchmarks.

The EEPS applies to Ohio's investor-owned utilities and retail suppliers. Ohio's largest electric utility is FirstEnergy, with 1.8 million customers in Ohio served by three operating companies: Ohio Edison, Toledo Edison, and the Cleveland Electric Illuminating Company. Second is American Electric Power of Ohio (AEP), with 1.5 million customers served by two operating companies: the Columbus Southern Power Company and the Ohio Power Company. Duke Energy Ohio and Dayton Power & Light Company (DP&L) both have over a half-million customers. These investor-owned utilities sell almost 90% of all retail electricity in the state.

Energy Savings Achieved vs. Targeted

According to self-reported data, AEP, Duke Energy, and DP&L exceeded their requirements in 2009 and 2010, while FirstEnergy fell far short in 2009 and will report on its 2010 savings in May 2011.[82] Program portfolios for AEP, DP&L, and Duke Energy as a whole were cost-effective in 2010 as determined by the Total Resource Cost test. These utilities' programs in 2009 and 2010 will save customers a net $351 million in utility costs over the program measures' lifetime.[83]

Unable to ramp up programs quickly, FirstEnergy received a waiver from the PUCO allowing it to meet the remainder of its 2009 requirements in future years.[84] Most recently, the PUCO waived annual requirements for FirstEnergy for 2009, 2010, 2011, and 2012. Instead, First Energy will be required to meet a cumulative benchmark by the end of 2012.[85] PUCO ruled that the Portfolio Plan, as filed by FirstEnergy, was not designed to meet the benchmarks in 2010, which PUCO addressed by allowing FirstEnergy to still comply by meeting a cumulative 2012 target (2.3%). FirstEnergy has applied for a rehearing regarding whether the plan was designed to achieve 2010 benchmarks, the results of which are pending at the Commission.

Table 25: Energy Efficiency Performance by Utility in 2009

Utility	2009 Requirement (MWh)	2009 Achieved (MWh)	Percent Attained	2010 Requirement (MWh)	2010 Achieved (MWh)	Percent Attained
American Electric Power[86]	136,944	**171,000**	125%	228,125	**306,000**	134%
Dayton Power & Light[87]	43,193	**40,442**	94%	71,781	**101,061**	141%
Duke Energy[88]	68,127	**86,402**	127%	109,420	**310,755**	284%
FirstEnergy[89]	166,310	**22,614**	14%	N/A	N/A	N/A
Total	**414,574**	**320,458**	**77%**	**409,326**	**717,816**	**175%**

Each utility has submitted plans to achieve their requirements through at least 2011, detailing program portfolios, budgets, and expected savings. Utilities also submit long-term plans forecasting their ability to meet targets in 2025. Except for Duke Energy, each utility projected savings levels in line with future requirements (Woodrum et al. 2010). In its long term forecast report, Duke Energy projected that it would not be able to cost-effectively achieve the long-term 22% requirement, forecasting that it could only meet 14 to 15 percent.[90] After a series of negotiations with stakeholders, however, Duke Energy agreed to a settlement agreement in which it agrees that "it is reasonable for Duke to assume that sufficient, cost-effective energy savings opportunities exist to allow the Company to meet the energy efficiency and demand reduction benchmarks stated in R.C. 4928.66 over the 10-year forecast period." It also states that CHP is a potentially cost-effective option for assisting Duke to meet its resource requirements.

Factors Affecting Performance

A number of factors drove the success of Ohio's other three utilities' meeting their goals in 2009 and 2010. Duke had programs approved prior to SB 221, allowing it to meet the requirements with programs already underway. AEP and DP&L began their energy efficiency efforts as a result of SB 221 and began with a portfolio of tried-and-true programs. Complementary policies allowing these

[82] PUCO staff have yet to file their required report and findings on the energy efficiency status reports of any utilities, as required.
[83] Calculation by Dylan Sullivan, Natural Resources Defense Council. Based on utility presentations and evaluation reports.
[84] Order, January 7, 2010, Docket 09-1004-EL-EEC, et al.
[85] Order, March 23, 2011, Docket 09-1947-EL-POR, et al.
[86] Savings calculated on a pro-rated basis. 2009: Docket No. 10-0318-EL-EEC; 2010: 11-1299-EL-EEC
[87] Savings calculated on a pro-rated basis. Docket No. 10-0303-EL-POR; 2010: 11-1276-EL-POR
[88] Calculated as incremental savings. 2009: Docket No. 10-0317-EL-EEC (Appendix A); 2010: 11-1311-EL-EEC
[89] Requirements for 2009 through 2012 waived. 2009 savings achieved filed in Docket No. 10-0277-EL-EEC
[90] Duke Long Term Forecast Repot 2010

three utilities to recover program costs and in AEP and Duke's case, earn performance incentives on well-performing programs have also helped drive energy savings.

Funding Levels

In order to achieve sustained levels of savings required in Ohio's EEPS, utilities are ramping up budgets to develop the necessary program delivery infrastructure. Ohio's electric utilities increased their collective budgets for energy efficiency programs from approximately $20 million per year between 2006 and 2008 to $152.8 million in 2010, according to the Consortium for Energy Efficiency.

Meeting Future Goals

Utilities are now initiating the three year efficiency portfolio and program planning cycle for 2012-14. As utilities in Ohio shape plans to meet Ohio's aggressive requirements, they may look to a report by ACEEE, together with Summit Blue Consulting, "Shaping Ohio's Energy Future: Energy Efficiency Works," which recommends five innovative programs to complement other proven utility programs: advanced residential and commercial buildings initiatives; manufacturing and rural and agriculture initiatives; and combined heat and power programs. Together, the innovative initiatives recommended would achieve about half of the 22% savings required under the EEPS by 2025.

According to AEP, most of the programs they put into place over the next three year cycle will be similar to current programs. In the longer term beyond the next 3 to 5 years, they will assess industrial long-range planning, continuous improvement, and integrating energy efficiency with industrial process improvement to achieve deeper levels of energy savings. For Duke Energy Ohio, much of their efficiency program outlook depends on changes to codes and standards, and how utilities may or may not get credit for part of the savings due to them. The utility claims that this issue heavily influences the types of programs they offer, especially when planning 7 or 8 years into the future. Ohio utilities are informally discussing how to design a building codes enhancement and compliance support program. The next phase of portfolio plans will likely include a building codes enhancement program.[91]

EERS under Fire

On March 23, 2011, First Energy and DP&L both submitted testimony to the State Senate Energy and Public Utilities Committee requesting the legislature to revisit Ohio's EERS. The utilities expressed frustration with the lack of clarity of whether savings should be calculated as annualized or pro-rated, and recommended the targets be halved. Although the original S.B. 221 was unclear on the proper savings methodology, the Commission rejected the use of annualized savings on multiple occasions.[92]

Pennsylvania[93]

Summary

Electric EERS	3% cumulative savings by 2013
Applicable Sector	Investor-owned electric distribution companies
Natural Gas EERS	None
Authority 1 Date Enacted Date Effective	66 Pa C.S. § 2806.1 10/15/2008 11/14/2008
Authority 2 Date Enacted	PUC Order Docket No. M-2008-2069887 1/15/2009

[91] Personal conversation, Daniel Sawmiller, Ohio Consumers Counsel. May 5, 2011.
[92] 08-888-EL-ORD, Entry on Rehearing (June 17, 2009) at 9.
[93] While PA PUC has reviewed this document, it does not endorse its findings

Legislative and Regulatory Background

In October 2008 Pennsylvania adopted Act 129, establishing an energy efficiency resource standard in Pennsylvania. Each electric distribution company (EDC) with at least 100,000 customers[94] must reduce energy consumption by a minimum 1% by May 31, 2011, increasing to 3% by May 31, 2013, measured against projected electricity consumption for the period from June 2009 to May 2010. Peak demand must be reduced by 4.5% by May 31, 2013. Ten percent of both consumption and peak demand reductions are to come from federal, state, and local government, including municipalities, school districts, institutions of higher education and nonprofit entities. Another ten percent must come from the low-income sector. The Pennsylvania Public Utility Commission (PUC) approved Energy Efficiency and Conservation (EE&C) plans for each EDC, which detailed program portfolios and savings targets tailored to each EDC. The PUC may also set targets for the period beyond 2013. Failure to achieve the reductions required (load and/or peak demand) subjects EDCs to a civil penalty of not less than $1M and not to exceed $20M.

Under the new legislation, the EDCs' EE&C plans propose a cost-recovery tariff mechanism to fund the EE&C measures and to ensure recovery of reasonable costs. The EDCs can also recover the costs through a reconcilable adjustment mechanism. The total cost associated with an EDC's energy efficiency and peak demand reduction plan may not exceed 2% of the EDC's total annual revenue as of December 31, 2006.

Energy Savings Achieved vs. Targeted

Pennsylvania EDCs officially began implementing programs counting towards their EERS on June 1, 2009. The 2nd quarter report of Program Year (PY) 2 indicates all of Pennsylvania's utilities are achieving significant savings levels.[95] Through November 2010, utilities had achieved approximately 58% of the 2011 goal, roughly on track to meet the 1% savings goal by June 2011.[96] Results for Program Year 2 have been promising given that in Program Year 1 utilities only achieved ~20% of the goal. In the cases of Allegheny, Met-Ed, and Penelec, savings in the 1st quarter of Program Year 2 exceeded all of those of PY 1. Twenty-seven programs began in the 1st quarter of PY 2, compared to 38 initiated in all of PY 1. The presence of a Statewide Evaluator (SWE) has been an extremely positive development for the state's utilities. The SWE provides timely reports that allow utilities to gauge performance and verify savings.

Table 26: Pennsylvania EERS Targets vs. Achieved

Program Administrator	Percent of 2011 Target Achieved end of PY 1	Percent of 2011 Target Achieved end of 2nd Quarter, PY 2	Percent of 2013 Target Achieved to date
Allegheny	1.4%	1.4%	0.5%
Duquesne	19.0%	22.4%	7.5%
Met-Ed	8.2%	37.1%	12.4%
Penelec	8.9%	45.4%	15.1%
Penn Power	11.7%	46.0%	15.3%
PECO	40.0%	113.0%	38.0%
PPL	22.0%	62.0%	21.0%
STATEWIDE*	**19%**	**58%**	**19.3%**

Source: Act 129 Statewide Evaluator Quarterly Report, Program Year One and Second Quarter, Program Year Two
*ACEEE Estimate, not endorsed by PA PUC

[94] Standards apply to the following utilities: PECO Energy, PPL Electric Utilities, West Penn Power (Allegheny), Pennsylvania Power Company (PennPower) Pennsylvania Electric (Penelec), Metropolitan Edison (Met-Ed), and Duquesne Light.
[95] Pennsylvania has a Statewide Evaluator, which reports on implementation status quarterly. As of the drafting of this report, the latest confirmed savings data comes from Program Year 2 (2010-2011) 2nd Quarter Report.
[96] Through six of the eight quarters given for utilities to meet the 1% goal in 2011, the theoretical "on-track" savings figure would be 75%.

Iowa

Summary

Energy Efficiency EERS	Varies by utility from 1-1.5% annually by 2013
Applicable Sector	Investor-owned utilities, Municipal utilities, Co-operatives
Natural Gas EERS	Annual goals by 2013 vary by utility: 0.74% (Muni's); 0.85% (MidAmerican); 0.94% (Black Hills) 1.2% (IPL)
Authority 1	Iowa Code § 476
Authority 2 Date Enacted Date Effective	Senate Bill 2386 5/06/2008 5/06/2008

Legislative and Regulatory Background

Iowa's utilities administer energy efficiency programs under a regulated structure with oversight by the Iowa Utilities Board (IUB) and significant input from the Office of Consumer Advocate and other energy efficiency stakeholders. Iowa Code 476.6.16 mandates that investor-owned utilities offer energy efficiency programs through cost-effective energy efficiency plans. The utilities recover program costs of the plans approved by the IUB through adding tariff riders to customer bills. Most publicly owned utilities in Iowa (municipal utilities), as well as rural electric cooperatives, provide energy efficiency programs, ensuring nearly statewide coverage. Iowa's utilities have long records of funding and providing comprehensive portfolios of energy efficiency programs to all major customer categories — residential, commercial, industrial and agricultural. Aside from a decrease in funding in the late 1990s as the state considered restructuring proposals, Iowa has long been a nationwide leader delivering utility energy efficiency programs.

Senate Bill 2386 amended Iowa Code 476.6, among other provisions, requires the IUB to develop energy savings performance standards for each utility. Each utility must file plans to meet specific energy efficiency goals. In compliance with this bill, the Iowa Utilities Board (IUB) issued an order asking investor-owned utilities (IOUs) to submit plans including a scenario to achieve a 1.5% annual electricity and natural gas savings goal.[97] Iowa's two investor-owned electric utilities, Interstate Power and Light Company (IPL) and MidAmerican Energy Company, complied with this request by filing Energy Efficiency Plans for 2009-2013 that outline how the utilities could meet the 1.5% electric target.[98] Both utilities determined the 1.5% natural gas target would be unattainable. While MidAmerican plans to meet the 1.5% electric goal, the IUB declined to approve a slightly lower electric goal for IPL due to potential rate impacts on IPL customers. Both IPL and MidAmerican's goals represent levels of electric savings around twice the levels achieved in 2008. Municipal and cooperative utilities also are required to implement energy efficiency programs, set energy savings goals, create plans to achieve those goals, and report to the IUB on progress.[99] Municipal and co-operative utilities filed goals on December 31, 2009.

Iowa's natural gas utilities also set annual energy efficiency savings targets for the period between 2009 and 2013. Annual goals vary—municipal utilities plan to save 0.74% by 2013; MidAmerican 0.85%; Black Hills Energy 0.94%; and IPL 1.2%.

Energy Savings Achieved vs. Targeted

As noted in the table below, both of Iowa's electric IOUs exceeded 2009 savings targets cost-effectively. Both MidAmerican and IPL reached customers in all sectors, using both traditional and innovative program designs to advance energy efficiency. IPL, in particular, received numerous accolades recognizing its excellence in marketing and education.

[97] Docket No. 199 IAC 35.4 (EEP-02-38; EEP-03-1; EEP 03-4), January 14, 2008.
[98] MidAmerican Energy Company: Docket No. Docket No. EEP-08-2. Interstate Power and Light Company: Docket No. EEP-08-1.

Table 27: Iowa Utility Savings Targets as % of Sales

Utility	2009 Goal	2009 Achieved	2010 Goal	2011 Goal	2012 Goal	2013 Goal
MidAmerican	1.09%	**1.2%**	1.50%	1.54%	1.51%	1.50%
Interstate Power and Light	0.9%	**1.3%**	0.9%	1.0%	1.2%	1.3%
Municipal Utilities*	NA	NA	0.71%	NA	1.09%	NA
Electric Cooperatives**	NA	NA	1.1%	NA	1.2%	NA

*Average Goals of Iowa Association of Municipal Utilities
**Average Goals of Iowa Association of Electric Cooperatives
Sources: IOUs: 2011 Operating Plans and Annual Reports for Program Year 2009. Muni's and Co-ops: "Evaluation of Energy Efficiency Goals and Programs Filed with the Iowa Utilities Board by the Iowa Association of Municipal Utilities" and "Evaluation of Energy Efficiency Goals and Programs Filed with the Iowa Utilities Board by the Iowa Association of Electric Cooperatives."

Factors Affecting Performance

Uncertainty looms in the years ahead, however, as a result of the recession. MidAmerican noted in its Annual Report for Program Year 2009 that the weakened economy dampened demand for some programs, especially residential and low-income, while the promise of reduced costs drove demand for other programs or parts of programs. Because of the unknown impact of the economy on energy efficiency, MidAmerican will place emphasis in the near future on low cost efficiency and efficiency that can be achieved through behavior change.

Funding Levels

In order to achieve levels of savings unattained in previous years, Iowa's utilities are increasing cost-effective spending on electric energy efficiency programs to meet their goals. IPL and MidAmerican plan to increase direct spending on programs from 2009 to 2013 by 30% ($60 to $78 million for IPL) and 37.5% ($40 to $55 million for MidAmerican), respectively. Municipal utilities will increase spending by 32 percent from 2010 to 2012 and electric cooperatives will increase spending by 12 percent from 2010 to 2014.

Collaboration among Stakeholders

As they ramp up savings, Iowa recognizes the importance of coordination among the numerous utilities in the state. To achieve this objective, the state's IOUs, municipal, and co-operative utilities participate in the Statewide Energy Efficiency Collaborative, sponsored by the OCA. The Collaborative helps utilities identify and advance, where appropriate, areas of coordinated energy efficiency processes. The Collaborative also includes other energy efficiency stakeholders to share best practices and investigate opportunities for deeper savings and new programs.

Massachusetts

Summary

Electric EERS	State law requires the electric distribution utilities to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan. After the required review and input by a key stakeholder efficiency council (which included a unanimous 11-0 vote), the Commission approved and fully funded the 2010-2012 Efficiency Procurement Plan in January of 2010 which includes electric utility savings targets of 1.4% in 2010, 2.0% in 2011; 2.4% in 2012

Applicable Sector	Utility, Investor-owned utilities, Cape Light Compact
Natural Gas EERS	State law requires the natural gas distribution utilities to procure all cost-effective efficiency resources through a 3-year Efficiency Procurement Plan and requires full funding of the Plan. After the required review and input by a key stakeholder efficiency council (which included a unanimous 11-0 vote), the Commission approved and fully funded the 2010-2012 Efficiency Procurement Plan in January of 2010 which includes natural gas utility savings targets of 0.63% in 2010, 0.83% in 2011; 1.15% in 2012
Authority 1	D.P.U. Order on Electric Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-116 through D.P.U 09-120)
Statutory Authority	Mass. Gen. Laws c. 25 § 21.

Legislative and Regulatory Background

Massachusetts is a leading state for utility energy efficiency programs with a successful implementation record spanning over 30 years and across all customer sectors. The Green Communities Act of 2008 ushered in a new era for greatly expanded efficiency programs by establishing an "efficiency procurement" approach to EERS policies. That is, the Green Communities Act requires electric and natural gas distribution utilities to invest in all cost-effective energy efficiency that is cheaper than supply resources. Starting in the fall of 2009, and triennially thereafter, the distribution utilities are now required to propose a joint, comprehensive, fully funded state-wide 3-year efficiency plan (for 2010-2012) to satisfy the all cost-effective efficiency procurement requirement for input and review by a new diverse stakeholder efficiency council. This new Massachusetts Energy Efficiency Advisory Council (EEAC) plays a central role in planning and overseeing the utilities' program administration. The EEAC is an 11 member stakeholder body, representing commercial, industrial, residential, low income, labor, and environmental interests, chaired by Massachusetts Department of Energy Resources (DOER), which works collaboratively with the utilities to develop state-wide coordinated energy efficiency plans. After EEAC review and approval, plans are submitted to the Department of Public Utilities (DPU) for analysis and cost-effectiveness testing. The EEAC and DOER help to keep programs on track to meet their energy savings goals. Plans are updated annually and may be modified mid-term. There are five electric energy efficiency program administrators and seven gas program administrators, whose work is overseen by the EEAC and approved by the DPU.

The Green Communities Act requires that electric and gas utilities procure all cost-effective energy efficiency before more expense supply resources, requiring a three year planning cycle. On January 28th, 2010 the DPU approved the first 3-year (2010-2012) electric and gas energy efficiency plans under the Green Communities Act, paving the way for the realization of the goals and efficiency procurement requirement established in the Act. The electric efficiency procurement plan is fully funded and ramps up savings each year, from a starting point of 1.0% in 2009, to 1.4% in 2010, 2.0% in 2011, and then to 2.4% of retail electricity sales in 2012. 2.4% is equivalent to a first year savings of 1,103 GWh in 2012. The energy efficiency investments in 2010-2102 will save 2,625 gigawatt-hours (GWh) of electricity in 2012 (the cumulative annual impact in 2012). The statewide totals are comprised entirely of the individual program administrator savings.[100]

Massachusetts's efficiency procurement approach to their EERS has resulted in one of the most, if not the most ambitious fully funded savings targets of any state. With annual electricity savings of 2.4 percent per year going forward from 2012, the Massachusetts programs would achieve cumulative annual energy savings equivalent to 30 percent of retail electricity sales in 2020. Customers will use 23.4% less electricity in 2020 than they were forecasted to use (based on the April 2009 revised ISO-NE CELT forecast). Retail energy use in 2020 will be 12.5% less than what customers used in 2009,

[100] D.P.U. Order on Electric Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-116 through D.P.U 09-120)

thereby reducing customer energy use over the next 11 years. (In visual terms, this will bend the curve of projected demand down.)

The natural gas plan will save 24.7 million therms in 2012, equivalent to 1.15 percent of retail natural gas sales in 2012. The fully funded energy efficiency investments in 2010-2102 will save over 57.3 million therms of natural gas in 2012 (the cumulative annual impact in 2012). The lifetime energy savings for the gas three-year plan will be almost 897 million therms.[101] Overall, the fully funded 2010-2012 electric and natural gas efficiency procurement plans will yield net consumer savings of more than $3.9 billion, reduce statewide carbon dioxide emissions by nearly 15 million short tons, and create more than 3,800 local jobs (ENE 2010).[102]

Energy Savings Achieved vs. Targeted

According to the fourth quarter report from the Massachusetts Program Administrators in 2010, the state is on track to meet its 2010 electric and natural gas requirements. The preliminary data shows PA's meeting 98% of their MWh goals, 103% of their Therms goals, and spending less than the allotted budget on electric and natural gas programs.[103]

Table 28 : Massachusetts Electric Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (MWh)	Electric Savings Achieved (MWh)	Percent of Target Achieved
2010	1.4%	625,004	609,788	98%
2011	2.0%	897,232		
2012	2.4%	1,103,423		
2010-2012	**5.8%**	**2,625,083**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011

Table 29: Massachusetts Natural Gas Savings Targets and Savings Achieved, 2010-2012

Year	Savings Target as Percent of Sales	Savings Goal (Therms)	Natural Gas Savings Achieved (Therms)	Percent of Target Achieved
2010	0.63%	13,586,666	13,926,865	103%
2011	0.89%	19,087,301		
2012	1.15%	24,687,219		
2010-2012	**2.67%**	**56,368,432**		

Note: Data is preliminary and subject to revision and check.
Source: Quarterly Report of the Program Administrators, Fourth Quarter, 2010. February 3, 2011

Factors Affecting Performance

Funding Levels

A major input required to make steep increases in energy savings attainable and sustainable will be unprecedented funding increases. According to the State of Massachusetts Department of Energy Resources (DOER), electric utilities budgeted $183.8 million for 2009 electric energy efficiency programs from ratepayer-funded sources, a 46 percent increase over 2008 spending. Required by the Green Communities Act, full funding for the procurement all cost-effective efficiency resources was proposed as part of the utilities' 3-year plans, reviewed and endorsed by the EEAC, and then

[101] D.P.U. Order on Gas Three-Year Energy Efficiency Plans, 2010-2012 (D.P.U. 09-121 through D.P.U. 09-128
[102] ENE (Environment Northeast) Spring 2010. *Efficiency Ramps up in Massachusetts.* Boston: ENE (Environment Northeast)
[103] A report with verified savings will be issued in mid- to late-2011.

approved by the DPU. Sources of funding include the System Benefits Charge on customer bills, an adjusting charge approved by DPU, revenues from the ISO New England (ISONE) Forward Capacity Market, and proceeds from the Regional Greenhouse Gas Initiate (RGGI). The Green Communities Act dedicates 80% of RGGI funds to energy efficiency.

Decoupling and Performance Incentives

Massachusetts is currently implementing decoupling for all of its gas and electric utilities: each utility must now include a decoupling proposal as a component of its next rate case to fully remove the disincentive to larger consumer efficiency programs.[104] To date, the state has five fully decoupled local distribution companies—National Grid Electric, Western Massachusetts Electric Company, Bay State Gas, National Grid Gas, and New England Gas. A shareholder incentive currently provides an opportunity for companies to earn about 5% of program costs as an incentive for meeting program goals. The incentive is based on a combination of elements including energy savings, net benefits to customers, and market transformation results.

Meeting Future Goals

The utility program administrators are implementing the strategic principle of accessing deeper savings first with statewide coordination and the active involvement of the EEAC. Deeper savings begin with planning for increased budgets for rebates and other financial incentives combined with increased one-on-one customer contact. Key to ongoing success in Massachusetts will be the continued leadership and long-term perspective from PAs, the EEAC and the state regulators, transparency and stakeholder participation, and continuous improvement and innovation in program offerings to improve the customer experience. A full discussion of Massachusetts's experience and programmatic successes can be found in Nowak et al. (2011).

[104] DPU Docket 07-50-A (July 2008)

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Request No. 3

Please refer to page 12 of Dr. Steinhurst's testimony, lines 6-12. Using Big Rivers' proposed Build Case, provide a detailed analysis showing how DSM and energy efficiency programs will eliminate the need for Big Rivers to build one or more of the proposed projects, and still permit Big Rivers to comply with all environmental regulations in a timely and less cost manner than the Build Case.

Response to Request No. 3 - Respondent: William Steinhurst

Please see Sierra Club's response to Commission Staff request No. 15.

Request No. 4

Please refer to the table on page 14 of Dr. Steinhurst's testimony.

a. Please provide all workpapers, models, databases, and other documents, in electronic form with formulas intact, used in developing each number in the table.

b. Please provide the basis, including all assumptions and supporting documents, used in developing each number in the table.

Response to Request No. 4 - Respondent: William Steinhurst

a. No workpapers, models, databases, or other documents were used in developing the table on page 14 of my testimony.

b. Please see Sierra Club's response to Commission Staff request No. 17.

Request No. 5.

For each table in Ms. Wilson's testimony.

a. Please provide all workpapers, models, databases, and other documents, in electronic form with formulas intact, used in developing each number in the table.

b. Please provide the basis, including all assumptions and supporting documents, used in developing each number in the table.

Response to Request No. 5 – Respondent: Rachel Wilson

a. The sources for the information found in the tables is found in the following locations:

Table Number	Source
1	Synapse Cash Flow Model, provided in response to KIUC 1-1
2	ICF/EEI analysis "EEI Preliminary Reference Case and Scenario Results," provided as Exhibit RSW-3
3	EPRI 2012 study "Analysis of Current and Pending EPA Regulations on the US Electric Sector," provided as Exhibit RSW-4
4	"Capital and O&M.xls" provided by BREC on June 14 in folder "Sargent & Lundy Production to Big Rivers"
5	Exhibit DePriest-2, page 5-5
6	"Capital and O&M.xls" provided by BREC on June 14 in folder "Sargent & Lundy Production to Big Rivers"
7	"Capital and O&M.xls" provided by BREC on June 14 in folder "Sargent & Lundy Production to Big Rivers"
8	Synapse Cash Flow Model, provided in response to KIUC 1-1
9	Synapse Cash Flow Model, provided in response to KIUC 1-1
10	Synapse Cash Flow Model, provided in response to KIUC 1-1

11	Synapse Cash Flow Model, provided in response to KIUC 1-1
12	Synapse Cash Flow Model, provided in response to KIUC 1-1

b. Provided in response to 5.a and in response to KIUC Data Request 1-1.

Request No. 6

For each input and assumption used in Ms. Wilson's analysis that differs from the inputs and assumptions in Big Rivers' Build Case, please list the input or assumption, and provide the basis for the input or assumption and all supporting worksheets or other documents.

Response to Request No. 6 - Respondent: Rachel Wilson

Any input or assumption that differs from that used by Big Rivers in its Build Case analysis is documented within the Synapse Cash Flow Model, provided in response to KIUC 1-1. Source documents include the EIA's Annual Energy Outlook 2012, which was provided as Exhibit RSW-6, and the Lazard 2010 Levelized Cost of Energy study, provided here.

REQEUST 1-6

Attachment 1

MAY 2010

LEVELIZED COST OF ENERGY ANALYSIS – VERSION 4.0

LAZARD

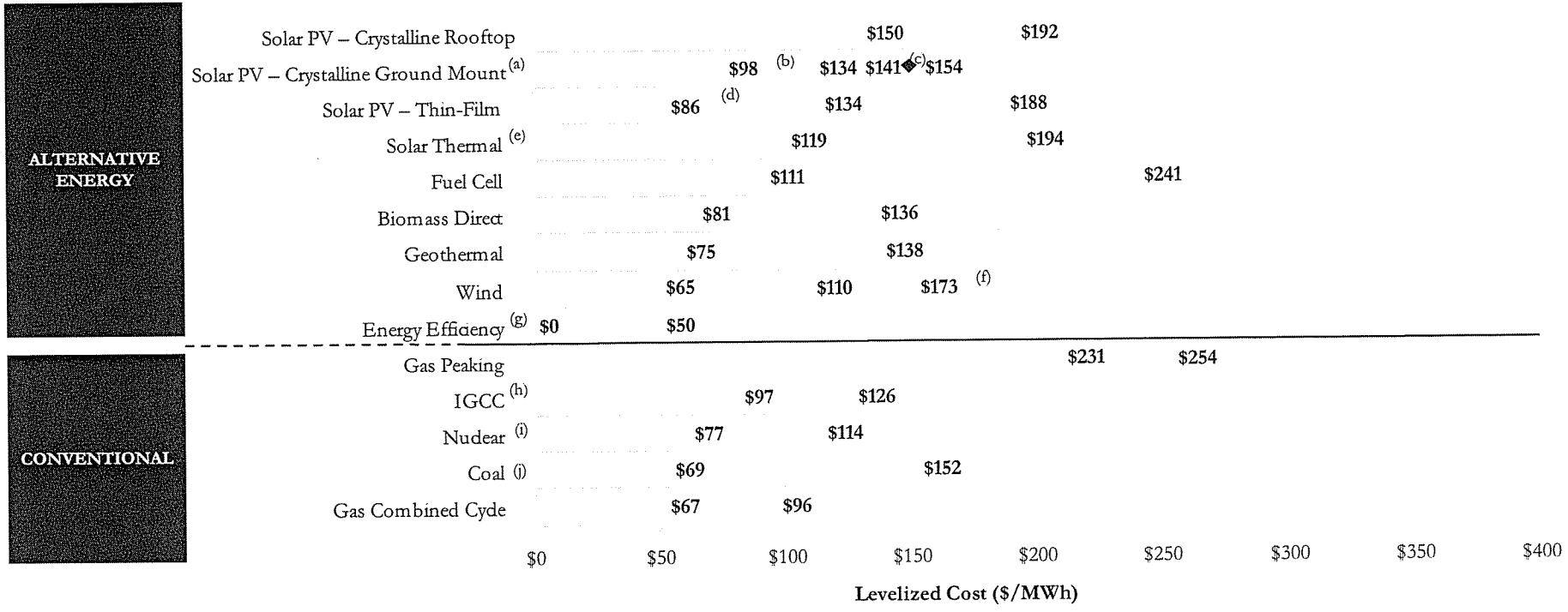
Introduction

Lazard's Levelized Cost of Energy Analysis ("LCOE") addresses the following topics:

- Comparative "levelized cost of energy" for various technologies on a $/MWh basis, including sensitivities, as relevant, for:
  - Fuel costs
  - Illustrative carbon emission costs
  - U.S. federal tax subsidies
  - Anticipated capital costs, over time
- Illustration of how the costs of solar-produced energy compare against peak power costs in large metropolitan areas of the U.S.
- Illustration of the implicit cost of carbon abatement in respect of resource planning alternatives
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Decomposition of the levelized costs of energy for various generation technologies by capital costs, fixed operations & maintenance expense, variable operations & maintenance expense, and fuel costs, as relevant
- Considerations regarding the applicability of various generation resources, taking into account factors such as location requirements/constraints, dispatch characteristics, land and water requirements and contingencies such as carbon pricing
- Summary assumptions for the various generation technologies examined
- Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies, including identification of key potential sensitivities not addressed in the scope of this presentation

Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are becoming increasingly cost-competitive with conventional generation technologies under some scenarios, before factoring in environmental and other externalities (e.g., RECs, potential carbon emission costs, transmission and back-up generation/system reliability costs) as well as construction and fuel costs dynamics affecting conventional generation technologies



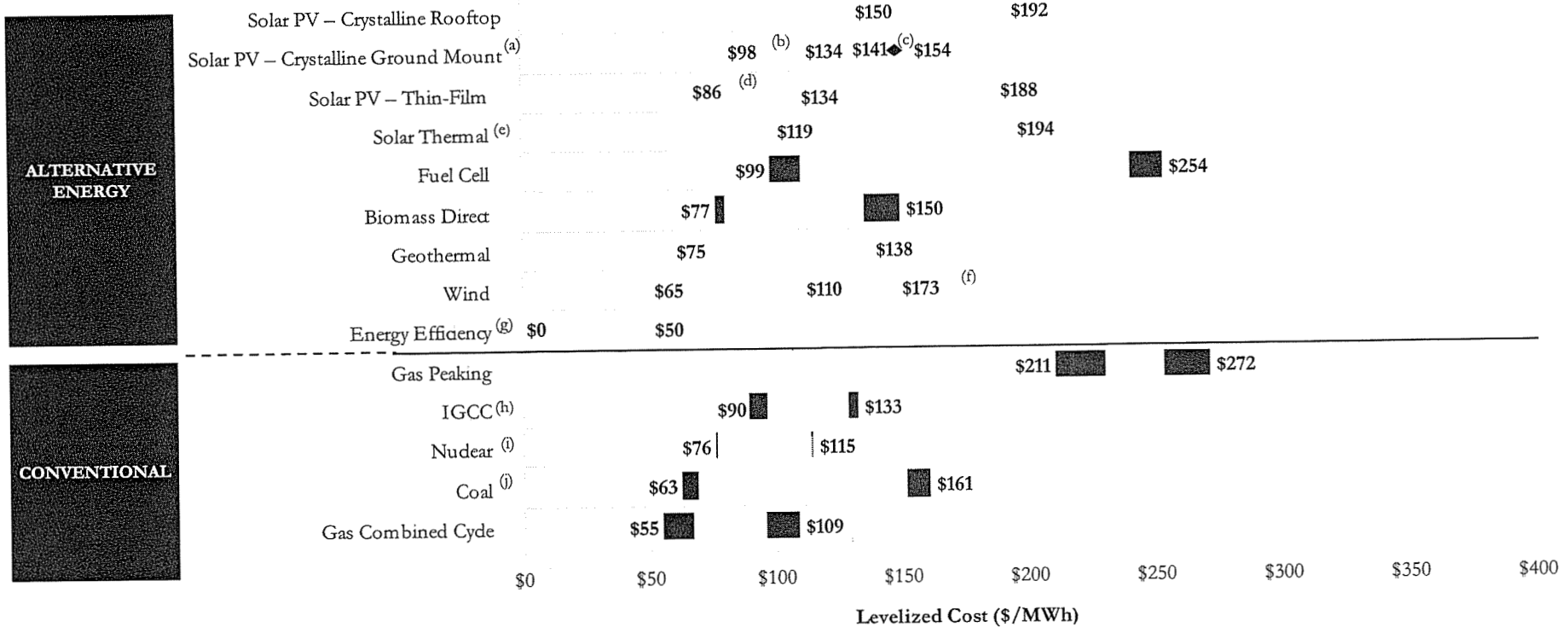
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.
(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.
(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.
(e) Low end represents solar tower and high end represents solar trough, each with 3 hour storage capability.
(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.75 – $5.00 per watt.
(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.
(h) High end incorporates 90% carbon capture and compression.
(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(j) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Levelized Cost of Energy Comparison – Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



Source: *Lazard estimates.*

Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.

(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.

(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.

(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.

(e) Low end represents solar tower and high end represents solar trough, each with 3 hour storage capability.

(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.75 – $5.00 per watt.

(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.

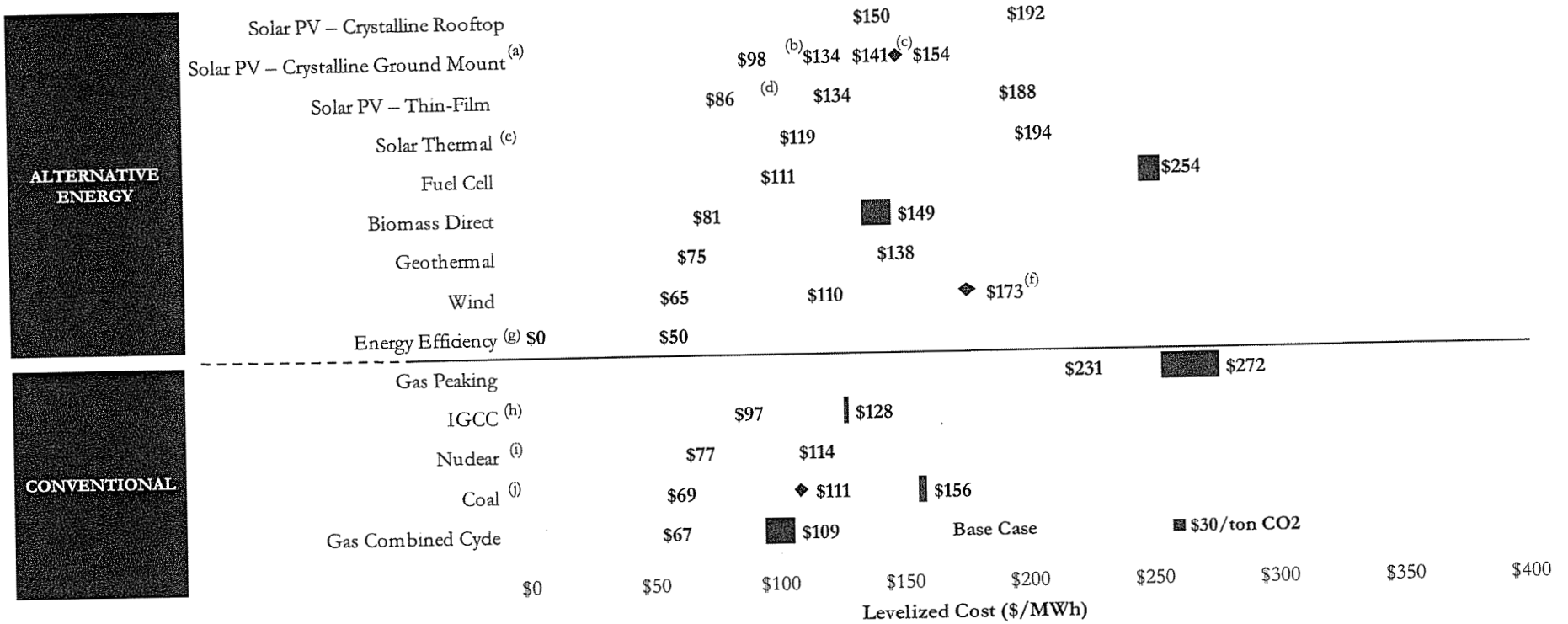
(h) High end incorporates 90% carbon capture and compression.

(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(j) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Levelized Cost of Energy – Sensitivity to Carbon Emission Costs

Conventional generation technologies are subject to uncertainty regarding the potential for future carbon emission costs, which would not affect Alternative Energy generation technologies except positively through credit positions or otherwise (n.b., these potential benefits are not reflected below)



Source: Lazard estimates.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.
(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.
(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.
(e) Low end represents solar tower and high end represents solar trough, each with 3 hour storage capability.
(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.75 – $5.00 per watt.
(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.
(h) High end of light horizontal bar incorporates 90% carbon capture and compression and a carbon emission cost of $30 per ton.
(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(j) Based on advanced supercritical pulverized coal. Diamond represents no carbon capture and compression, and a carbon emission cost of $30 per ton. High end of light horizontal bar incorporates 90% carbon capture and compression and a carbon emission cost of $30 per ton.

Cost of Carbon Abatement Through Resource Planning

A critical intent and result of climate legislation should be changes in generation resource planning through carbon price signals and RPS standards. Currently estimated 2030 carbon costs resulting from Waxman-Markey Bill range from approximately $30 to $85 per ton; given the implicit costs of carbon abatement from resource planning illustrated below, such prices would eventually incent the construction of gas-fired generation, wind and nuclear power; conversely, RPS standards and peak power pricing would be drivers for solar generation

- **This analysis does not take into account issues such as dispatch characteristics and other important qualitative factors**

		CONVENTIONAL GENERATION			ALTERNATIVE ENERGY RESOURCES			
	Units	Coal[b]	Gas Combined Cycle	Nuclear	Wind	Solar Thin-Film	Solar Crystalline[c]	Solar Thermal [d]
Capital Investment/KW of Capacity[a]	$/kW	$3,000	$957	$5,385	$2,250	$3,500	$3,500	$5,500
Total Capital Investment	**$mm**	**$1,800**	**$574**	**$3,339**	**$3,150**	**$7,805**	**$7,245**	**$7,150**
Memo: Total ITC/PTC Tax Subsidization	$mm	—	—	—	$945	$2,342	$2,174	$2,145
Facility Output	**MW**	600	600	620	1,400	2,230	2,070	1,300
Capacity Factor	%	93%	93%	90%	40%	25%	27%	43%
Effective Facility Output	**MW**	558	558	558	558	558	558	558
MWh/Year Produced	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$69	$67	$77	$65	$134	$171	$119
Total Cost of Energy Produced	**$mm/yr**	**$337**	**$328**	**$376**	**$318**	**$655**	**$836**	**$582**
Carbon Emitted	mm Tons/yr	4.58	1.94	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.63	4.58	4.58	4.58	4.58	4.58
vs. Gas		—	—	1.94	1.94	1.94	1.94	1.94
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($10)	$39	($20)	$318	$499	$244
vs. Gas		—	—	$49	($10)	$328	$508	$254
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		—	($4)	$9	($4)	$69	$109	$53
vs. Gas		—	—	$25	($5)	$168	$264	$131

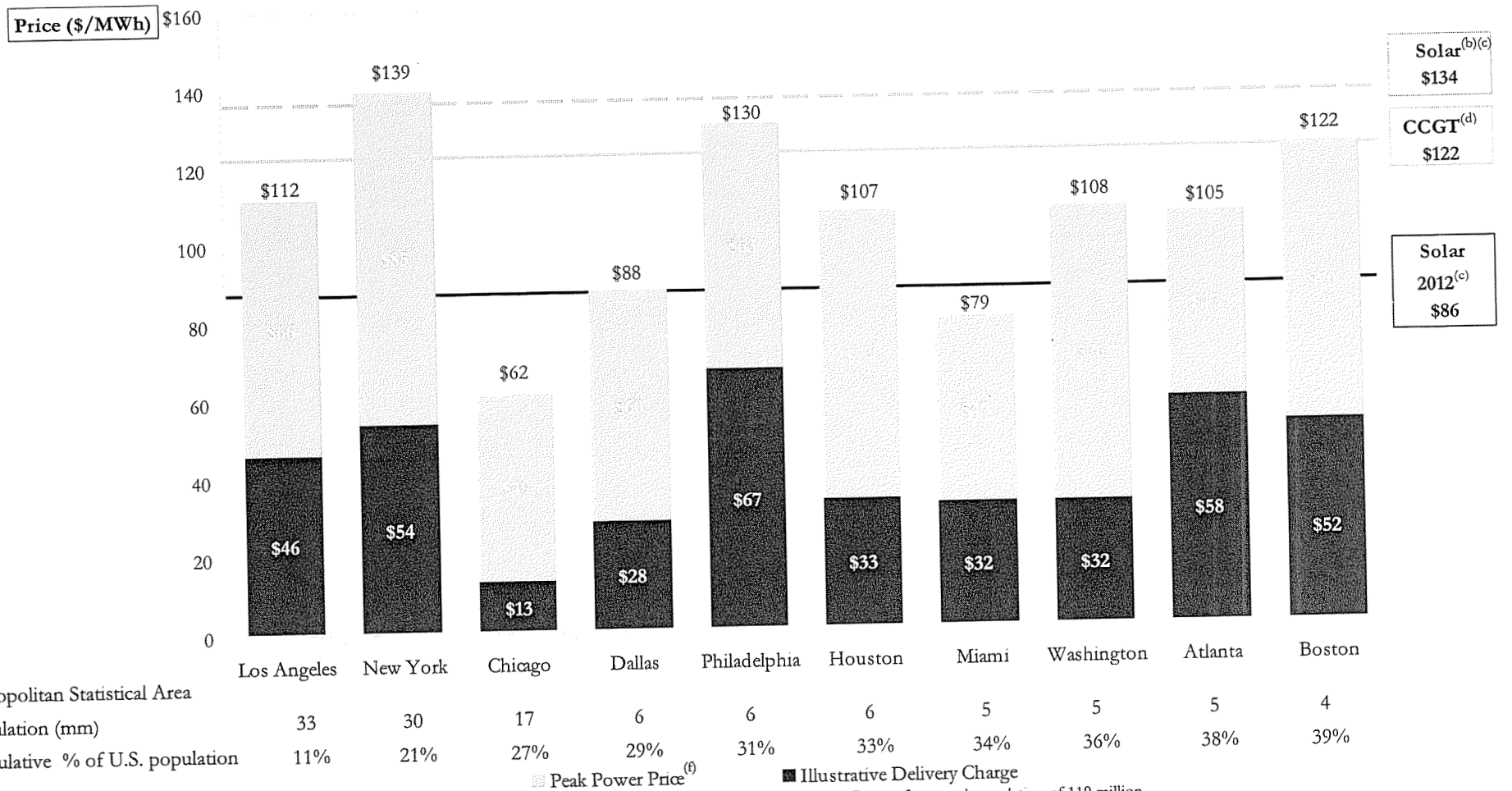
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Inputs for each of the various technologies are those associated with the low end levelized cost of energy.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) Based on advanced supercritical pulverized coal.
(c) Represents single-axis tracking crystalline.
(d) Represents low end of solar thermal tower.

Peak Pricing for the 10 Largest U.S. Metropolitan Areas[(a)]

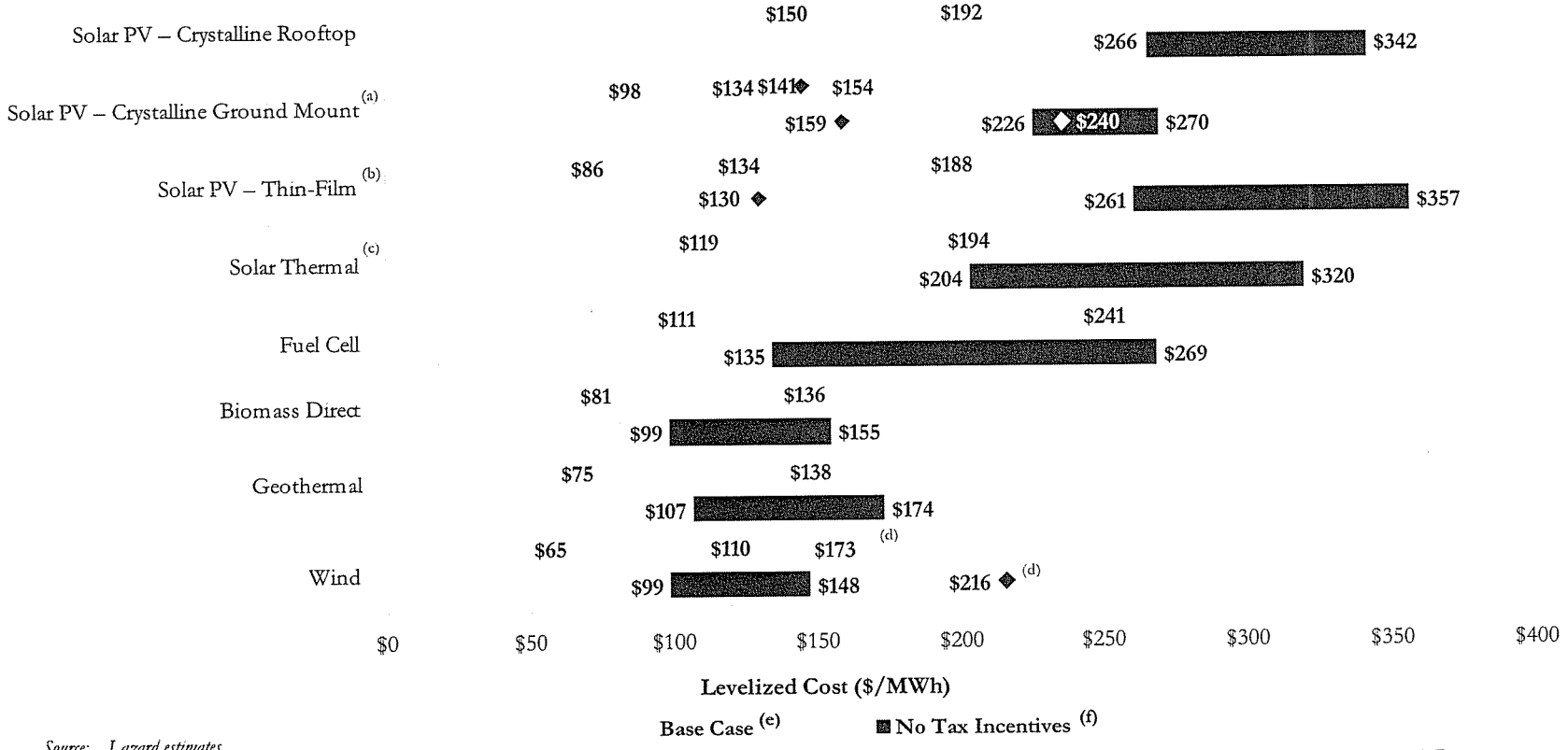
Setting aside the legislatively-mandated demand for solar and other Alternative Energy resources, solar is becoming a more economically viable peaking energy product in many areas of the U.S., and, as pricing declines, could become economically competitive across a broader array of geographies; this observation, however, does not take into account the full costs of incremental transmission and back-up generation/system reliability costs



(a) Defined as 10 largest Metropolitan Statistical Areas per the U.S. Census Bureau for a total population of 119 million.
(b) Represents low end of solar PV crystalline.
(c) Represents low end of solar PV thin-film.
(d) Assumes 25% capacity factor.
(e) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012.
(f) Represents the average of the hourly wholesale prices between 12 noon and 6pm at a normalized natural gas price.

Levelized Cost of Energy – Sensitivity to U.S. Federal Tax Subsidies

U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are important in all regions), notwithstanding high prevailing fossil fuel prices; future cost reductions in technologies such as fuel cells, solar PV and solar thermal have the potential to enable these technologies to approach "grid parity" without tax subsidies (albeit such observation does not take into account issues such as dispatch characteristics the cost of incremental transmission and back-up generation/system reliability costs or other factors)



Source: *Lazard estimates.*

Note: Assumes 2009 dollars, 60% debt at 8.0% interest rate and 40% common equity at 12% cost, 20-year economic life and 40% tax rate. Assumes natural gas price of $6.00 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation. Diamonds represent estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline and a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.

(b) Diamonds represent a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.

(c) Low end represents solar tower, high end represents solar trough, each with 3 hour storage capability.

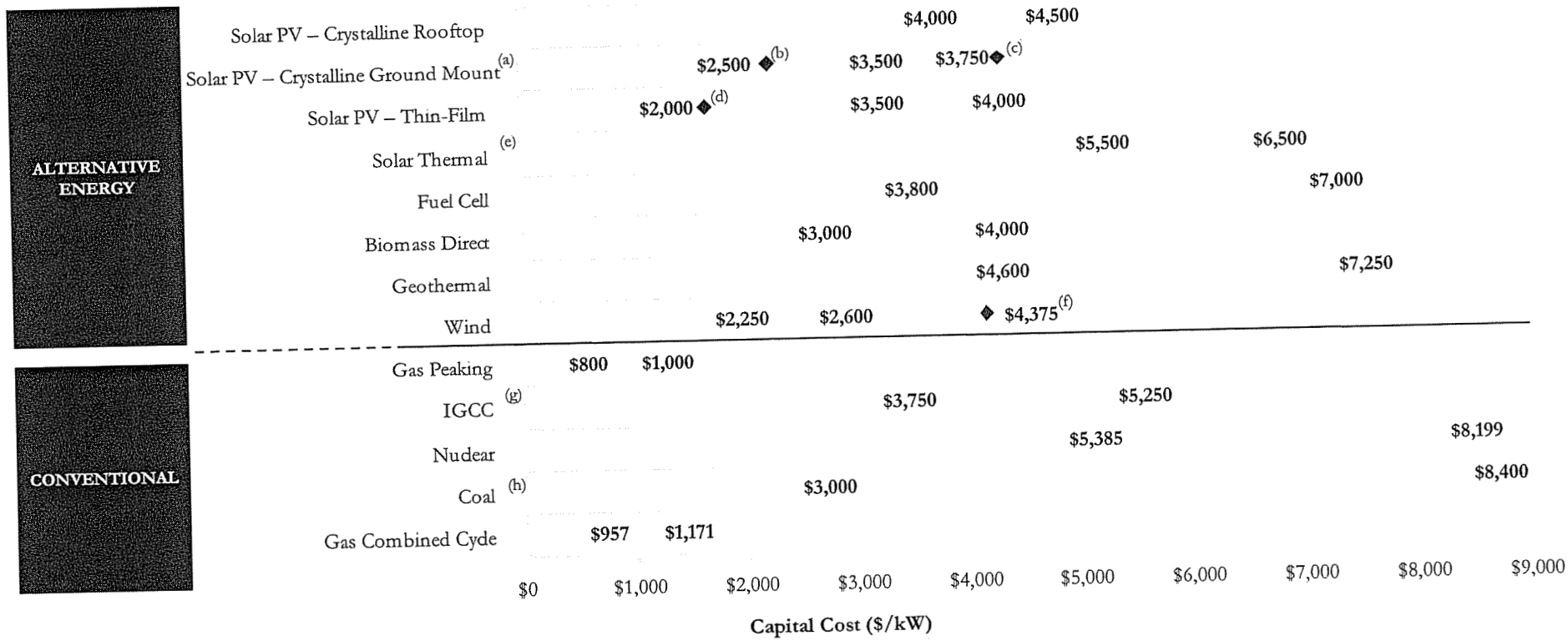
(d) Represents midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.75 – $5.00 per watt.

(e) Reflects production tax credit, investment tax credit, and accelerated asset depreciation, as applicable.

(f) Illustrates levelized cost of energy in the absence of U.S. federal tax incentives such as investment tax credits, production tax credits and assuming 20-year tax life for conventional technologies and 20-year MACRS for renewable energy technologies.

Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of conventional generation technologies (e.g., gas, coal, nuclear), declining costs for many Alternative Energy generation technologies, coupled with rising long-term construction and fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies



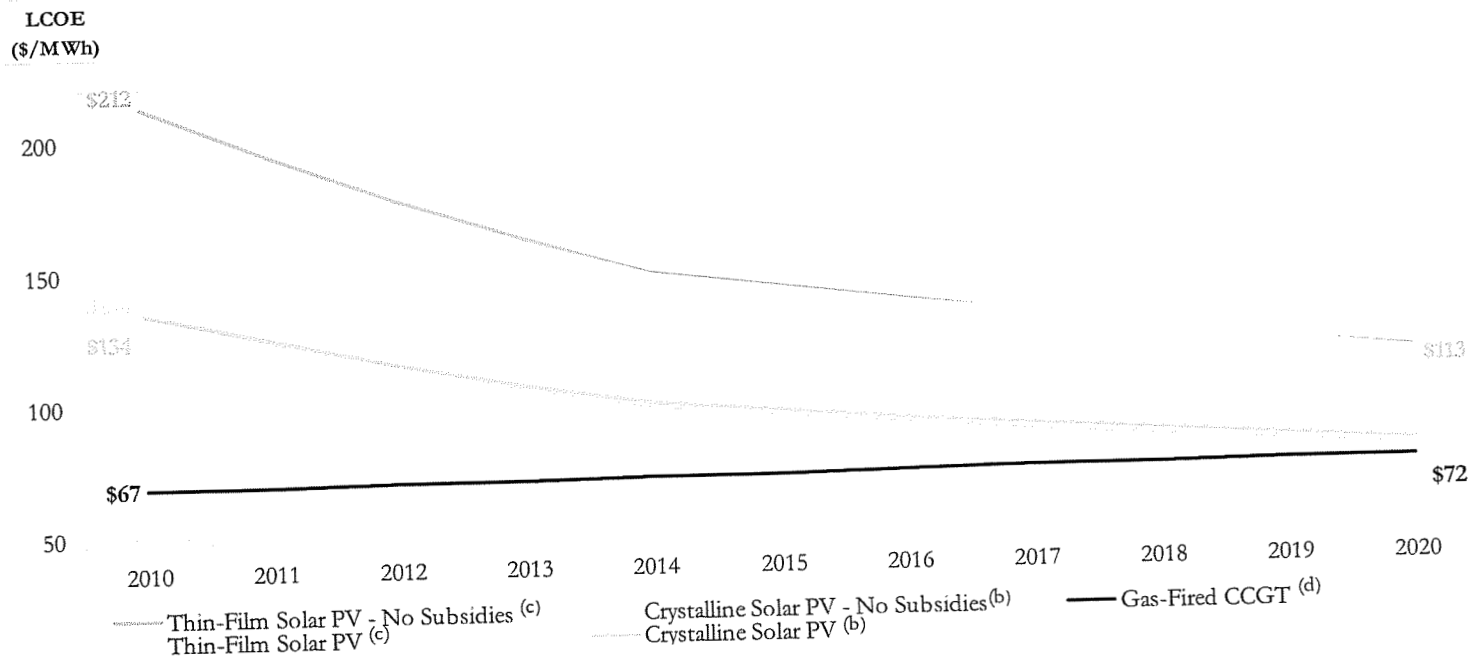
Source: *Lazard estimates.*

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.
(c) Represents a leading concentrating photovoltaic company's total system cost of approximately $4.00 per watt.
(d) Based on a leading thin-film company's guidance of 2012 total system cost of $2.00 per watt.
(e) Low end represents solar tower, high end represents solar trough, each with 3 hour storage capability.
(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.75 – $5.00 per watt.
(g) High end incorporates 90% carbon capture and compression.
(h) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Levelized Cost of Energy – Sensitivity to Capital Costs[(a)]

An important finding in respect of solar PV technologies is the potential for significant cost reductions over time as manufacturing scale along the entire production value chain increases; by contrast, conventional generation technologies are experiencing capital cost inflation (as well as fuel cost inflation), driven by long-term global demand for conventional generation equipment, where potentially cost-reducing manufacturing improvements for these mature technologies are largely incremental in nature

- This assessment, however, does not take into account the intermittent nature of solar PV as compared with the dispatchable nature of conventional generation; the key finding in this regard is that solar PV technologies will play an increasingly *complementary* role in generation portfolios



Source: *Lazard estimates.*

Note: Reflects investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-year economic life and 40% tax rate. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes natural gas price of $6.00 per MMBtu.

(a) Assumes capital costs for thin-film and crystalline solar PV decline by 10% annually through 2014 and 5% annually thereafter. Assumes capital costs for gas-fired CCGT increase by 2.5% annually.

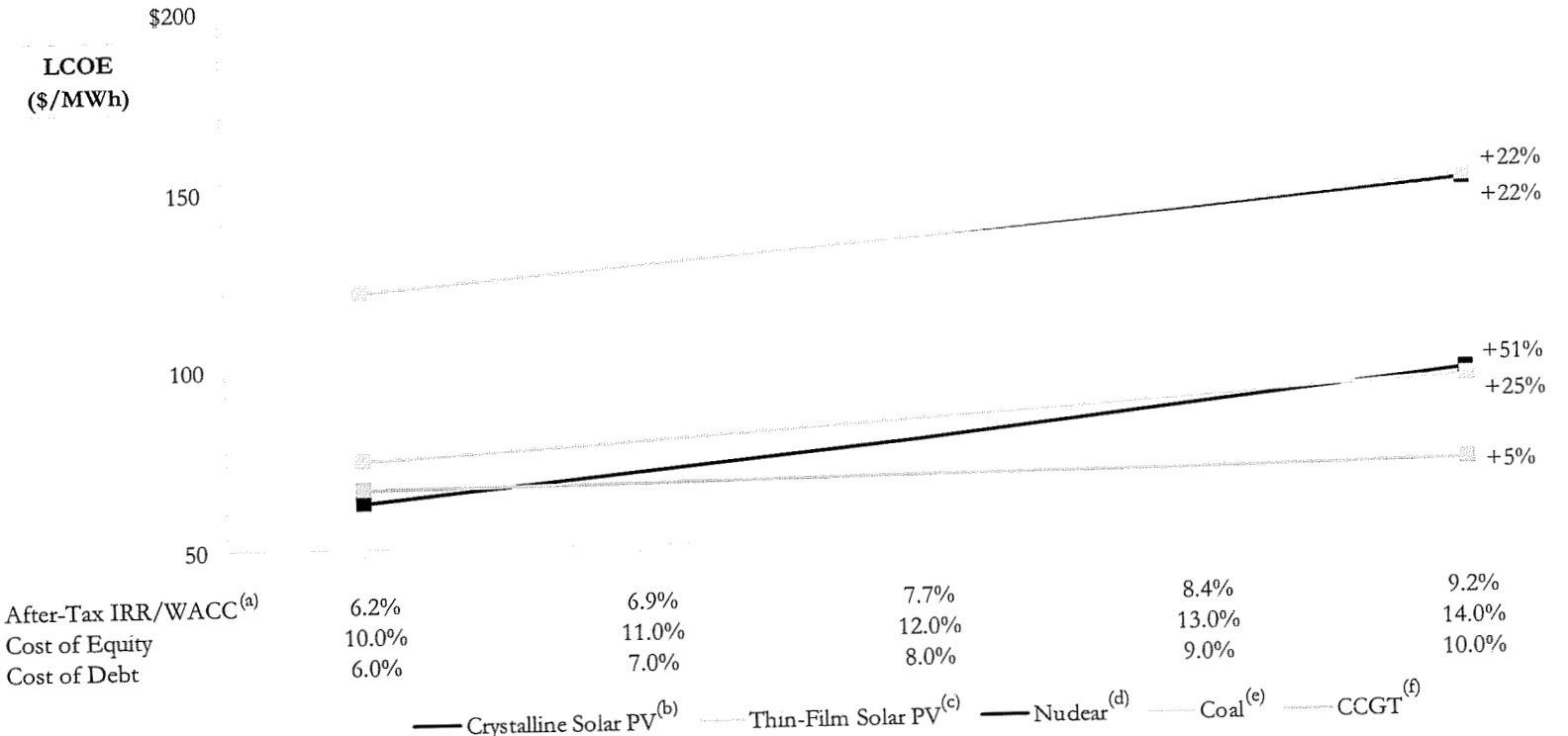
(b) Assumes 25% capacity factor.

(c) Assumes 27% capacity factor based on single-axis tracking.

(d) Assumes 93% capacity factor.

Levelized Cost of Energy – Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies resulting from the potential for intermittently disrupted capital markets is the reduced availability, and increased cost, of capital; these dynamics have a greater relative impact on Alternative Energy generation technologies, whose costs reflect essentially only return on, and of, the capital investment required to build them



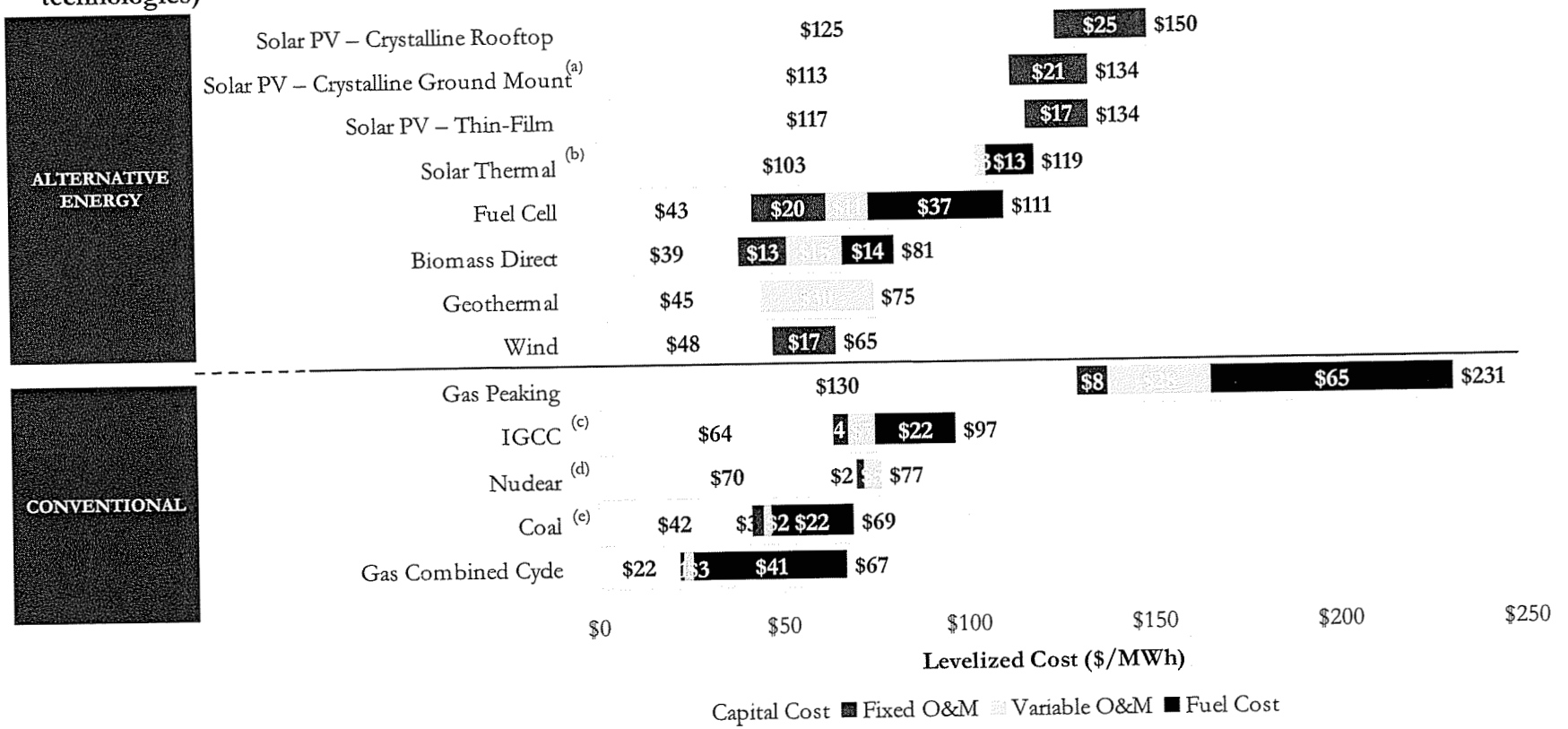
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at the stated interest rate, 20% common equity at the stated cost and 50% tax equity at 8.5% cost for Alternative Energy generation technologies. Assumes 60% debt at the stated interest rate and 40% equity at the stated cost for conventional generation technologies.Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Assumes capital structure comprising 60% debt and 40% equity at the stated interest rates and costs.
(b) Assumes 27% capacity factor based on single-axis tracking.
(c) Assumes 25% capacity factor.
(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(e) Based on advanced supercritical pulverized coal.
(f) Assumes 93% capacity factor.

Levelized Cost of Energy Components – Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as is anticipated with solar PV technologies)



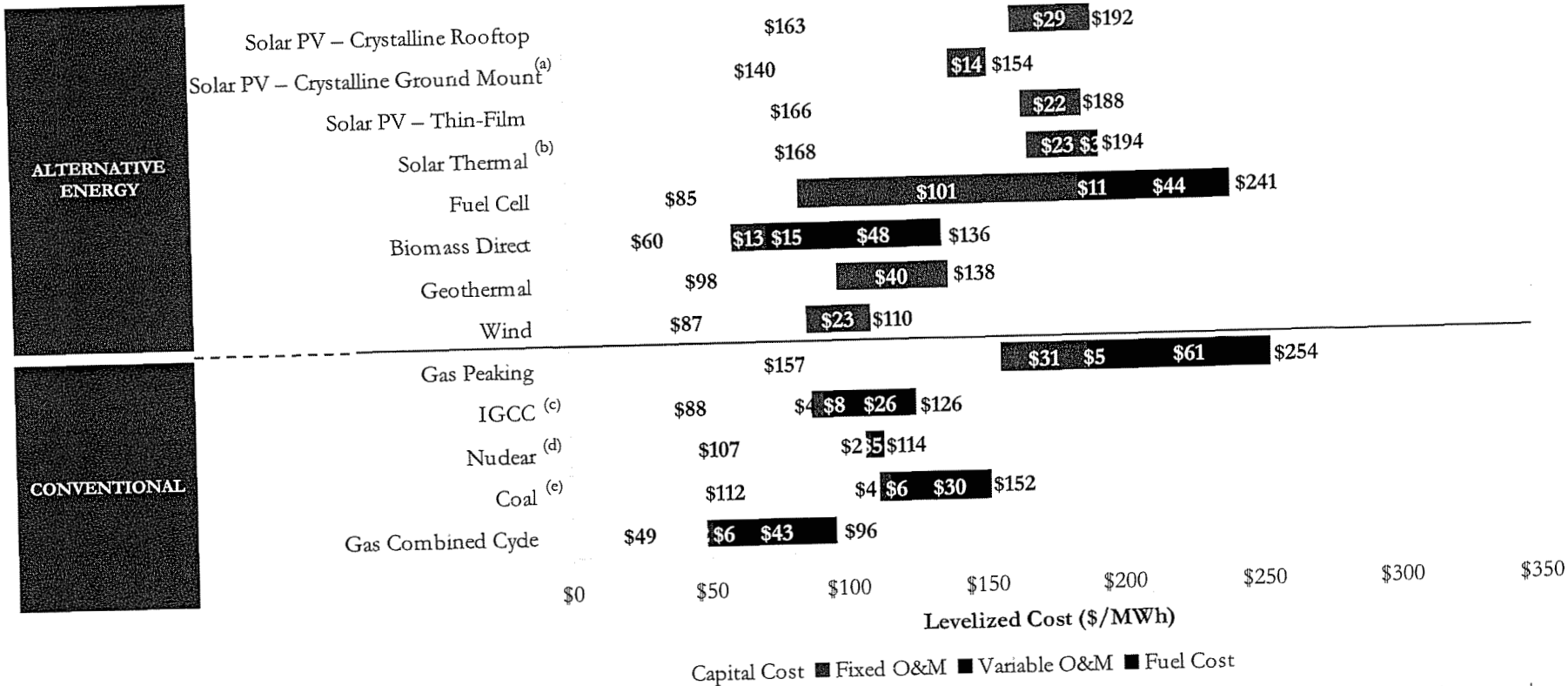
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Low end represents solar tower, high end represents solar trough, each with 3 hour storage capability.
(c) Incorporates no carbon capture and compression.
(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(e) Based on advanced supercritical pulverized coal. Incorporates no carbon capture and compression.

Levelized Cost of Energy Components – High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as is anticipated with solar PV technologies)



Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 4-20 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Low end represents solar tower, high end represents solar trough, each with 3 hour storage capability.
(c) Incorporates 90% carbon capture and compression.
(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(e) Based on advanced supercritical pulverized coal. Incorporates 90% carbon capture and compression.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is becoming increasingly competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., central station vs. customer-located), dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies), and contingencies such as carbon pricing

					LOCATION			DISPATCH			
		LEVELIZED COST OF ENERGY	CARBON NEUTRAL/ REC POTENTIAL	STATE OF TECHNOLOGY	CUSTOMER LOCATED	CENTRAL STATION	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	FUEL CELL	$111-241	? [a]	Emerging/ Commercial	✓		Universal				✓
	SOLAR PV	$134-192	✓	Commercial/ Evolving	✓	✓	Universal	✓	✓		
	SOLAR THERMAL	$119-194	✓	Emerging		✓	Southwest	✓	✓	✓	
	BIOMASS DIRECT	$81-136	✓	Mature		✓	Universal			✓	✓
	WIND	$65-110	✓	Mature		✓	Varies	✓			
	GEOTHERMAL	$75-138	✓	Commercial/ Evolving		✓	Varies				✓
CONVENTIONAL	GAS PEAKING	$231-254	✗	Mature	✓	✓	Universal		✓		
	IGCC	$97-126	✗ [b]	Emerging [c]		✓	Co-located or rural				✓
	NUCLEAR	$77-114	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$69-152	✗ [b]	Mature [c]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$67-96	✗	Mature	✓	✓	Universal			✓	✓

Source: Lazard estimates.

(a) Qualification for RPS requirements varies by location.

(b) Could be considered carbon neutral technology, assuming carbon capture and compression.

(c) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy – Key Assumptions

	Units	Solar PV			Solar Thermal		
		Thin-Film Utility[b]	Crystalline Ground Mount[c]	Crystalline Rooftop	Trough-No Storage[d]	Trough 3 Hours Storage	Tower[e]
Net Facility Output	MW	10	10	10	250	250	120 - 100
EPC Cost	$/kW	$3,500 - $4,000	$3,750 - $3,500	$4,000 - $4,500	$3,700 - $3,900	$4,600 - $4,700	$3,600 - $6,300
Capital Cost During Construction	$/kW	included	included	included	included	included	included
Other Owner's Costs	$/kW	included	included	included	$1,300 - $1,400	$1,700 - $1,800	$1,900 - included
Total Capital Cost[a]	$/kW	$3,500 - $4,000	$3,750 - $3,500	$4,000 - $4,500	$5,000 - $5,300	$6,300 - $6,500	$5,500 - $6,300
Fixed O&M	$/kW-yr	$37.50	$50.00 - $25.00	$25.00	$66.00	$60.00	$50.00 - $70.00
Variable O&M	$/MWh	—	—	—	—	$3.00	$3.00
Heat Rate	Btu/kWh	—	—	—	—	—	—
Capacity Factor	%	25% - 20%	27% - 20%	23% - 20%	29% - 26%	34% - 30%	43% - 35%
Fuel Price	$/MMBtu	—	—	—	—	—	—
Construction Time	Months	12	12	12	24	24	24
Facility Life	Years	20	20	20	20	20	20
CO_2 Equivalent Emissions	Tons/MWh	—	—	—	—	—	—
Investment Tax Credit	%	30%	30%	30%	30%	30%	30%
Production Tax Credit	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy	$/MWh	$134 $188	$134 $154	$150 $192	$161 $188	$167 $194	$119 $170

Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) An illustrative manufacturer of Thin-Film PV would be FirstSolar.

(c) Left side represents single-axis tracking crystalline; right side represents fixed installation. An illustrative manufacturer of high-efficiency Crystalline PV would be SunPower.

(d) Left side represents wet-cooled; right side represents dry-cooled. Illustrative manufacturers/developers of Trough Solar Thermal would be Abengoa Solar, Flagsol, SkyFuel, Solar Millennium, Solargenix and Siemens.

(e) Represents a range of solar thermal tower estimates. Illustrative manufacturers/developers of Solar Thermal Tower would be BrightSource Energy, eSolar and SolarReserve.

Levelized Cost of Energy – Key Assumptions (cont'd)

	Units	IGCC[b]	Gas Combined Cycle	Gas Peaking[c]	Coal[d]	Nuclear[e]	Fuel Cell[f]
Net Facility Output	MW	580	550	152 - 34	600	1,100	2.4
EPC Cost	$/kW	$3,054 - $4,193	$700 - $875	$580 - $700	$2,027 - $6,067	$3,750 - $5,250	$3,000 - $7,000
Capital Cost During Construction	$/kW	$696 - $1,057	$156 - $170	included	$486 - $1,602	$1,035 - $1,449	included
Other Owner's Costs	$/kW	included	$101 - $126	$220 - $300	$487 - $731	$600 - $1,500	$800 - included
Total Capital Cost[a]	$/kW	$3,750 - $5,250	$957 - $1,171	$800 - $1,000	$3,000 - $8,400	$5,385 - $8,199	$3,800 - $7,000
Fixed O&M	$/kW-yr	$26.40 - $28.20	$6.20 - $5.50	$6.80 - $27.00	$20.40 - $31.60	$12.80	$169 - $850
Variable O&M	$/MWh	$6.80 - $7.30	$3.50 - $2.00	$28.00 - $4.70	$2.00 - $5.90	—	$11.00
Heat Rate	Btu/kWh	8,800 - 10,520	6,800 - 7,220	10,830 - 10,200	8,960 - 12,000	10,450	6,240 - 7,260
Capacity Factor	%	75%	93% - 40%	10%	93%	90%	95%
Fuel Price	$/MMBtu	$2.50	$6.00	$6.00	$2.50	$0.50	$6.00
Construction Time	Months	57 - 63	36	25	60 - 66	69	3
Facility Life	Years	40	20	20	40	40	20
CO_2 Equivalent Emissions	Tons/MWh	0.74 - 0.89	0.40 - 0.42	0.63 - 0.60	0.95 - 1.27	—	0.26 - 0.42
Investment Tax Credit	%						30%
Production Tax Credit	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy	$/MWh	$97 - $126	$67 - $96	$231 - $254	$69 - $152	$77 - $114	$111 - $241

Source: *Lazard estimates.*

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) High end incorporates 90% carbon capture and compression.
(c) Low end represents assumptions regarding GE 7FA. High end represents assumptions regarding GE LM6000PC.
(d) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(f) Low end incorporates illustrative economic and efficiency benefits of combined heat and power ("CHP") applications.

Levelized Cost of Energy – Key Assumptions (cont'd)

	Units	Biomass Direct	Wind	Off-Shore Wind	Geothermal	Landfill Gas	Biomass Cofiring[b]
Net Facility Output	MW	35	100	210	30	5	2% - 20%[c]
EPC Cost	$/kW	$2,629 - $3,506	$1,850 - $2,200	$3,140 - $4,120	$4,032 - $6,354	$1,500 - $2,000	$50 - $500
Capital Cost During Construction	$/kW	$371 - $494	included	included	$568 - $896	included	included
Other Owner's Costs	$/kW	included	$400 - $400	$610 - $880	included	included	included
Total Capital Cost[a]	$/kW	$3,000 - $4,000	$2,250 - $2,600	$3,750 - $5,000	$4,600 - $7,250	$1,500 - $2,000	$50 - $500
Fixed O&M	$/kW-yr	$95.00	$60.00 - $60.00	$60.00 - $100.00	—	—	$10.00 - $20.00
Variable O&M	$/MWh	$15.00	—	$13.00 - $18.00	$30.00 - $40.00	$17.00	—
Heat Rate	Btu/kWh	14,500	—	—	—	13,500	10,000
Capacity Factor	%	85%	40% - 30%	45% - 32%	90% - 80%	80%	80%
Fuel Price	$/MMBtu	$1.00 - $3.30	—	—	—	$1.50 - $3.00	$0.00 - $2.00
Construction Time	Months	36	12	12	36	12	12
Facility Life	Years	20	20	20	20	20	20
CO_2 Equivalent Emissions	Tons/MWh	—	—	—	—	—	—
Investment Tax Credit	%	—	—	—	—	—	—
Production Tax Credit	$/MWh	$10	$20	$20	$20	$10	—
Levelized Cost of Energy	$/MWh	$81 - $136	$65 - $110	$112 - $235	$75 - $138	$55 - $87	$3 - $37

Source: *Lazard estimates.*

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2009 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $6.00 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) Represents retrofit cost of host coal plant.

(c) Additional output to a coal facility.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including government subsidies, RPS requirements, and continuously improving economics as underlying technologies improve and production volumes increase.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, and economic life) were identical for all technologies, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and U.S. federal tax incentives on the levelized cost of energy. These inputs were developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and illustrative carbon emission costs. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include scale benefits or detriments, the value of Renewable Energy Credits ("RECs") or carbon emissions offsets, other emissions costs (e.g., NOx, SOx) the impact of transmission costs, second-order system costs to support intermittent generation (e.g., backup generation, voltage regulation, etc.), and the economic life of the various assets examined.

Request No. 7.

Please refer to the testimony of Ms. Wilson.

a. Please explain in detail the extent to which Ms. Wilson incorporated potential future environmental laws or regulations relating to or affecting natural gas production (including potential laws or regulations relating to hydraulic fracturing) or natural gas combined cycle units into her analysis. If her answer is that she did not incorporate consideration of those subjects in her analysis, please explain why not.

b. Please provide a natural gas forward price curve showing the impact of such environmental laws and regulations over the expected life of the proposed natural gas combined cycle units.

c. Please provide all workpapers and other documents supporting the impact of potential future environmental laws or regulations on the price of natural gas over the expected life of the proposed natural gas combined cycle units.

d. Has Sierra Club adopted a public position regarding the appropriateness of the technique of hydraulic fracturing in connection with the production of natural gas, or advocated imposition of any limits, prohibitions, bans, or other laws or regulations restricting use of the technique of hydraulic fracturing in connection with the production of natural gas? If so, please provide all documents relating to the positions taken by Sierra Club on those subjects, including details relating to the positions, and an estimated impact on the natural gas forward prices used in Ms. Wilson's analysis if the positions taken by Sierra Club on those subjects are implemented by laws, regulations, or otherwise.

e. Does Sierra Club have an opinion about the likelihood that any limits, prohibitions, bans, restrictions or other laws or regulations will be imposed on use of the technique of hydraulic fracturing in connection with the production of natural gas? If so, please provide all documents relating to such opinion, details explaining the basis for the opinion, and an estimated impact on the natural gas forward prices used in Ms. Wilson's analysis if the limits, prohibitions, bans, restrictions or other laws or regulations Sierra Club believes are likely to be imposed on use of the technique of hydraulic fracturing in connection with the production of natural gas are implemented by laws, regulations, or otherwise.

f. Has Sierra Club proposed to any administrative agency or branch of a local, state or federal government any limits, prohibitions, bans, restrictions or other laws or regulations on use of the technique of hydraulic fracturing in connection with the production of natural gas? If so, please provide all documents relating to such proposals, details relating to the proposal, and an estimated impact on the natural gas forward prices used in Ms. Wilson's analysis if the proposals offered by Sierra Club are implemented by laws, regulations, or otherwise.

Response to Request No. 7

a. Future environmental laws or regulations relating to natural gas production are incorporated into my analysis to the extent that they are incorporated in the EIA's AEO 2012 Reference case natural gas price forecast.

Respondent: Rachel Wilson

b. I have not seen such a curve.

Respondent: Rachel Wilson

c. N/A

Respondent: Rachel Wilson

d. Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1). Sierra Club also objects to this request as it impinges on Sierra Club's First Amendment rights and privileges. *See, e.g., Watkins v. U.S.*, 354 U.S. 178, 197 (1957) (recognizing that forcing a witness to testify as to his "beliefs, expressions or associations is a measure of governmental interference"); *Perry v. Schwarzenegger*, 591 F.3d 1147 (9th Cir. 2010); *Grandbouche v. Clancy*, 825 F.2d 1463 (10th Cir. 1987) (both applying "freedom of association" protections against discovery requests). Finally, Sierra Club objects to this request as it is overly broad, unduly burdensome, oppressive, and calculated to take Sierra Club and its staff away from normal work activities, and require them to expend significant time and resources to determine how to respond to a request that impinges on its Constitutional rights and to provide complete and accurate answers to Big River's request for information, which are only of marginal value to Big Rivers, Kentucky Civil Rule 26.02.

Subject to and without waiving the foregoing objections, Sierra Club states that the Sierra Club website discusses the organization's position on natural gas. See http://content.sierraclub.org/naturalgas/. As the website indicates, Sierra Club supports closing loopholes in various environmental statutes that apply to natural

gas fracking, opposes natural gas fracking on state and national parks, and advocates for natural gas fracking fluid disclosure laws.

Respondent: Kristin Henry, Sierra Club Counsel

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Respondent: Kristin Henry, Sierra Club Counsel

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Respondent: Kristin Henry, Sierra Club Counsel

Request No. 8:

1. Please refer to the tables on pages 9 and 10 of Ms. Wilson's testimony.
    a. Please provide all analyses and other documents showing the impact of the coal retirements listed on power market prices in general and on power market prices in MISO.
    b. With regard to the 120 GW estimates:
        i. Of the 120 GW, how many GW of coal retirements were from coal generation in MISO?
        ii. What is the total capacity of coal generation (in GW) in MISO?
        iii. What is the total capacity of coal generation (in GW) in the United States?
        iv. What percent of the total coal capacity in the United States would a retirement of 120 GW represent?
        v. What percent of MISO coal capacity would the MISO retirements represent?
        vi. Has Sierra Club made any estimates of the impact of retiring 120 GW of coal on system reliability and resource adequacy, specifically in MISO?
        vii. Did ICF/EEI provide a list of generators they expect to be retired (adding up to the total GW of retirements reported)? If so, were any Big Rivers' facilities on that list?

Response to Request No. 8

a. I did not refer to any MISO specific analyses of retirements on power market prices.

Respondent: Rachel Wilson

b. i. The EPRI study does not quantify the number of GW of coal generation that retire in MISO under the natural gas minus $2 scenario.

ii. I believe that there is just over 70 GW of coal generating capacity in MISO.

iii. According to the EPRI study provided as Exhibit RSW-3, there are 316 GW of coal generation in the US.

iv. Retirement of 120 GW of coal generation would represent about 38% of the U.S. coal fleet.

v. As the EPRI study did not give a MISO specific estimate, I cannot calculate this percentage.

Respondent: Rachel Wilson

vi. Sierra Club objects to this request as it seeks information that is not relevant to and outside the scope this proceeding and is not "reasonably calculated to lead to the discovery of admissible evidence," Kentucky Civil Rule 26.02(1). Sierra Club also objects to this request as it impinges on Sierra Club's First Amendment rights and privileges. *See, e.g., Perry v. Schwarzenegger*, 591 F.3d 1147 (9th Cir. 2010); *Grandbouche v. Clancy*, 825 F.2d 1463 (10th Cir. 1987) (both applying "freedom of association" protections against discovery requests); *AFL-CIO v. FEC*, 333 F.3d 168 (D.C. Cir. 2003).

Respondent: Kristin Henry, Sierra Club Counsel

vii. The ICF/EEI study is different from the EPRI study. The EPRI study is the one that estimates 120 GW of coal retirements under a very specific sensitivity scenario of a natural gas price $2 below the reference forecast. I

have not seen a list of generators expected to be retired under either the ICF/EEI study or the EPRI study.

Respondent: Rachel Wilson

Request No. 9

Please refer to page 12 of Ms. Wilson's testimony, lines 15-16. Provide any allowance price forecast showing allowance prices different than the Pace forecast, and for each price forecast, provide the impact to the NPVRR of the Big Rivers Build Case (using Big Rivers' assumptions).

Response to Request No. 9 - Respondent: Rachel Wilson

Page 12, lines 15-16 of my testimony references historic allowance prices. I do not refer to any forecasts of emissions allowance prices.

Request No. 10

What modeling software did Ms. Wilson or Synapse use to perform the cost comparisons of the natural gas combined cycle scenarios versus Big Rivers' scenarios referenced in Ms. Wilson's testimony?

a. Provide copies of all models, databases, input and output files, input assumptions, in electronic format with formulas intact.

Response to Request No. 10 - Respondent: Rachel Wilson

I did not use any modeling software in my analysis.

a. The cash flow model was provided in Response to KIUC 1-1.

Request No. 11

What capital, fuel, allowance, and operation and maintenance costs did Ms. Wilson assume in her analysis for the combined cycle build? Provide all such costs, the basis for those assumptions, and all documents supporting those assumptions. Include the manufacturer and model number of the combined cycle units used as the basis for any assumption.

Response to Request No. 11 - Respondent: Rachel Wilson

Capital, fuel, allowance, and O&M cost assumptions for the natural gas combined-cycle replacement options are provided and documented within the cash flow model provided in Response to KIUC 1-1.

Request No. 12

What compliance option does Ms. Wilson use in her analysis for NAAQS, 316b, CCR, and effluent limitations?

a. Provide all capital and operation and maintenance cost estimates used by Ms. Wilson in her analysis for the equipment needed for compliance with NAAQS 316b, CCR and effluent limitations. Provide all bases for those estimates and all supporting documents. Provide the in service date for the equipment.

Response to Request No. 12 - Respondent: Rachel Wilson

Compliance options for the NAAQS, CCR rule, and 316(b) rule were the Sargent & Lundy recommended technologies contained in Exhibit DePriest-2. Compliance options for the effluent limitation rule are derived from the November 2010 EPRI report "Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act"(attached), specifically Chapter 4. See Table 4-6 (on page 4-23) for information regarding active and inactive pond closures and the table on page C-8 for information on wastewater treatment. Generally, if there was a low and a high range for costs, with each associated with a low and high range for capacity, we used these two points as floor and ceiling values, respectively. Then, we created a simple linear interpolation between the two points to scale for units with different capacities.

a. All capital and O&M costs used in the Synapse analysis are provided and documented within the cash flow model provided in Response to KIUC 1-1. The supporting documents have been provided in Exhibit RSW-6 and Response to Big Rivers 1-6. Capital costs for NAAQS, CCR and 316(b) compliance were

assumed to be incurred in 2017. Capital costs for effluent compliance were assumed to be incurred in 2018.

Request 1-12

Attachment 1

EPRI | ELECTRIC POWER RESEARCH INSTITUTE

Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act

Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act

1020557

Final Report, November 2010

EPRI Project Managers
J. Lingle
K. Ladwig

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NOTE

For further information about EPRI, call the EPRI Customer Assistance Center at 800.313.3774 or e-mail askepri@epri.com.

ACKNOWLEDGMENTS

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

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This report describes research sponsored by EPRI.

This analysis would not have been possible without the efforts of staff from the various power stations visited, along with participating staff from their corporate headquarters. At each site, several individuals took time from their busy days to explain their operations and provide data, and to provide access to their systems that generate and manage coal combustion residuals. Special acknowledgement is given to staff at the industrial facility that—while not the subject of the proposed rulemaking driving this analysis—also took significant time to explain and demonstrate the systems they use to comply with RCRA Subtitle C requirements.

This publication is a corporate document that should be cited in the literature in the following manner:

Engineering and Cost Assessment of Listed Special Waste Designation of Coal Combustion Residuals Under Subtitle C of the Resource Conservation and Recovery Act. EPRI, Palo Alto, CA: 2010. 1020557.

ABSTRACT

The Electric Power Research Institute (EPRI) undertook this project to identify engineering cost estimates for the changes at power plants needed to comply with the Subtitle C option in proposed federal rules regarding the management of coal combustion residuals.

The analysis represents a high level evaluation of various plant operations before such federal rules are finalized. It relies on best engineering judgment interpretations of applying the proposed regulations on current practices for generating, managing, and disposing of coal combustion residuals. In addition, the analysis assumes such upgrades can be performed without major modifications at the power plants and does not consider more extreme measures such as boiler retirement or replacement.

Based on site visits, potential operational and physical changes within the power plants and in ancillary areas such as ponds and landfills were identified. Model plant configurations were selected, and these model plants were divided into subsystems where upgrades required to comply with Subtitle C were determined and the costs to perform the upgrades were estimated.

Keywords

Coal combustion residuals
Subtitle C
Disposal
Cost

GLOSSARY

acfm	Actual cubic feet per minute
AACE	Association for the Advancement of Cost Engineering
CCR	Coal combustion residuals
DOT	U.S. Department of Transportation
EAF	Electric arc furnace
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FF	Fabric filter; also called a baghouse
FGD	Flue gas desulfurization
ft	feet
GCL	Geosynthetic clay liner
HP	Horsepower
hr	hour
in.	inch
LDR	Land disposal restrictions
lin. ft.	linear feet
LLDPE	Low-level density polyethylene
mgd	Million gallons per day
MW	Megawatt
NEPA	National Environmental Policy Act
NO_x	Oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
O&M	Operating and maintenance
O/o	Owner/operator
POG	Point of generation
PPE	Personal protective equipment

PRB	Power River Basin (coal)
PVC	Polyvinyl chloride
RCRA	Resource Conservation and Recovery Act
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
T/S/D	Treatment, storage, and disposal
TPH	tons per hour
U.S.	United States
URS	URS Corporation
USWAG	Utility Solid Waste Activities Group
WWT	Wastewater treatment
ZLD	Zero Liquid Discharge

EXECUTIVE SUMMARY

The Electric Power Research Institute (EPRI) undertook this project to identify and develop engineering cost estimates for the changes power plants would need to make to comply with the Subtitle C option in recently proposed federal rules [75 Federal Register (FR) 35128, June 21, 2010] regarding the management of coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act (RCRA).

The objective of this study was to develop reasonable engineering estimates of the incremental operational and capital costs for meeting Subtitle C requirements (one option discussed in the rulemaking) above and beyond current practice and the requirements under Subtitle D (another option in the proposed rules). The costs developed under this study are those that would be above and beyond the compliance costs incurred by power plants under the proposed Subtitle D option, from the point of generation (POG) to the point of disposal.

The project team visited five multiple-unit power plants to observe each process that generates or is used to handle coal combustion residuals. In addition, the project team visited a hazardous waste generator facility to observe how an existing facility generates and manages a listed hazardous waste by-product that is physically similar to coal fly ash in compliance with the Subtitle C requirements. Based on these site visits and knowledge of the Subtitle C regulations, the project team developed a conceptual understanding of operational and physical changes that could be needed within the power plants and in ancillary areas such as ponds and landfills.

The project team selected two different model power plant sizes and identified various configurations as a basis for estimating costs. The two model plant sizes selected were 2 x 200 megawatt (MW) and 2 x 800 MW in nameplate generating capacity. The cost estimates were developed by dividing the model plants into a number of affected subsystems, applying the conceptual upgrades to these subsystems and using accepted industry practices, specified assumptions, and/or recent data to estimate the costs of the upgrades.

This engineering analysis represents a high level evaluation of various plant operations before the federal rules are finalized. It relies on best engineering judgment interpretations of applying the proposed regulations on current practices for generating, managing, and disposing of coal combustion residuals. In addition, the analysis assumes such upgrades can be performed on the existing power plants, and does not consider more extreme measures such as boiler replacement.

A summary of the estimated costs for the assumed base power plant configurations is shown by subsystem in Table ES-1.

Table ES-1
Summary of Estimated Costs by Subsystem for Base Plant Configurations.

Power Plant Subsystem	Range
Bottom ash management system costs	$1,050,000 – 1,890,000
Economizer/fly ash management system costs (base case)	$2,310,000 - $3,730,000
FGD by-product/gypsum management system (base case)	$7,020,000 -$9,510,000
Land storage/landfill upgrades to RCRA standards*	$6,670,000 - $9,070,000
Additional costs to close active and inactive CCR ponds to Subtitle C requirements)**	$20,400,000
Wastewater Treatment Costs (including replacement ponds)	$8,400,000 – $65,300,000
Miscellaneous operational/administrative upgrades	$3,650,000 - $10,400,000
Additional costs for upgrades not included in the base configuration***	$200,000 - $19,400,000

Numbers in tables are rounded up to three significant figures.

*Does not include basic landfill construction, operation, or closure costs

**Cost will vary significantly depending on pond acreage. Cost shown is an estimated average

***A specific plant may need one or more of these additional upgrades

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1
INTRODUCTION AND BACKGROUND

The Electric Power Research Institute (EPRI) undertook this project to identify and develop engineering cost estimates for the changes power plants would need to make to comply with the Subtitle C option in the recently proposed federal rules[1] regarding coal combustion residual (CCR) management under the Resource Conservation and Recovery Act (RCRA). The project addresses only the incremental operational and capital costs of Subtitle C requirements above and beyond current practice and beyond the requirements under Subtitle D in the proposed rules. Throughout this report, the acronym "CCR" is used to be consistent with proposed U.S. Environmental Protection Agency (EPA) rulemaking.

This engineering analysis represents a high level evaluation of various plant operations before the federal rules are finalized. It relies on best engineering judgment interpretations of applying the proposed regulations on current practices for generating, managing, and disposing of CCRs. The report sections and appendices that follow include detailed technical descriptions of URS Corporation's (URS') development of estimates of the "upstream" costs that coal-fired electric generation units could reasonably expect to incur as a result of EPA's proposed Subtitle C option. In this report, the term "upstream" refers to all aspects of power generation from the plant process areas that generate CCRs through traditional by-product handling.

Background

On June 21, 2010, EPA proposed multiple options for regulating the disposal of CCRs generated at electric utility and independent power producer generating units under the RCRA. These rules would apply to the by-products of coal combustion, including fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) materials. EPA has requested public comments on the proposed new rules, which provide the following three approaches for managing disposal of CCRs.

Proposed RCRA Subtitle C Option

As proposed, the first approach would be to regulate disposal of CCRs under RCRA Subtitle C by creating a Special Waste category under a new Subpart S. CCRs destined for disposal would be a listed Special Waste. These CCRs would be regulated under Subtitle C from the point of generation (POG) to disposal, and would be subject to the same requirements as those for hazardous waste, including provisions for corrective action and financial responsibility.

[1] 75 FR 35128

The proposed Subtitle C rules indicate that CCR disposal in sand and gravel pits, quarries, and other large fill operations would be regulated as landfills[2]. Furthermore, existing units (e.g., landfills and surface impoundments) that have not been closed in accordance with proposed criteria would be subject to proposed Subtitle C requirements[3], including permitting.

The proposed Subtitle C rules also include provisions for liner requirements[4], surface impoundment stability[5], run-on and runoff controls[6], and fugitive dust control[7] while applying existing Subtitle C requirements[8] (siting, groundwater monitoring, financial assurance, corrective action, unit closure, and post-closure care). Although the proposed Subtitle C option would not require existing landfills to be retrofitted with new minimum-technology liners, these landfills would have to meet the groundwater monitoring, corrective action, and other requirements of Subtitle C to ensure that any groundwater releases are identified and remediated[9].

Provisions of Subtitle C relating to air emission standards for process vents and equipment leaks (Subparts AA and BB) would not likely be required as long as the CCRs contain less than 10% organic material[10]. Provisions of Subtitle C relating to air emission standards for certain waste units (Subpart CC) would not likely be required as long as the CCRs have an average volatile organic concentration of less than 500 parts per million by weight[11].

EPA has proposed to leave the Bevill determination in place for CCRs that are used beneficially[12]. However as noted earlier, EPA's proposal would not include certain current uses (disposal in sand and gravel pits, quarries, and other large fill operations) under the beneficial use determination.

RCRA Subtitle D Option

The second proposed approach is to regulate the disposal of CCRs under RCRA Subtitle D, which requires utilities to self-report and self-implement more stringent CCR management requirements. Under the proposed Subtitle D designation, operators of existing and new surface

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[2] 75 FR 35254; § 261.50 (d)

[3] 75 FR 35255, §264.1300

[4] 75 FR 35257, §264.1306

[5] 75 FR 35256, §264.1303

[6] 75 FR 35257, §264.1303 (g)

[7] 75 FR 35258, §264.1308

[8] 75 FR 35254, §261.50 (a)

[9] 75 FR 35257, §264.1306 (c)

[10] 40 CFR 264,1030(b) and .1050 (b)

[11] 40 CFR 264.1082 (c)(1)/ §265.1083 (c)(1)

[12] 75 FR 35254, §261.50 (d)

impoundments would be required to install composite liner and leachate collection systems[13]. If an existing surface impoundment does not have a liner system installed, it would be required to stop receiving CCRs within five years after the effective date of the proposed rule, and subsequently close within an additional two years[14].

RCRA Subtitle D Option – D Prime

EPA is also considering a third approach – called D Prime – that is a modification of the Subtitle D option. Under D Prime, existing surface impoundments would not have to be closed or have composite liners installed, but could be operated for their remaining useful life[15]. Operators of existing landfills and surface impoundments would be required to install groundwater monitoring systems. New landfills or ponds would have to meet all of the same engineering and control requirements as under Subtitle D.

Objective of Study

The objective of this study was to estimate the incremental operational and capital costs of Subtitle C requirements above and beyond current practice and the requirements under Subtitle D in the proposed rules, from the POG to the point of disposal. In a parallel EPRI project, the costs developed under this study will be applied to individual power plants on a nationwide basis as a function of unit size, CCR generation rates, and other factors to estimate the industry-wide incremental cost of compliance with Subtitle C rules.[16]

Methodology

To develop the estimated engineering costs of potential, incremental operational and physical changes needed for power plants to comply with the Subtitle C option in the recently proposed waste management rules, the project team completed the following three tasks:

- Visited five power plants to observe CCR handling and one hazardous waste generator to observe waste handling practices,
- Identified potential operational/physical changes needed to comply with Subtitle C, and
- Estimated costs to upgrade model plants, including costs for varied plant configurations.

Each task is briefly described below.

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[13] 75 FR 35243, §257.70; 75 FR 35244, §257.72

[14] 75 FR 35243, §257.70 (a)

[15] 75 FR 35210, II. "Alternative RCRA Subtitle D Approaches"

[16] EPRI, 2010. *Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from the Electric Generating Industry.* EPRI, Palo Alto, CA: 2010. 1022296.

Site Visits

The project team visited five multiple-unit power plants in June and July 2010. One of the stations had five generating units, two had four units, and two had two units. Individual unit sizes ranged from approximately 250 to 800 megawatt (MW) in nameplate generating capacity. Three of the stations fired Powder River Basin (PRB) coals in all units and two fired high-sulfur Eastern bituminous coals.

At each plant, the team spent a day interviewing station personnel and walking through the station to observe each process that generates or is used to handle CCRs. Detailed notes were taken, and simplified schematics were made of each plant following each site visit.

In addition, the project team visited a hazardous waste generator facility (iron and steel manufacturer) with an electric arc furnace (EAF) that produces a listed hazardous waste dust (K061). The reason for visiting this type of facility was to observe how an existing facility generates and manages a listed hazardous waste by-product that is physically similar to coal fly ash in compliance with the Subtitle C requirements.

Identification of Potential Operational/Physical Changes for Compliance

The project team analyzed site visit results to identify potential operational and physical changes needed for power plants to comply with the proposed Subtitle C option. The site visits also allowed the team to evaluate potential POG locations for application of the proposed rules.

In the analysis of POG, the team applied concepts codified by EPA. More specifically, when one makes the determination to discard or dispose of materials that are not subject to exclusion or variance from solid waste, those materials are regulated as solid wastes under RCRA[17]. A solid waste that is not excluded from regulation as a hazardous waste and that meets specific criteria (e.g., a characteristic of hazardous waste or a listing as a hazardous waste) is a hazardous waste under RCRA[18]. Disposal may be an active decision (e.g., placing materials in a landfill for disposal) or passive (e.g., discharge, spilling, or leaking solid waste or constituents of solid waste into the environment, air or water)[19].

The impact of applying the definition of solid waste rules is that the POG can vary depending upon plant operations. If CCRs are contained, the POG occurs at the point when the decision is made to discard or dispose of the CCRs. If, however, the CCRs are subject to discharge, spilling, or leaking, then the POG occurs at the point of discharge.

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[17] 40 CFR 261.2(a)(1)

[18] 40 CFR 261.3

[19] 40 CFR 260.10 Definitions, "*Disposal*" means the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

The effort to identify potential operational and physical changes included a review of the generation-based size distribution of coal-fired plants across the United States (U.S.) to determine appropriate unit sizes to use as model plants for developing subsequent cost estimates for these changes.

Estimation of Costs for Upgrading Model Plants

Two model plants—one with two 200 MW units (400 MW station) and one with two 800 MW units (1600 MW station)—were used as the basis for developing the costs of these changes. There is quite a range of variability in how U.S. power plants generate, collect, and manage CCRs. The configurations of the model plants were selected to reflect what was believed to be the most common practices, either today or in the future. However, the project team also considered various optional plant configurations in estimating the costs of upgrading model plants to reflect a broader range of CCR generation, collection, and management practices.

Estimated costs for upgrades were organized according to the following six subsystems and the associated miscellaneous operational/administrative upgrades:

- Bottom ash management system,
- Economizer/fly ash management system,
- FGD by-product/gypsum management system,
- Storm water segregation (eventually addressed by other tasks),
- Land storage/landfill upgrades to RCRA standards,
- Wastewater treatment, and
- Miscellaneous operational/administrative upgrades.

Organization of This Report

The remainder of this report is organized as follows:

- Section 2 is a description of the project team's site visits to five power stations and one hazardous waste generator.
- Section 3 identifies the incremental operational and capital changes required for compliance with the Subtitle C option, and describes the development of the models for estimating the costs associated with these changes.
- Section 4 contains the model plant estimated costs for the six subsystems and the miscellaneous operational/administrative upgrades, as well as an explanation of the assumptions on which these costs are based.
- The appendices contain detailed information on the cost assumptions described in Section 4.

2
SITE VISITS

The project team visited five power stations to observe how CCRs are handled, general housekeeping in CCR-contact areas, and operating and maintenance (O&M) issues. Station descriptions are provided below at a relatively high level; details about coal type, air pollution control systems, and CCR management systems are generally not attributed to specific stations.

Power Plant Descriptions

Overview

The five stations were all multiple-unit stations, with one having five generating units, two having four units, and two having two units. Accordingly, a total of 17 generating units were visited. Individual unit sizes ranged from approximately 250 to 800 MW in nameplate generating capacity. Three of the stations fired PRB coals in all units and two fired high-sulfur Eastern bituminous coals.

Each site visit began with a discussion of the processes employed at the station that generate or handle CCRs, as well as the water collection and treatment systems. Following these discussions, a walk-down and/or drive-through of the station was conducted with project team members and one or more utility staff members. Simplified schematics were made of each plant following each site visit.

Figure 2-1 is an example schematic of a generic plant with a selective catalytic reduction (SCR) system for oxides of nitrogen (NO_x) control and a gypsum-producing wet FGD system. This does not specifically represent any one of the stations or units visited. The generic schematic also shows a range of CCR treatment and handling options that may be implemented at a power plant.

Air Quality Control Systems

Of the 17 units, 10 are equipped with SCR for NO_x control and 7 are not. Eleven units have cold-side electrostatic precipitators (ESPs) for particulate control, two have reverse-gas fabric filters, and four have venturi wet scrubbers for combined particulate and sulfur dioxide (SO_2) control. Also, five of the units are equipped with SBS® (Sodium-based Solution) sulfur trioxide (SO_3) control systems.

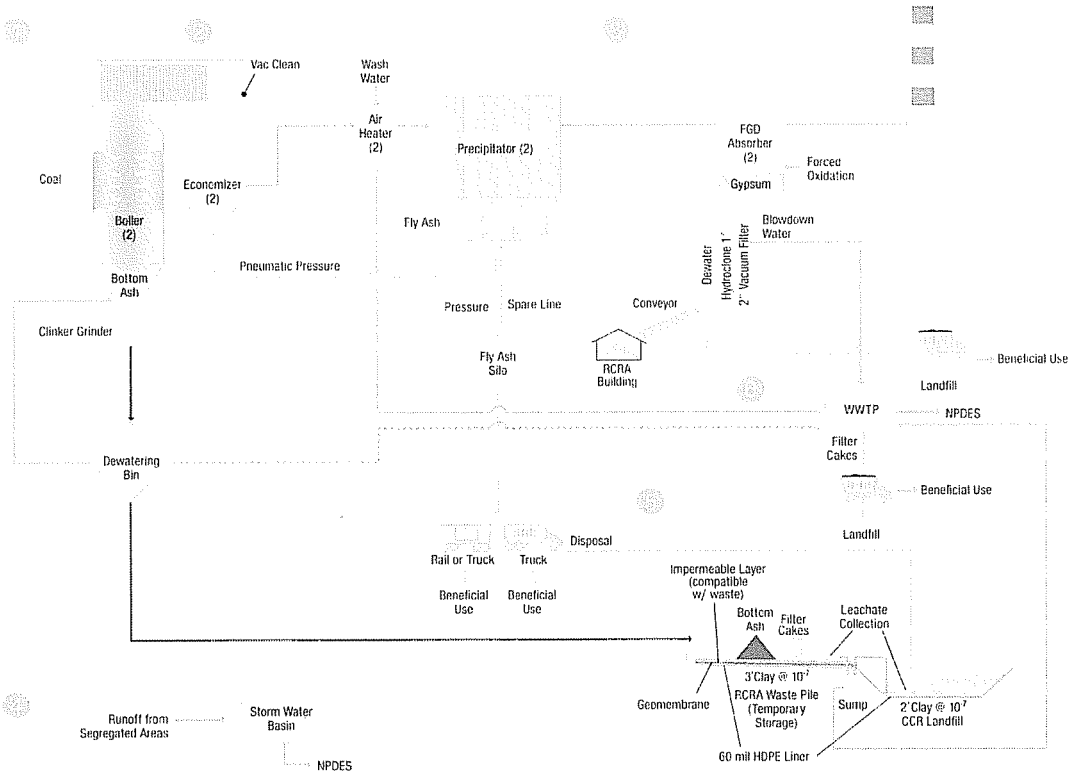

Figure 2-1
Simplified Schematic of Power Plant Process and CCR Handling Schemes

All 17 units have wet FGD in some form, with wet limestone forced oxidation systems being the most prevalent (10 units). However, two of these units are currently operating in a 100% natural oxidation mode (no forced oxidation air flow) but still produce a gypsum by-product. Of the remaining units, three units' wet FGD systems use limestone reagent but operate in inhibited oxidation mode, producing a calcium sulfite by-product, and the four venturi particulate control scrubbers mentioned above add lime to promote sulfur dioxide (SO_2) capture. These four scrubbers produce a mixture of gypsum and calcium sulfite as the FGD solid by-product, which is mixed with fly ash in the scrubber slurry. This configuration was prevalent in the 1970s and early 1980s, but now represents only a small percentage of the U.S. wet FGD population.

CCR Management Systems

Bottom Ash

The most prevalent bottom ash handling approach involves wet sluicing to a pond and/or "rim ditch" operation to recover the solids. This approach is used for 13 of the units. Two more units use wet sluicing but have dewatering bins to recover the solids. The water circuit is not completely closed in this case, as excess water is periodically discharged to a pond and plant makeup water is used to later make up losses. One station with a wet sluicing operation to a pond also has dewatering bins available, but abandoned their use due to excessive plugging of the dewatering screens at the bottom of the bins as a result of bottom ash fines.

The final two units use semi-dry bottom ash handling systems – submerged chain conveyor systems – where bottom ash drops out onto a horizontal water-flooded conveyor at the boiler bottom and is conveyed out through an upward-angled discharge. The bottom ash dewaters on the slow moving, angled portion of the conveyor. Nearly dry bottom ash is discharged into a three-sided pit adjacent to the boiler. It is then emptied with a front-end loader into open trucks.

All of the units attempt to beneficially use their bottom ash by-product to the greatest extent possible. In the case of the 13 units with pond and/or rim ditch operations, the bottom ash is recovered as it is needed for reuse. In the case of the four "semi-dry" bottom ash units (dewatering bins and submerged chain conveyor systems), the bottom ash is recovered to an intermediate storage area, where it is placed in a pile outdoors, on a surface lined with CCRs of some type. From this pad, it is reloaded for beneficial use or disposal.

Economizer Ash

In 13 of the 17 units, economizer ash is collected along with either the bottom ash or fly ash. Only four of the units have a completely segregated economizer ash system, in which economizer ash is pneumatically conveyed to a small silo. The economizer ash in the silo is subsequently trucked to beneficial use applications or to disposal.

Fly Ash

Ten units handle their fly ash in dry systems, with pneumatic transfer from the ESP or fabric filter hoppers to silos, while seven employ wet slurry transfer to ponds, as detailed below. Four of the units with dry fly ash handling systems rely on wet sluicing systems, as originally installed when the unit was built, as backup for ash handling when there are outages in the dry pneumatic systems.

The fate of the fly ash that is dry handled varies among the ten units. For four units that fire PRB coal, the fly ash is a high-value cement replacement by-product, and nearly all of the fly ash is trucked from the sites to beneficial use markets. Two of the PRB units are in a cold-winter climate, and the plant has an enclosed fly ash storage building to stockpile fly ash during the winter months when construction activity is minimal.

Two of the dry-fly-ash-handling units blend all of their fly ash with the FGD by-product to form a stabilized solid, as described below. The remaining four dry-fly-ash-handling units sell a portion of the ash to beneficial use markets, and the remainder is either used to stabilize calcium sulfite FGD by-product sludge or sent directly to landfill disposal.

Of the seven units that slurry their fly ash, three use sluice systems to transport the ash from the ESP hoppers directly to a pond, which is periodically drained and the fly ash recovered for land disposal. In the other four units, which have venturi scrubbers for combined particulate and SO_2 removal, the slurry of fly ash and FGD by-products is first dewatered in a "paste" dewatering system, where clear water is recovered and the solids in the slurry are concentrated to a paste consistency. This paste is pumped to a pond for further dewatering and solids disposal.

FGD By-Product

Nine of the units produce gypsum as a by-product that is beneficially used to the extent possible, either for wallboard production or cement production. A tenth FGD system produces gypsum by-product that is combined with the fly ash from that unit, quicklime, and FGD chloride purge water in a pug mill to produce a stable landfill material.

The FGD systems on the three units that produce calcium sulfite hemihydrate as a solid by-product (in the form of a sludge with 30 to 40 wt% moisture) mix this material with fly ash and FGD chloride purge water in a pug mill. For one unit's by-product, quicklime is also added to promote strength development, while for the other two units quicklime is not added.

As described above, for the four remaining units the fly ash and FGD by-product are collected together in venturi scrubbers. The slurry of fly ash and FGD by-products is first dewatered in a "paste" dewatering system, where clear water is recovered for reuse and the solids in the slurry are concentrated to a paste consistency and pumped to a pond for further dewatering and disposal.

FGD Wastewater

Five of the ten units with gypsum-producing wet FGD systems blow down their chloride purge streams to wastewater treatment plants that use traditional physical/chemical treatment processes (pH adjustment, iron, and organo-sulfide addition, clarification, etc.). Of these, two units discharge treated water through a National Pollutant Discharge Elimination System (NPDES)-permitted outfall, and three inject the water in deep wells. These three systems are at an NPDES no-discharge plant. Of the remaining gypsum-producing FGD systems, four treat their wastewater only for pH and total suspended solids in ponds before discharge, and the fifth mixes its chloride purge stream with the gypsum and fly ash from that unit, for land disposal.

In the three sulfite-producing wet FGD systems and in the combined particulate/SO_2 control systems, the dewatered FGD by-product still contains a considerable amount of water because these solids do not dewater as effectively as does gypsum. For these systems, water leaving with the dewatered FGD by-product, as well as water added at the pug mill in the sulfite-producing FGD systems, takes care of the required chloride purging and no separate wastewater stream is generated.

Landfills

Four of the five plants visited have active landfills nearby, either on the plant site or on contiguous property. Of those, two send only minimal amounts of solids to the landfill (e.g., primarily wastewater treatment filter cake) while two dispose of a significant fraction of their CCRs. The fifth plant, which does not have an active landfill, is beneficially using most of the bottom ash produced but pumping the remaining CCRs as slurries for disposal in ponds.

Ponds

All of the plants visited have active ponds. At three of the sites, some ponds are used for dewatering and/or disposal of CCRs. At the other two sites, ponds are used primarily for treating process or runoff water streams prior to discharge, and include at least some CCR-contact water.

Three of the five plants visited have NPDES-permitted wastewater discharge points, while two plants are Zero Liquid Discharge (ZLD) plants without NPDES permits for plant wastewater discharges.

Hazardous Waste Facility Description

The project team also visited an industrial facility that generates an emission control dust that is a listed hazardous waste (EPA hazardous waste number K061, emission control dust from the primary production of steel in electric furnace). The intent of this visit was to observe how this listed hazardous waste dust is appropriately managed under the RCRA Subtitle C regulation. The hazardous waste dust is commonly referred to as EAF dust, and has a consistency similar to coal fly ash.

The following information focuses only on hazardous waste generation and management at the facility, highlighting those issues that are most similar to the proposed Subtitle C requirements faced by generators of CCRs.

Air Quality Control

EAF dust is captured in a baghouse at the facility visited. The reverse-gas baghouse contains 7,000 bags, each 1 foot in diameter by 30 feet high. The process flue gas flow rate is 2.2 million actual cubic feet per minute (acfm). The baghouse collects approximately 50 to 100 tons/day of EAF dust. By comparison, a baghouse or ESP at a typical 500 MW power plant collects about 200 to 300 tons/day of fly ash.

Waste Management

The fabric filter compartment hoppers and EAF dust transport systems are totally enclosed in a building that meets the RCRA container building standards. This facility was constructed about five years ago and was designed for ease of maintenance and to minimize or eliminate discharges of EAF dust. Windows and doors were built to close and the building has a ventilating fan with a bag filter to maintain negative pressure, thus preventing losses of EAF dust from the building. Concrete floors are curbed, joints are sealed, and the floor is coated with an epoxy paint, tinted to make visible to the O&M staff any dust that may escape the filters.

The O&M staff wears "Level C" personal protective equipment (PPE) for weekly vacuuming of the building floors using a commercial, riding sweeper/vacuum cleaner. The facility is inspected each shift and forms are scanned into an electronic data system. Piping and metal structures in the building are completely wiped down twice per year to prevent dust accumulation, and at other times as needed. The facility uses a program of dust elimination through enhanced and continuous O&M (e.g., daily compartment bag checks, piping checks, immediate mitigation).

Dust is transferred via air slides and a pneumatic system to an adjacent silo for storage and loaded directly from the silo into top-loading, enclosed railcars for delivery to a reclamation facility (for recovery of zinc content). The loading chute from the hopper has an "elephant nose" nozzle to minimize any spillage during loading operations. The chute makes a tight seal to the rail car hatch opening during dust loading. It has a double wall, with dust flowing through the inner flow path and a vacuum applied to the annulus between the two walls to collect any escaping dust.

The railcar loading area is completely enclosed and designed so that the facility can wash down any dust on the railcar or in the containment area into a sump. Contents in the sump are transferred to the railcar as part of the loading process so that 100% of the EAF dust and any associated water go to reclamation. The facility doors are closed as well as the railcar hatches not connected to the chute while the railcar is in the loading facility to minimize the potential for any dust releases. All EAF dust from the facility is shipped (as hazardous waste) to an off-site reclamation facility where zinc is recovered from the dust.

Special screw-top waste barrels are used to collect cleanup materials and discarded PPE. These materials are disposed of in a dedicated 90-day accumulation container (lugger box) that is hauled away periodically.

All plant employees receive eight hours of hazardous waste training each year, and environmental personnel are required to complete three-day hazardous waste training and U.S. Department of Transportation (DOT) training every three years. Contract personnel who perform maintenance are also required to have hazardous waste training.

3
MODEL PLANTS

Identification of Potential Operational/Physical Changes to Power Plants

Based on the site visits to five power plants and one hazardous waste generator, and knowledge of the Subtitle C regulations, the project team developed a conceptual understanding of operational and physical changes that could be needed within the immediate area of the units themselves and in ancillary areas such as ponds and landfill.

Potential Upgrades

It was clear from the site visits that most stations routinely operate with discharges of CCRs from process equipment to the area surrounding the equipment, and resulting CCR contact with the ground, floors, process piping, handrails, in ditches, etc. Also, in most plants there is an opportunity for CCRs to contact process and storm water streams as a result of wash-down and rainfall events. These CCRs are all generally contained within the power plant, and cleaning and repair is part of routine plant operation and maintenance activities (O&M).

In comparison, the experience at the hazardous waste site showed that considerable effort is placed on preventing process leaks, and that the facility is set up to readily identify, correct, and clean up any leaks of the dry powdered hazardous substance that do occur. Furthermore, there is little opportunity for the hazardous substance to come into contact with process or storm waters. The only water contact results from rinsing the external surfaces of rail cars after loading, and this rinse water is added to the contents of the car before it leaves the loading area.

If CCRs are regulated under Subtitle C, it is presumed that power plants would have to handle them in a manner similar to the way wastes are handled at the hazardous waste generating facility. Typical upgrades would include cleaning and epoxy coating floors in CCR contact areas, sealing walls and doors, and providing negative pressure ventilation in dust-generating areas. Potential CCR contact areas would need to have curbing installed to minimize the incidental transfer of CCRs from floors into adjacent areas by foot and vehicle traffic or by wash down. Some of these upgrades could represent significant engineering challenges and capital expenditures for power plants.

Along with these physical changes, additional operating and maintenance costs would be realized. Minor CCR leaks at flanges and valves currently are seen as a routine operating issue, and are typically deferred until a future outage or until the leak becomes much worse before being repaired. In a Subtitle C scenario, these minor leaks would have to be repaired immediately and the resulting spills cleaned up within 24 hours. Additionally, O&M personnel would have to spend more time in regulatory-required initial and annual training. The net effect

of these changes would be an increase in O&M costs, likely including increased operating and/or maintenance staffing levels.

Plant drains in potential CCR contact areas would have to be closed or otherwise segregated to avoid CCR contact water mixing with non-CCR process and storm waters. FGD dewatering areas may present an exception, however, because most FGD systems have a drain and sump system where the drain water is incorporated back into the FGD process at some point.

CCRs are routinely transported in pipes (e.g., sluiced bottom ash to dewatering bins), pneumatic transport lines (dry-handled fly ash), and belt conveyors (FGD gypsum or calcium sulfite by-product). In pipes and ash transport lines, increased diligence in inspection and maintenance can reduce and/or prevent leaks. In the case of open belt conveyors for gypsum or other FGD by-product transfer, material loss can occur because of wind disturbance and/or material falling from the bottom of the belt on the return path. In a Subtitle C environment, these fugitive losses would have to be managed, most likely by converting to fully enclosed "pipe" conveyors.

CCRs are also routinely transported in truck semi-trailers, railcars, and barges. These transportation devices are routinely loaded in the immediate plant vicinity from dewatering bins (bottom ash), dry silos (fly ash), or piles of semi-moist material (e.g., FGD by-product). This loading is generally done in open-air facilities, with at most a roof overhead and partial sidewalls. Dry material is often unloaded from silos through simple canvas chutes, and allowed to free fall into truck trailers through open hatches. This results in some material loss on windy days. Hatches often are opened and/or bed covers removed in an area adjacent to the immediate loading area, and filled trailers are closed or covered at adjacent areas as well. Ash can sometimes escape from open hatches or trailer beds in the immediate vicinity of the loading areas.

The hazardous waste facility observations show that the opening, filling, and closing/covering of transportation vessels would have to occur in a completely enclosed facility. Thus, truck loading facilities would have to be completely enclosed, with tight-closing roll-up doors at either end, tight-closing personnel entry doors, a negative draft ventilation system, and a mezzanine installed to allow driver access to close hatches and/or install covers over the load. Furthermore, for dry powders like fly ash, more sophisticated loading chutes would be required, with tight seals at the trailer loading hatch and a double-wall chute with a vacuum applied in the annular area to minimize fugitive losses. In large plants that generate a lot of CCRs that are removed by truck, it is likely that additional truck loading facilities would have to be added, as the procedures described above will significantly slow the rate at which trucks can be filled.

Key Plant Configurations Affecting Costs

During the plant site visits, some situations were identified at a few plants that would clearly have a significant impact on the cost of compliance for affected plants. These situations included CCR handling in open areas (i.e., no sidewalls and doors) and plants that do not have existing NPDES water discharge permits. Each of these circumstances is discussed further below.

Open CCR Processing Areas

One of the plants visited was located in a southern state with a relatively mild climate. The hopper area below the particulate control device, where fly ash is pneumatically emptied from the hoppers and conveyed away to a silo, is "open air." That is, the particulate control device and hoppers form a roof over this area, but there are no sidewalls from grade up to the perimeter of the particulate control device to enclose this area. Thus, when CCR leaks occur in the pneumatic transfer equipment and the wind is blowing, fly ash can be dispersed into the plant area around the particulate control device. The hazardous waste site experience shows that this area would need to be enclosed, with tight-fitting entry doors and windows, negative-draft ventilation, etc.

In contrast, plants in cold-winter areas tend to have sidewalls, doors, and windows already in place, and so would only require upgrades to improve sealing and to add the negative draft. The cost of enclosing an open area would be substantially greater than just improving the sealing and draft of an area already enclosed.

Furthermore, some units have CCR processing areas, such as the hopper area under an ESP, that are not paved with impervious groundcovers such as concrete. Instead, these areas are sometimes paved with asphalt or aggregates. These areas would have to be cleared of the existing groundcover and paved with epoxy-coated concrete or other sealed surfaces in a Subtitle C environment.

In some cases, gypsum stack-out and loading areas are paved with compacted gypsum, either in open-air or enclosed areas. Such areas would also have to be enclosed, if not already, and paved with impervious materials such as coated concrete in a Subtitle C scenario.

NPDES Permit Status

Three of the five plants visited have active NPDES permits that take precedence over RCRA tank requirements with respect to wastewater handling (commonly referred to as the RCRA wastewater treatment unit exemption). Thus, tanks (including dewatering systems in tanks) that handle wastewater subject to an NPDES permit at these plants do not have to meet "RCRA tank" standards, e.g., requiring secondary containment. In contrast, two of the five plants visited were ZLD facilities, meaning they had no NPDES-permitted wastewater outfalls. In this case, it is possible that all tanks that handle CCR-contact wastewaters at this plant would have to meet RCRA tank standards.

However, for this project the need to meet RCRA tank standards for ZLD facilities was not considered in developing compliance costs. EPRI estimates that 10% or less of all coal-fired plants operate in a ZLD mode[20]. Furthermore, many of these plants may have NPDES permits for internal outfalls. One of the five plants visited operated in such a manner. Of the remaining plants, a number may qualify for the RCRA exemption if they operate without an NPDES permit primarily to achieve water quality improvements.

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[20] *Summary of Zero Liquid Discharge (ZLD) Water Management Installations at U.S. Power Plants*, EPRI, Palo Alto, CA, 2008, EPRI Report 1015592

Although the cost implications to individual plants could be significant, the limited number of plants that may be impacted did not justify adding this situation to the industry-wide cost estimating scenario. Also not considered in this analysis was the potential impact of steam electric effluent guidelines regulations currently being considered by the EPA.

Protocols for Estimating Upgrade Costs – the Model Plant Approach

Use of Model Plant as Initial Basis

The approach taken for estimating plant upgrade costs was to assume model plant sizes and configurations for which the costs were estimated. Estimates were developed for two different model plant sizes to allow the calculation of scaling factors for estimating costs for different unit sizes. As shown in Figures 3-1 and 3-2, the model plants were assumed to have two units each, to reflect that most coal-fired stations have multiple generating units. This often impacts the sizes of ancillary equipment such as fly ash loading facilities, gypsum dewatering facilities, ponds, and landfills that are generally common to the entire station.

The two model plant sizes selected were 2 x 200 MW and 2 x 800 MW in nameplate generating capacity. In selecting these unit sizes, the distribution of coal-fired generating unit sizes in the U.S. was considered, based on information from the most recent Form EIA-767 data available from the Department of Energy's Energy Information Agency. This distribution is illustrated in Figure 3-3 on two bases – number of units and percentage of coal-based net generation.

The results in the figure show that there is a significant increase in the number of units in the size range of 200 MW and smaller. This would be of less interest if these units did not generate a significant fraction of the total coal-fired power generated. However, in the 101- to 200-MW size range, there is also a peak in percentage of generation that is not exceeded until unit sizes are greater than 500 MW. This is the rationale for picking 2 x 200 MW for the smaller station unit size.

For the larger plant size, the selection of 2 x 800 MW was intended to represent as large a size as practical to provide an ample range of unit size above 200 MW, without getting into very large units that represent only a small percentage of the net generation. For example, units larger than 900 MW generated only 5% of the total in this data set.

Model Plant Configuration

This section describes the configurations of the model plants with respect to CCR handling systems. Also described are optional configurations that were considered for upgrades to ensure better coverage of the population of coal-fired units in the U.S. The base plant configurations for CCR handling are described first, then the optional configurations.

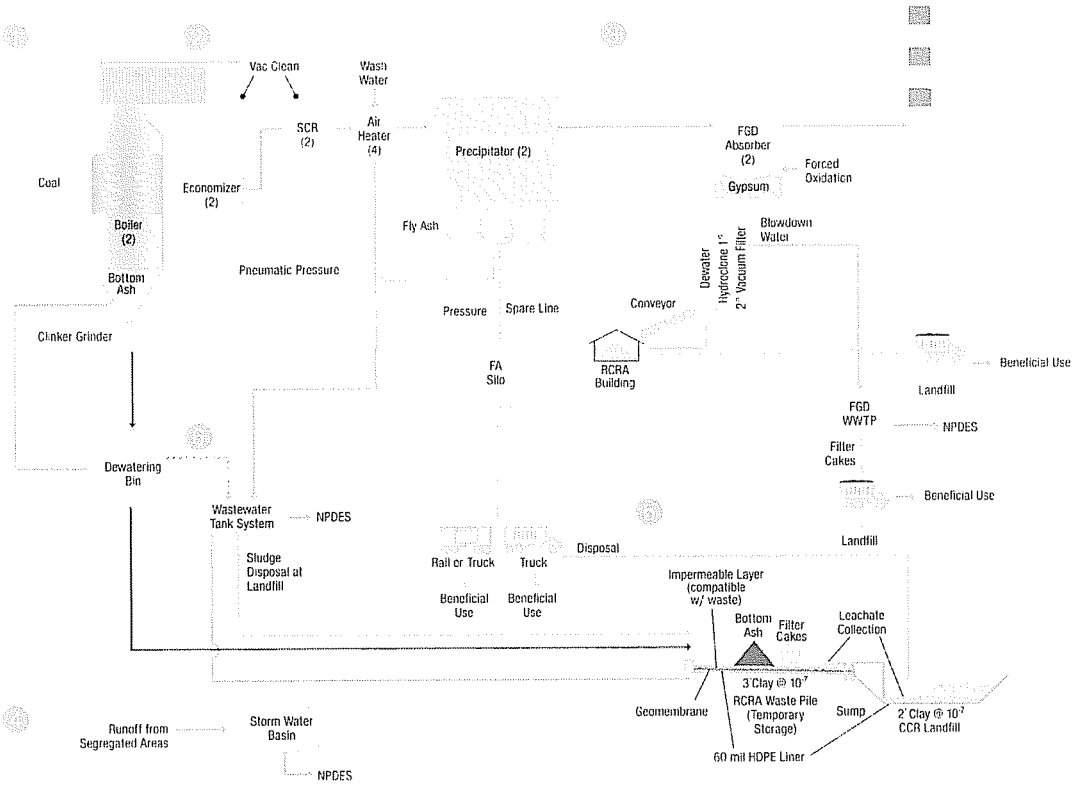

Figure 3-1
Model Plant with Two 800 MW Units

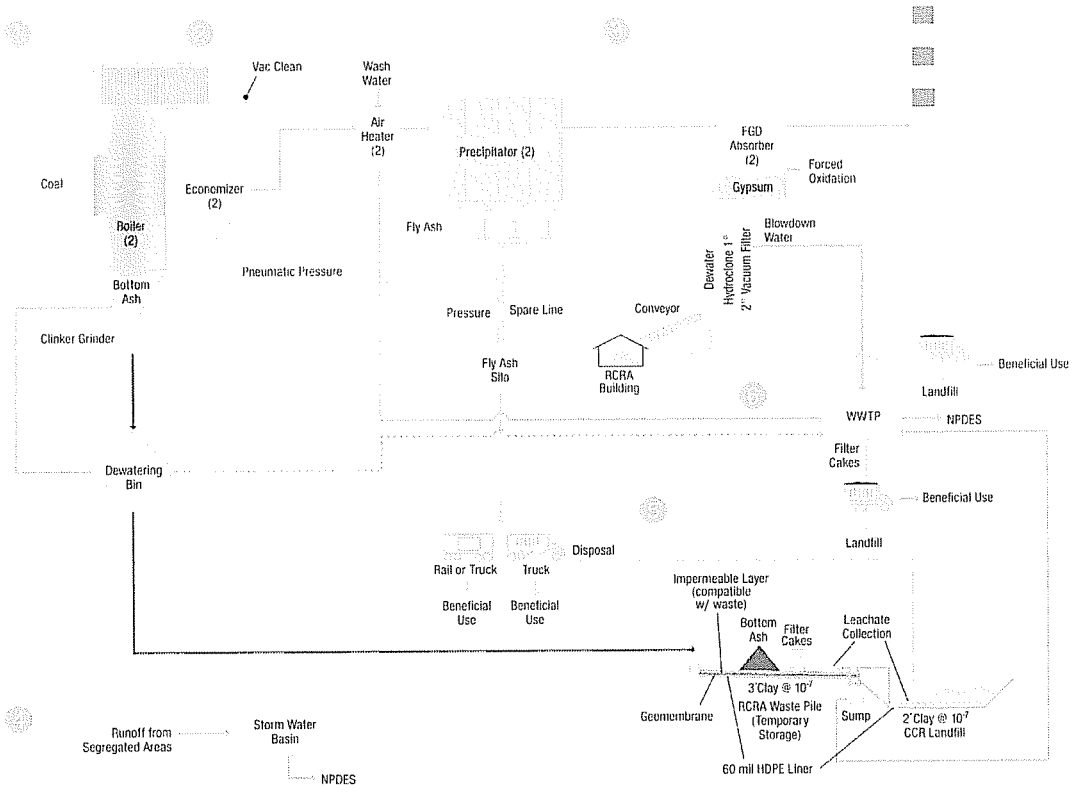

Figure 3-2
Model Plant with Two 200 MW Units

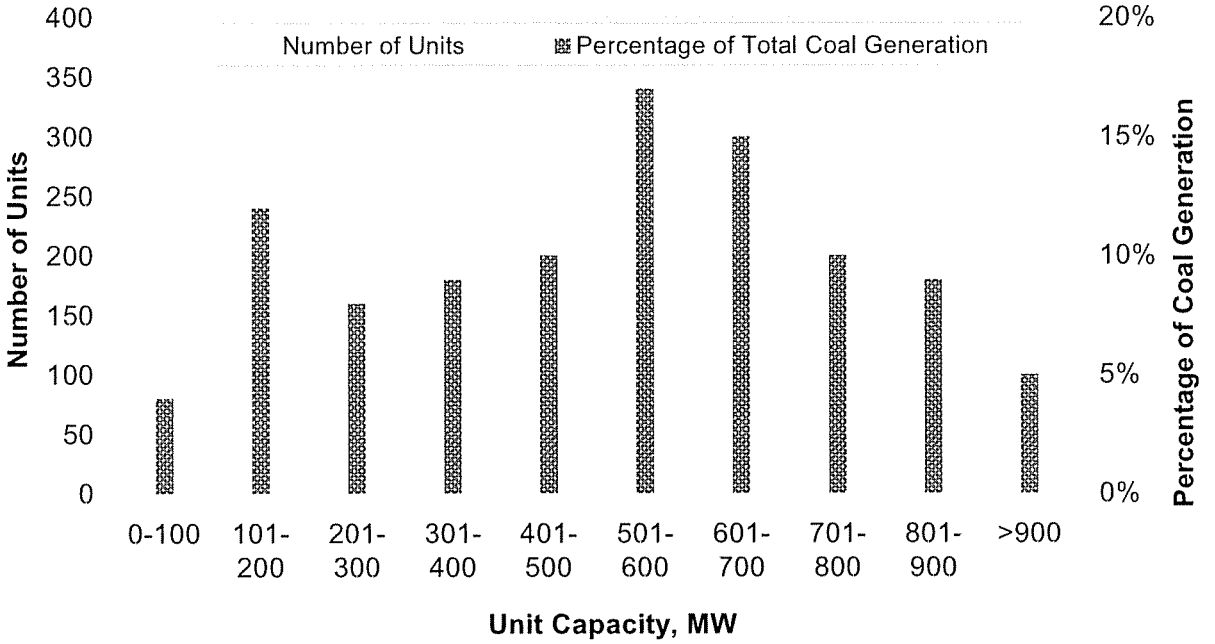

Figure 3-3
U.S. Coal-fired Power Generation Unit Size Distribution

Costs of converting from wet to dry management are not included in this analysis. Those costs are being developed in a separate Utility Solid Waste Activities Group (USWAG) study[21].For purposes of the costs developed in this report, it is assumed that the wet to dry conversion has already occurred and all CCRs are managed dry. However, wastewater treatment costs are included as part of this analysis. Wet to dry conversion costs are addressed in the EPRI national cost analysis[22].

Base Configuration

Bottom Ash Handling

For this project, it was assumed that in the model plant base configuration, all units would have dry-bottom boilers (i.e., not slag-tap boilers) with closed-loop water sluice systems for quenching and sluicing bottom ash. The wet sluicing systems include a clinker grinder and sluicing system at the bottom of the boiler, slurry transfer piping, elevated dewatering bins, a

[21] *Cost Estimates for the Mandatory Closure of Surface Impoundments Used for the Management of Coal Combustion Byproducts at Coal-Fired Electric Utilities*, USWAG, Washington, D.C., November 2010

[22] EPRI, 2010. *Cost Analysis of Proposed National Regulation of Coal Combustion Residuals from the Electric Generating Industry*. EPRI, Palo Alto, CA: 2010. 1022296

clarifier for removal of fine solids, a recovered water tank, and a sluice pump. Moist bottom ash is emptied from the dewatering bins (after dewatering) into trucks for shipment off site.

Fly Ash Handling

The base units have cold-side ESPs for control of particulate matter. The 800-MW units have two ESP casings that are "siamesed" together (share a common wall along the centerline of the unit), and each has four to eight rows of hoppers. The 200-MW units have only one ESP casing each and fewer rows of hoppers. All units have pressure or vacuum pneumatic ash transport systems. Each station (two units) has pneumatic transport from the ESP area to a pair of storage/load out silos common to both units, each equipped with a fabric filter (FF) dust collector on top of the silo. The active silo empties to trucks via a dry unloader. The fly ash product contains less than 5% free moisture.

FGD By-product Handling

All units are equipped with limestone/forced oxidation wet FGD systems for SO_2 control. Gypsum dewatering is conducted in a building common to the two units at each station. Absorber blow down is fed to dedicated hydrocyclones for each unit for primary dewatering. Hydrocyclone underflow is fed to horizontal vacuum belts for secondary dewatering. The 2 x 800-MW station has three horizontal belts – one per unit with a common spare. The 2 x 200-MW station has two horizontal belts – one per unit sized to handle slurry from both units when a belt is off line. The horizontal belt product is transferred by belt conveyors to a common gypsum storage building contiguous with the dewatering building. Product gypsum is loaded out for shipping to a wallboard plant via front-end loader into semi-trailers.

FGD Wastewater Treatment

Primary hydrocyclone overflow is sent to a common bank of secondary hydrocyclones at each station, and its overflow is fed to a wastewater treatment system. The wastewater treatment system consists of a typical physical/chemical treatment: pH adjustment, desaturation of gypsum, ferric chloride addition, organo-sulfide addition, and clarification. The clarifier underflow is fed to a filter press. The filter press produces sludge with ~50-70% solids, which empties into roll-off bins that are hauled off by truck. This sludge is disposed of in a CCR landfill on site.

Active Ponds

For the purpose of this analysis, active ponds are considered to be those ponds that are currently receiving CCR slurry streams and will be operational when the new rules are projected to become effective. Few active ponds are anticipated to remain in use at the model stations after the effective date of the land disposal restrictions (LDRs) under the Subtitle C option; primarily this would only be impoundments that manage uncontaminated storm water (i.e., rainwater that has not been in contact with CCR materials). It is assumed that any other ponds that meet the regulatory definition of a CCR surface impoundment would begin closure activities within 90

days following the last placement of CCR materials in such ponds[23]. These closures would be conducted in accordance with 40 CFR 264.228 and subpart G of 40 CFR 264. (See Appendix C for closure steps/specifications.)

Inactive Ponds

EPA proposes to regulate surface impoundments that have not completed closure to RCRA standards[24]. For the purpose of this analysis, inactive ponds ("ponds that have not completed closure") are considered to be those that have stopped receiving CCRs and exist with moderate vegetation growing over the cap (no free liquids). It is anticipated that these ponds will need a composite cap with a permeability less than or equal to the proposed liner system in the Subtitle C option and continued groundwater monitoring to demonstrate compliance with the closure standards in 40 CFR 264.228 and subpart G of 40 CFR 264. (See Appendix C for closure steps/specifications.) It is further assumed that these activities would be conducted in accordance with a schedule developed by the facility (no specific deadline in the proposed rules).

Landfills

As the same liner and capping standards are proposed for both the Subtitle D and Subtitle C landfills, the costs to develop and cap a CCR landfill under either alternative would be similar. Therefore, this analysis does not include those costs, as the objective of this project is to identify and estimate only the additional costs resulting from the Subtitle C option.

The design for the landfills serving the model plants does include:

- Upgrades (security fencing) to prevent unknowing entry and minimize the possibility of unauthorized access to the landfill area,
- A RCRA waste pile for CCR storage (shown adjacent to the landfill on the model plant diagrams but could be located elsewhere in the facility as needed), and
- A RCRA tank to manage leachate as CCR special waste.

Optional Plant Configurations

Bottom Ash Handling

A submerged flight wet chain conveyor (also called a submerged scraper chain conveyor or submerged chain conveyor) is considered an optional configuration. The submerged chain conveyor discharge is currently to an open, three-sided, down-sloped concrete bunker, from which moist bottom ash is emptied into open-topped trucks with a front-end loader. True dry systems (such as United Conveyor Corporation's PAX and VAX systems, and Allen-Sherman-

[23] 40 CFR 2265.113(a)

[24] 75 FR 35177

Hoff's MAC system) were not considered as alternatives for pricing because they represent a very small percentage of the boiler population and in most cases would require extremely expensive upgrades to existing boilers. Similarly, wet bottom, slag-tap configurations were considered to represent a small percentage of the boiler population and were not considered separately.

Fly Ash Handling

For cost estimation purposes, fabric filters and hot-side ESPs were assumed to look about the same as the model cold-side ESPs at the hoppers and ash evacuation systems, other than ash evacuation cycle differences. Therefore, separate cases were not necessary.

Wet particulate scrubbers with ash or combined ash/FGD by-product slurry blow down were considered to look substantially like sulfite-producing wet FGD systems in most cases, and so were also not considered as separate cases. However, such systems generally do not have slurry dewatering equipment beyond a thickener (or paste system) for primary dewatering.

Details of the fly ash pneumatic conveying system, such as pressure versus vacuum pneumatic designs, dense- versus dilute-phase conveying, and hybrid vacuum/pressure systems were seen as being below the level of concern for these estimates. Consequently, variations in the pneumatic transport system design were not considered as optional configurations. Also, mechanical conveyors such as drag chains, bucket elevators, screw conveyors, and air slides are used for fly ash handling in a limited number of units in the U.S., but were not considered as options that would be seen in a high percentage of plants.

FGD By-product Handling

Belt conveying of gypsum by-product away from the near proximity of the dewatering building was considered as an optional configuration for transport to an adjacent wallboard plant, to a stacker for loading onto barges, or to a remote gypsum storage/truck loading facility.

An alternate FGD technology considered for cost estimation purposes was an inhibited/natural oxidation wet FGD system producing calcium sulfite sludge as an FGD by-product. In such a system, absorber blow down goes to a thickener for primary dewatering. Thickener underflow is fed to a drum vacuum filter or centrifuges to produce a thixotropic sludge with 60-70 wt% solids. Dewatered sludge is transferred to a pug mill, where it is blended with fly ash and lime to produce a landfill- or mine-fill-compatible material.

Combined particulate/SO_2 scrubbers would be considered in the same manner as the wet particulate scrubbers discussed above.

For dry or semi-dry FGD systems, it was considered that most of these will look like the cold-side ESP/fabric filter case with respect to generation and handling of CCRs; they typically have an ESP or fabric filter as an integral part of the process. These FGD types may have mechanical ash transport systems other than pneumatic, particularly for spray dryer absorber dropout and recycle handling, but these would generally be considered internal recycle streams and not CCRs.

FGD Wastewater Treatment

No alternative FGD wastewater configurations were considered in the cost estimates. In gypsum-producing FGD systems with thickeners for primary dewatering, the wastewater stream would come from the thickener overflow rather than from secondary hydrocyclones. However, this has little impact on the wastewater treatment system other than possibly affecting the solids loading to the filter press. For sulfite-producing wet FGD systems, no wastewater stream is generally required, as the chloride purge can generally be handled with the 30 to 40% free moisture in the dewatered by-product.

Additional Wastewater Treatment

Plants that handle all of their ash dry still maintain small ponds where miscellaneous CCR-contact waters are treated before discharge. This includes air heater wash water, equipment cleaning wash water, and runoff from CCR truck washing. In addition, other low volume wastewater streams may be comanaged in these ponds. Under Subtitle C, these ponds would be required to close and would be replaced by new tank-based wastewater treatment facilities. The wastewater treatment facility may require only pH adjustment and clarification, but would likely require a filter press to further dewater clarifier underflow, and may require additional physical/chemical treatments.

Plants that currently manage fly ash or bottom ash in large ash ponds typically also comanage several other larger volume wastewater streams in the ash ponds, such as cooling tower blowdown or coal pile runoff. Closure of all ash ponds under Subtitle C will necessitate replacement ponds for these currently comanaged non-CCR-contact liquids.

4
ESTIMATED COSTS

Most of the cost estimates described in this document were developed using the two 200-MW- and two 800-MW-unit plant models (i.e., a 400-MW station and a 1600-MW station) as the initial bases. For estimating incremental landfill costs, estimates were also developed for an 800-MW station and a 3200-MW station. The specific assumptions used in developing costs for these models and the cost estimate results are described in the following subsections.

General Assumptions

The analysis does not consider replacing any boilers, building new boiler enclosures or making changes to air pollution control equipment in use at power plants. These types of changes could fundamentally impact the power generation process and would require detailed engineering beyond the scope of this analysis.

The coal-fired power plants that were modeled are assumed to be current generators of hazardous wastes and will require RCRA permits. These permits will trigger facility-wide RCRA Corrective Action Investigations and any releases of CCRs in process areas must be eliminated.

Early POG assumptions are used because of the breadth of the CCR listing description and the observed current CCR management practices (e.g., accumulation of CCRs in sumps and in process areas). Individual plants may be able to demonstrate POGs further downstream at disposal areas, but the costs in this analysis are based on a conservative assumption that assumes a POG further upstream in the process areas.

It was assumed that the model plants will not beneficially use 100% of CCRs. Although several of the plants visited as part of this project strive for 100% beneficial use, all admit that they do not achieve this goal due to market conditions and other factors. All plants currently have back-up storage/disposal areas for periods when CCRs cannot be used. Therefore, both material storage facilities and disposal facilities that meet applicable standards would be required at each of the plants. Plants that dispose of CCRs at commercial hazardous waste facilities or regional company-owned facilities will be addressed separately in the national cost estimate.

As described in Section 3, model plant configurations include closed-circuit dewatering bins for bottom ash and cold-side ESPs or fabric filters (FFs) for fly ash collection with pneumatic ash handling and concrete-paved and enclosed hopper areas. They also include gypsum-producing wet FGD with hydrocyclones and vacuum filter gypsum dewatering equipment located in an enclosed dewatering building, with gypsum transferred via conveyor to a storage area close to the boiler. Bottom ash, economizer ash, fly ash, and gypsum are all trucked from storage areas close to the boiler in dry or semi-dry form.

In addition, a number of optional configurations were included in the cost estimates. These included options to retrofit: an open ESP or FF hopper area (no existing sidewalls); unpaved ESP or FF hopper area floors, or floors currently paved with asphalt or aggregate; gypsum conveyed rather than trucked off site; and sulfite-producing wet FGD (or gypsum-producing wet FGD with a thickener for primary dewatering).

Wastewater treatment facilities will be needed to replace the existing wastewater treatment function of ash ponds, FGD ponds, and CCR-contact-water ponds. Only very basic physical/chemical systems were considered in this analysis, primarily to provide settling and solids removal. More expensive treatment trains that have been employed at some plants, such as biological treatment, were not included. The costs estimated here are believed to represent the minimum costs for wastewater treatment facilities.

Surface impoundments, or ponds, containing CCRs have been subdivided into two categories: active and inactive ponds. The first category describes active ponds that are currently receiving CCR slurry streams and would be operational at the time the proposed rules potentially become effective. Inactive ponds are those that have stopped receiving CCRs and exist with moderate vegetation growing over the cap (in many cases, these may have been "closed" many years before the date the rules potentially become effective). Given the difference in conditions between active and inactive ponds on the date the proposed CCR rules would become effective, costs would vary and are presented for both cases in Work Item 6.

Additional task-specific assumptions/exclusions, engineering factors, cost methods, and references are provided and discussed in detail in the appendices to this report. These appendices are cross-referenced to the pertinent work items.

Excluded Costs

The costs that have been excluded in these estimates are the following:

- Waste generation fees/taxes,
- Property acquisition costs (assumes various construction activities will occur on existing station footprint),
- National Environmental Policy Act (NEPA) investigations of "greenfield" land,
- RCRA remediation costs (these costs are very facility-specific and could be modeled in the future using a range of potential remediation measures and associated costs),
- Installation of FGD by-product dewatering equipment for wet FGD systems that currently use ponds for primary and/or secondary dewatering (these costs were addressed by USWAG contractor, EOP),
- Landfill development and capping costs – it was determined that the requirements in EPA's proposed rules for Subtitle C and Subtitle D would require essentially the same types of liners and caps so only the incremental costs of specific Subtitle C requirements such as landfill security are included (see Work Item 5 below),

- Costs to comply with 40 CFR 264 Subparts AA, BB, and CC (the organic fraction of CCR wastes is expected to be below 10% or less than 500 parts per million volatile organic chemicals for model plants),
- Costs of upgrading to Subpart J tank standards for zero discharge wastewater systems, and
- Off-site transportation and disposal costs for any plants that are unable to dispose of CCRs on site (model plants assume on-site disposal). EPRI will address off-site disposal costs in its national cost estimate.

Basis for Cost Estimates

The cost estimates in this report were developed by dividing the model plants into a number of affected subsystems. Costs were developed for the following subsystems (with the associated work item number referenced on the cost estimate tables in this document):

- Bottom ash management system (Work Item 1),
- Economizer/fly ash management system (Work Item 2),
- FGD by-product/gypsum management system (Work Item 3),
- Storm water segregation (Work Item 4),
- Landfill storage/landfill upgrades to RCRA standards (Work Item 5),
- Wastewater treatment (Work Item 6), and
- Miscellaneous operational/administrative upgrades (Work Item 7).

The cost estimates are presented and discussed by work item number in separate subsections below.

Work Item 1 – Bottom Ash Management System

Table 4-1 summarizes cost estimates for Work Item 1. The cost estimates for the bottom ash management system address the area around the bottom of the boiler and the bottom ash loading facilities. Underneath the boiler, it was assumed that this area should look like the bottom of the EAF baghouse in the hazardous waste facility visited – clean, light-color epoxy-coated concrete, and curbing around the area to contain any spills. Costs were developed for cleaning and coating existing concrete floors, sealing cracks and voids, and curbing the perimeter of the boiler area. Typical footprints of 200-MW and 800-MW boilers were used to establish the area to be treated. The costs developed were on a per unit basis.

Table 4-1
Summary of Capital Costs for Work Item 1: Bottom Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Bottom Ash Management System: 800-MW Unit					
1a	Area Under Boiler	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	200' x 150' area with 700 linear (lin.) ft. curb	$640,000	Per unit
1b	Area Surrounding Dewatering Bins	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	40' x 80' area with 240 lin. ft. curb	$100,000	Per unit
1c	Truck Loading from Dewatering Bins	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from Dewatering Bin in the center of building.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb	$410,000	Per station
Item 1 Total for Plants with Two Units				$1,890,000	
Bottom Ash Management System: 200-MW Unit					
1a	Area Under Boiler	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	120' x 90' area with 420 lin. ft. curb	$260,000	Per Unit
1b	Area Surrounding Dewatering Bins	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	30' x 50' area with 160 lin. ft. curb	$60,000	Per Unit
1c	Truck Loading from Dewatering Bins	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from Dewatering Bin in the center of building.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb	$410,000	Per Station
Item 1 Total for Plants with Two Units				$1,050,000	

The processing area around the dewatering bins was assumed to require similar treatment, with cleaning, epoxy coating, and curbing to allow rapid identification and cleanup of any spills. The truck loading facility under the dewatering bins was assumed to require a new enclosure. The enclosure has tight-sealing roll-up doors at either end that can be closed while the truck is loading. It also has a mezzanine level within the enclosure that allows truck drivers to safely reach the top level of their trailers to open and close hatches or to remove and re-install bed covers or tarps. The truck loading facility was sized to enclose one over-the-road tractor trailer (typically 65 to 75 feet [ft] in length) plus room to adjust the positioning of the trailer below the loading chute. It was assumed that each two-unit station would have one dewatering bin per unit, but only one truck loading area shared between the two units.

The Work Item 1 capital cost estimates were developed by a URS estimator using major item equipment and construction costs from recent URS project data or from a commercial cost estimating software package (AspenTech's KBase). Table 4-2 summarizes the various scope and pricing assumptions employed. The major item equipment and construction labor total installed costs were marked up by 15% to account for engineering, 5% to account for construction oversight, and 5% for owner expenses. Additionally, a 35% contingency has been applied to these dollar amounts to account for numerous unforeseen minor cost items not directly addressed in these high-level estimates (nominally Association for the Advancement of Cost Engineering [AACE] Class 4 estimates). This contingency factor represents the midpoint of the typical high-side error in AACE Class 4 estimates[25]. In addition, the values in the summary tables have all been rounded up to the nearest $10,000. For more detailed information on the Work Item 1 costs, see Appendix A.

Additional manpower would also be needed to maintain the bottom ash area to minimize spills and leaks, and to clean up any spills within 24 hours. This was addressed by adding costs for additional O&M manpower in Work Item 7.

[25] AACE International Recommended Practice No. 18R-97. "Cost Estimate Classification System – As Applied in Engineering, Procurement, and Construction for the Process Industries." TCM Framework: 7.3 – Cost Estimating and Budgeting, AACE International, 2005.

Table 4-2
Summary of Cost Estimate Scope Assumptions for Work Items 1 through 3

Scope Assumptions	Comments
Labor Rates/ Productivity	Estimate is based on an average wage rate of $85.00 per hour, which includes the direct base wage rate, payroll taxes, insurance, fringe benefits, small tools consumables, small tools, temporary facilities, equipment rental, construction supervision, and contractor overhead and profit. Estimate is based on Gulf Coast labor units with an adjustment to the productivity of 30%, this includes productivity losses for working in an operating unit and in confined spaces.
Budgetary Quotes / Pricing	Material pricing for blowers, bag houses, and conveyors is based on pricing from AspenTech's KBase pricing software. Metal building costs are based on current in-house pricing of a 17-ft eave-height building adjusted for area labor cost and adjusted for the different height buildings. All other costs are based on current URS in-house data. All costs are presented in 2010 dollars.
Support Activities	Costs for construction service labor are included at 10% of the direct labor man-hours. Scaffolding is included at 13% of the direct labor man-hours for work scopes that require scaffolding.
Material Indirects	Estimate includes sales tax on direct materials at 8% of the direct material cost. Freight is included at 3% of the direct material cost where applicable.
Work Schedule	The average workweek for the project is 40 man-hours per week (4-10s or 5-8s); estimate does not include any allowance for overtime premium.
Construction Equipment	Included in the wage rate.
Engineering	Included at 15% of the total installed cost.
Owner's Cost	Included at the following rates: Construction management at 5% of total installed costs. Owner personnel at 5% of total installed costs.
Escalation	Escalation is not included in these estimates.
Contingency	Included at 35% of total installed costs.

Table 4-2 (continued)
Summary of Cost Estimate Scope Assumptions for Work Items 1 through 3

Scope Assumptions	Comments
Exclusions/Clarifications	No allowance for underground obstructions is included.
	Removal of contaminated soil, if required, is not included.
	Removal or relocation of facilities other than those defined is not included.
	Any repairs or maintenance of existing facilities to enable continued use in existing service is excluded.
	Any upgrading of existing facilities to meet current regional, safety, or environmental standards other than those defined is not included.
	Scheduled premiums or contractor incentives are not included.
	Any credit for scrap arising from material dismantled by the project is not included.
	Owner's costs other than those noted above are not included.
	Costs for obtaining permits are not included.
	Warehouse expenses are not included.
	Preferred purchasing allowances are not included.
	Site groundwater remediation if required is not included.
	Deactivation of equipment is not included.
	Any cost associated with asbestos and or lead paint abatement is excluded.

Work Item 2 – Economizer Ash/Fly Ash Management System

Because fly ash is a fine, powdery material that would be handled in dry, or nearly dry form, the hopper area under an ESP or baghouse was assumed to require improvements to RCRA container-building standards. The improvements estimated include tightly sealing existing sidewalls, retrofitting upgraded doors and windows, and adding a negative ventilation system with a bag filter. As for the bottom ash management area, costs were included for cleaning, coating, and curbing around the perimeter of the floor in this area. The areas requiring these upgrades were estimated based on typical sizing for ESPs on bituminous-coal-fired 200-MW and 800-MW plants.

Pricing was also developed for two options for the area under the ESP: adding sidewalls, doors, and windows to enclose this area for plants that do not have existing sidewalls, and adding a concrete floor in this area for plants that currently do not have this area paved in concrete (e.g. currently asphalt or aggregate). These options would replace the corresponding base upgrade costs for the model plant configuration (enclosure upgrades and/or floor upgrades, respectively), which assumes existing sidewalls and concrete floors. The costs were estimated on a per unit basis for the two-unit station.

The economizer ash/fly ash management system also is assumed to include dry handling of the ash from the hoppers to a central storage silo (one silo per unit). The two silos feed a common truck loading facility directly underneath. The truck loading facility under the silos would require similar upgrades as the bottom ash loading area: cleaned and coated concrete; curbing; and complete enclosure with roll-up doors at either end, personnel entry doors, a mezzanine, and negative draft ventilation. In addition, the existing ash loading chute would be replaced with a telescoping, double-walled chute that has a vacuum applied to the annulus between the walls, and a tight-fitting friction seal to the hatch at the top of the trailer. The silo/truck unloading area cost estimates assume one such facility per station.

A third and fourth option in the economizer ash/fly ash management system are the installation of additional redundancy in the ash transfer and in the truck loading area, respectively. The redundancy in the ash transfer area would be to add a backup ash transfer pneumatic line from the ESP area to the silo area (600 ft of 10-inch (in.) line with associated tees, elbows, concrete pedestals and valves). Redundancy in the ash truck loading area would be required primarily for larger plants where ash volumes are large and truck loading facilities may already be operating at or near capacity. Truck loading in a Subtitle C operating environment could easily take twice as much time as existing loading operations because of the need to close doors, open and close hatches within the enclosure, ensure a tight fit of the chute to the hatch, wipe down the trailer, etc. Thus, some facilities may need to as much as double their truck loading capacity to keep up. The redundant system was assumed to include a new 1000-ton silo (to be fed from either unit), dustless unloader (100-ton/hour (hr) [TPH] capacity), double wall truck loading chute, and the same features included in the upgrades for the existing unloading facility as described above.

Some plants would need to upgrade their truck loading facilities to improve the ability to moisture condition the ash as it is loaded into the truck/trailer. However, the costs of upgrades to a new, wet loader were not included in either the upgrades to existing loading facilities or the optional new, redundant silo/truck loading facility in preparing this report.

Another consideration is whether truck and/or tire washing facilities would be required in the upgraded truck loading facilities. The approach taken for these estimates was to assume that emphasis would be placed on preventing and/or cleaning up minor fly ash spillage during the truck loading process, thus minimizing the need for truck or tire washing. For example, the double-wall loading chute is meant to greatly reduce or eliminate dust loss during truck loading. Minor dust leakage around the hatch might be dry wiped and any spills on the loading facility floor might be swept up before the end doors are opened and the truck is moved. Wet cleanup would have a significant disadvantage of generating a CCR-contact wastewater to be treated. Therefore, truck and/or tire washing facilities were not included in these estimates.

The cost estimates for Work Item 2 are summarized in Table 4-3.

Table 4-3
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 800-MW Unit					
2a	Coat and Seal Area Under ESP	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	100' x 140' area with 480 lin. ft. curb	$330,000	Per Unit
2b	ESP Enclosure	(Existing enclosure around ESP hoppers, i.e. northern plant location) Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Tighten and seal enclosure building.	Enclosure measuring 140' long x 100' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; one 22,400 acfm fan with filter housing and 40 horsepower (HP) motor.	$1,120,000	Per Unit
2c	Fly Ash Truck Loading	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from storage silo in the center of building with a telescoping double wall chute. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay and annulus on chute.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb.	$830,000	Per Station
Item 2 Total for Plants with Two Units				$3,730,000	

Table 4-3 (continued)
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 800-MW Unit (continued)					
2-Option 1	ESP Enclosure	(No existing enclosure around ESP hoppers, i.e. southern plant location) Build a sealed enclosure around ESP hopper area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	Enclosure measuring 140' long x 100' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; (1) 22,400 CFM fan with filter housing and 40 HP motor; curbed and coated concrete floor with rollover curbs; 480 lin. ft.	$3,770,000	Per Unit
2- Option 2	Concrete Containment Area Under ESP	Remove existing surface material (gravel, asphalt, etc.) and replace with curbed and coated concrete containment area.	100' x 140' area with 480 lin. ft. curb.	$520,000	Per Unit
2- Option 3	Redundant Pneumatic Transfer Line	Install redundant transfer line from ESP area to fly ash storage/loading facility	600' of 10" line	$1,500,000	Per Station
2 - Option 4	Redundant Ash Storage/Truck Loading Facility	Install silo with baghouse, building similar to Item 2c above	100-ton silo with 1000 acfm baghouse, 1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. ft. curb.	$3,610,000	Per Station

Table 4-3 (continued)
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 200 MW Unit					
2a	Coat and Seal Area Under ESP	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	50' x 110' area with 320 lin. ft. curb	$150,000	Per Unit
2b	ESP Enclosure	(Existing enclosure around ESP hoppers, i.e. northern plant location) Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Tighten and seal enclosure building.	Enclosure measuring 110' long x 50' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; (1) 8,800 acfm fan with filter housing and 20 HP motor.	$590,000	Per Unit
2c	Fly Ash Truck Loading	Construct truck loading building consisting of 1 truck bay, with mezzanine level to access top of truck, closed at either end by sealed doors. Truck will be loaded from storage silo in the center of building with a telescoping double wall chute. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay and annulus on chute.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 linear ft curb.	$830,000	Per Station
Item 2 Total for Plants with Two Units				$2,310,000	

Table 4-3 (continued)
Summary of Capital Costs for Work Item 2: Economizer Ash/Fly Ash Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Economizer / Fly Ash Management System: 200 MW Unit (continued)					
Option 1	ESP Enclosure	(No existing enclosure around ESP hoppers, i.e. southern plant location) Build a sealed enclosure around ESP hopper area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	Enclosure measuring 110' long x 50' wide x 32' high from grade to bottom of existing ESP enclosure; 1 roll-up door; 2 personnel doors; one 8,800 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 320 lin. ft. curb.	$1,740,000	Per Unit
2- Option 2	Concrete Containment Area Under ESP	Remove existing surface material (gravel, asphalt, etc) and replace with curbed and coated concrete containment area.	50' x 110' area with 320 lin. ft. curb.	$220,000	Per Unit
2- Option 3	Redundant Pneumatic Transfer Line	Install redundant transfer line from ESP area to fly ash storage/loading facility	600' of 10" line	$1,500,000	Per Station

The Work Item 2 capital cost estimates were developed by a URS estimator using the same approach as described for Work Item 1. For more detailed information on the Work Item 2 costs, see Table 4-2 and Appendix A.

Work Item 3 – FGD By-product/Gypsum Management System

The model plants are assumed to have limestone/forced oxidation wet FGD systems installed and operating, with hydrocyclones for primary dewatering and horizontal belt filters for secondary dewatering. A common dewatering building is installed for both units' FGD blowdown slurry. The dewatered gypsum is transferred to a contiguous storage/truck loading facility via conveyor belt.

For operation in a Subtitle C environment, it was assumed that upgrades similar to those for the ash handling facilities would be required in the common dewatering building and in the gypsum storage/loading building: cleaning and coating concrete floors; adding curbs around perimeters; sealing up sidewalls, upgrading doors and windows; and installing a negative draft ventilation system.

A new truck loading building is assumed to be required adjacent to the existing gypsum storage/loading building. In most existing facilities, trucks drive into the gypsum storage/loading building through open doors, are loaded by a large front-end loader, then drive out through another door on the other end of the building. With the new truck loading building, the trucks would drive only through the new loading area, which would have tight sealing doors at either end, a negative draft system, and a mezzanine level to allow drivers to safely remove and install tarps over their loads. The front-end loader would only enter the new loading building far enough to dump material into the truck or trailer beds. The addition of this new loading facility would minimize fugitive emissions due to wind blowing through open doors, and minimize material carry-out on truck/trailer tires.

Several options were priced for the FGD by-product management system. One is that several gypsum storage/loading buildings in the U.S. do not have concrete-paved floors, but instead have a floor of compacted gypsum. In a Subtitle C environment, a more impervious floor covering would be required, so a cost was estimated for removing the compacted gypsum and paving the floor of the building with concrete, including curbing around the perimeter, sealing of crack and joints, and epoxy coating. Another option is that some gypsum-producing FGD systems in the U.S. do not have an enclosed building in which the product gypsum is stored for subsequent load-out after it is produced. These plants instead stack the gypsum in an outdoor storage area. In a Subtitle C environment, it is likely that these plants would have to build a new gypsum storage/loading building that meets RCRA container building standards. An option cost was developed for such a building for each model plant size.

Two other options were developed for gypsum conveying. The base case assumes the gypsum storage/loading building is contiguous with the dewatering building, such that any gypsum conveyors are contained within the building. Any gypsum spills around the conveyors would have to be cleaned up within 24 hours, which would likely require a daily sweep down of the area around the conveyors. However, in some plants there is some distance between the dewatering building and the gypsum storage/containment area, and this transfer is by a conveyor that runs outdoors. Any such existing conveyor is likely open on the sides and bottoms, allowing gypsum loss by wind blowing across the material or by falling from the belt on the return belt run.

The first conveying option (third of the overall Work Item 3 options) is to demolish the existing belt conveyor run and replace it with a totally enclosed pipe conveyor. This cost is estimated for a 250-ft run, but the cost per foot can be applied to varied run lengths. The second conveying option (fourth option overall for the FGD by-product management area) is to add a second pipe conveyor. In a Subtitle C environment, options for stacking out gypsum on the ground are not available, and a conveyor outage could shut the entire power plant down. Costs are provided for installing a new, redundant pipe conveyor, again for a 250-ft run, but the cost per foot can be applied to other run lengths. This option is most likely to be applied to larger units/stations that fire high-sulfur coal where gypsum production rates are high.

A fifth option is considered for the FGD by-product management area, for FGD systems that produce calcium sulfite sludge rather than gypsum as a solid by-product. In such systems, a thickener rather than hydrocyclones is used for primary dewatering, and secondary dewatering is more frequently accomplished with rotary drum filters or centrifuges. However, all of these devices are sometimes used for dewatering in gypsum-producing FGD systems as well. The sulfite-producing wet FGD system will also have a pug mill or equivalent device for blending dewatered calcium sulfite sludge, fly ash, chloride purge or other water, and in some cases quicklime to produce a stable landfill mixture.

It was decided that within the accuracy of these estimates, the applicable upgrade costs for the gypsum-producing FGD system of the model plants could be applied to a sulfite-producing FGD system as well. These would at a minimum include the upgrades shown below in Table 4-4 for the area under dewatering equipment and the dewatering building itself, which would be reasonable estimates for the area below the thickener and the building containing the rotary drum filters and pug mill. Most sulfite-producing wet FGD systems that produce a stabilized byproduct stack the product on an outdoor pad, from which the material is loaded into trucks to haul to a landfill. In a Subtitle C environment, the material would likely need to be stacked in a RCRA container building and loaded into trucks in an enclosed loading building. For this circumstance, the Option 2 – New Gypsum Containment Building and the Truck Loading from Storage costs in Table 4-4 would also apply.

Table 4-4
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Flue Gas Desulfurization By-product/Gypsum Management System: 800-MW Unit					
3a	Area Under Dewatering Equipment	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	100' x 120' area with 440 lin. ft. curb.	$290,000	Based on 2 100% 50 TPH belt filters; Per Station
3b	Dewatering Equipment Building	(Existing enclosure around dewatering equipment) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal enclosure building.	1 building measuring 120' long x 100' wide x 50' high; 1 roll-up door; 2 personnel doors; one 30,000 acfm fan with filter housing and 60 HP motor.	$1,430,000	Based on 2 100% 50 TPH belt filters; Per Station

Table 4-4
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System (Continued)

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Flue Gas Desulfurization By-product/Gypsum Management System: 800-MW Unit (continued)					
3c	Gypsum Containment Building	(Existing enclosure around gypsum storage) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal storage building.	1 building measuring 425' long x 100' wide x 50' high; 2 roll-up doors; 2 personnel doors; one 106,250 acfm fan with filter housing and 200 HP motor.	$6,050,000	Per Station
3d	Gypsum Containment Building Floor	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	425' x 100' area with 1050 lin. ft. curb.	$920,000	Per Station
3e	Truck Loading from Storage	Construct truck loading building consisting of 1 truck bay, with mezzanine to access top to truck, closed at either end by sealed doors. Truck will be loaded from gypsum storage building. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. ft curb.	$820,000	Per Station
Item 3 Total (Gypsum Producer)				$9,510,000	Total Cost Per Station

Table 4-4
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System (Continued)

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
Flue Gas Desulfurization By-product/Gypsum Management System: 800-MW Unit (continued)					
3 – Option 1	Gypsum Containment Building Floor	Remove existing surface material in gypsum storage area and replace with curbed and coated concrete containment area.	425' x 100' area with 1050 lin. ft. curb.	$1,540,000	Per Station
3 – Option 2	New Gypsum Containment Building	(No existing enclosure around gypsum storage) Build a sealed enclosure around gypsum storage area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	1 building measuring 425' long x 100' wide x 50' high; 400' long 50 TPH conveyor with travelling tripper; 1 roll-up door; 2 personnel doors; one 106,250 acfm fan with filter housing and 200 HP motor; curbed and coated concrete floor with rollover curbs; 1050 lin. ft. curb.	$16,850,000	Per Station
3 – Option 3	Conveying to Storage	Demolish existing conveyor from dewatering building to gypsum storage area and replace with pipe conveyor.	250 linear feet of existing conveyor replaced with pipe conveyor.	$850,000	Per Station; Use $2500/ft new conveyor cost
3 – Option 4	Redundant Conveying to Storage	Add second pipe conveyor	250 linear feet of new pipe conveyor parallel to new conveyor installed in Option 3 above	$760,000	Per Station; Use $2250/ft new conveyor cost
3 - Option 5	Sulfite producing FGD System	Assume Items 3a, 3b, 3e, and 3 - option 2 above will apply. Includes upgrades to area under dewatering and pug mill equipment, upgrades to dewatering/pug mill building, new stabilized byproduct RCRA storage building, and new enclosed truck loading facility.	See above	$19,390,000	Total Cost Per Station

Table 4-4
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System (Continued)

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
FGD By-product/Gypsum Management System: 200-MW Unit					
3a	Area Under Dewatering Equipment	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	60' x 90' area with 300 lin. ft. curb.	$150,000	Based on 2 100% 50 TPH belt filters; Per Station
3b	Dewatering Equipment building	(Existing enclosure around dewatering equipment) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal enclosure building.	1 building measuring 100' long x 80' wide x 50' high; 1 roll-up door; 2 personnel doors; one 20,000 acfm fan with filter housing and 40 HP motor.	$1,040,000	Based on 2 100% 50 TPH belt filters; Per Station
3c	Gypsum Containment Building	(Existing enclosure around gypsum storage) Provide ventilating fan with bag house filter to maintain negative pressure in building. Tighten and seal storage building.	1 building measuring 250' long x 100' wide x 50' high; 2 roll-up doors; 2 personnel doors; one 62,500 acfm fan with filter housing and 125 HP motor.	$4,100,000	Per Station
3d	Gypsum Containment Building Floor	Clean existing concrete, apply coating to area, seal joints, construct concrete curb for containment.	250' x 100' area with 700 lin. ft. curb.	$560,000	Per Station
3e	Truck Loading from Storage	Construct truck loading building consisting of 1 truck bay, with mezzanine to access top to truck, closed at either end by sealed doors. Truck will be loaded from gypsum storage building. Provide ventilating fan with bag house filter to maintain negative pressure in loading bay.	1 building measuring 100' long x 15' wide x 25' high; 2 roll-up doors; 2 personnel doors; one 1125 acfm fan with filter housing and 20 HP motor; curbed and coated concrete floor with rollover curbs; 230 lin. Ft. curb.	$820,000	Per Station
Item 3 Total (gypsum producer)				$6,670,000	

Table 4-4
Summary of Capital Costs for Work Item 3: FGD By-product/Gypsum Management System (Continued)

Work Item No.	General Work Description	Definition of Work	Size	Estimated Cost	Comment
FGD By-product/Gypsum Management System: 200-MW Unit (continued)					
3 - Option 1	Gypsum Containment Building Floor	Remove existing surface material in gypsum storage area and replace with curbed and coated concrete containment area.	250' x 100' area with 700 lin. ft. curb.	$910,000	Per Station
3 - Option 2	New Gypsum Containment Building	(No existing enclosure around gypsum storage) Build a sealed enclosure around gypsum storage area. Provide ventilating fan with bag house filter to maintain negative pressure in ESP enclosure. Provide sealed and curbed concrete floor.	1 building measuring 250' long x 100' wide x 50' high; 225' long 50 TPH conveyor with travelling tripper; 1 roll-up door; 2 personnel doors; one 62,500 acfm fan with filter housing and 125 HP motor; curbed and coated concrete floor with rollover curbs; 700 lin. ft. curb.	$10,120,000	Per Station
3 - Option 3	Conveying to Storage	Demolish existing conveyor from dewatering building to gypsum storage area and replace with pipe conveyor.	250 linear feet of existing conveyor replaced with pipe conveyor.	$850,000	Per Station; Use $2500/ft replacement cost.
3 - Option 4	Redundant Conveying to Storage	Add second pipe conveyor	250 linear feet of new pipe conveyor parallel to new conveyor installed in Option 3 above	$760,000	Per Station; Use $2250/ft new conveyor cost
3 - Option 5	Sulfite producing FGD System	Assume Items 3a, 3b, 3f, and 3 - option 2 above will apply. Includes upgrades to area under dewatering equipment, upgrades to dewatering/pug mill building, new stabilized byproduct RCRA storage building, and new enclosed truck loading facility.	See above	$12,130,000	Total Cost Per Station

The Work Item 3 capital cost estimates were developed by a URS estimator using the same approach as described above for Work Item 1. For more detailed information on the Work Item 3 costs, see Table 4-2 and Appendix A.

Work Item 4 – Storm Water Segregation System

It was originally anticipated that work would be needed to segregate storm water so it does not contact or comingle with CCRs. However, it is anticipated that the identified upgrades to various plant systems (discussed in Work Items 1-3 and 5-7) will effectively segregate CCRs from uncontaminated storm water. As a result, this analysis does not include any additional cost estimates to upgrade storm water systems.

Work Item 5 – Land Storage/Landfill Upgrades to RCRA Standards

Equivalent liner and capping standards are proposed for both the Subtitle D and Subtitle C landfills. Consequently, the cost to develop and cap a CCR landfill under either alternative would be similar. These costs are also similar to what a new facility would cost even in the absence of the proposed national regulation. Therefore, this analysis does not include the construction costs to develop and close a CCR landfill.

Cost estimates were developed for security upgrades for the landfill area. Assumptions for the security fencing included provision of a barrier, consisting of a fence with locked gates, or a structure with locked access; the potential for security access consisting of electronic pass codes and/or card keys; and posting of signs, legible from a distance of 25 feet, in English as well as in any locally prevailing additional languages to identify the enclosure as containing hazardous waste materials and prohibiting unauthorized access.

As noted earlier, one of the general assumptions for CCR handling is that not all materials would be beneficially used due to market fluctuations and other factors, and it is not always possible to predict when a CCR would be used, temporarily stored, or disposed. A 10-acre RCRA waste pile for CCR storage was developed as part of the model plant design to provide for operational flexibility. Such a unit would satisfy either the Subtitle C standards for waste storage prior to disposal, or storage prior to beneficial use or as a testing/treatment area for verification of land disposal restriction standards.

The landfill upgrades also include adding a RCRA tank with appropriate testing and secondary containment designed to manage leachate from the landfill. (If all Subtitle C standards apply—such leachate would be CCR Special Waste under the "mixture and derived from" rules.)[26]

Additionally a 35% contingency has been applied to the dollar amounts for the land storage and landfill upgrades to account for numerous unforeseen minor cost items not directly addressed in these high-level estimates (nominally AACE Class 4 estimates). As noted previously, this contingency factor represents the mid-point of the typical high-side error in AACE Class 4 estimates.

[26] §261.3 (b), (c)

The operation and maintenance associated with a Subtitle C landfill is expected to be greater than the costs of operating an impoundment or a Subtitle D landfill. For the cost estimate, it was assumed (based on URS professional judgment) that it would require one additional worker for Subtitle C landfills up to the two 800-MW unit model design and two additional workers for landfills at and above the two 800-MW unit model. The annual cost of such a worker was developed using the following from the Bureau of Labor Statistics: Environmental Engineering Technician @ $ 21.99 mean ($45,730 annual) plus 50% fringe and 67% of salary plus fringe for overhead and profit, which equates to $160,875/yr loaded costs per worker.

Table 4-5 summarizes the cost estimates for Work Item 5.

Table 4-5
Summary of Costs for Work Item 5: Land Storage/Landfill Upgrades to RCRA Standards*

General Work Description	Cost Estimate			
	400 MW Station	800 MW Station	1600 MW Station	3200 MW Station
Landfill Security	$733,000	$890,000	$1,100,000	$1,370,000
Leachate Tank (RCRA tank standards)	$1,410,000	$1,410,000	$2,810,000	$4,220,000
RCRA Waste Pile (Constructed at landfill)	$3,480,000	$3,480,000	$3,480,000	$3,480,000
Item 5 Total Estimated Cost for Landfills & RCRA Waste Pile Per Station	$5,630,000	$5,780,000	$7,390,000	$9,070,000
Landfill O&M (Increase over impoundment O&M - additional Subtitle C requirements)	$161,000	$161,000	$322,000	$322,000

* Numbers in Table 4-5 have been rounded up to three significant figures.

For more detailed information on the Work Item 5 costs, see Appendix B.

Work Item 6 – Wastewater Treatment System

Tanks associated with dewatering of CCRs are assumed to be part of an NPDES permitted wastewater treatment system. Such tanks are subject to the Subtitle C wastewater treatment unit exemption and costs to upgrade these tanks to Subtitle C, Subpart J standards were not included in this cost estimate.

The definition of a CCR surface impoundment within the proposed rules[27] is very broad and may be interpreted to include other ponds designed to manage wastewaters or storm waters derived from or mixed with CCRs at stations that currently manage CCRs in a "dry" form (e.g., storm water impoundments at "dry" facilities that contain minimal CCR amounts resulting from wash water runoff from loading areas). The Work Item 6 cost estimate includes costs for converting pond-based systems to tank-based wastewater treatment systems, for both FGD wastewater and ash contact wastewater.

[27] 75 FR35255, §264.1301 Definitions

The estimate includes the costs to close active ponds (ponds receiving CCR slurry streams that will be operational when the proposed rules would become effective). The costs to close the active ponds include elimination of free liquids, stabilization of waste to a bearing capacity sufficient to support final cover, and a combination landfill cover system designed and constructed to: provide long-term minimization of liquids, function with minimal maintenance, promote drainage and minimize erosion, accommodate settling/subsidence and have a permeability less than or equal to the permeability of any bottom liner system (or natural subsoils).

Work Item 6 also includes an estimate to close inactive ponds. As noted earlier, EPA proposes to regulate surface impoundments that have not completed closure to RCRA standards. For the purpose of this analysis, inactive ponds ("ponds that have not completed closure") are considered to be those that have stopped receiving CCRs and have moderate vegetation growing over the cap (no free liquids). It is anticipated that these ponds will need a composite cap with a permeability less than or equal the proposed liner system in the Subtitle C option, and continued groundwater monitoring to demonstrate compliance with the closure standards in 40 CFR 264.228 and subpart G of 40 CFR 264.

At some plants, inactive pond areas not previously closed to RCRA standards have been recovered for use to build landfills, warehouses, cooling towers, etc. Closure costs for such circumstances could be significantly greater than assumed moderate vegetation growing over the cap. The costs for such closures will be site specific and have not been included in the Work Item 6 estimates. However, the project team recognizes that this could be a significant cost item for some plants.

Additionally a 35% contingency has been applied to the dollar amounts for the pond closures to account for numerous unforeseen minor cost items not directly addressed in these high-level estimates (nominally AACE Class 4 estimates). As noted previously, this contingency factor represents the mid-point of the typical high-side error in AACE Class 4 estimates.

Some power stations have discussed the possibility of developing a regional landfill to comply with the Subtitle C requirements of the proposed rules. An estimate was developed for a stand-alone WWT system for such a landfill to manage leachate and other wastewaters as part of Work Item 6.

The two tank-based WWT systems described above could treat very different water flow rates. The leachate flow rate from a large regional landfill could be approximately 0.1 million gallons per day (mgd). In contrast, an existing pond-based treatment for process wastewater and storm water derived from or mixed with CCRs, as discussed several paragraphs above, could treat wastewater flow rates on the order of 2 mgd or greater. Consequently, three wastewater flow rates were selected for developing cost estimates for tank-based WWT systems: 0.1 mgd, 0.5 mgd, and 2 mgd. In addition, construction materials, equipment, and operating costs will vary considerably between FGD wastewater and ash contact water treatment systems, due to the higher salinity and solids content of FGD wastewater.

The WWT cost estimates shown in Table 4-6 were developed from engineering cost models under development at EPRI that are based on actual costs of WWT systems of various sizes installed at U.S. utility power plants. The model cost estimates incorporate contingency factors, and are based on systems installed in a building (for freeze protection) and on conventional physical/chemical treatment. Equipment in the WWT systems includes an equalization tank, reaction tanks, clarifier(s), sand filters, filter press(es), and various chemical dosing systems. These include ferric chloride dosing, lime addition, hydrochloric acid dosing, organo-sulfide dosing, and polymer dosing systems. These cost estimates represent systems with redundancy in most key equipment, since a failure in a filter press pump, or filter could result in a WWT system outage of several days to a week. These systems are considered to meet the minimum requirements. They do not include any considerations for advanced wastewater treatment steps, such as biological treatment, or higher wastewater flows, both of which could substantially increase costs.

Table 4-6 summarizes the cost estimates for Work Item 6. Additional detail is provided for these estimates in Appendix C.

Work Item 7 – Miscellaneous Operational/Administrative Upgrades

For costing purposes, the two-200-MW-unit model plant was considered to be similar to a small RCRA treatment, storage, and disposal (T/S/D) including exempt tanks, one 90-day RCRA container building, and various RCRA land disposal units (one RCRA waste pile, two closing surface impoundments, and one RCRA landfill). High range cost assumptions were calculated for the two-800-MW-unit model plant assuming similarities to a large T/S/D with exempt tanks, two 90-day RCRA container buildings, and multiple land disposal units (one RCRA waste pile, six closing surface impoundments, and one large landfill).

Work Item 7 costs were developed using available and applicable information from the Redig memorandum[28], as modified by the Inflation Calculator[29] (using 2007 as starting time and 2010 as ending time). For other items, data from the *Golder Analyses*[30] or, alternatively, from *Estimating Costs for the Economic Benefits of RCRA Non-Compliance*[31] were used, the latter as modified by the referenced Inflation Calculator. [Note: Costs derived from this EPA document represent fully loaded costs (including fringe benefits, labor overhead and profit estimates).] Where engineering assumptions were made, URS relied on professional judgment gained from experience in its consulting practice.

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[28] September 10, 2007 Memorandum: "Revised Prices for Calculating Environmental Benefit," from Michael X Redig, Hazardous Waste Regulation Section, Tallahassee (FL)

[29] Inflation Calculator: http://www.usinflationcalculator.com/inflation/current-inflation-rates (as applied the week of September 13, 2010)

[30] October 28, 2010 analysis by Golder Associates, Inc (*Golder Analysis*) of draft Table 4-7 that suggested several revisions based upon their actual data /experiences with like facilities.

[31] "Estimating Costs for the Economic Benefits of RCRA Non-Compliance," USEPA, September 1997, December 1997 Update

Table 4-6
Summary of Costs for Work Item 6: Wastewater Treatment System*

General Work Description	Estimated Cost	Cost Basis
Active Pond Closures [Ponds that are currently receiving CCR slurry streams and will be operational when rules become effective]:		
Active pond closure - per Subtitle D requirements	$192,000	$/acre
Active pond closure - per Subtitle C requirements	$275,000	$/acre
Active pond closure - Incremental cost to close an active pond per Subtitle C relative to Subtitle D	$65,000	$/acre
Mean acreage of active ponds/plant: 148 acres	$9,620,000	Per Station
Inactive Ponds Closure [Ponds that have stopped receiving CCRs and exist with moderate vegetation growing over the cap.]:		
For Subtitle D requirements of the proposed rules - not required to close inactive ponds.	0	$/acre
Closure of an inactive pond per Subtitle C Requirements	$221,000	$/acre
Incremental cost to close an active pond per Subtitle C relative to Subtitle D	$221,000	$/acre
Mean acreage of inactive ponds/plant: 48 acres	$10,700,000	Per Station
Wastewater Treatment:		
Water treatment system for CCR contact water (0.1 to 2.0 mgd)	$6,000,000 to $22,500,000	Per Station
Water treatment system for FGD wastewater (0.1 to 2.0 mgd)	$22,800,000 to $60,800,000	Per Station with FGD
Replacement ponds for other streams (non-CCR contact water) (10-acre pond with 2 foot recompacted clay liner. Includes contingency)	$2,400,000	1 or 2 Per station with ash ponds

* Numbers in Table 4-6 have been rounded up to three significant figures.

For more detailed information on the Work Item 6 costs other than wastewater treatment, see Appendix C.

The cost for RCRA Corrective Action Assessment /Investigation may vary significantly depending upon site conditions. For this analysis, the source of the lower range ($750,000) is from *Regulatory Impact Analysis for EPA's Proposed RCRA Regulation of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry*[32] and the higher estimate ($3,500,000) is from the *Golder Analysis*. While it is felt that this range is appropriate for the power industry as a whole, URS professional experience also indicates that actual costs for an individual power plant could exceed the upper bound, under certain site circumstances.

Instead of proposing significant equipment changes (in multiple configurations) to facilitate the containment of CCRs at the model plants, this analysis assumes a 35% increase in the operation and maintenance staff at the model plants. These staff would be focused on increased inspections, maintenance, immediate response to spills and equipment repair/replacement efforts. The increase for O&M labor cost is also intended to account for the cost of any routine equipment that is replaced.

Table 4-7 summarizes cost estimates for Work Item 7.

[32] *Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry, USEPA*, April 30, 2010

Table 4-7
Summary of Costs for Work Item 7: Miscellaneous Operational/Administrative Upgrades

General Work Description	Initial (one-time) Cost Estimate		Annual Cost Estimate
	2x200 MW Units	2x800 MW Units	
Notification Requirements	$328	$329	$110
Pt A Permit Application	$12,100	$17,300	Not estimated
Pt B Permit Application	$721,000	$1,020,000	Not estimated
Permit Fees	$15,000	$549,000	Not estimated
General Waste Analysis, LDR Waste Analysis, and Written Waste Analysis Plan	$14,800	$14,800	$13,000
Written Inspection Schedule	$1,320	$1,320	$1,390
Personnel Training	$18,600	$48,000	$15,900 to $48,000
Emergency Response Plan	$2,630	$2,630	Not estimated
Contingency Plan	$2,630	$2,630	Not estimated
Biennial Report Preparation	--	--	$875
Operating Record	$41,000	$47,000	$7,230
Groundwater Monitoring Plan	$20,000	$30,000	$5,400
Groundwater Sampling	$347,000	$445,000	$29,100 to $146,000
Closure and Post-closure Plans	$125,000	$143,000	$1,750
Closure Certification	$108,000	$147,000	0
Financial Assurance for Closure and Post-Closure	$68,000	$68,000	$56,100
Financial Assurance for Third Party Liability Coverage	$109,000	$109,000	$102,000
Corrective Action Schedule	$1,320	$1,320	$656
Corrective Action: Facility Assessments/Investigations	$750,000	$3,500,000	Not estimated
Additional O&M Staff focused on CCR maintenance, spills and response	$1,290,000	$4,190,000	$1,290,000 to $4,190,000
Total	$3,650,000	$10,400,000	$1,530,000 to 4,580,000

* Numbers in Table 4-7 have been rounded up to three significant figures.

For more detailed information on the Work Item 7 costs, see Appendix D.

A
COST ESTIMATE SHEETS FOR WORK ITEMS 1–3

This appendix presents the cost estimate details for Work Items 1 through 3. Note that the estimate details do not reflect the 35% contingency discussed in Section 4. This contingency was applied as the costs from the detailed estimates shown in this appendix were summarized in Tables 4-1 and 4-3 through 4-4.

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): 1a

WORK ITEM NUMBER: 800 MW

(Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est. by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 1A						-		-		-	
AREA UNDER BOILER						-		-		-	
HYDROBLAST CONCRETE	30,000	SF	0.00	0.03		900	85.00	30	76,500	-	76,530
SEAL JOINTS & APPLY EPOXY COATING	30,000	SF	1.50	0.07		1,950	85.00	45,000	165,750	-	210,750
INSTALL CONCRETE CURB	700	LF	13.74	0.96		672	85.00	9,618	57,120	-	66,738
						-		-	-	-	-
						-		-	-	-	-
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	Basis					-		-	-	-	-
ENGINEERING COST	354,018	DC$			15.00%	% OF TIC		-	-		70,804
CONSTRUCTION MANAGEMENT	354,018	DC$			5.00%	% OF TIC		-	-		23,627
OWNER'S COST	354,018	DC$			5.00%	% OF TIC		-	-		23,627
TOTAL COST WORK ITEM 1a						3,522		54,648	299,370	-	472,076

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)

1b
WORK ITEM NUMBER

800 MW
(Misc.)

EPRI
(Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)

CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.

Date: 9/9/2010

Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 1B						-		-	-	-	-
AREA SURROUNDING DEWATERING BINS						-		-	-	-	-
HYDROBLAST CONCRETE	3,200	SF	0.00	0.03		96	85.00	3	8,160	-	8,163
SEAL JOINTS & APPLY EPOXY COATING	3,200	SF	1.50	0.07		208	85.00	4,800	17,680	-	22,480
INSTALL CONCRETE CURB	240	LF	13.74	0.96		230	85.00	3,298	19,550	-	22,848
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						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	53,491	DC$			15.00%	% OF TIC		-	-		10,698
CONSTRUCTION MANAGEMENT	53,491	DC$			5.00%	% OF TIC		-	-		3,570
OWNER'S COST	53,491	DC$			5.00%	% OF TIC		-	-		3,570
TOTAL COST WORK ITEM 1b						534		8,101	45,390	-	71,329

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)
1c WORK ITEM NUMBER
800 MW (Misc.)

EPRI (Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)
CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 1c						-		-	-	-	-
TRUCK LOADING FRM DEWATERING BINS						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS 1EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	-	EA	57021	833		-	85.00	-	-	-	-
BAG HOUSE 1125CFM KBASE PRICING	-	EA	32948	800		-	85.00	-	-	-	-
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	225,590	DC$			15.00%	% OF TIC		-	-		45,118
CONSTRUCTION MANAGEMENT	225,590	DC$			5.00%	% OF TIC		-	-		15,056
OWNER'S COST	225,590	DC$			5.00%	% OF TIC		-	-		15,056
TOTAL WORK ITEM 1c						554		26,034	47,056	152,500	300,820

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)

2a (WORK ITEM NUMBER)

800 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B.

Date: 9/9/2010

Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 2a						-		-	-	-	-
COAT & SEAL AREA UNDER ESP						-		-	-	-	-
HYDROBLAST CONCRETE	14,000	SF	0.00	0.03		420	85.00	14	35,700	-	35,714
SEAL JOINTS & APPLY EPOXY COATING	14,000	SF	1.50	0.07		910	85.00	21,000	77,350	-	98,350
INSTALL CONCRETE CURB	480	LF	13.74	0 96		461	85.00	6,595	39,185	-	45,780
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	179,844	DC$			15.00%	% OF TIC		-	-		35,969
CONSTRUCTION MANAGEMENT	179,844	DC$			5.00%	% OF TIC		-	-		12,003
OWNER'S COST	179,844	DC$			5.00%	% OF TIC		-	-		12,003
TOTAL WORK ITEM 2a						1,791		27,609	152,235	-	239,819

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
2b
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
						-		-	-	-	-
WORK ITEM 2b						-		-	-	-	-
ELECTROSTATIC PRECIPITATOR ENCLOSURE						-		-	-	-	-
						-		-	-	-	-
"(100' X 140"32'HIGH) TIGHTEN ECLOSURE	29,366	SF	0.15	0.0150		440	85.00	4,405	37,400	-	41,805
DOORS COST INCLUDED IN ENCLOSURE COST						-		-	-	-	-
FAN 22,400CFM (KBASE PRICING)	1	EA	94361	826.00		826	85.00	94,361	70,210	-	164,571
BAG HOUSE 22,400CFM (KBASE PRICING)	1	EA	245792	1955		1,955	85.00	245,792	166,175	-	411,967
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	618,343	DC$			15.00%	% OF TIC		-	-		123,669
CONSTRUCTION MANAGEMENT	618,343	DC$			5.00%	% OF TIC		-	-		41,268
OWNER'S COST	618,343	DC$			5.00%	% OF TIC		-	-		41,268
TOTAL 2b						3,221		344,558	273,785	-	824,548

ESTIMATE WORKSHEET

EPRI
(Customer)

URS CORPORATION

WORK ITEM COST
(Major Account)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)

2c
WORK ITEM NUMBER

CLEVELAND, OH. 13813148
(Location) (Job No)

Est by: A. C. B.

Date: 9/9/2010

Rev: A

800 MW
(Misc.)

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2c						-		-	-	-	-
FLY ASH TRUCK LOADING						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	1	EA	57021	833		833	85.00	57,021	70,805	-	127,826
BAG HOUSE 1125CFM KBASE PRICING	1	EA	32948	800		800	85.00	32,948	68,000	-	100,948
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
TELESCOPING DOUBLE WALL CHUTE WITH ANNUL	1	EA	4200.00	20.00		20	85.00	4,200	1,700	-	5,900
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	460,264	DC$			15.00%	% OF TIC		-	-		92,053
CONSTRUCTION MANAGEMENT	460,264	DC$			5.00%	% OF TIC		-	-		30,718
OWNER'S COST	460,264	DC$			5.00%	% OF TIC		-	-		30,718
TOTAL 2c						2,207		120,203	187,561	152,500	613,753

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
2 - OPTION 1
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2 - OPTION 1						-		-	-	-	-
ESP ENCLOSURE						-		-	-	-	-
						-		-	-	-	-
ENCLOSURE UNDER ESP (100' X 140' X 32'HIG	14,000	SF			100.00	-		-	-	1,400,000	1,400,000
DOORS COST INCLUDED IN ENCLOSURE COST						-		-	-	-	-
FAN 22,400CFM (KBASE PRICING)	1	EA	94361	826.00		826	85.00	94,361	70,210	-	164,571
BAG HOUSE 22,400CFM (KBASE PRICING)	1	EA	245792	1955		1,955	85.00	245,792	166,175	-	411,967
CURB 6" X 6"	480	LF	3.24	0.31		148.80	85.00	1,555.20	12,648.00	-	14,203
ROLL OVER CURB	12	LF	4.25	0.50		6.00	85.00	51.00	510.00	-	561
EPOXY COAT FLOOR	14,000	SF	2	0.07		910	85	21000	77350		98350
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	2,089,652	DC$			15.00%	% OF TIC		-	-		417,930
CONSTRUCTION MANAGEMENT	2,089,652	DC$			5.00%	% OF TIC		-	-		139,463
OWNER'S COST	2,089,652	DC$			5.00%	% OF TIC		-	-		139,463
TOTAL 2 - option 1						3,846		362,759	326,893	1,400,000	2,786,509

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
2 - OPTION 2
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	*Quantity*	*Unit*	*Material* $/Unit	*Man-Hrs* /Unit	*Sub-Cont* $/Unit	*Total* Man-Hours	*$/Hr*	*Material* $	Labor $	Sub-Contract $	Total Cost $
2 - OPTION 2						-		-	-	-	-
PROVIDE CONC CONTAINMENT UNDER ESP						-		-	-	-	-
						-		-	-	-	-
REMOVE GRAVEL OR ASPHALT	14,000	SF		0.03		420	85.00	-	35,700	-	35,700
FINE GRADE	14,000	SF		0.01		70	85.00	-	5,950	-	5,950
FORMS	480	LF	2.00	0.20		96	85.00	960	8,160	-	9,120
EXPANSION JOINTS	840	LF	0.50	0.05		42	85.00	420	3,570	-	3,990
INSTALL WWM	14,000	SF	0.25	0.01		140	85.00	3,500	11,900	-	15,400
POUR CONCRETE 6" TK	259	CY	95.00	2.00		519	85.00	24,630	44,115	-	68,745
FINISH CONCRETE	14,000	SF	0.05	0.03		420	85.00	700	35,700	-	36,400
INSTALL 6' X 6' CURB	480	LF	3.24	0.31		148.80	85.00	1,555.20	12,648.00	-	14,203
EPOXY COAT CONCRETE	14,000	SF	1.50	0.07		910	85.00	21000	77350		98350
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	287,858	DC$			15.00%	% OF TIC		-	-		57,572
CONSTRUCTION MANAGEMENT	287,858	DC$			5.00%	% OF TIC		-	-		19,212
OWNER'S COST	287,858	DC$			5.00%	% OF TIC		-	-		19,212
TOTAL 2 - OPTION 2						2,766		52,765	235,093	-	383,853

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)
2 - OPTION 3 (WORK ITEM NUMBER)
800 MW (Misc.)

EPRI (Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)
CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2 - OPTION 3						-		-	-	-	-
10" FLY ASH TRANSFER LINE	600	LF	1130.80	3.01		1,805	85.00	678,478	153,425	-	831,903
INCLUDES 10" PIPING, 6 FLANGES						-		-	-	-	-
2 KNIFE GATE VALVES AND 20 CONC PEDISTALS						-		-	-	-	-
FOR SUPPORT AT 30FT ON CENTER						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	831,903	DC$			15.00%	% OF TIC		-	-		166,381
CONSTRUCTION MANAGEMENT	831,903	DC$			5.00%	% OF TIC		-	-		55,521
OWNER'S COST	831,903	DC$			5.00%	% OF TIC		-	-		55,521
TOTAL 2 - Option 3						1,805		678,478	153,425	-	1,109,326

ESTIMATE WORKSHEET

URS CORPORATION

WORK ITEM COST
(Major Account)
2 - Option 4
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2 - Option 4						-		-	-	-	-
HAZARDOUS WASTE TRUCK LOADING						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	1	EA	57021	833		833	85.00	57,021	70,805	-	127,826
BAG HOUSE 1125CFM KBASE PRICING	1	EA	32948	800		800	85.00	32,948	68,000	-	100,948
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
TELESCOPING DOUBLE WALL CHUTE WITH ANNUL	1	EA	4200.00	20.00		20	85.00	4,200	1,700	-	5,900
1000TN FLY ASH STORAGE BIN	1	EA	505873.00	10401.00		10,401	85.00	505,873	884,085	-	1,389,958
FLY ASH SILO BAG HOUSE	1	EA	76116.00	909.00		909	85.00	76,116	77,265	-	153,381
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	2,003,603	DC$			15.00%	% OF TIC		-	-		400,721
CONSTRUCTION MANAGEMENT	2,003,603	DC$			5.00%	% OF TIC		-	-		133,720
OWNER'S COST	2,003,603	DC$			5.00%	% OF TIC		-	-		133,720
TOTAL 2 - Option 4						13,517		702,192	1,148,911	152,500	2,671,765

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
3a
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3a						-		-	-	-	-
CLEAN & COAT EXIST CONC UNDER DEWATERING EQUIP						-		-	-	-	-
AND INSTALL CURB						-		-	-	-	-
						-		-	-	-	-
HYDROBLAST CONCRETE	12,000	SF	0.00	0.03		360	85.00	12	30,600	-	30,612
SEAL JOINTS & APPLY EPOXY COATING	12,000	SF	1.50	0.07		780	85.00	18,000	66,300	-	84,300
INSTALL CONCRETE CURB	440	LF	13.74	0.96		422	85.00	6,046	35,870	-	41,916
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	156,828	DC$			15.00%	% OF TIC		-	-		31,366
CONSTRUCTION MANAGEMENT	156,828	DC$			5.00%	% OF TIC		-	-		10,467
OWNER'S COST	156,828	DC$			5.00%	% OF TIC		-	-		10,467
								-	-	-	-
TOTAL 3A						1,562		24,058	132,770	-	209,126

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)

3b (WORK ITEM NUMBER)

800 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3b						-		-	-	-	-
DEWATERING EQUIP BUILDING						-		-	-	-	-
SEAL 120' LONG X 100' WIDE X 50' TALL METAL BLD & INSTALL FAN AND BAG HOUSE						-		-	-	-	-
TIGHTEN ENCLOSUREMETAL BUILDING (120' X 100'	34,000	SF	0.15	0.0150		510	85.00	5,100	43,350	-	48,450
						-		-	-	-	-
BLOWER 30,000CFM (KBASE PRICING)	1	EA	124228	896		896	85.00	124,228	76,160	-	200,388
BAG HOUSE 30,000 CFM (KBASE PRICING)	1	EA	324375	2549		2,549	85.00	324,375	216,665	-	541,040
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	789,878	DC$			15.00%	% OF TIC		-	-		157,976
CONSTRUCTION MANAGEMENT	789,878	DC$			5.00%	% OF TIC		-	-		52,716
OWNER'S COST	789,878	DC$			5.00%	% OF TIC		-	-		52,716
								-	-	-	-
TOTAL 3b						3,955		453,703	336,175	-	1,053,287

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): 3c

WORK ITEM NUMBER: 800 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est. by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3c						-		-	-	-	-
GYPSUM CONTAINMENT BUILDING						-		-	-	-	-
TIGHTEN ENCLOSUREMETAL BUILDING 425'L	95,000	SF	0.15	0.015		1,425	85.00	14,250	121,125	-	135,375
BLOWER 106,250 CFM (KBASE PRICING)	1	EA	363836	1757		1,757	85.00	363,836	149,345	-	513,181
BAG HOUSE 106,250 CFM (KBASE PRICING)	1	EA	2117481	6951		6,951	85.00	2,117,481	590,835	-	2,708,316
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	3,356,872	DC$			15.00%	% OF TIC		-	-		671,374
CONSTRUCTION MANAGEMENT	3,356,872	DC$			5.00%	% OF TIC		-	-		224,038
OWNER'S COST	3,356,872	DC$			5.00%	% OF TIC		-	-		224,038
								-	-	-	-
TOTAL 3c						10,133		2,495,567	861,305	-	4,476,322

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
3d
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3d						-		-	-	-	-
GYPSUM CONTAINMENT BUILDING FLOOR						-		-	-	-	-
REMOVE GRAVEL OR ASPHALT	42,500	SF		0.03		1,275	85.00	-	108,375	-	108,375
FINE GRADE	42,500	SF		0.01		213	85.00	-	18,105	-	18,105
FORMS	1,050	LF	2.00	0.20		210	85.00	2,100	17,850	-	19,950
EXPANSION JOINTS	2,000	LF	0.50	0.05		100	85.00	1,000	8,500	-	9,500
INSTALL WWM	42,500	SF	0.25	0.01		425	85.00	10,625	36,125	-	46,750
POUR CONCRETE 6" TK	787	CY	95.00	2.00		1,574	85.00	74,769	133,790	-	208,559
FINISH CONCRETE	42,500	SF	0.05	0.03		1,275	85.00	2,125	108,375	-	110,500
INSTALL 6' X 6' CURB	1,050	LF	3.24	0.31		325.50	85.00	3,402.00	27,667.50	-	31,070
EPOXY COAT CONCRETE	42,500	SF	1.50	0.07		2763	85.00	63750	234813		298563
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	851,371	DC$			15.00%	% OF TIC		-	-		170,274
CONSTRUCTION MANAGEMENT	851,371	DC$			5.00%	% OF TIC		-	-		56,820
OWNER'S COST	851,371	DC$			5.00%	% OF TIC		-	-		56,820
								-	-	-	-
TOTAL 3d						8,160		157,771	693,600	-	1,135,286

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): 3e

WORK ITEM NUMBER: 800 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3e						-		-	-	-	-
TRUCK LOADING FROM STORAGE						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS 1EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	1	EA	57021	833.00		833	85.00	57,021	70,805	-	127,826
BAG HOUSE 1125CFM KBASE PRICING	1	EA	32948	800.00		800	85.00	32,948	68,000	-	100,948
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	454,364	DC$			15.00%	% OF TIC		-	-		90,873
CONSTRUCTION MANAGEMENT	454,364	DC$			5.00%	% OF TIC		-	-		30,324
OWNER'S COST	454,364	DC$			5.00%	% OF TIC		-	-		30,324
								-	-	-	-
TOTAL 3e						2,187		116,003	185,861	152,500	605,886

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
3 - OPTION 1
WORK ITEM NUMBER
800 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3 - OPTION 1						-		-	-	-	-
GYPSUM CONTAINMENT BUILDING FLOOR						-		-	-	-	-
REMOVE GRAVEL OR ASPHALT	42,500	SF		0.03		1,275	85.00	-	108,375	-	108,375
FINE GRADE	42,500	SF		0.01		213	85.00	-	18,105	-	18,105
FORMS	1,050	LF	2.00	0.20		210	85.00	2,100	17,850	-	19,950
EXPANSION JOINTS	2,125	LF	0.50	0.05		106	85.00	1,063	9,010	-	10,073
INSTALL WWM	42,500	SF	0.25	0.01		425	85.00	10,625	36,125	-	46,750
POUR CONCRETE 6" TK	787	CY	95.00	2.00		1,574	85.00	74,769	133,790	-	208,559
FINISH CONCRETE	42,500	SF	0.05	0.03		1,275	85.00	2,125	108,375	-	110,500
INSTALL 6' X 6' CURB	1,050	LF	3.24	0.31		325.50	85.00	3,402.00	27,667.50	-	31,070
EPOXY COAT CONCRETE	42,500	SF	1.50	0.07		2763	85.00	63750	234813		298563
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	851,943	DC$			15.00%	% OF TIC		-	-		170,389
CONSTRUCTION MANAGEMENT	851,943	DC$			5.00%	% OF TIC		-	-		56,859
OWNER'S COST	851,943	DC$			5.00%	% OF TIC		-	-		56,859
								-	-	-	-
TOTAL 3 - option 1						8,166		157,833	694,110	-	1,136,049

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)
3 - option 2 WORK ITEM NUMBER
800 MW (Misc.)

EPRI (Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)
CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3 - OPTION 2						-		-	-	-	-
NEW GYPSUM CONTAINMENT BUILDING						-		-	-	-	-
METAL BUILDING 425' LONG X 100' WIDE X 50'	42,500	SF			120.00	-		-	-	5,100,000	5,100,000
DOORS INCLUDED IN BUILDING COST						-		-	-	-	-
CONVEYOR 50TPH 400' LONG (KBASE PRICIN	1	EA	267673	5178.00		5,178	85.00	267,673	440,130	-	707,803
CONVEYOR TRAVELING TRIPPER						-		-	-	-	-
INSTALL 6' X 6' CURB	1,050	LF	3.24	0.31		325.50	85.00	3,402.00	27,667.50	-	31,070
EPOXY COAT CONCRETE	42,500	SF	1.50	0.07		2763	85.00	63750	234813		298563
BLOWER 106,250 CFM (KBASE PRICING)	1	EA	363836	1757.00		1,757	85.00	363,836	149,345	-	513,181
BAG HOUSE 106,250 CFM (KBASE PRICING)	1	EA	2117481	6951.00		6,951	85.00	2,117,481	590,835	-	2,708,316
ROLL OVER CURB	12	LF	4.25	0.50		6.00	85.00	51.00	510.00	-	561
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	9,359,493	DC$			15.00%	% OF TIC		-	-		1,871,899
CONSTRUCTION MANAGEMENT	9,359,493	DC$			5.00%	% OF TIC		-	-		624,653
OWNER'S COST	9,359,493	DC$			5.00%	% OF TIC		-	-		624,653
								-	-	-	-
TOTAL 3 - option 2						16,980		2,816,193	1,443,300	5,100,000	12,480,697

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)

1a
WORK ITEM NUMBER

200 MW
(Misc.)

EPRI
(Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)

CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.

Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 1A						-		-		-	
AREA UNDER BOILER						-		-		-	
HYDROBLAST CONCRETE	10,800	SF	0.00	0.03		324	85.00	11	27,540	-	27,551
SEAL JOINTS & APPLY EPOXY COATING	10,800	SF	1.50	0.07		702	85.00	16,200	59,670	-	75,870
INSTALL CONCRETE CURB	420	LF	13.74	0.96		403	85.00	5,771	34,255	-	40,026
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	143,447	DC$			15.00%	% OF TIC		-	-		28,689
CONSTRUCTION MANAGEMENT	143,447	DC$			5.00%	% OF TIC		-	-		9,574
OWNER'S COST	143,447	DC$			5.00%	% OF TIC		-	-		9,574
TOTAL COST WORK ITEM 1a						1,429		21,982	121,465	-	191,283

ESTIMATE WORKSHEET

URS CORPORATION

WORK ITEM COST
(Major Account)

WORK ITEM 1b
WORK ITEM NUMBER

200 MW
(Misc.)

EPRI
(Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)

CLEVELAND, OH. 13813148
(Location) (Job No)

Est by: A. C. B.

Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 1B						-		-	-	-	-
AREA SURROUNDING DEWATERING BINS						-		-	-	-	-
HYDROBLAST CONCRETE	1,500	SF	0.00	0.03		45	85.00	2	3,825	-	3,827
SEAL JOINTS & APPLY EPOXY COATING	1,500	SF	1.50	0.07		98	85.00	2,250	8,330	-	10,580
INSTALL CONCRETE CURB	160	LF	13.74	0.96		154	85.00	2,198	13,090	-	15,288
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	29,695	DC$			15.00%	% OF TIC		-	-		5,939
CONSTRUCTION MANAGEMENT	29,695	DC$			5.00%	% OF TIC		-	-		1,982
OWNER'S COST	29,695	DC$			5.00%	% OF TIC		-	-		1,982
TOTAL COST WORK ITEM 1b						297		4,450	25,245	-	39,598

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)

WORK ITEM 1c (WORK ITEM NUMBER)

200 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 1c						-		-	-	-	-
TRUCK LOADING FRM DEWATERING BINS						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS 1EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	-	EA	57021	833		-	85.00	-	-	-	-
BAG HOUSE 1125CFM KBASE PRICING	-	EA	32948	800		-	85.00	-	-	-	-
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	225,590	DC$			15.00%	% OF TIC		-	-		45,118
CONSTRUCTION MANAGEMENT	225,590	DC$			5.00%	% OF TIC		-	-		15,056
OWNER'S COST	225,590	DC$			5.00%	% OF TIC		-	-		15,056
TOTAL WORK ITEM 1c						554		26,034	47,056	152,500	300,820

ESTIMATE WORKSHEET

EPRI
(Customer)

URS CORPORATION

WORK ITEM COST
(Major Account)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)

WORK ITEM 2a
WORK ITEM NUMBER

CLEVELAND, OH. 13813148
(Location) (Job No)

Est by: A. C. B.

Date: 9/9/2010
Rev: A

200 MW
(Misc.)

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
WORK ITEM 2a						-		-	-	-	-
COAT & SEAL AREA UNDER ESP						-		-	-	-	-
HYDROBLAST CONCRETE	5,500	SF	0.00	0.03		165	85.00	6	14,025	-	14,031
SEAL JOINTS & APPLY EPOXY COATING	5,500	SF	1.50	0.07		358	85.00	8,250	30,430	-	38,680
INSTALL CONCRETE CURB	320	LF	13.74	0.96		307	85.00	4,397	26,095	-	30,492
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	83,202	DCS			15.00%	% OF TIC		-	-		16,640
CONSTRUCTION MANAGEMENT	83,202	DCS			5.00%	% OF TIC		-	-		5,553
OWNER'S COST	83,202	DCS			5.00%	% OF TIC		-	-		5,553
TOTAL WORK ITEM 2a						830		12,652	70,550	-	110,949

ESTIMATE WORKSHEET — EPRI (Customer) — **URS** CORPORATION

WORK ITEM COST (Major Account)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

WORK ITEM 2b (WORK ITEM NUMBER)

CLEVELAND, OH. (Location) — 13813148 (Job No)

Est by: A. C. B. — Date: 9/9/2010

200 MW (Misc.) — Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
						-		-	-	-	-
WORK ITEM 2b						-		-	-	-	-
ELECTROSTATIC PRECIPITATOR ENCLOSURE						-		-	-	-	-
						-		-	-	-	-
(110' X 50' X 32'HIGH)TIGHTEN ENCLOSURE	15,740	SF	0.15	0.02		236	85.00	2,361	20,060	-	22,421
						-		-	-	-	-
FAN 8,800CFM (KBASE PRICING)	1	EA	50691	662.00		662	85.00	50,691	56,270	-	106,961
BAG HOUSE 8,800CFM (KBASE PRICING)	1	EA	107796	1047		1,047	85.00	107,796	88,995	-	196,791
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	326,173	DCS			15.00%	% OF TIC		-	-		65,235
CONSTRUCTION MANAGEMENT	326,173	DCS			5.00%	% OF TIC		-	-		21,769
OWNER'S COST	326,173	DCS			5.00%	% OF TIC		-	-		21,769
TOTAL 2b						1,945		160,848	165,325	-	434,945

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): **2c**

WORK ITEM NUMBER: **200 MW** (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2c						-		-	-	-	-
FLY ASH TRUCK LOADING						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	1	EA	57021	833		833	85.00	57,021	70,805	-	127,826
BAG HOUSE 1125CFM KBASE PRICING	1	EA	32948	800		800	85.00	32,948	68,000	-	100,948
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
TELESCOPING DOUBLE WALL CHUTE WITH ANNUL	1	EA	4200.00	20.00		20	85.00	4,200	1,700	-	5,900
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	460,264	DCS			15.00%	% OF TIC		-	-		92,053
CONSTRUCTION MANAGEMENT	460,264	DCS			5.00%	% OF TIC		-	-		30,718
OWNER'S COST	460,264	DCS			5.00%	% OF TIC		-	-		30,718
TOTAL 2c						2,207		120,203	187,561	152,500	613,753

ESTIMATE WORKSHEET

URS CORPORATION

WORK ITEM COST
(Major Account)
2 - OPTION 1
WORK ITEM NUMBER
200 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2 - OPTION 1						-		-	-	-	-
ESP ENCLOSURE						-		-	-	-	-
						-		-	-	-	-
ENCLOSURE UNDER ESP (140' X 100' X 32'HIG	5,500	SF			100.00	-		-	-	550,000	550,000
DOORS COST INCLUDED IN ENCLOSURE COST						-		-	-	-	-
FAN 8,800 CFM (KBASE PRICING)	1	EA	50691	662.00		662	85.00	50,691	56,270	-	106,961
BAG HOUSE 8,800 CFM (KBASE PRICING)	1	EA	107796	1047		1,047	85.00	107,796	88,995	-	196,791
CURB 6" X 6"	320	LF	3.24	0.31		99.20	85.00	1,036.80	8,432.00	-	9,469
ROLL OVER CURB	12	LF	4.25	0.50		6.00	85.00	51.00	510.00	-	561
EPOXY COAT FLOOR	14,000	SF	2	0.07		910	85	21000	77350		98350
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	962,132	DCS			15.00%	% OF TIC		-	-		192,426
CONSTRUCTION MANAGEMENT	962,132	DCS			5.00%	% OF TIC		-	-		64,213
OWNER'S COST	962,132	DCS			5.00%	% OF TIC		-	-		64,213
TOTAL 2 - option 1						2,724		180,575	231,557	550,000	1,282,984

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
2 - OPTION 2
WORK ITEM NUMBER
200 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2 - OPTION 2						-		-	-	-	-
PROVIDE CONC CONTAINMENT UNDER ESP						-		-	-	-	-
						-		-	-	-	-
REMOVE GRAVEL OR ASPHALT	5,500	SF		0.03		165	85.00	-	14,025	-	14,025
FINE GRADE	5,500	SF		0.01		28	85.00	-	2,380	-	2,380
FORMS	320	LF	2.00	0.20		64	85.00	640	5,440	-	6,080
EXPANSION JOINTS	320	LF	0.50	0.05		16	85.00	160	1,360	-	1,520
INSTALL WWM	5,500	SF	0.25	0.01		55	85.00	1,375	4,675	-	6,050
POUR CONCRETE 6" TK	102	CY	95.00	2.00		204	85.00	9,676	17,340	-	27,016
FINISH CONCRETE	5,500	SF	0.05	0.03		165	85.00	275	14,025	-	14,300
INSTALL 6' X 6' CURB	320	LF	3.24	0.31		99.20	85.00	1,036.80	8,432.00	-	9,469
EPOXY COAT CONCRETE	5,500	SF	1.50	0.07		358	85.00	8250	30388		38638
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	119,477	DCS			15.00%	% OF TIC		-	-		23,895
CONSTRUCTION MANAGEMENT	119,477	DCS			5.00%	% OF TIC		-	-		7,974
OWNER'S COST	119,477	DCS			5.00%	% OF TIC		-	-		7,974
TOTAL 2 - OPTION 2						1,154		21,413	98,065	-	159,320

ESTIMATE WORKSHEET

URS CORPORATION

WORK ITEM COST
(Major Account)
2 - OPTION 3
WORK ITEM NUMBER
200 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
2 - OPTION 3						-		-	-	-	-
10" FLY ASH TRANSFER LINE	600	LF	1130.80	3.01		1,805	85.00	678,478	153,425	-	831,903
INCLUDES 10" PIPING, 6 FLANGES						-		-	-	-	-
2 KNIFE GATE VALVES AND 20 CONC PEDISTALS						-		-	-	-	-
FOR SUPPORT AT 30FT ON CENTER						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	831,903	DC$			15.00%	% OF TIC		-	-		166,381
CONSTRUCTION MANAGEMENT	831,903	DC$			5.00%	% OF TIC		-	-		55,521
OWNER'S COST	831,903	DC$			5.00%	% OF TIC		-	-		55,521
TOTAL 2 - Option 3						1,805		678,478	153,425	-	1,109,326

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): 3a

WORK ITEM NUMBER: 200 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3a						-		-	-	-	-
CLEAN & COAT EXIST CONC UNDER DEWATERING EQUIP						-		-	-	-	-
AND INSTALL CURB						-		-	-	-	-
						-		-	-	-	-
HYDROBLAST CONCRETE	5,400	SF	0.00	0.03		162	85.00	5	13,770	-	13,775
SEAL JOINTS & APPLY EPOXY COATING	5,400	SF	1.50	0.07		351	85.00	8,100	29,835	-	37,935
INSTALL CONCRETE CURB	300	LF	13.74	0.96		288	85.00	4,122	24,480	-	28,602
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	80,312	DCS			15.00%	% OF TIC		-	-		16,062
CONSTRUCTION MANAGEMENT	80,312	DCS			5.00%	% OF TIC		-	-		5,360
OWNER'S COST	80,312	DCS			5.00%	% OF TIC		-	-		5,360
								-	-	-	-
TOTAL 3A						801		12,227	68,085	-	107,095

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account)

3b (WORK ITEM NUMBER)

200 MW (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B. Date: 9/9/2010 Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3b						-		-	-	-	-
DEWATERING EQUIP BUILDING						-		-	-	-	-
SEAL 120' LONG X 100' WIDE X 50' TALL METAL BLD & INSTALL FAN AND BAG HOUSE						-		-	-	-	-
TIGHTEN ENCLOSUREMETAL BUILDING (100' X 80' X	26,000	SF	0.15	0.02		390	85.00	3,900	33,150	-	37,050
DOOR INCLUDED IN BUILD PRICING						-		-	-	-	-
BLOWER 20,000CFM (KBASE PRICING)	1	EA	92512	807		807	85.00	92,512	68,595	-	161,107
BAG HOUSE 20,000 CFM (KBASE PRICING)	1	EA	221897	1828		1,828	85.00	221,897	155,380	-	377,277
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	575,434	DC$			15.00%	% OF TIC		-	-		115,087
CONSTRUCTION MANAGEMENT	575,434	DC$			5.00%	% OF TIC		-	-		38,404
OWNER'S COST	575,434	DC$			5.00%	% OF TIC		-	-		38,404
								-	-	-	-
TOTAL 3b						3,025		318,309	257,125	-	767,330

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): **3c**

WORK ITEM NUMBER: **200 MW** (Misc.)

EPRI (Customer)

COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)

CLEVELAND, OH. (Location) — 13813148 (Job No)

Est by: A. C. B. — Date: 9/9/2010 — Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3c						-		-	-	-	-
GYPSUM CONTAINMENT BUILDING						-		-	-	-	-
TIGHTEN ENCLOSURE METAL BUILDING 250'L X 100	60,000	SF	0.15	0.015		900	85.00	9,000	76,500	-	85,500
BLOWER 62,500 CFM (KBASE PRICING)	1	EA	230717	1358		1,358	85.00	230,717	115,430	-	346,147
BAG HOUSE 62,500 CFM (KBASE PRICING)	1	EA	1253334	6951		6,951	85.00	1,253,334	590,835	-	1,844,169
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	2,275,816	DC$			15.00%	% OF TIC		-	-		455,163
CONSTRUCTION MANAGEMENT	2,275,816	DC$			5.00%	% OF TIC		-	-		151,888
OWNER'S COST	2,275,816	DC$			5.00%	% OF TIC		-	-		151,888
								-	-	-	-
TOTAL 3c						9,209		1,493,051	782,765	-	3,034,755

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
3d
WORK ITEM NUMBER
200 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3d						-		-	-	-	-
GYPSUM CONTAINMENT BUILDING FLOOR						-		-	-	-	-
REMOVE GRAVEL OR ASPHALT	25,000	SF		0.03		750	85.00	-	63,750	-	63,750
FINE GRADE	25,000	SF		0.01		125	85.00	-	10,625	-	10,625
FORMS	700	LF	2.00	0.20		140	85.00	1,400	11,900	-	13,300
EXPANSION JOINTS	1,250	LF	0.50	0.05		63	85.00	625	5,355	-	5,980
INSTALL WWM	25,000	SF	0.25	0.01		250	85.00	6,250	21,250	-	27,500
POUR CONCRETE 6" TK	463	CY	95.00	2.00		926	85.00	43,981	78,710	-	122,691
FINISH CONCRETE	25,000	SF	0.05	0.03		750	85.00	1,250	63,750	-	65,000
INSTALL 6' X 6' CURB	700	LF	3.24	0.31		217.00	85.00	2,268.00	18,445.00	-	20,713
EPOXY COAT CONCRETE	25,000	SF	1.50	0.07		1625	85.00	37500	138125		175625
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	505,184	DC$			15.00%	% OF TIC		-	-		101,037
CONSTRUCTION MANAGEMENT	505,184	DC$			5.00%	% OF TIC		-	-		33,716
OWNER'S COST	505,184	DC$			5.00%	% OF TIC		-	-		33,716
								-	-	-	-
TOTAL 3d						4,846		93,274	411,910	-	673,653

ESTIMATE WORKSHEET — **URS** CORPORATION

WORK ITEM COST (Major Account): 3e
WORK ITEM NUMBER: 200 MW
(Misc.)

EPRI (Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT (Project Title)
CLEVELAND, OH. (Location) 13813148 (Job No)

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3e						-		-	-	-	-
TRUCK LOADING FROM STORAGE						-		-	-	-	-
METAL BUILDING 100' L X 15' WIDX 25' HIGH	1,500	SF			95.00	-		-	-	142,500	142,500
ADD FOR SEALED ELECTRIC ROLL UP DOOR	2	EA			5000.00	-		-	-	10,000	10,000
6"X 6" CURB	160	LF	3.24	0.31		49.60	85.00	518.40	4,216.00	-	4,734
ROLL OVER CURB	24	LF	4.25	0.50		12.00	85.00	102.00	1,020.00	-	1,122
METAL LINER FOR LOADING AREA 12x 80 3EA	11,685	LB	1.40	0.02		175	85.00	16,359	14,875.00	-	31,234
SUMPS 1EA	1	CY	250.00	20.00		20	85.00	250	1,700	-	1,950
FAN 1125CFM KBASE PRICING	1	EA	57021	833.00		833	85.00	57,021	70,805	-	127,826
BAG HOUSE 1125CFM KBASE PRICING	1	EA	32948	800.00		800	85.00	32,948	68,000	-	100,948
LOADING RACK	1	EA	8805.00	297.00		297	85.00	8,805	25,245	-	34,050
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	454,364	DC$			15.00%	% OF TIC		-	-		90,873
CONSTRUCTION MANAGEMENT	454,364	DC$			5.00%	% OF TIC		-	-		30,324
OWNER'S COST	454,364	DC$			5.00%	% OF TIC		-	-		30,324
								-	-	-	-
TOTAL 3e						2,187		116,003	185,861	152,500	605,886

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
3 - OPTION 1
WORK ITEM NUMBER
200 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3 - OPTION 1						-		-	-	-	-
GYPSUM CONTAINMENT BUILDING FLOOR						-		-	-	-	-
REMOVE GRAVEL OR ASPHALT	25,000	SF		0.03		750	85.00	-	63,750	-	63,750
FINE GRADE	25,000	SF		0.01		125	85.00	-	10,625	-	10,625
FORMS	700	LF	2.00	0.20		140	85.00	1,400	11,900	-	13,300
EXPANSION JOINTS	1,300	LF	0.50	0.05		65	85.00	650	5,525	-	6,175
INSTALL WWM	25,000	SF	0.25	0.01		250	85.00	6,250	21,250	-	27,500
POUR CONCRETE 6" TK	463	CY	95.00	2.00		926	85.00	43,981	78,710	-	122,691
FINISH CONCRETE	25,000	SF	0.05	0.03		750	85.00	1,250	63,750	-	65,000
INSTALL 6' X 6' CURB	700	LF	3.24	0.31		217.00	85.00	2,268.00	18,445.00	-	20,713
EPOXY COAT CONCRETE	25,000	SF	1.50	0.07		1625	85.00	37500	138125		175625
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	505,379	DCS			15.00%	% OF TIC		-	-		101,076
CONSTRUCTION MANAGEMENT	505,379	DCS			5.00%	% OF TIC		-	-		33,729
OWNER'S COST	505,379	DCS			5.00%	% OF TIC		-	-		33,729
								-	-	-	-
TOTAL 3 - option 1						4,848		93,299	412,080	-	673,913

ESTIMATE WORKSHEET

WORK ITEM COST
(Major Account)
3 - option 2
WORK ITEM NUMBER
200 MW
(Misc.)

EPRI
(Customer)
COST ELEMENTS FOR EPRI SUBTITLE C COSTING PROJECT
(Project Title)
CLEVELAND, OH. 13813148
(Location) (Job No)

URS CORPORATION

Est by: A. C. B.
Date: 9/9/2010
Rev: A

DESCRIPTION	Quantity	Unit	Material $/Unit	Man-Hrs /Unit	Sub-Cont $/Unit	Total Man-Hours	$/Hr	Material $	Labor $	Sub-Contract $	Total Cost $
3 - OPTION 2						-		-	-	-	-
NEW GYPSUM CONTAINMENT BUILDING						-		-	-	-	-
METAL BUILDING 250' LONG X 100' WIDE X 50'	25,000	SF			120.00	-		-	-	3,000,000	3,000,000
DOORS INCLUDED IN BUILDING COST						-		-	-	-	-
CONVEYOR 50TPH 225' LONG (FACTORED DOWN KBASE P	1	EA	165000	3268.00		3,268	85.00	165,000	277,780	-	442,780
CONVEYOR TRAVELING TRIPPER						-		-	-	-	-
INSTALL 6' X 6' CURB	700	LF	3.24	0.31		217.00	85.00	2,268.00	18,445.00	-	20,713
EPOXY COAT CONCRETE	25,000	SF	1.50	0.07		1625	85.00	37500	138125		175625
BLOWER 62,500 CFM (KBASE PRICING)	1	EA	230717	1358.00		1,358	85.00	230,717	115,430	-	346,147
BAG HOUSE 62,500 CFM (KBASE PRICING)	1	EA	1253334	4491.00		4,491	85.00	1,253,334	381,735	-	1,635,069
ROLL OVER CURB	12	LF	4.25	0.50		6.00	85.00	51.00	510.00	-	561
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
						-		-	-	-	-
	Basis					-		-	-	-	-
ENGINEERING COST	5,620,895	DC$			15.00%	% OF TIC		-	-		1,124,179
CONSTRUCTION MANAGEMENT	5,620,895	DC$			5.00%	% OF TIC		-	-		375,139
OWNER'S COST	5,620,895	DC$			5.00%	% OF TIC		-	-		375,139
								-	-	-	-
TOTAL 3 - option 2						10,965		1,688,870	932,025	3,000,000	7,495,351

B
DETAILED INFORMATION ON WORK ITEM 5 COSTS

ACCESS AND SECURITY PROVISIONS

Assumptions:
- A barrier, consisting of a fence with locked gates, or a structure with locked access shall be provided.
- Security access consisting of electronic pass codes and/ or card keys may be provided.
- Signage shall be posted, legible from a distance of 25 feet, in English as well as any locally prevailing additional languages, identifying the enclosure as containing hazardous waste materials and prohibiting unauthorized access.
- Inspections shall be carried out in accordance with 40 CFR Part 270.14(b)(5) to meet 40 CFR 264.15, 264.174, and 264.195. The schedule shall include a description of the elements to be inspected and the inspection frequency.
- Access issues included on the checklist shall include: security procedures, inspection procedures, posting of signs at appropriate points, and control of any deterioration or malfunctions detected to the extent possible.
- A log showing how deteriorations or malfunctions will be and are remedied shall be maintained for at least three years. Routine inspections shall include verification of the integrity of site access controls. Periodic (at least once per shift or three times daily) checks by site security personnel shall be provided as a part of routine operations. All checks shall be documented in the security logs.
- A Plan shall be developed and complied with, outlining provisions for emergency response, including protocols for access and control, training required, and documentation of any response actions.
- For storage and disposal facilities, access requirements shall be included in the Closure Plan and Post-closure Care and Maintenance Plan.

Cost Element	Unit	Quantity	Unit Cost	Total Cost	Cost Reference
Capital cost elements					
Perimeter fencing -400 MW facility - 8 ft high with triple strand barbed wire	L.F	7000	$75.00	$525,000.00	2010 fence cost from landfill design/build project with allowance for gates
Signage - 400 MW Facility	Each	70	$250.00	$17,500.00	Experience - 1 sign per 100 ft.
Total Cost - 400 MW				$542,500.00	
With 35% Contingency				732,375	

Cost Element	Unit	Quantity	Unit Cost	Total Cost	Cost Reference
Capital cost elements					
Perimeter fencing -800 MW facility - 8 ft high with triple strand barbed wire	L.F	8500	$75.00	$637,500.00	2010 fence cost from landfill design/build project with allowance for gates
Signage - 800 MW Facility	Each	85	$250.00	$21,250.00	Experience - 1 sign per 100 ft.
Total Cost - 800 MW				$658,750.00	
With 35% Contingency				889,313	

Cost Element	Unit	Quantity	Unit Cost	Total Cost	Cost Reference
Capital cost elements					
Perimeter fencing - 1600 MW facility - 8 ft high with triple strand barbed wire	L.F	10500	$75.00	$787,500.00	2010 fence cost from landfill design/build project with allowance for gates
Signage - 1600 MW Facility	Each	105	$250.00	$26,250.00	Experience - 1 sign per 100 ft.
Total Cost - 1600 MW				$813,750.00	
With 35% Contingency				1,098,563	

Cost Element	Unit	Quantity	Unit Cost	Total Cost	Cost Reference
Capital cost elements					
Perimeter fencing - 3200 MW facility - 8 ft high with triple strand barbed wire	L.F	13000	$75.00	$975,000.00	2010 fence cost from landfill design/build project with allowance for gates
Signage - 3200 MW Facility	Each	130	$250.00	$32,500.00	Experience - 1 sign per 100 ft.
Total Cost - 3200 MW				$1,007,500.00	
With 35% Contingency				1,360,125	

LEACHATE STORAGE TANKS

Assumptions:
- Under Subtitle C leachate cannot be managed in lagoon/ ponds
- Leachate to be managed in above ground leachate storage tanks with structural secondary containment
- The average 100-acre ± landfill will need 4 - 250,000-gallon storage tanks over the life of the facility

Cost Element	Units	Quantity	Unit Cost	Compliant premium	35% Contingency	Cost Reference
Capital cost elements						
Leachate Storage Tanks - 400 MW Facility	Each - 250,000 Gallon Tank	2	$520,000.00	$1,040,000.00	$1,404,000	Manufacturer Quote - Above ground tanks including secondary containment
Leachate Storage Tanks - 800 MW Facility	Each - 250,000 Gallon Tank	2	$520,000.00	$1,040,000.00	$1,404,000	Manufacturer Quote - Above ground tanks including secondary containment
Leachate Storage Tanks - 1600 MW Facility	Each - 250,000 Gallon Tank	4	$520,000.00	$2,080,000.00	$2,808,000	Manufacturer Quote - Above ground tanks including secondary containment
Leachate Storage Tanks - 3200 MW Facility	Each - 250,000 Gallon Tank	6	$520,000.00	$3,120,000.00	$4,212,000	Manufacturer Quote - Above ground tanks including secondary containment

	PROJECT **EPRI Subtitle C vs D Comparison**		SHEET 1	REV NO
CALCULATION SHEET	SUBJECT Preliminary Project Costs Sheets		CLIENT PROJECT #	URS JOB NO 13813148
DRAFT	ACTIVITY Preliminary RCRA Waste Pile Construction Cost Estimate	LAST UPDATED BY RHH	DATE LAST MODIFIED 9/23/2010	REVIEWED BY NSG

BASIS OF THE ESTMATE		
YEAR & QUARTER COST BASIS	Q3 - 2010	
TOTAL AREA OF DISTURBANCE (FACILITY AREA)	15	Acres
OVERALL WASTE PILE SIZE	10	Acres

	TASK	ITEM	None UNIT	ENTIRE SITE QUANTITY	INSTALLED UNIT COST	ENTIRE LF COST	NOTES
MOBILIZATION / SITE SETUP	**PRE-MOBILIZATION COSTS / MOBILIZATION / SITE SET-UP**						
	1	MOBILIZATION	L S	1	$70,000	$70,000	Mob/Demob & insurance: (2.5% of Total Bid Price) includes administration (mtgs health & safety, trailer phone/fax/electricity temporary facilities utilities roll off boxes waste disposal, and cleanup)
	2	CLEARING AND GRUBBING - BRUSH/GRASS	ACRE	10.0	$1,500	$15,000	Assumes 66% of area is brush/grass
	3	CLEARING AND GRUBBING - HEAVY WOODS	ACRE	5.0	$3,000	$15,000	Assumes 33% of area is heavy woods
EARTHWORK/SUBGRADE PREP	**EARTHWORK**						
	4	TOPSOIL STRIPPING	CYD	8,067	$4	$32,267	Assume 6-inches of topsoil over the cell area
	5	SOIL EXCAVATION	CYD	48,400	$3	$145,200	Excavation and stockpiling of on-site soils - average excavation of 3 feet
	6	ROCK EXCAVATION AND BLASTING	CYD	0	$16	$0	
	7	REUSE OF EXCAVATED SOIL AS STRUCTURAL FILL	CYD	12,100	$6	$72,600	Assumed to be on-site material. Assumes 25% of excavation
	8	SUBGRADE IMPROVEMENT - REMOVE AND REPLACE (IF REQUIRED)	SQ.FT	21,780	$1.00	$21,780	Assumes overexcavation to 3-ft deep and replacement with structural fill. Assume 5% of LF footprint
LINER SYSTEM	**LINER SYSTEM INSTALLATION**						
	9	EXCAVATE ANCHOR TRENCH	L.F.	2,820	$3	$8,460	2,820 LF of anchor trench around 10 acres of laydown area
	10	60 MIL HDPE LINER	SQ. FT.	435,600	$0.55	$239,580	Assume 10 acres with no overlaps
	11	DOUBLE-SIDED GEOCOMPOSITE	SQ. FT.	435,600	$0.65	$283,140	Assume 10 acres with no overlaps
	12	GCL	SQ. FT.	0	$0.65	$0	
	13	RECOMPACTED CLAY LAYER	CYD	48,400	$12	$580,800	Assume existing in-situ soils will be suitable for reuse with some processing (rock picking/screening, weathering, etc.) (10 acres @ 3ft thick). assumes $10/cy for general excavation and placement and $5/cy for processing
LEACHATE COLLECTION SYSTEM	**LEACHATE COLLECTION SYSTEM**						
	14	6-IN PERF HDPE TOE PIPE	L.F.	800	$15	$12,000	$5/LF purchase + $10/LF to fuse and install
	15	6-IN PERF HDPE FLOOR PIPE	L.F.	1,760	$15	$26,400	$5/LF purchase + $10/LF to fuse and install
	16	LEACHATE CLEANOUTS	L.F.	400	$15	$6,000	$5/LF purchase + $10/LF to fuse and install (4) cleanouts @ 50LF per cleanout
	17	FILTER STONE - LEACHATE COLLECTION PIPES	TON	1,700	$30	$51,000	(5.2 SQ FT*(floor pipe) LF+12.4 SQ FT*(toe pipe) LF)/27*1.2*2 ton/cyd
	18	GEOTEXTILE FOR LEACHATE PIPING	SQ. FT.	35,840	$0.20	$7,168	x LF*14-FT wide roll
	19	COARSE STONE IN SUMP	TON	45	$30	$1,350	Assume (1) sump at 20ft x 20ft by 1.5ft thick
	20	FILTER STONE IN SUMP	TON	40	$30	$1,200	Assume (1) sump at 20ft x 20ft by 1.5ft thick
	21	1-FT SAND DRAINAGE/PROTECTIVE COVER LAYER	CYD	16,133	$20	$322,667	Assumes that bottom ash will not be available and sand will be utilized
	22	SUMP/SIDESLOPE RISERS/PUMPS/ELECT	L.S	1	$100,000	$100,000	Includes an 18-in diameter pipe, elect power pole and transformer panel pump PLC & appurtences installed in the landfill
	23	ELECTRICAL DROP FOR PUMPS	L.S.	1	$100,000	$100,000	Includes hook-up from an existing service
	24	HDPE FLAT STOCK	L.S.	1	$5,000	$5,000	Insulates and protects the liner system
LEACHATE MANAGEMENT SYSTEM	**LEACHATE MANAGEMENT SYSTEM**						
	25	LEACHATE STORAGE TANKS - 250,000 GALLON TANK	EACH	0	$520,000	$0	RCRA laydown area will utilize the same leachate storage tanks as the landfill cells
	26	LEACHATE LOADOUT STRUCTURE	L.S.	0	$75,000	$0	Includes wet well, pumps, loadout arm, etc.
	27	LEACHATE MANHOLES	EACH	2	$5,000	$10,000	Assumed manhole at riser connection and additional manhole for long span
	28	LEACHATE PIPING TO STORAGE TANKS FOR DISCHARGE	L.F.	1,000	$35	$35,000	Includes excavation, pipe, and backfill
SITE DEVELOPMENT	**ROADS**						
	29	ACCESS ROAD GRADING	CYD	4,400	$5	$22,000	Based on 3-ft average depth of cut/fill. Assume 1,320 LF access road @ 30 feet wide
	30	GRAVEL ACCESS ROAD	TON	4,400	$30	$132,000	Assume 1 320LF road x 30 ft wide x 1.5 thick
	31	GEOTEXTILE BENEATH GRAVEL ACCESS ROAD	SQ. FT.	39,600	$0.20	$7,920	Assume 1,320 LF access road @ 30 feet wide
	32	GRAVEL PERIMETER ROADS	TON	1,667	$30	$50,010	Assume perimeter road length of 3,000 LF
	33	GEOTEXTILE BENEATH GRAVEL PERIMETER ROADS	SQ. FT.	60,000	$0.30	$18,000	Assume perimeter road is 3,000 LF by 20 ft wide
	34	TEMPORARY ROADS - GRAVEL ONLY	TON	1,111	$30	$33,330	1000 LF x 20 ft wide x 9-inches
	SITE E&S AND PONDS						
	35	SITE EROSION AND SEDIMENT CONTROL	ACRE	15	$3,500	$52,500	Based on greenfield site
	36	STORMWATER DETENTION BASIN STRUCTURES	EACH	0	$200,000	$0	Includes construction of sediment ponds
	37	STORMWATER PIPING	L.F.	0	$40	$0	100LF of piping per discharge
	38	STORMWATER BASIN OUTLET STRUCTURES	EACH	0	$15,000	$0	Includes risers and outlet pipes
	39	PERMANENT GRASS LINED CHANNELS	L.F.	300	$20	$6,000	Assume 10% of 3,000 feet of perimeter ditch
	40	PERMANENT TRM-LINED CHANNELS	L.F.	2,400	$30	$72,000	Assume 80% of 3,000 feet of perimeter ditch
	41	PERMANENT RIP RAP DRAINAGE CHANNELS	L.F.	300	$60	$18,000	Assume 10% of 3,000 feet of perimeter ditch
TOTALS		TOTAL				$2,573,371	
		Cost per acre				$ 257,337.13	
		TOTAL with 35% Contingency				$ 3,474,051	

CALCULATION SHEET **DRAFT**	PROJECT **EPRI Subtitle C vs D Comparison**		SHEET 2	REV NO 0
	SUBJECT Preliminary Project Costs Sheets		CLIENT PROJECT # 0	URS JOB NO 13813148
	ACTIVITY **Preliminary RCRA Waste Pile Assumptions & Limitations**	LAST UPDATED BY: RHH	DATE LAST MODIFIED 9/23/2010	REVIEWED BY: NSG

	The following key assumptions and limitations are associated with the project design, implementation and performance:
1	The cost estimates were prepared using 2010 dollars and do not include any escalation.
2	No contingency has been included for this cost estimate.
3	The unit rate costs are based on the following sources: RS Means Heavy Construction Cost Data (2008), Manufacturer/Supplier Data, and URS experience.
4	The cost estimates include only capital costs. Operation and maintenance costs are not included in this estimate.
5	This estimate does not include any costs associated with engineering, permitting, or Construction Quality Assurance (CQA).
6	The RCRA laydown area has been sized for 10 acres of lined area with no specific volume.
7	We have assumed that the site will not require wetland, stream, or historical site mitigation.
8	Cultural Resources costs have been excluded from this estimate.
9	Costs have not been included for property acquisition or for the removal/relocation of utilities.
10	We have assumed that the site is a greenfield and utilities are readily available.
11	We have assumed that this site does not contain any karst formations or other instabilities.
12	We have assumed that there is no demolition of existing structures required for the site.
13	We have assumed that this site will not require dewatering.
14	We assume that an under drain sytem is not required.
15	We have assumed that the foundation soils will provide adequate support for the liner system and that groundwater is located at a sufficient depth below the bottom of the liner to facilitate reuse of the existing soil as a geologic buffer layer.
16	We have assumed that this site will not require a geologic buffer. Therefore, no geologic buffer costs are included in this estimate.
17	We have assumed that 33% of the RCRA laydown area footprint requiring clearing and grubbing is heavy woods and 66% is brush/grass.
18	We have assumed that any subgrade improvements would include excavation and replacement of existing materials.
19	We have assumed that the RCRA laydown area liner cross section will consist of a 3-foot clay layer, a 60-mil geomembrane, a geocomposite, and a 1-foot protective layer.
20	We have assumed that the low permeability clay for the bottom liner will be available from on-site soils.
21	We have assumed that the leachate collection and management system will utilize the same above ground storage tanks as the landfill. These costs have been included in the landfill estimate.
22	Groundwater monitoring costs are not included in this estimate.
23	We have assumed that the RCRA laydown area will utilize the three stormwater ponds constructed for the landfill. Ditches and swales will be constructed to control stormwater on the site and direct it to the ponds.
24	We have assumed that push walls are not required for the management of the materials on the RCRA waste pile
25	For estimating purposes, it has been assumed that the preferred method of transporting CCP to the landfill will be using trucks to haul the material from the plant to the landfill. There are no costs associated with transporting the CCP included in this estimate.
26	Statements of Probable Construction Cost prepared by URS represent URS's judgement as a design professional familiar with the construction industry. It is recognized, however, that neither URS nor the Owner has control over the cost of labor, materials or equipment nor over the contractor's methods of determining the bid price or other competitive bidding, market, or negotiating conditions. Accordingly, URS cannot and does not warrant or represent that proposals, bids or actual construction costs will not vary from any statement of Probable Construction Cost or other estimates or evaluations prepared by URS.

C
DETAILED INFORMATION ON WORK ITEM 6 COSTS

Regulatory Summary – Pond Closures

TASK 6A – Closing Active/Inactive Surface Impoundments - Regulation Summary

Subtitle D (40 CFR 257.100) Active Impoundment Closure Requirements

- May occur with CCRs in place or through CCR removal and decontamination
- Must eliminate free liquids
- Stabilize wastes to a bearing capacity sufficient to support the final cover
- Cover with final cover that is designed and constructed to:
  - Provide long-term minimization of migration of liquids through closed impoundment
  - Function with minimum maintenance
  - Promote drainage and minimize erosion
  - Accommodate settling/subsidence
  - Have a permeability less than or equal to the permeability of any bottom liner system or natural subsoils present or a permeability no greater than $1x10^{-5}$ cm/s, whichever is less
  - Minimize infiltration through the closed CCR impoundment by use of an infiltration layer that contains a minimum 18-inches of earthen material
  - Minimize erosion of final cover by use of erosion layer that contains a minimum 6-inches of earthen material capable of sustaining native plant growth

Subtitle C (40 CFR 264.1305) Active Impoundment Closure Requirements

- 40 CFR 264.1305 requires that surface impoundments must be closed in accordance with 40 CFR 264.228 and subpart G of 40 CFR 264
- 40 CFR 264.228 requires that:
  - Remove or decontaminate all waste close or eliminate free liquids/solidifying the remaining wastes and waste residues
  - Stabilize waste to a bearing capacity sufficient to support final cover
  - Install a cover system that is designed and constructed to:

- Provide long-term minimization of liquids through the impoundment
- Function with minimal maintenance
- Promote drainage and minimize erosion
- Accommodate settling/subsidence
- Have a permeability less than or equal to the permeability of any bottom liner system or natural subsoils present

Subtitle D (40 CFR 257.100) Inactive Impoundment Closure Requirements

- No specific mention of closure requirements for Inactive Impoundments, unless they cannot meet the requirements of 40 CFR 257.64 (a) (Unstable Areas) – (see rule 40 CFR 257.65)

Subtitle C Inactive Impoundment Closure Requirements

- 40 CFR 264.1300 (a) & (b) imply that all facilities that store CCR materials may require closure in accordance with 40 CFR 265.228
- Therefore cap system will be the same as Active Impoundment Closures for all Inactive Impoundments

Assumptions

Subtitle C Active Impoundment Closure

- Typical RCRA Subtitle C Cap will be utilized
  - Clay component – 24-inches of compacted clay or geosynthetic clay liner (GCL)
    - GCL assumed for this cost estimate for its cost competitiveness and easy applicability to the majority of sites (i.e., can be delivered to all sites, whereas clay availability varies widely based on region)
  - Flexible Membrane Liner – 40-mil low-level density polyethylene (LLDPE) or 30-mil polyvinyl chloride (PVC)
    - Assume textured 40-mil LLDPE
  - Natural or geosynthetic drainage layer – 12-inches sand or Drainage Geocomposite
    - Assume drainage geocomposite because of its applicability to most sites (i.e., natural drainage materials availability/price vary widely from site to site)
  - Cover soil – 24-inches of cover soil with upper 6 inches capable of sustaining vegetation.
    - Assume 18 inches of site soil and 6 inches of topsoil.
- Site will be dewatered to remove free water and a ring-drain will be installed around the perimeter to alleviate any pore water pressure and prevent seeps
- Area will be bridged with site soil to create a stable base to support the cap system construction

  - Assume an average of 5 feet of material across the site.
- Crown will be created to promote surface water drainage and account for potential settlement by regrading CCRs in conjunction with the placement of the soil bridge material.

Subtitle C Inactive Impoundment Closure

- Clearing and grubbing may be required – moderately dense brush and small trees
- Typical RCRA Subtitle C Cap will be utilized
  - Clay component – 24-inches of compacted clay or GCL
    - GCL assumed for this cost estimate for its cost competitiveness and easy applicability to the majority of sites (i.e., can be delivered to all sites, whereas clay availability varies widely based on region)
  - Flexible Membrane Liner – 40-mil LLDPE or 30-mil PVC
    - Assume textured 40-mil LLDPE
  - Natural or geosynthetic drainage layer – 12-inches sand or Drainage Geocomposite
    - Assume drainage geocomposite because of its applicability to most sites (i.e., natural drainage materials availability/price vary widely from site to site)
  - Cover soil – 24-inches of cover soil with upper 6 inches capable of sustaining vegetation.
    - Assume 18 inches of site soil and 6 inches of topsoil.
- Assumes two feet of bridge soil is required
- Crown will be created to promote surface water drainage and account for potential settlement by regrading CCRs.
- Assume site (side slopes, etc.) is stable.

Subtitle Typical D Active Impoundment Closure

- RCRA Subtitle D Cap will be utilized
- Clay component – 18-inches of compacted low permeability (1x10-6 cm/s) soil
- Cover soil – minimum 6 inches capable of sustaining vegetation.
- Site will be dewatered to remove free water and a ring-drain will be installed around the perimeter to alleviate any power water pressure and prevent seeps
- Area will be bridged with site soil to create a stable base to support the cap system construction
  - Assume an average of 5 feet of material across the site.
- Crown will be created to promote surface water drainage and account for potential settlement by regrading CCRs in conjunction with the placement of the soil bridge material.

Subtitle Typical D Inactive Impoundment Closure

- Not required to be capped unless located in an unstable area

Major Cost Components

Subtitle C Cap System Active Impoundments

- Dewatering
- Ring Drain Installation
- Crown construction/CCR regrading
- Bridge soil placement
- GCL
- 40-mil LLDPE Geomembrane
- 18 inches site soil cover
- 6 inches topsoil cover

Subtitle C Cap System Inactive Impoundments

- Clearing and grubbing – heavy brush and small trees
- Ring Drain Installation
- Crown construction/CCR regrading
- GCL
- 40-mil LLDPE Geomembrane
- 18 inches site soil cover
- 6 inches topsoil cover

Subtitle D Cap System Active Impoundments

- Dewatering
- Crown construction/CCR regrading
- Bridge soil placement
- 18 inches low permeability cover material
- 6 inches topsoil cover

Subtitle D Cap System Inactive Impoundments

- None

ITEM 6 - ACTIVE POND C

Assumptions:
- Typical RCRA Subtitle C Cap will be utilized
  - 24-inches of compacted clay or GCL
  - Flexible Membrane Liner – Assume textured 40-mil LLDPE
  - Drainage Geocomposite
- Cover soil – 24-inches of cover soil with upper 6 inches capable of sustaining vegetation.
  - Assume 18 inches of site soil and 6 inches of topsoil.

Site will be dewatered to remove free water and a ring-drain will be installed around the perimeter to alleviate any pore water pressure and prevent seeps
- Dewatering is anticipated to be a major cost item, but on a per-acre basis, will be insignificant over the cost of 50 to 100 acre capping projects
- Area will be bridged with site soil to create a stable base to support the cap system construction
  - Assume an average of 5 feet of material across the site.
- Crown will be created to promote surface water drainage and account for potential settlement by regrading CCRs in conjunction with the placement of the soil bridge material.
  - Assume an average of 5 feet of material across the site is regraded

Cost Element	Units	Quantity for 1 acre	Unit Cost	Compliant premium	Cost Reference
Capital cost elements					
Ring Drain Installation	LF	200	$20.00	$4,000.00	RSMeans (various components) and experience
Crown Construction/Regrading	CY	8067	3	$24,200.00	RSMeans (02315 410 5560) and experience
Bridge Soil Placement	CY	8067	8	$64,533.33	RSMeans (02300 500 0010) and experience
GCL	SF	43560	0.65	$28,314.00	Manufacturer Quotes/ Experience - woven/non-woven GCL (shallow slopes/low load)
40-mil LLDPE Geomembrane	SF	43560	0.5	$21,780.00	Manufacturer Quotes/ Experience - double sided textured
Geocomposite Drainage Layer	SF	43560	0.65	$28,314.00	Manufacturer Quotes/ Experience - low load shallow slopes
18 inches site soil fill	CY	2420	8	$19,360.00	RSMeans (02300 500 0010) and experience
6 inches topsoil	CY	807	15	$12,100.00	RSMeans (02060 150 0900) and experience - offsite borrow near site
Total Cost				$203,000.00	
With 35% Contingency				$274,050.00	

Detailed Information on Work Item 6 Costs

ITEM 6 - ACTIVE POND D

Assumptions:
- Typical RCRA Subtitle D Cap will be utilized
  - 18-inches of compacted clay
  - 6 inches of topsoil
- Site will be dewatered to remove free water and a ring-drain will be installed around the perimeter to alleviate any pore water pressure and prevent seeps
  - Dewatering is anticipated to be a major cost item, but on a per-acre basis, will be insignificant over the cost of 50 to 100 acre capping projects
- Area will be bridged with site soil to create a stable base to support the cap system construction
  - Assume an average of 5 feet of material across the site.
- Crown will be created to promote surface water drainage and account for potential settlement by regrading CCRs in conjunction with the placement of the soil bridge material
  - Assume an average of 5 feet of material across the site is regraded

Cost Element	Units	Quantity for 1 acre	Unit Cost	Compliant premium	Cost Reference
Capital cost elements					
Ring Drain Installation	L.F.	200	$20.00	$4,000.00	RSMeans (various components) and experience
Crown Construction/ Regrading	CY	8067	3	$24,200.00	RSMeans (02315 410 5560) and experience
Bridge Soil Placement	CY	8067	8	$64,533.33	RSMeans (02300 500 0010) and experience
Compacted Clay	CY	2420	15	$36,300.00	Experience - clay cost widely variable site to site - typical offsite, but local, borrow cost
6 inches topsoil	CY	807	15	$12,100.00	RSMeans (02060 150 0900) and experience - offsite borrow, near site
Total Cost				$142,000.00	
With 35% Contingency				$191,700.00	

ITEM 6 - INACTIVE POND C

Assumptions:
- Assumes clearing and grubbing of heavy brush and medium trees
- Typical RCRA Subtitle C Cap will be utilized
  - 24-inches of compacted clay or GCL
  - Flexible Membrane Liner – Assume textured 40-mil LLDPE
  - Drainage Geocomposite
- Cover soil – 24-inches of cover soil with upper 6 inches capable of sustaining vegetation.
  - Assume 18 inches of site soil and 6 inches of topsoil.
- Area will be bridged with site soil to create a stable base to support the cap system construction
  - Assume an average of 2 feet of material across the site.
- Crown will be created to promote surface water drainage and account for potential settlement by regrading CCRs in conjunction with the placement of the soil bridge material
  - Assume an average of 5 feet of material across the site is regraded

Cost Element	Units	Quantity for 1 acre	Unit Cost	Compliant premium	Cost Reference
Capital cost elements					
Site Clearing	Acre	1	$3,000.00	$3,000.00	RSMeans (02230 200 0010) and experience
Crown Construction/Regrading	CY	8067	3	$24,200.00	RSMeans (02315 410 5560) and experience
Bridge Soil Placement	CY	3227	8	$25,813.33	RSMeans (02300 500 0010) and experience
GCL	S.F.	43560	0.65	$28,314.00	Manufacturer Quotes/Experience - woven/non-woven needle-punched GCL
40-mil LLDPE Geomembrane	SF	43560	0.5	$21,780.00	Manufacturer Quotes/Experience - double sided textured
Geocomposite Drainage Layer	SF	43560	0.65	$28,314.00	Manufacturer Quotes/Experience
18 inches site soil fill	CY	2420	8	$19,360.00	RSMeans (02300 500 0010) and experience
6 inches topsoil	CY	807	15	$12,100.00	RSMeans (02060 150 0500) and experience - offsite borrow, near site
Total Cost				$163,000.00	
With 35% Contingency				$220,050.00	

Assumptions

Subtitle C Wastewater Treatment

- Basic physical/chemical treatment
  - Lime addition, desaturation, primary clarifier, equalization tank
  - Units for addition of organosulfide, iron/acid, and polymer
  - Secondary clarifier, filter, filter press, and sludge tank.

Cost Component	Mean Capital Cost ($)	Annual O&M Cost ($)
FGD Wastewater Treatment:		
All Lignite, Subbituminous, Western Bituminous Plants and Eastern Bituminous Plants < 250 MW	23,000,000	1,400,000
Eastern Bituminous Plants ? 250 MW ? 1500 MW	36,000,000	2,800,000
Eastern Bituminous Plants > 1500 MW	61,000,000	10,400,000
Low Volume CCR Wastewater Treatment:		
Plants < 200 MW	6,000,000	800,000
Plants 200 – 1000 MW	10,000,000	1,000,000
Plants > 1000 MW	22,500,000	1,700,000

PROJECT		SHEET	REV NO
EPRI Subtitle C vs D Comparison		1	
SUBJECT		CLIENT PROJECT #	URS JOB NO
Preliminary Project Costs Sheets			13813148
ACTIVITY	LAST UPDATED BY	DATE LAST MODIFIED	REVIEWED BY
Preliminary Non-CCR Waste Water Pond Construction Cost Estimate	RHH	11/11/2010	NSG

BASIS OF THE ESTMATE		
YEAR & QUARTER COST BASIS	Q3 - 2010	
TOTAL AREA OF DISTURBANCE (FACILITY AREA)	15	Acres
OVERALL PONDSIZE	10	Acres

ITEM	None UNIT	ENTIRE SITE QUANTITY	INSTALLED UNIT COST	ENTIRE LF COST	NOTES
TS / MOBILIZATION / SITE SET-UP					
MOBILIZATION	L S	1	$46,000	$46,000	Mob/Demob & insurance: (2 5% of Total Bid Price) includes administration (mtgs. health & safety. trailer, phone/fax/electricity temporary facilities. utilities. roll off boxes waste disposal, and cleanup)
CLEARING AND GRUBBING - BRUSH/GRASS	ACRE	15.0	$1,500	$22,500	Assumes 100% of area is brush/grass
CLEARING AND GRUBBING - HEAVY WOODS	ACRE	0.0	$3,000	$0	Assumes 0% of area is heavy woods
TOPSOIL STRIPPING	CYD	8,067	$4	$32,267	Assume 6-inches of topsoil over the cell area.
SOIL EXCAVATION	CYD	242,000	$3	$726,000	Excavation and stockpiling of on-site soils - average excavation of 15 feet
ROCK EXCAVATION AND BLASTING	CYD	0	$16	$0	
REUSE OF EXCAVATED SOIL AS STRUCTURAL FILL	CYD	0	$6	$0	Assume no structural fill required. pond is excavated only.
ATION					
RECOMPACTED CLAY LAYER	CYD	32,267	$15	$484,000	Assume existing in-situ soils will be suitable for reuse with some processing (rock picking/screening, weathering, etc) (10 acres @ 2ft thick) assumes $10/cy for general excavation and placement and $5/cy for processing
PROTECTIVE GRAVEL LAYER - 12 INCHES	CYD	16,133	$25	$403,333	12 inch gravel layer to protect clay liner during pond cleanout
E					
DISCHARGE PUMP	L.S.	1	$75,000	$75,000	includes wet well, pumps, etc.
PIPING FOR DISCHARGE	L.F.	1,000	$35	$35,000	Includes excavation, pipe, and backfill, assumed 1,000 linear feet
SITE EROSION AND SEDIMENT CONTROL	ACRE	15	$1,500	$22,500	Based on greenfield site
TOTAL				**$1,846,600**	

D
DETAILED INFORMATION ON WORK ITEM 7 COSTS

11/1/2010

7. Miscellaneous Operational/Administrative Upgrades

Low range cost assumptions are for two x 200 MW units model plant - a small T/S/D with exempt tanks, one 90-day RCRA container building, and various land disposal units (one RCRA waste pile, two closing surface impoundments, and one landfill) High range cost assumptions are for two x 800 MW units model plant - a large T/S/D with exempt tanks, two 90-day RCRA container buildings, and multiple land disposal units (one RCRA waste pile, six closing surface impoundments, and two large landfills)

Work Item Number	Component	Definition of Work	Capital/Initial Cost Estimate Low Range ($)	Capital/Initial Cost Estimate High Range ($)	Ongoing Annual Cost Estimate ($)	Reference
7a	Notification Requirements	Owner/operator (o/o) notification under 40 CFR §262 12. [Costs as in Table 3-4 of reference (2), updated to 2010 dollars.]	328	329	110	(3) , and (4)
7b	Pt A Permit Application	O/o of a T/S/D facility must obtain a permit and must submit the information required in the RCRA Hazardous Waste Part A Permit Application (EPA Form 8700-23) for a first permit application (or for a revised permit application) [40 CFR Part 270] Includes completing the Pt A form, scale drawing, Photos of facility, and topographical map Estimates are from Golder Analysis.	12,100	17,300	Not estimated	(2)
7c	Pt B Permit Application	Used Golder Analysis.	721,000	1,020,000	Not estimated	(2)
7d	Permit Fees	Regulatory agencies charge permit application fees to cover the costs of hazardous waste permit processing (Low is based on Texas (75 surface acre, 6 unit facility) and high is based on California HW Land Disposal permit)	15,000	548,260	Not estimated	(5)
7e	General Waste Analysis, Land Disposal Restriction (LDR) Waste Analysis, and Written Waste Analysis Plan	Before an o/o treats, stores, or disposes of any hazardous wastes, he must obtain a detailed chemical and physical analysis of a representative sample of the wastes that covers all information needed to treat, store, or dispose of the waste in compliance with parts 264 and 268 [§264 13] General Analysis - $1836 (3 wastes @ 3 analysis each /waste x $204/analysis for parameters not covered in TCLP); LDR analysis - $12,222 (3 wastes @ 3 analysis each /waste x $1358) for UTS standards Labor = ($715 50) 3 events, 4 5 hr/event @ $ 53/hr [Recurring costs - LDR analysis & labor only]	14,774	14,774	12,938	(3) and (4)

7f	Written Inspection Schedule	The o/o must develop and follow a written schedule for inspecting monitoring equipment, safety and emergency equipment, security devices, and operating and structural equipment (such as *dikes and sump pumps) that are important to* preventing, detecting, or responding to environmental or human health hazards [§264 15(b)] [Costs as in Table 3-4 of reference (2), updated to 2010 dollars.]	1,312	1,312	1.384	(3) and (4)
7g	Personnel Training	The training program must ensure that personnel are able to respond emergencies [§264 16] [From reference (2) in 2010 dollars: cost to develop & document training = $2740; From reference (1) in 2010 dollars: cost per person for 40 hr training = $578; cost per person for 8 hr training = $210] Not including training development, cost of annual personnel training for 200 MW plant = $15,806 (Assumes 63* workers/site of which 1 env mgr, 4 env staff, 2 shift superv receive 40 hr training while remainder receiving 8 hr training.) Not including training development, cost of annual personnel training for 800 MW plant = $45,208 (Assumes 196* workers/site of which 1 env mgr, 6 env staff, 4 shift superv /mgrs receive 40 hr training while remainder receiving 8 hr training) Recurring costs = the cost of annual training which ranges from $15,806 to $47,948 * Reference (4)	18.546	47,948	range	(1) , (4), & (5)
7h	*Emergency Response Plan*	Amend Facility Emergency Reponses plan to include RCRA provisions (e eg, Emergency *coordinator, Arrangements wi* Local Authorities, Emergency Equipment , etc) [§264 32, 34, 37, 55] [Costs as in page 3, reference (1), updated to 2010 dollars.]	2,629	2,629	Not estimated	(1) and (4)
7i	Contingency Plan	Contingency plan must minimize hazards to human health or the environment from fires, explosions, or any unplanned sudden or non-sudden release of hazardous waste or hazardous waste constituents to air, soil, or surface water [§264 51] [Costs as in page 3, reference (1), updated to 2010 dollars.]	2,629	2,629	Not estimated	(1) and (4)

7j	Biennial Report Preparation	Generator shipping any hazardous waste off-site to any t/s/d facility within the U S must prepare and submit a single copy of a Biennial Report on EPA Form 8700–13A by March 1 of each even numbered year [§262 41] [Costs as in Table 3-4 of reference (2), updated to 2010 dollars.]	0	0	875	(3) and (4)
7k	Operating Record	O/o must keep a written operating record at his facility (details of waste generation, management & disposal; analytical results; determinations ; records; reports; closure estimates; etc) [Costs as in Golder Analysis]	41,000	47,000	41,000 - 47,000	(2)
7l	Groundwater Monitoring Plan	Assumes Ground Water Monitoring Plan with detection monitoring for two impoundments, a RCRA waste pile, and one landfill [§264, Subpart F] [Costs as in page 3, reference (1), updated to 2010 dollars.]	20,000	30,000	5,400	(2)
7m	Groundwater Sampling	[§264, Subpart F] **Assumes wells in place already for 50% of plants and that data**	347,000	445,000	range	(2)
7n	Closure and Post-Closure Plans	O/o must have a written closure plan / pot closure plan The model plants will require closure plans for all RCRA units In addition, post -closure plans will be required for all land disposal units (surface impoundments, waste piles, landfills) §264 112, 118] Model plants include several land disposal units and 1997s cost estimate ($28,980) assumes just one landfill URS professional experience added 50 % to cost estimate for low range value and 75% to cost estimate for high estimate prior to inflation calculation to account for increased complexities at model plants	125,000	142,200		(2)
7o	Closure Certification	Assumes surface impoundments will be closed at different times - requiring separate closure certifications (2 x $12,617 up to 6 x $12,617) [§264 115] [Costs as in page 3, reference (1), updated to 2010 dollars.]	108,000	147,000	0	(2)
7p	Financial Assurance for Closure and Post-Clo	O/o must establish financial assurance for closure/ post closure care of the facility [§264 143, 145] [Costs as in Table 3-4 of reference (2), updated to 2010 dollars.]	67,916	67,916	56,099	(3) and (4)

7q	Financial Assurance for Third Party Liability Coverage	O/o must have and maintain liability coverage for sudden accidental occurrences in the amount of at least $1 million per occurrence with an annual aggregate of at least $2 million. exclusive of legal defense costs [§264 147] [Costs as in Table 3-4 of reference (2), updated to 2010 dollars]	108,666	108,666	101,874	(3) and (4)
7r	Corrective Action Schedule	O/o seeking a permit must institute corrective action (CA) as needed for all releases of hazardous waste or constituents from any solid waste management unit CA is to be specified in the permit and addressed by schedules if it isn't completed before permit issuance [§264 101] [Costs as in Table 3-4 of reference (2). updated to 2010 dollars.]	1,312	1,312	656	(1) and (4)
7s	Corrective Action: Facility Assessments/Investigations	2007 State agency calculation for RCRA remediation costs = $ 20, 497 per RFA and $ $75,883 for RFI updated to 2010 dollars.	750,000	3,500.000	Not Estimated	(2)and (6)
7t	Additional Operation and Maintenance Staff focused on CCR Housekeeping	40 CFR 264/ 265 196 - Stop flow of wastes into 2ndary containment & remove wastes within 24 hrs Assumes maintenance staff will increase by 35 %. From URS professional judgment: maintenance staff of small model plant = increase of 8 workers; maintenance staff of large plants = increase of 26 workers From Bureau of labor statistics: Env Eng Tech @ $ 21.99 mean ($45,730 annual) plus 50 % fringe and 67% of combined salary & fringe for overhead & profit = $160, 875 /yr loaded costs per worker	1,287,000	4,182,750	966,000 - 4,350.000	
		TOTAL COSTS	**$3,644,212**	**$10,327,025**	**$179,336**	(5)

References: (1) - September 10, 2007 Memorandum: "Revised Prices for Calulating Environmental Benefit," from Michael X Redig, Hazardous Waste Regulation Section, Tallahassee (FL); (2) October 28, 2010 analysis by Golder Associates, Inc (Golder Analysis) of draft Table 4-7 that suggested several revisions based upon their actual data /experiences with like facilities if the costs deviated by more than 35%, (3) - "Estimating Costs for the Economic Benefits of RCRA Non-Compliance," USEPA, September 1997, December 1997 Update; (4) Inflation calculator: http://www usinflationcalculator com/inflation/current-inflation-rates/ as applied the week of September 13,2010; (5) URS professional judgment; and (6) EPA, April 30, 2010, *"Regulatory Impact Analysis For EPA's Proposed RCRA Regulation Of Coal Combustion Residues (CCR) Generated by the Electric Utility Industry."*

Cost Methodology: Where available, used the applicable information from reference (1) as modified by reference (3), or 5 1% , using 2007 as starting time and 2010 as ending time for reference (3) as of week of September 13, 2010 For other items, used estimates and methods (estimated level of effort in hrs by labor categories) from reference (2) as modified by reference (3). When using reference (2), the costs represent fully loaded costs (including fringe benefits,labor overhead and profit estimates). Where ranges were presented in cost references and/ or where engineering assumptions were made - URS relied on professional judgment gained from experience in its consulting practise

The Electric Power Research Institute, Inc. (EPRI, www.epri.com) conducts research and development relating to the generation, delivery and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety and the environment. EPRI also provides technology, policy and economic analyses to drive long-range research and development planning, and supports research in emerging technologies. EPRI's members represent more than 90 percent of the electricity generated and delivered in the United States, and international participation extends to 40 countries. EPRI's principal offices and laboratories are located in Palo Alto, Calif.; Charlotte, N.C.; Knoxville, Tenn.; and Lenox, Mass.

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Program:

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Coal Combustion Product Use

1020557

Electric Power Research Institute
3420 Hillview Avenue, Palo Alto, California 94304-1338 • PO Box 10412, Palo Alto, California 94303-0813 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

Request No. 13

Explain in detail how Ms. Wilson modeled Big Rivers' debt structure when assuming retirement of the existing fleet and construction of new natural gas combined cycle (NGCC) units?

a. How would retiring Big Rivers' entire fleet affect Big Rivers' financial statements and equity as a percentage of assets?

b. How was Big Rivers' current debt modeled?

c. What sort of financing was assumed given Big Rivers' current debt structure and the additional amount of debt required when constructing new NGCC units?

d. What is the additional amount of debt required to build new NGCC units?

e. What interest rate was assumed on the new debt?

Response to Request No. 13 - Respondent: Rachel Wilson

The modeling performed did not take into account debt structure. To model debt we followed the Company in using a debt rate of 5.5%, which was taken directly from the Coupon Rate used in the Debt tab of the "Financial Forecast (2012-2026) Build 03-08-2012.xlsx"spreadsheet, supplied by the Company and contained in the "April 26 CD Information filed in Resp to Motion to Dismiss" folder on the USB drive Big Rivers filed confidentially on June 14, 2012.

a. See response to primary question, above.

b. See response to primary question, above.

c. See response to primary question, above.

d. See response to primary question, above.

e. See response to primary question, above.

Request No. 14

Please refer to Exhibit RW-3. That exhibit is a study entitled, "EEI Preliminary Reference Case and Scenario Results." At the bottom of each page of that study is a notice that states, "EEI CONFIDENTIAL BUSINESS INFORMATION: Do Not Cite, Quote or Distribute." Each page of the study, except the cover page, also includes a notice of ICF International's copyright.

a. What rights or authority does Sierra Club have to copy, cite, quote, and distribute the study? Please provide all evidence of such rights or authority.

b. Please provide the business contact information for each person who provided the study to Sierra Club or who Sierra Club contacted to obtain the right or authority to copy, cite, quote, and distribute the study.

Response to Request No. 14 - Respondent: Rachel Wilson

Senator Voinovich put the study in the public record during the U.S. Senate Committee on Environment and Public Works' hearing on U.S. EPA's proposed Clean Air Transport Rule in July 2010. The study is now also publicly available at the following website: http://grist.s3.amazonaws.com/eparegs/icf-eei_scenario_results_21may2010.pdf

Request No. 15

Please provide all emails, memos, and other documents, sent by Sierra Club to the Kentucky Attorney General, Ventyx, or KIUC since January 1, 2012.

Response to Request No. 15 - Respondent: Kristin Henry, Sierra Club Counsel

Sierra Club objects to this requests to the extent it seeks emails, memos, or other documents that are not relevant to this proceeding. Subject to and without waiving the foregoing objection, responsive documents are attached.

REQUEST 1-15

Attachment 1

SIERRA CLUB

KIUC's 1st Set of Data Requests to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:21 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, May 21, 2012 at 1:07 PM
Subject: KIUC's 1st Set of Data Requests to BREC, Docket No. 2012-00063
To: "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Quang D. Nguyen" <QuangD.Nguyen@ky.gov>, "Faith B. Burns" <faith.burns@ky.gov>, "Richard G. Raff" <richard.raff@ky.gov>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>
Cc: "dbrown@stites.com" <dbrown@stites.com>, Kurt Boehm <KBoehm@bkllawfirm.com>

Counsel, attached please find the KENTUCKY INDUSTRIAL UTILITY CUSTOMERS INC's FIRST SET OF DATA REQUESTS TO BIG RIVERS ELECTRIC CORPORATION in .Word and .Pdf format for filing in the above-referenced matter. Hard copies will follow by regular, U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

1st Set of Data Request to BREC.pdf
167K

1st Set of Data Requests.docx
36K

Fwd: Attorney General's Initial Data Requests

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:21 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Cook, Larry (KYOAG)** <larry.cook@ag.ky.gov>
Date: Mon, May 21, 2012 at 1:23 PM
Subject: Attorney General's Initial Data Requests
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Jim Miller <jmiller@smsmlaw.com>
Cc: dbrown@stites.com, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, joe@jchilderslaw.com, childerslaw@yahoo.com, kristin.henry@sierraclub.org, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, Kurt Boehm <KBoehm@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>

ALL,

Please find attached the Attorney General's initial requests to BREC. The original and hard copies were filed with the Commission just a few moments ago. A Word copy is being sent to Jim Miller under separate cover.

Yours,

Larry

OAG_Initial DRs_2012-00063.pdf
1379K

SIERRA CLUB

Big Rivers KPSC Case No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:20 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
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85 Second Street
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---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Wed, May 23, 2012 at 10:42 AM
Subject: Big Rivers KPSC Case No. 2012-00063
To: Michael Kurtz <MKurtz@bkllawfirm.com>, jmiller@smsmlaw.com, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, James Giampietro <james.giampietro@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, tkamuf@smsmlaw.com, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>
Cc: dbrown@stites.com, Kurt Boehm <KBoehm@bkllawfirm.com>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>

Counsel:

For future reference, please include Assistant Attorneys General Larry Cook and Matt James on your email distribution/service lists regarding this matter.

Larry.Cook@ag.ky.gov

Matt.James@ag.ky.gov

Thank you.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

SIERRA CLUB

Fwd: KIUC correspondence to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:20 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
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85 Second Street
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415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, May 25, 2012 at 11:19 AM
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063
To: Jim Miller <jmiller@smsmlaw.com>
Cc: "dbrown@stites.com" <dbrown@stites.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "joe@jchilderslaw.com" <joe@jchilderslaw.com>, "childerslaw@yahoo.com" <childerslaw@yahoo.com>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, Kurt Boehm <KBoehm@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Albert Yockey <Albert.Yockey@bigrivers.com>

Jim.

I understand. Thank you for considering our request. We will move forward with licensing the model from Ventyx, and obtaining from Aces the data necessary to run the model and reproduce the results produced by Aces. We assume there will be no problems or delays pursuing this avenue. If there are, we may need to revisit the issue.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Friday, May 25, 2012 12:14 PM
To: Michael Kurtz
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey

Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Mike:

Big Rivers has considered the request in your e-mail message of yesterday that Big Rivers allow and arrange for your consultant to go to the offices of Big Rivers' consultants, and have Big Rivers' consultants conduct runs of the models they are using in their engagements with Big Rivers to develop cases based upon KIUC's preferred assumptions. Big Rivers is unwilling to agree to that request for a number of reasons. Big Rivers has provided and continues to provide vast amounts of information to the Commission staff and the intervenors well in advance of the due date for Big Rivers' responses to the first information requests.

Jim

James M. Miller

Sullivan, Mountjoy, Stainback & Miller, P.S.C.

100 St. Ann Street

P.O. Box 727

Owensboro, KY 42302-0727

Telephone (270) 926-4000

Direct Dial (270) 691-1640

Fax (270) 683-6694

CONFIDENTIALITY STATEMENT:

This message from the law firm of Sullivan, Mountjoy, Stainback & Miller, P.S.C. contains information which is privileged and confidential, and is solely for the use of the intended recipient. If you are not the intended recipient, be aware that any review, disclosure, copying, distribution, or use of the contents of this message is strictly prohibited. If you have received this in error, please immediately destroy it and notify us at (270) 926-4000.

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Thursday, May 24, 2012 3:13 PM
To: Jim Miller
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Thanks Jim.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Thursday, May 24, 2012 4:12 PM
To: Michael Kurtz
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Mike,

I just picked up your message. We will discuss this and I will get back to you as quickly as I can.

Jim

-----Original Message-----
From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Thu 5/24/2012 10:33 AM
To: Jim Miller
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Jim.

As you are aware, Phil Hayet with Hayet Power Systems Consulting has been investigating requirements to obtain the same models and data that were used by Big Rivers' outside consultants, ACES Power Marketing ("ACES") and Pace Global ("Pace"), in order to be able to reproduce the results developed for this proceeding, as well as to create new results of our own. After having spoken with Christian Whitaker at Pace Global, John Sturm at ACES, and Julie Albright and Brenton Meece at Ventyx (developer of the PAR model used by ACES), Mr. Hayet has concluded that our first priority would be to gain access to the PAR model, although he has not ruled out the possibility that he would want to be able to re-run some cases performed by PACE using the Aurora model.

Based on discussions with Ventyx, Mr. Hayet is aware that the cost of a three month license of PAR would be approximately $30 thousand dollars. While this may be the route that we ultimately choose, we also want to explore the possibility of Mr. Hayet being permitted to go onsite to ACES' office for the purpose of working one-on-one with ACES' modeling staff to develop cases based on our preferred assumptions. Mr. Hayet has done that before and that has been both a cost effective and expedient approach for other projects of a similar nature. While we have been able to gain a basic understanding of the modeling work that was performed by ACES and Pace, there are still some gaps that we hope will be filled in after our discovery is answered. At that point we should know whether we will need to run both models. If so, we may need permission to go to access and run the models at both ACES and Pace's offices due to the time constraints of the procedural schedule and the cost-effectiveness of this approach compared to acquiring licenses directly.

Thus we request that you contact both ACES and Pace to identify dates during which Mr. Hayet could make one or two on-site visits at each of their offices for a 2 - 3 day period at each office to conduct our analyses using their models and databases. At this time, we believe that the most likely course will be a single visit by Mr. Hayet to the ACES' office for a 2 - 3 day period. We propose dates of June 11 through 13 for this purpose as there is limited time between when the first round of discovery will be answered and delivered to us and when our second set of questions are due.

As mentioned in our letter from May 11, the short time frame of this proceeding requires that we obtain access to this data and the models, as soon as possible, and at this stage we are only aware of the cost to license the PAR model. We are still having discussions with John Sturm at ACES regarding requirements to be able to obtain the database that ACES used, in the event that we decide to license the PAR model ourselves. This additional information concerning the requirements necessary to instead be able to go on-site to ACES' office (and possibly Pace's office) to conduct the modeling runs with their assistance would be helpful in making our final decision about how to proceed.

As stated in our last letter, we can arrange to have a conference call with Company and/or consultant/contractor personnel to expedite this process. We would appreciate a quick response to this letter given the limited time available.

Thanks

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Friday, May 18, 2012 4:34 PM
To: Michael Kurtz
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Mike:

We have been working since receiving your message of last week to assemble the information you requested. At this point we can provide the following information about access to the models employed by Big Rivers' consultants in conducting their analyses. The data compilation of all input files, output files, assumptions, and other requested data is underway.

Response from ACES Power Marketing ("APM")

APM used the Ventyx Planning and RISK model. We understand that its license agreements indicate that it cannot release the licensed software or any proprietary Ventyx information. KIUC may contact Ventyx and request the cost and installation requirement by calling Julie Albright at 832-553-0880.

Response from Pace Global

The model used by Pace Global is a product of EPIS, Inc. called AuroraXMP, commonly referred to as Aurora. Aurora is an hourly merit-order dispatch simulator that calculates hourly dispatch for integrated grid operations. A license is required to use the Aurora model. Pace Global's contact at EPIS is Deborah Austin Smith. http://epis.com/aurora_xmp/power_forecasting.php. Their formal contact address is EPIS, Inc., 1800 Blankenship Road Suite 350, West Linn, OR 97068. Phone: (503) 722-2023.
In addition, Pace Global has made several proprietary modifications to the leased Aurora model in order to enhance and improve its inherent capabilities. These modifications are confidential and proprietary, however, they can be leased from Pace Global in order to facilitate a simulation by a third party for their exclusive internal use. Licensing restrictions are based on the intended use, distribution, and access requirements of the user. To facilitate use of Aurora, Pace Global can provide input data tables in Aurora database format if necessary.

Pace Global can provide documentation and instructions on the use of its proprietary modifications to the Aurora model should third parties wish to license it. The Aurora model contains integrated instructions documentation for licensed users and can be obtained directly from the Licensor, EPIS. The contact at PACE Global is Christian Whitaker, Christian.Whitaker @PaceGlobal.com, (703) 227-1036.

Response from Sargent & Lundy

Sargent & Lundy tells us that their model is an Excel spreadsheet that can be provided without licensing.

We would expect to provide most of the production input data under a petition for confidential treatment. I think we already have confidentiality coverage for several members of the KIUC and Attorney General teams, and I have e-mailed the form of confidentiality agreement to Joe Childers for Sierra Club and Ben Taylor.

Jim

James M. Miller
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St. Ann Street
P.O. Box 727

Owensboro, KY 42302-0727
Telephone (270) 926-4000
Direct Dial (270) 691-1640
Fax (270) 683-6694

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Friday, May 18, 2012 1:58 PM
To: Jim Miller
Cc: 'dbrown@stites.com'; 'Hans, Jennifer (KYOAG)'; 'Howard, Dennis (KYOAG)'; 'Cook, Larry (KYOAG)'; 'joe@jchilderslaw.com'; 'Joe Childers (childerslaw@yahoo.com<mailto:childerslaw@yahoo.com>)'; 'kristin.henry@sierraclub.org'; 'Nguyen, Quang D (PSC)'; 'Burns, Faith (PSC)'; Kurt Boehm; Tyson Kamuf
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Jim.

It has been a week since I sent you the attached letter seeking information on how the KIUC experts can have access to the computer models relied upon by Big Rivers. We are preparing our data requests that will be served Monday, and I want to direct your attention to this matter again.

In the recent Kentucky Power ECR case, the experts for Sierra Club had difficulty obtaining the computer models relied upon by AEP. Sierra Club was forced to file a motion to compel. We want to avoid those types of problems here. Also, we want to keep this case on track and not be required to seek amendment of the procedural schedule.

Your assistance is appreciated.

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com<mailto:mkurtz@BKLlawfirm.com>

From: Michael Kurtz
Sent: Friday, May 11, 2012 2:33 PM
To: Jim Miller
Cc: dbrown@stites.com<mailto:dbrown@stites.com>; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); 'joe@jchilderslaw.com'; 'Joe Childers (childerslaw@yahoo.com<mailto:childerslaw@yahoo.com>)'; kristin.henry@sierraclub.org<mailto:kristin.henry@sierraclub.org>; Nguyen, Quang D (PSC); 'Burns, Faith (PSC)'; Kurt Boehm
Subject: KIUC correspondence to BREC, Docket No. 2012-00063

Please see attached letter regarding the above-referenced docket. Please advise if you have any problems opening.

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
MKurtz@BKLlawfirm.com<mailto:MKurtz@BKLlawfirm.com>

SIERRA CLUB

Fwd: FW: ACES

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:49 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jun 11, 2012 at 12:28 PM
Subject: FW: ACES
To: Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Michael Kurtz
Sent: Monday, June 11, 2012 1:17 PM
To: 'Jim Miller'
Cc: Tyson Kamuf; Brown, David; Kurt Boehm; Philip Hayet; Lane Kollen
Subject: RE: ACES

Jim.

Phil would be in the best position to answer those technical questions. I don't know.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Monday, June 11, 2012 1:08 PM
To: Michael Kurtz
Cc: Tyson Kamuf; Brown, David; Kurt Boehm; Philip Hayet; Lane Kollen
Subject: RE: ACES

Mike,

I am awaiting the list of conditions from ACES, including a confidentiality agreement, and should probably get those to you before we talk. We are supposed to see that this afternoon. Who will be the licensee of the Ventyx software for KIUC? Are any of the other intervenors or their experts licensed or getting licensed on the software, as far as you know?

Jim

James M. Miller

Sullivan, Mountjoy, Stainback & Miller, P.S.C.

100 St. Ann Street

P.O. Box 727

Owensboro, KY 42302-0727

Telephone (270) 926-4000

Direct Dial (270) 691-1640

Fax (270) 683-6694

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 11, 2012 10:40 AM
To: Jim Miller
Cc: Tyson Kamuf; 'Brown, David'; Kurt Boehm; 'Philip Hayet'; 'Lane Kollen'
Subject: ACES

Jim.

I just listened to your voice mail from Friday afternoon. Just talking with me will do little good about whether the ACES resolution you mentioned will work.

Can you do a conference call today before 12:30 eastern, or after 4:00 eastern to discuss?

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

Fwd: Conference call

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:48 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kristin Henry** <kristin.henry@sierraclub.org>
Date: Mon, Jun 11, 2012 at 1:58 PM
Subject: Re: Conference call
To: "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>

Looks good to me.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
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kristin.henry@sierraclub.org

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On Mon, Jun 11, 2012 at 1:45 PM, Howard, Dennis (KYOAG) <dennis.howard@ag.ky.gov> wrote:

The OAG is fine with all the suggested changes.

Dennis Howard, II
Assistant Executive Director
Office of Rate Intervention
Office of the Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601
502.696.5453
dennis.howard@ag.ky.gov

From: Brown, David [mailto:DBROWN@stites.com]
Sent: Monday, June 11, 2012 4:24 PM

To: Kurt Boehm; Lane Kollen
Cc: Michael Kurtz; Kristin Henry; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Shannon Fisk
Subject: RE: Conference call

Kurt - a few more edits.

David

David C. Brown
Stites & Harbison, PLLC
400 W. Market Street
Suite 1800
Louisville, KY 40202-3352
Direct Dial: (502) 681-0421
Fax: (502) 779-8251
dbrown@stites.com

From: Kurt Boehm [mailto:KBoehm@bkllawfirm.com]
Sent: Monday, June 11, 2012 4:01 PM
To: Kurt Boehm; 'Lane Kollen'; Brown, David
Cc: Michael Kurtz; 'Kristin Henry'; 'Cook, Larry (KYOAG)'; 'Philip Hayet'; 'Hans, Jennifer (KYOAG)'; 'Howard, Dennis (KYOAG)'; 'Shannon Fisk'
Subject: RE: Conference call

As discussed on the call, a revised Motion for Stay is attached. We intend to file this by the end of the

day.

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

office: 513-421-2255

mobile: 513-290-6683

fax: 513-421-2764

From: Kurt Boehm
Sent: Monday, June 11, 2012 1:58 PM
To: 'Lane Kollen'; Brown, David
Cc: Michael Kurtz; Kristin Henry; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Shannon Fisk
Subject: RE: Conference call

Counsel- In advance of the 3:00 call, please review KIUC's draft of a Motion to Stay the procedural schedule until BREC has answered the first set of DRs. We would like to discuss the possibility of making this a joint motion.

Thanks

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

office: 513-421-2255

mobile: 513-290-6683

fax: 513-421-2764

From: Lane Kollen [mailto:lkollen@jkenn.com]
Sent: Monday, June 11, 2012 1:33 PM
To: Brown, David

Cc: Michael Kurtz; Kristin Henry; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Kurt Boehm; Shannon Fisk
Subject: Re: Conference call

Okay w me.

Lane

On 6/11/2012 1:30 PM, Brown, David wrote:

OK with me.

David Brown

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 11, 2012 1:26 PM
To: 'Kristin Henry'
Cc: Lane Kollen; Brown, David; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Kurt Boehm; Shannon Fisk
Subject: RE: Conference call

Fine with me.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Monday, June 11, 2012 1:23 PM
To: Michael Kurtz
Cc: Lane Kollen; Brown, David; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Kurt Boehm; Shannon Fisk
Subject: Re: Conference call

I am not available until later in the day. Can we do 3:00 eastern.

On Jun 11, 2012 6:28 AM, "Michael Kurtz" <MKurtz@bkllawfirm.com> wrote:

A conference call to discuss BREC's response to our joint motion is in order. How about this afternoon at 2:00 eastern?

866-906-9888 pass code 518-4986

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

Fwd: FW: KIUC discovery issue

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:40 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kristin Henry** <kristin.henry@sierraclub.org>
Date: Tue, Jun 12, 2012 at 12:31 PM
Subject: Re: FW: KIUC discovery issue
To: Kurt Boehm <KBoehm@bkllawfirm.com>
Cc: Shannon Fisk <sfisk@earthjustice.org>, Philip Hayet <philhaye@concentric.net>, Michael Kurtz <MKurtz@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>

We can confirm that I am seeing the same problems with 1a, 2a, 2b, 3, and 5 listed below. However, I cannot comment on the others at this point.

Kristin Henry
Staff Attorney
Sierra Club
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415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

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On Tue, Jun 12, 2012 at 8:58 AM, Kurt Boehm <KBoehm@bkllawfirm.com> wrote:
>
> Shannon and Kristin- Phil Hayet asked me if you would confirm with your consultants that they are having the same issues (described below) with Big Rivers' data?
>
>
>
> Thanks
>
>
>
> Kurt J. Boehm, Esq.
>
> BOEHM, KURTZ & LOWRY
>
> 36 East Seventh Street, Suite 1510
>
> Cincinnati, Ohio 45202
>
> office: 513-421-2255
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> mobile: 513-290-6683
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> fax: 513-421-2764
>
>
>
> From: Kurt Boehm
> Sent: Monday, June 11, 2012 5:40 PM
> To: 'Jim Miller'; 'tkamuf@smsmlaw.com'
> Cc: Michael Kurtz; 'Brown, David'; Philip Hayet; Lane Kollen
> Subject: KIUC discovery issue
>
>
>
> Jim and Tyson-
>
> KIUC's consultants have identified several problems with the data supplied by Big Rivers in response to KIUC's First Set of Data Requests. Please address these problems at the earliest possible time.
>
> Below is a description of each problem followed by KIUC's requested action by Big Rivers to rectify the problem:
>
> 1. The April 26, 2012 CD provided input and output data associated with the Company's Financial Models. The following problems were encountered. The Company's Base Case Financial Model was found in:

>
> Financial Forecast (2012-2026) Base Case (No Env. Comp.) 02-.xls
>
> a) As stated in KIUC's Question 1 from our first set of DRs, some of the cell entries in the Financial Model spreadsheet point to spreadsheets that were not supplied. Question 1 requested the Company to supply all spreadsheets that were referenced but had not been supplied to that point. For example, the Worktab PCM, Cell N77 in the above file pointed to another spreadsheet (Big Rivers 2012-2026 (CAIR) Base Case exhibits determin (2-2-12).xlsx) that was not provided. That cell referenced market price data for the month of Jan 2012. BR's DR response stated "Please see the CD Big Rivers filed May 29, 2012, in response to the May 11, 2012, letter from KIUC's counsel to Big River's counsel." The May 29th CD still did not contain the referenced spreadsheets, and it was not clear what file on the May 29th CD BR wanted us to refer to.
>
> b) However, production cost results were supplied by ACES on the May 24 CD in other files that can be matched up to some degree to the results found in the Financial Model spreadsheets. For example, the file associated with the Base Case from May 24th is Big Rivers.15Year.CAIR Base Case.xlsm.
>
> c) Still there are some values in the Base Case Financial Model spreadsheet that cannot be matched precisely. For example, VO&M and SO2 Tons do not appear to match exactly. Most likely it is because ACES performed some calculation in the spreadsheets that we were not given, most likely related to splitting out costs and other results between Big Rivers and Henderson Municipal Power and Light. Without the missing spreadsheets, we don't know all of the additional calculations that ACES performed.
>
> KIUC Request: Please direct KIUC to the referenced spread sheets or properly comply with KIUC Q1.1 and supply all other spreadsheets that were referenced from within each of the Financial Model spreadsheets.
>
> 2) PACE Global supplied two of the files that were on the May 29th CD, and one could not be opened properly:
>
> PACE_Big Rivers Data Request Outputs_120524.xlsx
>
> a) An error message appeared in trying to open this file indicating that Excel found unreadable content in the file. After allowing Excel to try to recover from this error, Excel reported a message stating, "Replaced Part: /xl/worksheets/sheet3.xml part with XML error. The name in the end tag of the element must match the element type in the start tag. Line 2, column 17076013.
>
> b) After that message went away the file opened, two worktabs were found in the spreadsheet:
>
> Output Stochastic Energy Prices- This contains annual market price values ($/MWH - onpeak, offpeak, all hours) for 200 iterations for the years 2012 - 2030. It is not clear what the iterations were and how this information was factored into the evaluations that ACES performed, and there is no documentation that explains that. It would be more clear if ACES gave us fully populated input database files.
>
> Output Hourly Energy Prices - This worktab was completely blank. It is possible that it was blank because of the error that was encountered in opening the file.
>
> KIUC Request: Please re-send a working file PACE_Big Rivers Data Request Outputs_120524.xlsx, which includes market price data.
>
> 3. It appears that the file ACES used containing market price data was - Copy of 2012-26 hrly energy price forecast for PCM (1-18-12) nominal.xlsx. However, there was a problem with this file, as it was unreadable, and Excel indicated that the file was corrupted and could not be opened.
>
> KIUC Request: Please resend a working file.
>
> 4. It appears that the Company did not supply the ACES input assumptions and output results for the Buy and Buy No Smelter Load cases.
>

> There is a very specific Excel spreadsheet for each of the two cases that appear to be missing, and some associated folders appear to be missing.
>
> a) For the "Buy" case, the spreadsheet missing is Big Rivers.15Year.CSAPR By Gen.VarLimits.xlsm.
>
> b) For the "Buy No Smelter Load" case, the spreadsheet missing is Big Rivers.15Year.CSAPR By Gen.VarLimits NoSmelters.xlsm
>
> KIUC Request: For each of those cases, please provide either the location or a working file with the associated folders identified as Assumptions, Data, and Exhibits. There appears to be two files supplied that are very close in the name to the above spreadsheet names, but not identical. KIUC is concerned that unless we have files with the exact name, we may not be looking at the correct files.
>
> 5. On the CD supplied May 29, 2012, Big Rivers supplied the following file - (C-M by eq) sens 2 exh. det. Rev 1 no smltrs 021412.xlsx - This file can't be opened, first Excel reported it had unrecoverable data, then Excel stated it was corrupt.
>
> KIUC Request: Please supply a working file.
>
>
>
> Thank you in advance for your efforts in rectifying this situation.
>
> Kurt
>
>
>
> Kurt J. Boehm, Esq.
>
> BOEHM, KURTZ & LOWRY
>
> 36 East Seventh Street, Suite 1510
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> Cincinnati, Ohio 45202
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> mobile: 513-290-6683
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> fax: 513-421-2764
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>

SIERRA CLUB

Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:43 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
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415.977.5716 phone
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kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kurt Boehm** <KBoehm@bkllawfirm.com>
Date: Tue, Jun 12, 2012 at 8:56 AM
Subject: RE: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063
To: "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>
Cc: "dbrown@stites.com" <dbrown@stites.com>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>

I am forwarding the below email to the parties prior to the 2pm call because it may come up in our discussion.

Kurt

From: Kurt Boehm
Sent: Monday, June 11, 2012 5:40 PM
To: 'Jim Miller'; 'tkamuf@smsmlaw.com'
Cc: Michael Kurtz; 'Brown, David'; Philip Hayet; Lane Kollen
Subject: KIUC discovery issue

Jim and Tyson-

KIUC's consultants have identified several problems with the data supplied by Big Rivers in response to KIUC's First Set of Data Requests. Please address these problems at the earliest possible time.

Below is a description of each problem followed by KIUC's requested action by Big Rivers to rectify the problem:

1. The April 26, 2012 CD provided input and output data associated with the Company's Financial Models. The following problems were encountered. The Company's Base Case Financial Model was found in:

Financial Forecast (2012-2026) Base Case (No Env. Comp.) 02-.xls

a) As stated in KIUC's Question 1 from our first set of DRs, some of the cell entries in the Financial Model spreadsheet point to spreadsheets that were not supplied. Question 1 requested the Company to supply all spreadsheets that were referenced but had not been supplied to that point. For example, the Worktab PCM, Cell N77 in the above file pointed to another spreadsheet (Big Rivers 2012-2026 (CAIR) Base Case exhibits determin (2-2-12).xlsx) that was not provided. That cell referenced market price data for the month of Jan 2012. BR's DR response stated "Please see the CD Big Rivers filed May 29, 2012, in response to the May 11, 2012, letter from KIUC's counsel to Big River's counsel." The May 29th CD still did not contain the referenced spreadsheets, and it was not clear what file on the May 29th CD BR wanted us to refer to.

b) However, production cost results were supplied by ACES on the May 24 CD in other files that can be matched up to some degree to the results found in the Financial Model spreadsheets. For example, the file associated with the Base Case from May 24th is Big Rivers.15Year.CAIR Base Case.xlsm.

c) Still there are some values in the Base Case Financial Model spreadsheet that cannot be matched precisely. For example, VO&M and SO2 Tons do not appear to match exactly. Most likely it is because ACES performed some calculation in the spreadsheets that we were not given, most likely related to splitting out costs and other results between Big Rivers and Henderson Municipal Power and Light. Without the missing spreadsheets, we don't know all of the additional calculations that ACES performed.

KIUC Request: Please direct KIUC to the referenced spread sheets or properly comply with KIUC Q1.1 and supply all other spreadsheets that were referenced from within each of the Financial Model spreadsheets.

2) PACE Global supplied two of the files that were on the May 29th CD, and one could not be opened properly:

PACE_Big Rivers Data Request Outputs_120524.xlsx

a) An error message appeared in trying to open this file indicating that Excel found unreadable

content in the file. After allowing Excel to try to recover from this error, Excel reported a message stating, "Replaced Part: /xl/worksheets/sheet3.xml part with XML error. The name in the end tag of the element must match the element type in the start tag. Line 2, column 17076013.

b) After that message went away the file opened, two worktabs were found in the spreadsheet:

Output Stochastic Energy Prices- This contains annual market price values ($/MWH - onpeak, offpeak, all hours) for 200 iterations for the years 2012 - 2030. It is not clear what the iterations were and how this information was factored into the evaluations that ACES performed, and there is no documentation that explains that. It would be more clear if ACES gave us fully populated input database files.

Output Hourly Energy Prices - This worktab was completely blank. It is possible that it was blank because of the error that was encountered in opening the file.

KIUC Request: Please re-send a working file PACE_Big Rivers Data Request Outputs_120524.xlsx, which includes market price data.

3. It appears that the file ACES used containing market price data was - Copy of 2012-26 hrly energy price forecast for PCM (1-18-12) nominal.xlsx. However, there was a problem with this file, as it was unreadable, and Excel indicated that the file was corrupted and could not be opened.

KIUC Request: Please resend a working file.

4. It appears that the Company did not supply the ACES input assumptions and output results for the Buy and Buy No Smelter Load cases.

There is a very specific Excel spreadsheet for each of the two cases that appear to be missing, and some associated folders appear to be missing.

a) For the "Buy" case, the spreadsheet missing is Big Rivers.15Year.CSAPR By Gen.VarLimits.xlsm.

b) For the "Buy No Smelter Load" case, the spreadsheet missing is Big Rivers.15Year.CSAPR By Gen.VarLimits NoSmelters.xlsm

KIUC Request: For each of those cases, please provide either the location or a working file with the associated folders identified as Assumptions, Data, and Exhibits. There appears to be two files supplied that are very close in the name to the above spreadsheet names, but not identical. KIUC is concerned that unless we have files with the exact name, we may not be looking at the correct files.

5. On the CD supplied May 29, 2012, Big Rivers supplied the following file - (C-M by eq) sens 2 exh. det. Rev 1 no smltrs 021412.xlsx - This file can't be opened, first Excel reported it had unrecoverable data, then Excel stated it was corrupt.

KIUC Request: Please supply a working file.

Thank you in advance for your efforts in rectifying this situation.

Kurt

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

office: 513-421-2255

mobile: 513-290-6683

fax: 513-421-2764

From: Nguyen, Quang D (PSC) [mailto:QuangD.Nguyen@ky.gov]
Sent: Tuesday, June 12, 2012 8:51 AM

To: Michael Kurtz; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; James Giampietro; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG)
Cc: dbrown@stites.com; Kurt Boehm; Raff, Richard (PSC)
Subject: RE: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

The contact number for the informal conference is (502) 564-9110. Conference Access Code: 5643941.

From: Nguyen, Quang D (PSC)
Sent: Tuesday, June 12, 2012 7:50 AM
To: 'Michael Kurtz'; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; 'James Giampietro'; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG)
Cc: dbrown@stites.com; Kurt Boehm; Raff, Richard (PSC)
Subject: RE: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

All –

Please advise as to your availability today at 2pm, EDT, for a telephonic informal conference to discuss the status of the discovery issue and the procedural schedule. I will forward the call in information shortly.

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 11, 2012 5:06 PM
To: jmiller@smsmlaw.com; DeRouen, Jeff (PSC); Nguyen, Quang D (PSC); Burns, Faith (PSC); Raff, Richard (PSC); tkamuf@smsmlaw.com; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; 'James Giampietro'
Cc: dbrown@stites.com; Kurt Boehm
Subject: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

Counsel, attached please find the JOINT MOTION TO STAY PROCEDURAL SCHEDULE of KIUC, SIERRA CLUB and ATTORNEY GENERAL filed in the above-referenced matter. Hard copies will follow by regular, U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

SIERRA CLUB

Fwd: Modeling

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:39 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
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kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kristin Henry** <kristin.henry@sierraclub.org>
Date: Thu, Jun 14, 2012 at 4:48 PM
Subject: Modeling
To: Michael Kurtz <MKurtz@bkllawfirm.com>

Hi Mike

I talked to Synapse and, on further thought, they decided that we do not need to have access to the modeling files for this case. Sierra Club doesn't have enough money to pay for modeling this time, so they said that it is okay if they don't see the files. They said that they have been talking to Phil and will continue to talk to Phil about possible approaches to re-running the model.

Thanks for even considering my request.

Kristin Henry
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kristin.henry@sierraclub.org

SIERRA CLUB

KIUC's Supplemental Data Requests to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:36 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
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kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, Jun 22, 2012 at 1:54 PM
Subject: KIUC's Supplemental Data Requests to BREC, Docket No. 2012-00063
To: "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>
Cc: Kurt Boehm <KBoehm@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Jody Kyler <jkyler@bkllawfirm.com>, "sbaron@jkenn.com" <sbaron@jkenn.com>

Counsel, attached pleas find KIUC'S SUPPLEMENTAL SET OF DATA REQUESTS TO BIG RIVERS ELECTRIC CORPORATION in .Word and .Pdf format for filing in the above-referenced matter. Hard copies will follow by regular, U.S. Mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

Supplemental Set of Data Requests FINAL.docx
48K

KIUC Supplemental Data Requests to BREC.pdf
235K

SIERRA CLUB

Docket No. 2012-00063- Status of Discovery Issue

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:34 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
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---------- Forwarded message ----------
From: **Tyson Kamuf** <tkamuf@smsmlaw.com>
Date: Fri, Jun 22, 2012 at 2:01 PM
Subject: RE: Docket No. 2012-00063- Status of Discovery Issue
To: Kurt Boehm <KBoehm@bkllawfirm.com>, Jim Miller <jmiller@smsmlaw.com>
Cc: dbrown@stites.com, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, Jody Kyler <jkyler@bkllawfirm.com>, Philip Hayet <philhaye@concentric.net>, Lane Kollen <lkollen@jkenn.com>

Kurt and Mike:

As you know, we received from you this afternoon the Non-Disclosure Agreement and Non-Disclosure Certificate signed by Phil Hayet. ACES will now provide Mr. Hayet access to the database. ACES thinks the easiest way for Mr. Hayet to access the database is for Ventyx to release the database directly to Mr. Hayet. ACES has already told Ventyx that it can do so. If Mr. Hayet prefers, ACES has also posted the database on a password protected FTP site, and ACES can provide Mr. Hayet the password.

With regard to Kurt's email below, on the June 12 call, we did not agree that ACES would re-run every scenario. ACES did, however, ask Ventyx to use the stripped-down database to run a scenario to verify that the stripping down of the database did not create any errors or eliminate any necessary information. Ventyx did so, and Ventyx's results were within one-tenth of one percent of ACES' results. This fulfills our commitments made on the June 12 call to provide a working database.

Tyson Kamuf

Sullivan, Mountjoy, Stainback & Miller, P.S.C.

100 St. Ann Street, P.O. Box 727

Owensboro, Kentucky 42302-0727

tkamuf@smsmlaw.com

(270) 926-4000

(270) 683-6694 fax

From: Kurt Boehm [mailto:KBoehm@bkllawfirm.com]
Sent: Thursday, June 21, 2012 1:22 PM
To: Jim Miller; Tyson Kamuf
Cc: dbrown@stites.com; Raff, Richard (PSC); 'Nguyen, Quang D (PSC)'; Michael Kurtz; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; James Giampietro; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Jody Kyler; Philip Hayet; Lane Kollen
Subject: Docket No. 2012-00063- Status of Discovery Issue

Jim and Tyson-

This is an update concerning KIUC's effort to get the "stripped down database" from ACES and the PAR model from Ventyx as discussed on the June 12, 2012 conference call with the parties and Staff.

We have been coordinating with Ventyx, given they were doing the work to strip down the database, and we knew

they had been in turn coordinating with ACES. Our assumption is that all of the work is being performed in accordance with the agreement we reached on the June 12 call. Last week, KIUC consultant Phil Hayet coordinated with Ventyx to meet at their offices today, June 21, 2012, to obtain the PAR model and the stripped down database. We assumed that ACES would have given Ventyx the green light to release the stripped down database at that time. This had to be cancelled as details concerning the confidentiality agreement have not been finalized, and work on the database has not been completed as per our agreement from the conference call.

When Mr. Hayet attempted to finalize details yesterday regarding the software and database, he learned that two critical items were still outstanding. 1) Run definitions had not been provided by ACES, and in fact did not exist, and 2) no runs had been performed to evaluate whether or not the stripped down database would reproduce the results that ACES had generated and that were filed in testimony.

With regard to the first item, without the run definitions for each case that ACES performed, neither Ventyx nor Mr. Hayet would be able to know how to recreate the ACES runs. This is because the database has many modeling elements located within it, and a proper run definition is required to select the appropriate subset of elements to create the desired run. As of late yesterday, it was Mr. Hayet's understanding that ACES created some document that they supplied to Ventyx, from which the run definitions could be created.

With regard to the second item, as of late yesterday, no runs had been made to prove that all of the runs that ACES had made previously run could be recreated exactly. While we are certainly hopeful that the runs can be reproduced exactly, problems often crop up with this type of work that have to be worked through, and our agreement with Big Rivers was that the data supplied would definitely reproduce the results ACES had previously produced. That was confirmed by Tyson on the June 12 conference call. The mere fact that ACES had to create a written document to tell Ventyx how to recreate the run definitions means that no runs have been performed to validate that the Big Rivers results could be recreated exactly.

It may be possible that since last night ACES has verified that all of the cases can be successfully reproduced using the stripped down database, however, we are not aware of the status. We still need to be supplied with the database once the appropriate validation has been completed, and we need to re-schedule with Ventyx for installation. We request that Big Rivers provide us with a plan to complete these steps as quickly as possible, if they have not been completed already.

We are aware that the confidentiality agreement must be signed before Mr. Hayet may be provided with the database, and we are working to complete that today.

Thanks,

Kurt

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

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SIERRA CLUB

Case No. 2012-00063 Big Rivers

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:35 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
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---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Fri, Jun 22, 2012 at 2:42 PM
Subject: Case No. 2012-00063 Big Rivers
To: Jim Miller <jmiller@smsmlaw.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, Michael Kurtz <MKurtz@bkllawfirm.com>, Kurt Boehm <KBoehm@bkllawfirm.com>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, joe@jchilderslaw.com
Cc: "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, James Giampietro <james.giampietro@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>

Attached please find the Public Version of the Attorney General's 2nd Set of Data Requests to Big Rivers, which was filed with the PSC yesterday. Hard copies of both the confidential and non-confidential versions were also mailed to the parties on June 21, 2012.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

12-63 brec ag public supp dr.pdf
711K

SIERRA CLUB

Fwd: Hayet Power System Consulting

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:38 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
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Sierra Club
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San Francisco, CA 94105-3441
415.977.5716 phone
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kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, Jun 22, 2012 at 8:20 AM
Subject: RE: Hayet Power System Consulting
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Wayne Harris <WayneH@acespower.com>
Cc: Jim Miller <jmiller@smsmlaw.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, "Brown, David" <DBROWN@stites.com>, Kurt Boehm <KBoehm@bkllawfirm.com>, Jody Kyler <jkyler@bkllawfirm.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, Shannon Fisk <sfisk@earthjustice.org>, Kristin Henry <kristin.henry@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Michael Kurtz
Sent: Friday, June 22, 2012 10:56 AM
To: 'Wayne Harris'
Cc: 'Jim Miller'; 'Tyson Kamuf'; 'Brown, David'; Kurt Boehm; Jody Kyler; Hans, Jennifer (KYOAG); Shannon Fisk; Kristin Henry; Nguyen, Quang D (PSC)

Subject: RE: Hayet Power System Consulting

Mr. Harris.

We took the NDA you sent last night and accepted all changes. We have red lined the attached off of that. You understand that the model outputs will be treated as public, just as Big Rivers has treated the model outputs. We have made clear in the attached that model inputs (such as fuel costs, market price assumptions) used by ACES will only be disclosed to the Commission and to those parties who have signed a confidentiality agreement with Big Rivers.

We trust that this now addresses your concerns.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Wayne Harris [mailto:WayneH@acespower.com]
Sent: Thursday, June 21, 2012 9:35 PM
To: Michael Kurtz
Cc: 'Jim Miller'; 'Tyson Kamuf'
Subject: RE: Hayet Power System Consulting

Mr. Kurtz:

Please find our redline and clean versions of the proposed Non-Disclosure Agreement and Certificate. It is my understanding that the parties to your case have addressed model inputs and outputs in another agreement to

which APM is not a party, or alternatively you may choose to subsequently address those issues within the parameters of your case. Accordingly, APM will not address those matters in this Non-Disclosure Agreement.

Hopefully we have made some progress and will be able to complete this document tomorrow. Please advise me at your earliest convenience.

Sincerely,

Wayne Harris
Chief Counsel
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032
Email: wayneh@acespower.com
Tele.: (317) 344-7017

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Thursday, June 21, 2012 5:12 PM
To: Wayne Harris
Cc: 'Brown, David'; Kurt Boehm; Jody Kyler; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Nguyen, Quang D (PSC); Hans, Jennifer (KYOAG); Shannon Fisk; Kristin Henry
Subject: RE: Hayet Power System Consulting

Mr. Harris.

We respect the desire of ACES to safeguard its proprietary data base. However, you need to recognize that that data base was relied upon by Big Rivers in its environmental surcharge application and the Commission and parties must have reasonable access to it.

We have taken your proposed NDA and have made the attached changes. Fundamentally, Mr. Hayet will be the only person having access to and using the data base. We expect that the model outputs resulting from the data base use will be treated as public information, just as Big Rivers has treated the model outputs. However, we will treat the data base input assumptions such as market price forecasts, fuel prices, etc. as confidential. Such information will only be provided to the Commission and the parties under seal.

We hope that you find the attached NDA acceptable.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Wayne Harris [mailto:WayneH@acespower.com]
Sent: Wednesday, June 20, 2012 6:26 PM
To: Michael Kurtz
Subject: RE: Hayet Power System Consulting

Mr. Kurtz:

I reviewed your proposed Non-Disclosure Agreement and find that certain aspects do not pertain to ACES Power Marketing. We are not a party to this proceeding. Our interests in safeguarding the database that we are willing to provide to your client's consultant are paramount. Our company has expended significant capital in the creation of the database and uses this database as a mechanism for making profits. We therefore regard the database a proprietary and an ACES Power Marketing trade secret. We will require accountability for anyone having access to the database. We are willing to provide the database to the consultant who is licensed by Ventyx to use the PaR software in conjunction with our database. I have designed our Non-Disclosure Agreement to meet these objectives.

Please review this revised version and call me with any questions or concerns.

Sincerely,

Wayne Harris
Chief Counsel
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032
Email: wayneh@acespower.com
Tele.: (317) 344-7017

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]

Sent: Wednesday, June 20, 2012 2:36 PM
To: Wayne Harris
Subject: RE: Hayet Power System Consulting

Mr. Harris.

We have reviewed the Non-Disclosure Agreement you sent yesterday. It is fundamentally different than the Non-Disclosure Agreement between Big Rivers and KIUC, the Attorney General and the Sierra Club in the environmental surcharge proceeding. We have therefore modeled KIUC's agreement with ACES on the Big Rivers Agreement.

The ACES database is central to Big Rivers carrying its burden of proof in this case. The procedural schedule recently adopted by the Commission assumes that the information in the possession of ACES will be provided promptly. We therefore hope to have this worked out with ACES very soon.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Wayne Harris [mailto:WayneH@acespower.com]
Sent: Tuesday, June 19, 2012 12:04 PM
To: Michael Kurtz
Subject: Hayet Power System Consulting

Mr. Kurtz:

I represent ACES Power Marketing LLC. It is my understanding that you are counsel for KIUC and that you or KUIC has retain Phil Hayet of Hayet Power System Consulting with regard to the case currently before the Kentucky Public Service Commission under Case No. 2011-00401, and captioned as *"In the Matter of: Application of Kentucky Power Company For Approval Of Its 2011 Environmental Compliance Plan, For Approval Of Its Amended Environmental Cost Recovery Surcharge Tariff, And For the Grant Of A Certificate Of Public Convenience And Necessity For The Construction And Acquisition Of Related Facilities"*. It is further my understanding that Hayet Power System Consulting desires to have access to the Big Rivers' portion of ACES Power Marketing's Ventyx Planning & Risk (PaR) proprietary database for use exclusively in the aforementioned case after Hayet Power System Consulting has obtained a license from Ventyx.

As may have been communicated to you by counsel for Big Rivers, APM is willing to disclose the Big Rivers portion of the ACES Power Marketing's Ventyx Planning & Risk (PaR) proprietary database to Hayet Power System Consulting and Phil Hayet, subject to: (1) the execution by Hayet Power System Consulting and Phil Hayet of the attached Non-Disclosure Agreement and Non-Disclosure Certification; and (2) verification that Hayet Power System Consulting has executed a license agreement with Ventyx for the Planning & Risk (PaR) software.

Please review the attachments and advise me at your convenience of your client's/expert's approval to these terms.

Sincerely,

Wayne Harris
Chief Counsel
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032
Email: wayneh@acespower.com
Tele.: (317) 344-7017

Think before you print

NOTICE: This email message and any attachments are for the sole and confidential use of the intended recipients and may contain proprietary and/or confidential information which may be privileged or otherwise protected from disclosure. Any unauthorized review, use, disclosure or distribution is strictly prohibited. If you are not the intended recipient, please contact the sender by reply email and delete the original message from your computer system and destroy any copies of the message as well as any attachments and notify me immediately at (317) 344-7000.

Think before you print

Redlined NDA - Between Hayet and ACES Power Marketinga.docx
26K

SIERRA CLUB
FOUNDED 1892

2012-00063 [PUBLIC] Ben Taylor & Sierra Club's 3rd Data Request to Big Rivers

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:32 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Cook, Larry (KYOAG)** <larry.cook@ag.ky.gov>
Date: Wed, Jun 27, 2012 at 10:28 AM
Subject: RE: 2012-00063 [PUBLIC] Ben Taylor & Sierra Club's 3rd Data Request to Big Rivers
To: James Giampietro <james.giampietro@sierraclub.org>, "Kurt J. Boehm" <kboehm@bkllawfirm.com>, jmiller@smsmlaw.com, tkamuf@smsmlaw.com, dbrown@stites.com, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, Philip Hayet <philhaye@concentric.net>, Lane Kollen <lkollen@jkenn.com>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, Jody Kyler <jkyler@bkllawfirm.com>
Cc: Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>

FYI, the AG will not have any modeling-related DRs for BREC.

Yours,

Larry Cook

From: James Giampietro [mailto:james.giampietro@sierraclub.org]
Sent: Wednesday, June 27, 2012 1:21 PM
To: Kurt J. Boehm; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; dbrown@stites.com; Raff, Richard (PSC); Nguyen, Quang D (PSC); Michael Kurtz; James, Matt (KYOAG); Hans, Jennifer (KYOAG); Philip Hayet; Lane Kollen; Cook, Larry (KYOAG); Howard, Dennis (KYOAG); Jody Kyler
Cc: Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica
Subject: 2012-00063 [PUBLIC] Ben Taylor & Sierra Club's 3rd Data Request to Big Rivers

Attached please find a cover letter and the PUBLIC version of Sierra Club's 3rd Data Request to Big Rivers in both .PDF and .DOC formats. Paper copies will be delivered to the Commission and mailed out to parties today. In a few minutes a confidential version of this data request will be emailed to those who have singed the confidentiality agreement.

--

James Giampietro

Sierra Club Environmental Law Program

85 2nd Street, 2nd Floor

San Francisco CA, 94105

Office: (415)977-5638

Fax: (415)977-5793

SIERRA CLUB

KIUC's Third Set of Data Requests to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:30 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Wed, Jun 27, 2012 at 2:08 PM
Subject: KIUC's Third Set of Data Requests to BREC, Docket No. 2012-00063
To: "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>
Cc: Kurt Boehm <KBoehm@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Jody Kyler <jkyler@bkllawfirm.com>, "sbaron@jkenn.com" <sbaron@jkenn.com>

Counsel, attached please find KIUC'S THIRD SET OF DATA REQUESTS TO BIG RIVERS ELECTRIC CORPORATION in .Word and .Pdf format for filing in the above-referenced matter. Hard copies will follow by regular, U.S. Mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

KIUC 3rd Set of Data Requests, #2012-00063.pdf
115K

Third Set of Data Requests FINAL.docx
33K

SIERRA CLUB

Fwd: Motion to Compel

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:10 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Wed, Jun 6, 2012 at 12:54 PM
Subject: RE: Motion to Compel
To: Kristin Henry <kristin.henry@sierraclub.org>
Cc: Michael Kurtz <MKurtz@bkllawfirm.com>, "Brown, David" <DBROWN@stites.com>, Philip Hayet <philhaye@concentric.net>, Shannon Fisk <sfisk@earthjustice.org>, Jody Kyler <jkyler@bkllawfirm.com>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>

Kristin:

I apologize, but the pleading has been filed. Electronic delivery will be forthcoming shortly. Joe Childers electronically signed for you and Shannon.

Thank you.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Wednesday, June 06, 2012 3:45 PM
To: Hans, Jennifer (KYOAG)
Cc: Michael Kurtz; Brown, David; Philip Hayet; Shannon Fisk; Jody Kyler; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)

Subject: Re: Motion to Compel

I had a few minor edits if it hasn't gone out yet. Also, please sign for me.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

On Wed, Jun 6, 2012 at 11:54 AM, Hans, Jennifer (KYOAG) <jennifer.hans@ag.ky.gov> wrote:

I have signed, and we will file and send copies to docket list by regular mail today. When I receive a stamped copy, I will scan and circulate it to all counsel by email today.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, June 06, 2012 2:19 PM
To: 'Brown, David'; Philip Hayet
Cc: Hans, Jennifer (KYOAG); Shannon Fisk; Jody Kyler; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG);

Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

Same

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Brown, David [mailto:DBROWN@stites.com]
Sent: Wednesday, June 06, 2012 2:18 PM
To: Philip Hayet
Cc: Michael Kurtz; Hans, Jennifer (KYOAG); Shannon Fisk; Jody Kyler; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: Re: Motion to Compel

Jennifer - please sign my name to the final.

David Brown

Sent from my iPhone

On Jun 6, 2012, at 1:56 PM, "Philip Hayet" <philhaye@concentric.net> wrote:

> Mike,
>
> I am reviewing it right now.
>
> Phil
>
> **From:** Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
> **Sent:** Wednesday, June 06, 2012 1:49 PM

To: 'Hans, Jennifer (KYOAG)'; Brown, David; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

You have my permission. David may be out of pocket for a while, but I'm sure is fine to sign for him if he does not respond personally.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Hans, Jennifer (KYOAG) [mailto:jennifer.hans@ag.ky.gov]
Sent: Wednesday, June 06, 2012 1:52 PM
To: Michael Kurtz; Brown, David; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

I can file it today. I am happy to sign for you and David if I have both of your permissions, and I see where Joe has already signed on behalf of the Sierra Club.

Great effort everyone!

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, June 06, 2012 1:41 PM
To: 'Brown, David'; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

All.

Here is what should be considered the final version of the motion, plus the referenced letter. I can overnight from my office. Jennifer, if it is convenient you could sign for the parties and file today. Either way. Let me know.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Brown, David [mailto:DBROWN@stites.com]

Sent: Wednesday, June 06, 2012 9:38 AM
To: Michael Kurtz; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

I think the additions by the Sierra Club are very fine. There are a few editing comments that i will send momentarily.

David

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, June 06, 2012 9:17 AM
To: 'Shannon Fisk'; Brown, David
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

All.

Shannon/Kristen.

Thank you for the additions. I think the motion is very compelling. I would like to file it today. I will accept all changes and then make final clean ups. I don't think affidavits are essential and I don't want to delay, so I will remove those references.

Jennifer, we would like to have the AG sign on if you give the go ahead.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Shannon Fisk [mailto:sfisk@earthjustice.org]

Sent: Tuesday, June 05, 2012 10:47 PM
To: Brown, David; Michael Kurtz
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org
Subject: RE: Motion to Compel

Thanks, Mike and David, for drafting this. Attached are some proposed edits and additions from Kristin and me. Please let us know if you have any questions, concerns, etc.

Shannon

From: Brown, David [mailto:DBROWN@stites.com]
Sent: Tuesday, June 05, 2012 1:30 PM
To: Michael Kurtz
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Shannon Fisk
Subject: RE: Motion to Compel

Mike and All - attached is a clean and marked copy of the original draft that came out last night. Sorry it turned out so messy. What I have tried to do is (i) make it a joint motion, (ii) explain the process and the main issue up front, and (iii) give the Commission the option to issue a subpoena althoguh ACES is in Indiana. The rest of the editing is mainly to eliminate repetition and keeping the focus on the main issue. Mike, I'll leave this up to you. Also I thought I saw some comment from you but they did not make it into this draft.

David

David C. Brown
Stites & Harbison, PLLC
400 W. Market Street
Suite 1800
Louisville, KY 40202-3352
Direct Dial: (502) 681-0421
Fax: (502) 779-8251
dbrown@stites.com

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Tuesday, June 05, 2012 11:48 AM
To: Brown, David
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; sfisk@earthjustice.org
Subject: Re: Motion to Compel

David. Please send your changes to Kristen and Shannon also. Hopefully we will file a joint motion.

Sent from my iPad

On Jun 5, 2012, at 11:41 AM, "Brown, David" <DBROWN@stites.com> wrote:

Mike - I have revisions to suggest and will get thsoe to you in a bit. I think we need to put the precise issue up front.

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Tuesday, June 05, 2012 10:36 AM
To: Brown, David; Jody Kyler
Subject: Fwd: Motion to Compel

Sent from my iPhone

Begin forwarded message:

From: Philip Hayet <philhaye@concentric.net>
Date: June 5, 2012 7:57:36 AM EDT
To: Michael Kurtz <MKurtz@bkllawfirm.com>, 'Lane Kollen' <lkollen@jkenn.com>
Subject: RE: Motion to Compel

Mike,

Here are my changes. If you would like to discuss please call my cell at
770-855-1815. I may not be immediately available but will be able to call
back. I will be back in the office tomorrow.

Thanks,

Phil

-----Original Message-----
From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 04, 2012 10:51 AM
To: 'Lane Kollen'; 'Philip Hayet'
Subject: FW: Motion to Compel

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com

-----Original Message-----
From: Jody Kyler

Sent: Sunday, June 03, 2012 6:10 PM
To: Michael Kurtz
Subject: Motion to Compel

Mike,

Attached is a draft Motion to Compel in the Big Rivers' Environmental Surcharge case. I will probably review the Motion again, but wanted to get
you something now since I will likely be in the Columbus hearing Monday and
Tuesday and at Kentucky new lawyer training on Wednesday and Thursday. I
based the information in the May 11, 2012 letter on the e-mails I reviewed,
but you may want to verify that I quoted the final letter actually sent on May 11, 2012 accurately.

Thanks,

Jody

Fwd: Big Rivers Modeling Case 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:17 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Mon, Jun 4, 2012 at 2:32 PM
Subject: RE: Big Rivers Modeling Case 2012-00063
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>
Cc: Brenton Meese <Brenton.Meese@ventyx.abb.com>, Jim Miller <jmiller@smsmlaw.com>, dbrown@stites.com, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, joe@jchilderslaw.com, childerslaw@yahoo.com, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, Kurt Boehm <KBoehm@bkllawfirm.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Albert Yockey <Albert.Yockey@bigrivers.com>, Roger.Hickman@bigrivers.com, briana@acespower.com, johnst@acespower.com, Joseph McLeer <Joseph.McLeer@ventyx.abb.com>, Shannon Fisk <sfisk@earthjustice.org>, Christopher Leung <cleung@earthjustice.org>, kristin.henry@sierraclub.org

Counsel:

This is just to advise you that Assistant Attorney General Matt James also joined me on this call. Matt has signed the Confidentiality Agreement supplied by counsel for Big Rivers.

Thank you.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 04, 2012 9:49 AM
To: 'Kristin Henry'

Cc: Brenton Meese; Jim Miller; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com; briana@acespower.com; johnst@acespower.com; Joseph McLeer; Shannon Fisk; Christopher Leung
Subject: RE: Big Rivers Modeling Case 2012-00063

Kristen.

Yes, the call is today at 5:00 eastern. 866-906-9888 pass code 518-4986

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Monday, June 04, 2012 12:06 AM
To: Michael Kurtz
Cc: Brenton Meese; Jim Miller; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com; briana@acespower.com; johnst@acespower.com; Joseph McLeer; Shannon Fisk; Christopher Leung
Subject: Re: Big Rivers Modeling Case 2012-00063

Mike,

I just wanted to confirm that the call-in information is the same for the new 5:00 pm time.

Thanks,

Kristin Henry

On Wed, May 30, 2012 at 6:03 AM, Michael Kurtz <MKurtz@bkllawfirm.com> wrote:

Everyone.

Thank you for the response. It looks like Monday June 4 at 11:00 am Eastern is the best time. Please use the following call in number: 866-906-9888 pass code 518-4986

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Brenton Meese [mailto:Brenton.Meese@ventyx.abb.com]

Sent: Tuesday, May 29, 2012 9:11 PM

To: Jim Miller; Michael Kurtz; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com
Cc: briana@acespower.com; johnst@acespower.com; Joseph McLeer

Subject: RE: Big Rivers Modeling Case 2012-00063

The Ventyx project manager, Joe McLeer, is very constrained next Monday as he will be at a client site in New Brunswick, Canada.

It is possible that Joe can attend if the call can take place at 11:00am Eastern or thereabouts. We would like to request that an (800) dial-in number be issued with the meeting notice. Please include him on any invitation. Thanks.

BRENTON MEESE
Executive Account Manager
(O) 678.825.1467
(M) 404.964.8882

VENTYX
an ABB company
www.ventyx.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Tuesday, May 29, 2012 6:31 PM
To: Michael Kurtz; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com
Cc: Brenton Meese; briana@acespower.com; johnst@acespower.com
Subject: RE: Big Rivers Modeling Case 2012-00063

All:

Big Rivers can participate in a call on Monday as requested by ACES.

Jim

-----Original Message-----
From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Tue 5/29/2012 3:32 PM
To: Jim Miller; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com
Cc: 'Brenton.Meese@ventyx.abb.com'; 'briana@acespower.com'; 'johnst@acespower.com'
Subject: Big Rivers Modeling Case 2012-00063

Counsel,

After having explored the option of our going to ACES Power Marketing's ("ACES") office to make KIUC's production cost runs, we have now decided to obtain a PAR model license from Ventyx, and will make our own runs. This email is going to all parties involved in providing the software, data and results, including Big Rivers, Ventyx, and ACES Power Marketing,

Mr. Hayet is coordinating with Ventyx to acquire a license to access the same tools (EnerPrise database/Microsoft SQL) that ACES uses to run the PAR model. Mr. Hayet is aware this will require certain hardware and software requirements, which he will arrange for with Ventyx. Mr. Hayet will also work with Ventyx to install the software with the goal of being able to reproduce ACES' results on his own computer. In order to do that, Mr. Hayet understands from Ventyx, that early coordination between ACES, Ventyx, and me will be required.

We suggest that we arrange a conference call for tomorrow if at all possible, between Mr. Hayet, Ventyx, and ACES (and whoever else would be appropriate) to discuss the technical details to help smooth the way, and to minimize unnecessary delays. For example, one question that will have to be answered is whether ACES will provide a database containing just the Big Rivers data, or a large database with all of the companies that it models in it, including Big Rivers. This will be important for us to know what we will have to do to install the model. We are also aware that Ventyx would likely have other questions as well that will have to be answered.

We are targeting the week of June 11th to install the software, so we would like to work through all of the details prior to that.

We would like to have this call tomorrow or Thursday if at all possible so that we can clear Ventyx to proceed with the process and we can finalize the license We would like to ask ACES, Ventyx, Mr. Hayet, and anyone else who wants to be on the call, to indicate times that you are not available on Wednesday and on Thursday, and we will find a time that will hopefully work for everyone.

Thank you for your assistance.

Mike

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com

--

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

Fwd: BREC Environmental Complinace

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:59 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jun 4, 2012 at 3:07 PM
Subject: RE: BREC Environmental Complinace
To: Shannon Fisk <sfisk@earthjustice.org>, "Brown, David" <DBROWN@stites.com>, Philip Hayet <philhaye@concentric.net>, Kristin Henry <kristin.henry@sierraclub.org>
Cc: Christopher Leung <cleung@earthjustice.org>

Supporting statement or affidavit would be good. Yes, specific examples would be good also. We really need to explain why this information is critical in a big picture way. This could all be resolved with one email from BREC requesting the ACES release the information.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Shannon Fisk [mailto:sfisk@earthjustice.org]
Sent: Monday, June 04, 2012 6:02 PM
To: Michael Kurtz; 'Brown, David'; 'Philip Hayet'; 'Kristin Henry'
Cc: Christopher Leung
Subject: RE: BREC Environmental Complinace

Mike,

I was just thinking the same thing. I will discuss with Kristen, and then we'll get back to you soon.

I gave your motion a quick review and one thought on this is whether you want to include a supporting statement from Phil and/or our expert if we sign on explaining that they always get this sort of information in these types of proceedings. In addition, do we want to add a specific example of how having the specific modeling files, including the various vectors and switches, can be important (the 20% demand vector issue from the Big Sandy proceeding is one such example).

Shannon

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 04, 2012 5:50 PM
To: Shannon Fisk; 'Brown, David'; 'Philip Hayet'; 'Kristin Henry'
Subject: BREC Environmental Complinace

Shannon/Kristen.

It appears that KIUC and Sierra Club are in agreement with respect to the discovery impasse. I think a joint motion to compel would carry the most weight with the Commission. A draft motion is attached. If you want to go jointly, then please review and make any improvements you think appropriate. I think we should file something sooner rather than later.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

SIERRA CLUB

Fwd: BREC

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:10 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Tue, Jun 5, 2012 at 12:22 PM
Subject: BREC
To: "philhaye@concentric.net" <philhaye@concentric.net>, Shannon Fisk <sfisk@earthjustice.org>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, David Brown <DBROWN@stites.com>

Phil can you prepare a short affidavit that mimics the technical assertions in the motion. Shannon can you have your expert do the same?

Sent from my iPad

Fwd: KIUC's Motion to Compel - Docket #2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:11 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Shannon Fisk** <sfisk@earthjustice.org>
Date: Tue, Jun 5, 2012 at 8:18 AM
Subject: RE: KIUC's Motion to Compel - Docket #2012-00063
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Kristin Henry <kristin.henry@sierraclub.org>

Thanks, Mike. We'll look it over and get back to you.

From: Michael Kurtz [MKurtz@bkllawfirm.com]
Sent: Tuesday, June 05, 2012 11:00 AM
To: Kristin Henry; Shannon Fisk
Subject: KIUC's Motion to Compel - Docket #2012-00063

F.Y.I. Attached please find a current draft of KIUC's Motion to Compel for filing in the BREC environmental surcharge case.

Mike

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764
MKurtz@BKLlawfirm.com<mailto:MKurtz@BKLlawfirm.com>

SIERRA CLUB

Fwd: Joint Motion to Compel - Big Rivers - Case No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:50 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Wed, Jun 6, 2012 at 1:18 PM
Subject: RE: Joint Motion to Compel - Big Rivers - Case No. 2012-00063
To: Kristin Henry <kristin.henry@sierraclub.org>

You are most welcome. Sorry that I missed your edits – good eye by the way. Unfortunately, we have a 3:00 pm EST mail drop that we had to make. I will get used to the time difference for you and other West Coasters eventually. ☺

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Wednesday, June 06, 2012 4:10 PM
To: Hans, Jennifer (KYOAG)
Subject: Re: Joint Motion to Compel - Big Rivers - Case No. 2012-00063

Jennifer,

Thanks for taking care of this.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

On Wed, Jun 6, 2012 at 1:13 PM, Hans, Jennifer (KYOAG) <jennifer.hans@ag.ky.gov> wrote:

Dear Counsel:

Please find attached a courtesy electronic copy of the Joint Motion of Kentucky Industrial Utility Customers, Inc., Ben Taylor and Sierra Club, and Attorney General to Compel or, in the alternative, to Issue Subpoena Duces Tecum, which was filed with the Commission today in the above-referenced docket. Please advise if you have any problems opening. Hard copies have been mailed today as indicated on the certificate of service.

Respectfully yours,

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

SIERRA CLUB

Fwd: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:28 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Cook, Larry (KYOAG)** <larry.cook@ag.ky.gov>
Date: Thu, Jul 12, 2012 at 6:50 AM
Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063
To: Kurt Boehm <KBoehm@bkllawfirm.com>, Jim Miller <jmiller@smsmlaw.com>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, kristin.henry@sierraclub.org, sfisk@earthjustice.org, childerslaw81@gmail.com, cleung@earthjustice.org, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>
Cc: dbrown@stites.com, Jody Kyler <jkyler@bkllawfirm.com>

The AG will call in.

From: Kurt Boehm [mailto:KBoehm@bkllawfirm.com]
Sent: Thursday, July 12, 2012 9:32 AM
To: 'Jim Miller'; Nguyen, Quang D (PSC); Michael Kurtz; Tyson Kamuf; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); James, Matt (KYOAG); kristin.henry@sierraclub.org; sfisk@earthjustice.org; childerslaw81@gmail.com; James, Matt (KYOAG); cleung@earthjustice.org; DeRouen, Jeff (PSC)

Cc: dbrown@stites.com; Jody Kyler

Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Quang- KIUC is available at 1pm today.

[Quoted text hidden]

SIERRA CLUB

Fwd: KIUC's Direct Testimony and Exhibits, (Confidential and Non-Confidential), Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:26 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jul 23, 2012 at 1:41 PM
Subject: KIUC's Direct Testimony and Exhibits, (Confidential and Non-Confidential), Docket No. 2012-00063
To: "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, "sfisk@earthjustice.org" <sfisk@earthjustice.org>, "childerslaw81@gmail.com" <childerslaw81@gmail.com>, "cleung@earthjustice.org" <cleung@earthjustice.org>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>
Cc: "dbrown@stites.com" <dbrown@stites.com>, Jody Kyler <jkyler@bkllawfirm.com>, Kurt Boehm <KBoehm@bkllawfirm.com>, "sbaron@jkenn.com" <sbaron@jkenn.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>

Counsel, attached please find the DIRECT TESTIMONY AND EXHIBITS of LANE KOLLEN, and the PUBLIC VERSIONS of the DIRECT TESTIMONY AND EXHIBITS of PHILIP HAYET and STEPHEN J. BARON on behalf of KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. for filing in the

above-referenced docket. I also attach the CONFIDENTIAL EXHIBITS filed under seal. Hard copies have been sent by regular, U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

5 attachments

- **Hayet Direct Testimony & Exhibits - (PUBLIC) FINAL.pdf**
  124K
- **Baron Direct Testimony & Exhibits (PUBLIC) - FINAL.pdf**
  608K
- **Kollen Direct Testimony & Exhibits FINAL.pdf**
  1808K
- **CONFIDENTIAL Hayet Direct Exhibits.pdf**
  40K
- **CONFIDENTIAL Baron Direct Exhibits.pdf**
  385K

SIERRA CLUB

Fwd: Big Rivers

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:25 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, Jul 27, 2012 at 12:14 PM
Subject: Re: Big Rivers
To: Shannon Fisk <sfisk@earthjustice.org>
Cc: "Kristin Henry (kristin.henry@sierraclub.org)" <kristin.henry@sierraclub.org>

Thanks

Sent from my iPhone

On Jul 27, 2012, at 3:02 PM, "Shannon Fisk" <sfisk@earthjustice.org> wrote:

Mike,

Thanks for reaching out on this. Rachel is going to call Phil to discuss further. I'll keep you posted.

Shannon

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Friday, July 27, 2012 9:54 AM
To: Shannon Fisk; Kristin Henry
Cc: 'Brown, David'; Kurt Boehm; 'Philip Hayet'; '1-Lane Kollen'
Subject: Big Rivers

Shannon/Kristin.

Data requests to intervenors are due Monday. It may be helpful if we could coordinate. For example, perhaps you could ask us to re-run the financial model with some of your adjustments included.

Are either of you available for a conference call this afternoon to discuss. Say 2:00 eastern.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

SIERRA CLUB

Fwd: KIUC 1st Set of Data Requests to Sierra Club, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:23 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jul 30, 2012 at 10:06 AM
Subject: KIUC 1st Set of Data Requests to Sierra Club, Docket No. 2012-00063
To: Jim Miller <jmiller@smsmlaw.com>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Tyson Kamuf <tkamuf@smsmlaw.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, "sfisk@earthjustice.org" <sfisk@earthjustice.org>, "childerslaw81@gmail.com" <childerslaw81@gmail.com>, "cleung@earthjustice.org" <cleung@earthjustice.org>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>
Cc: Kurt Boehm <KBoehm@bkllawfirm.com>, Jody Kyler <jkyler@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>

Counsel, attached please find KIUC's First Set of Data Requests to Sierra Club in .Word and .Pdf format filed in the above-referenced matter. Hard copies will follow by regular U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

1st Set of Data Requests to Sierra Club.docx
28K

KIUC 1st Set DR to Sierra Club.pdf
102K

SIERRA CLUB

Two more e-mails to produce

Shannon Fisk <sfisk@earthjustice.org> Sun, Aug 5, 2012 at 10:28 PM
To: "james.giampietro@sierraclub.org" <james.giampietro@sierraclub.org>, "Ruben Mojica (ruben.mojica@sierraclub.org)" <ruben.mojica@sierraclub.org>
Cc: "Kristin Henry (kristin.henry@sierraclub.org)" <kristin.henry@sierraclub.org>

Please include the attached two e-mails with all of the ones that Kristin sent you for the responses to Big Rivers' requests number 15 and 16. Those are the only two e-mails I have with KIUC that Kristin wasn't included on.

Shannon Fisk
Earthjustice
156 William Street
Suite 800
New York, New York 10038
T: 212-791-1881 ext. 8239
C: 215-327-9922

www.earthjustice.org

Because the earth needs a good lawyer

---------- Forwarded message ----------
From: Michael Kurtz <MKurtz@bkllawfirm.com>
To: Shannon Fisk <sfisk@earthjustice.org>
Cc:
Date: Mon, 30 Jul 2012 08:29:47 -0700
Subject: RE: Discovery
Thanks Shannon. We are going to ask you the single question that Phil developed with Rachel.

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com

-----Original Message-----
From: Shannon Fisk [mailto:sfisk@earthjustice.org]
Sent: Monday, July 30, 2012 10:31 AM
To: Michael Kurtz
Subject: Discovery

Mike, we'll be serving on you later today the discovery that we discussed last week.

Sent from my Samsung smartphone on AT&T

---------- Forwarded message ----------
From: Michael Kurtz <MKurtz@bkllawfirm.com>
To: Christopher Leung <cleung@earthjustice.org>
Cc: Shannon Fisk <sfisk@earthjustice.org>, Kim Walton <KWalton@bkllawfirm.com>, Sheila Fisk <SFisk@bkllawfirm.com>
Date: Thu, 12 Jul 2012 14:29:16 -0700
Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Chris.

Sorry. We will fix our certificate.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Christopher Leung [mailto:cleung@earthjustice.org]
Sent: Thursday, July 12, 2012 10:22 AM
To: Michael Kurtz
Cc: Shannon Fisk
Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Hi Michael,

One small detail: The motion's certificate of service states that Shannon and I work at the Chicago office of the Natural Resources Defense Council. We actually both work at Earthjustice's New York office at the address listed below. Thanks.

Chris

Christopher Leung

Staff Attorney

Earthjustice

156 William Street, Suite 800

New York, New York 10038

T: 212-791-1881 x8235

F: 212-918-1556

www.earthjustice.org

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, July 11, 2012 4:51 PM
To: 'Nguyen, Quang D (PSC)'; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); James, Matt (KYOAG); kristin.henry@sierraclub.org; Shannon Fisk; childerslaw81@gmail.com; James, Matt (KYOAG); Christopher Leung; DeRouen, Jeff (PSC)
Cc: dbrown@stites.com; Jody Kyler; Kurt Boehm
Subject: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Counsel, attached pleas find KIUC's MOTION FOR EXTENSION OF TIME AND REQUEST FOR INFORMAL CONFERENCE filed in the above-referenced docket. Hard copies have been sent by regular, U.S. mail.

We have requested that the Commission schedule an informal conference tomorrow (July 12) in order to discuss this motion.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

Request No. 16

Please provide all emails, memoranda, and other documents sent to Sierra Club from the Kentucky Attorney General, Ventyx, or KIUC since January 1, 2012.

Response to Request No. 16 - Respondent: Kristin Henry, Sierra Club Counsel

Sierra Club objects to this requests to the extent it seeks emails, memos, or other documents that are not relevant to this proceeding. Subject to and without waiving the foregoing objection, responsive documents are attached.

REQUEST 1-16

Attachment 1

SIERRA CLUB

KIUC's 1st Set of Data Requests to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:21 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, May 21, 2012 at 1:07 PM
Subject: KIUC's 1st Set of Data Requests to BREC, Docket No. 2012-00063
To: "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Quang D. Nguyen" <QuangD.Nguyen@ky.gov>, "Faith B. Burns" <faith.burns@ky.gov>, "Richard G. Raff" <richard.raff@ky.gov>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>
Cc: "dbrown@stites.com" <dbrown@stites.com>, Kurt Boehm <KBoehm@bkllawfirm.com>

Counsel, attached please find the KENTUCKY INDUSTRIAL UTILITY CUSTOMERS INC's FIRST SET OF DATA REQUESTS TO BIG RIVERS ELECTRIC CORPORATION in .Word and .Pdf format for filing in the above-referenced matter. Hard copies will follow by regular, U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

1st Set of Data Request to BREC.pdf
167K

1st Set of Data Requests.docx
36K

Fwd: Attorney General's Initial Data Requests

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:21 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
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---------- Forwarded message ----------
From: **Cook, Larry (KYOAG)** <larry.cook@ag.ky.gov>
Date: Mon, May 21, 2012 at 1:23 PM
Subject: Attorney General's Initial Data Requests
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Jim Miller <jmiller@smsmlaw.com>
Cc: dbrown@stites.com, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, joe@jchilderslaw.com, childerslaw@yahoo.com, kristin.henry@sierraclub.org, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, Kurt Boehm <KBoehm@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>

ALL,

Please find attached the Attorney General's initial requests to BREC. The original and hard copies were filed with the Commission just a few moments ago. A Word copy is being sent to Jim Miller under separate cover.

Yours,

Larry

OAG_Initial DRs_2012-00063.pdf
1379K

SIERRA CLUB

Big Rivers KPSC Case No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:20 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
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---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Wed, May 23, 2012 at 10:42 AM
Subject: Big Rivers KPSC Case No. 2012-00063
To: Michael Kurtz <MKurtz@bkllawfirm.com>, jmiller@smsmlaw.com, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, James Giampietro <james.giampietro@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, tkamuf@smsmlaw.com, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>
Cc: dbrown@stites.com, Kurt Boehm <KBoehm@bkllawfirm.com>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>

Counsel:

For future reference, please include Assistant Attorneys General Larry Cook and Matt James on your email distribution/service lists regarding this matter.

Larry.Cook@ag.ky.gov

Matt.James@ag.ky.gov

Thank you.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

SIERRA CLUB

Fwd: KIUC correspondence to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:20 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
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---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, May 25, 2012 at 11:19 AM
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063
To: Jim Miller <jmiller@smsmlaw.com>
Cc: "dbrown@stites.com" <dbrown@stites.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "joe@jchilderslaw.com" <joe@jchilderslaw.com>, "childerslaw@yahoo.com" <childerslaw@yahoo.com>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, Kurt Boehm <KBoehm@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Albert Yockey <Albert.Yockey@bigrivers.com>

Jim.

I understand. Thank you for considering our request. We will move forward with licensing the model from Ventyx, and obtaining from Aces the data necessary to run the model and reproduce the results produced by Aces. We assume there will be no problems or delays pursuing this avenue. If there are, we may need to revisit the issue.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Friday, May 25, 2012 12:14 PM
To: Michael Kurtz
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey

Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Mike:

Big Rivers has considered the request in your e-mail message of yesterday that Big Rivers allow and arrange for your consultant to go to the offices of Big Rivers' consultants, and have Big Rivers' consultants conduct runs of the models they are using in their engagements with Big Rivers to develop cases based upon KIUC's preferred assumptions. Big Rivers is unwilling to agree to that request for a number of reasons. Big Rivers has provided and continues to provide vast amounts of information to the Commission staff and the intervenors well in advance of the due date for Big Rivers' responses to the first information requests.

Jim

James M. Miller

Sullivan, Mountjoy, Stainback & Miller, P.S.C.

100 St. Ann Street

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Owensboro, KY 42302-0727

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CONFIDENTIALITY STATEMENT:

This message from the law firm of Sullivan, Mountjoy, Stainback & Miller, P.S.C. contains information which is privileged and confidential, and is solely for the use of the intended recipient. If you are not the intended recipient, be aware that any review, disclosure, copying, distribution, or use of the contents of this message is strictly prohibited. If you have received this in error, please immediately destroy it and notify us at (270) 926-4000.

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Thursday, May 24, 2012 3:13 PM
To: Jim Miller
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Thanks Jim.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

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Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Thursday, May 24, 2012 4:12 PM
To: Michael Kurtz
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Mike,

I just picked up your message. We will discuss this and I will get back to you as quickly as I can.

Jim

-----Original Message-----
From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Thu 5/24/2012 10:33 AM
To: Jim Miller
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Jim.

As you are aware, Phil Hayet with Hayet Power Systems Consulting has been investigating requirements to obtain the same models and data that were used by Big Rivers' outside consultants, ACES Power Marketing ("ACES") and Pace Global ("Pace"), in order to be able to reproduce the results developed for this proceeding, as well as to create new results of our own. After having spoken with Christian Whitaker at Pace Global, John Sturm at ACES, and Julie Albright and Brenton Meece at Ventyx (developer of the PAR model used by ACES), Mr. Hayet has concluded that our first priority would be to gain access to the PAR model, although he has not ruled out the possibility that he would want to be able to re-run some cases performed by PACE using the Aurora model.

Based on discussions with Ventyx, Mr. Hayet is aware that the cost of a three month license of PAR would be approximately $30 thousand dollars. While this may be the route that we ultimately choose, we also want to explore the possibility of Mr. Hayet being permitted to go onsite to ACES' office for the purpose of working one-on-one with ACES' modeling staff to develop cases based on our preferred assumptions. Mr. Hayet has done that before and that has been both a cost effective and expedient approach for other projects of a similar nature. While we have been able to gain a basic understanding of the modeling work that was performed by ACES and Pace, there are still some gaps that we hope will be filled in after our discovery is answered. At that point we should know whether we will need to run both models. If so, we may need permission to go to access and run the models at both ACES and Pace's offices due to the time constraints of the procedural schedule and the cost-effectiveness of this approach compared to acquiring licenses directly.

Thus we request that you contact both ACES and Pace to identify dates during which Mr. Hayet could make one or two on-site visits at each of their offices for a 2 - 3 day period at each office to conduct our analyses using their models and databases. At this time, we believe that the most likely course will be a single visit by Mr. Hayet to the ACES' office for a 2 - 3 day period. We propose dates of June 11 through 13 for this purpose as there is limited time between when the first round of discovery will be answered and delivered to us and when our second set of questions are due.

As mentioned in our letter from May 11, the short time frame of this proceeding requires that we obtain access to this data and the models, as soon as possible, and at this stage we are only aware of the cost to license the PAR model. We are still having discussions with John Sturm at ACES regarding requirements to be able to obtain the database that ACES used, in the event that we decide to license the PAR model ourselves. This additional information concerning the requirements necessary to instead be able to go on-site to ACES' office (and possibly Pace's office) to conduct the modeling runs with their assistance would be helpful in making our final decision about how to proceed.

As stated in our last letter, we can arrange to have a conference call with Company and/or consultant/contractor personnel to expedite this process. We would appreciate a quick response to this letter given the limited time available.

Thanks

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Friday, May 18, 2012 4:34 PM
To: Michael Kurtz
Cc: dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Mike:

We have been working since receiving your message of last week to assemble the information you requested. At this point we can provide the following information about access to the models employed by Big Rivers' consultants in conducting their analyses. The data compilation of all input files, output files, assumptions, and other requested data is underway.

Response from ACES Power Marketing ("APM")

APM used the Ventyx Planning and RISK model. We understand that its license agreements indicate that it cannot release the licensed software or any proprietary Ventyx information. KIUC may contact Ventyx and request the cost and installation requirement by calling Julie Albright at 832-553-0880.

Response from Pace Global

The model used by Pace Global is a product of EPIS, Inc. called AuroraXMP, commonly referred to as Aurora. Aurora is an hourly merit-order dispatch simulator that calculates hourly dispatch for integrated grid operations. A license is required to use the Aurora model. Pace Global's contact at EPIS is Deborah Austin Smith. http://epis.com/aurora_xmp/power_forecasting.php. Their formal contact address is EPIS, Inc., 1800 Blankenship Road Suite 350, West Linn, OR 97068. Phone: (503) 722-2023.
In addition, Pace Global has made several proprietary modifications to the leased Aurora model in order to enhance and improve its inherent capabilities. These modifications are confidential and proprietary, however, they can be leased from Pace Global in order to facilitate a simulation by a third party for their exclusive internal use. Licensing restrictions are based on the intended use, distribution, and access requirements of the user. To facilitate use of Aurora, Pace Global can provide input data tables in Aurora database format if necessary.

Pace Global can provide documentation and instructions on the use of its proprietary modifications to the Aurora model should third parties wish to license it. The Aurora model contains integrated instructions documentation for licensed users and can be obtained directly from the Licensor, EPIS. The contact at PACE Global is Christian Whitaker, Christian.Whitaker @PaceGlobal.com, (703) 227-1036.

Response from Sargent & Lundy

Sargent & Lundy tells us that their model is an Excel spreadsheet that can be provided without licensing.

We would expect to provide most of the production input data under a petition for confidential treatment. I think we already have confidentiality coverage for several members of the KIUC and Attorney General teams, and I have e-mailed the form of confidentiality agreement to Joe Childers for Sierra Club and Ben Taylor.

Jim

James M. Miller
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From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Friday, May 18, 2012 1:58 PM
To: Jim Miller
Cc: 'dbrown@stites.com'; 'Hans, Jennifer (KYOAG)'; 'Howard, Dennis (KYOAG)'; 'Cook, Larry (KYOAG)'; 'joe@jchilderslaw.com'; 'Joe Childers (childerslaw@yahoo.com<mailto:childerslaw@yahoo.com>)'; 'kristin.henry@sierraclub.org'; 'Nguyen, Quang D (PSC)'; 'Burns, Faith (PSC)'; Kurt Boehm; Tyson Kamuf
Subject: RE: KIUC correspondence to BREC, Docket No. 2012-00063

Jim.

It has been a week since I sent you the attached letter seeking information on how the KIUC experts can have access to the computer models relied upon by Big Rivers. We are preparing our data requests that will be served Monday, and I want to direct your attention to this matter again.

In the recent Kentucky Power ECR case, the experts for Sierra Club had difficulty obtaining the computer models relied upon by AEP. Sierra Club was forced to file a motion to compel. We want to avoid those types of problems here. Also, we want to keep this case on track and not be required to seek amendment of the procedural schedule.

Your assistance is appreciated.

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com<mailto:mkurtz@BKLlawfirm.com>

From: Michael Kurtz
Sent: Friday, May 11, 2012 2:33 PM
To: Jim Miller
Cc: dbrown@stites.com<mailto:dbrown@stites.com>; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); 'joe@jchilderslaw.com'; 'Joe Childers (childerslaw@yahoo.com<mailto:childerslaw@yahoo.com>)'; kristin.henry@sierraclub.org<mailto:kristin.henry@sierraclub.org>; Nguyen, Quang D (PSC); 'Burns, Faith (PSC)'; Kurt Boehm
Subject: KIUC correspondence to BREC, Docket No. 2012-00063

Please see attached letter regarding the above-referenced docket. Please advise if you have any problems opening.

Michael L. Kurtz, Esq.
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Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
MKurtz@BKLlawfirm.com<mailto:MKurtz@BKLlawfirm.com>

Fwd: FW: ACES

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:49 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
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415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jun 11, 2012 at 12:28 PM
Subject: FW: ACES
To: Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>

Michael L. Kurtz, Esq.

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Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Michael Kurtz
Sent: Monday, June 11, 2012 1:17 PM
To: 'Jim Miller'
Cc: Tyson Kamuf; Brown, David; Kurt Boehm; Philip Hayet; Lane Kollen
Subject: RE: ACES

Jim.

Phil would be in the best position to answer those technical questions. I don't know.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Monday, June 11, 2012 1:08 PM
To: Michael Kurtz
Cc: Tyson Kamuf; Brown, David; Kurt Boehm; Philip Hayet; Lane Kollen
Subject: RE: ACES

Mike,

I am awaiting the list of conditions from ACES, including a confidentiality agreement, and should probably get those to you before we talk. We are supposed to see that this afternoon. Who will be the licensee of the Ventyx software for KIUC? Are any of the other intervenors or their experts licensed or getting licensed on the software, as far as you know?

Jim

James M. Miller

Sullivan, Mountjoy, Stainback & Miller, P.S.C.

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CONFIDENTIALITY STATEMENT:

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From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 11, 2012 10:40 AM
To: Jim Miller
Cc: Tyson Kamuf; 'Brown, David'; Kurt Boehm; 'Philip Hayet'; 'Lane Kollen'
Subject: ACES

Jim.

I just listened to your voice mail from Friday afternoon. Just talking with me will do little good about whether the ACES resolution you mentioned will work.

Can you do a conference call today before 12:30 eastern, or after 4:00 eastern to discuss?

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

Fwd: Conference call

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:48 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
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kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kristin Henry** <kristin.henry@sierraclub.org>
Date: Mon, Jun 11, 2012 at 1:58 PM
Subject: Re: Conference call
To: "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>

Looks good to me.

Kristin Henry
Staff Attorney
Sierra Club
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kristin.henry@sierraclub.org

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On Mon, Jun 11, 2012 at 1:45 PM, Howard, Dennis (KYOAG) <dennis.howard@ag.ky.gov> wrote:

The OAG is fine with all the suggested changes.

Dennis Howard, II
Assistant Executive Director
Office of Rate Intervention
Office of the Attorney General
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601
502.696.5453
dennis.howard@ag.ky.gov

From: Brown, David [mailto:DBROWN@stites.com]
Sent: Monday, June 11, 2012 4:24 PM

To: Kurt Boehm; Lane Kollen
Cc: Michael Kurtz; Kristin Henry; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Shannon Fisk
Subject: RE: Conference call

Kurt - a few more edits.

David

David C. Brown
Stites & Harbison, PLLC
400 W. Market Street
Suite 1800
Louisville, KY 40202-3352
Direct Dial: (502) 681-0421
Fax: (502) 779-8251
dbrown@stites.com

From: Kurt Boehm [mailto:KBoehm@bkllawfirm.com]
Sent: Monday, June 11, 2012 4:01 PM
To: Kurt Boehm; 'Lane Kollen'; Brown, David
Cc: Michael Kurtz; 'Kristin Henry'; 'Cook, Larry (KYOAG)'; 'Philip Hayet'; 'Hans, Jennifer (KYOAG)'; 'Howard, Dennis (KYOAG)'; 'Shannon Fisk'
Subject: RE: Conference call

As discussed on the call, a revised Motion for Stay is attached. We intend to file this by the end of the

day.

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

office: 513-421-2255

mobile: 513-290-6683

fax: 513-421-2764

From: Kurt Boehm
Sent: Monday, June 11, 2012 1:58 PM
To: 'Lane Kollen'; Brown, David
Cc: Michael Kurtz; Kristin Henry; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Shannon Fisk
Subject: RE: Conference call

Counsel- In advance of the 3:00 call, please review KIUC's draft of a Motion to Stay the procedural schedule until BREC has answered the first set of DRs. We would like to discuss the possibility of making this a joint motion.

Thanks

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

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mobile: 513-290-6683

fax: 513-421-2764

From: Lane Kollen [mailto:lkollen@jkenn.com]
Sent: Monday, June 11, 2012 1:33 PM
To: Brown, David

Cc: Michael Kurtz; Kristin Henry; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Kurt Boehm; Shannon Fisk
Subject: Re: Conference call

Okay w me.

Lane

On 6/11/2012 1:30 PM, Brown, David wrote:

OK with me.

David Brown

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 11, 2012 1:26 PM
To: 'Kristin Henry'
Cc: Lane Kollen; Brown, David; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Kurt Boehm; Shannon Fisk
Subject: RE: Conference call

Fine with me.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Monday, June 11, 2012 1:23 PM
To: Michael Kurtz
Cc: Lane Kollen; Brown, David; Cook, Larry (KYOAG); Philip Hayet; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Kurt Boehm; Shannon Fisk
Subject: Re: Conference call

I am not available until later in the day. Can we do 3:00 eastern.

On Jun 11, 2012 6:28 AM, "Michael Kurtz" <MKurtz@bkllawfirm.com> wrote:

A conference call to discuss BREC's response to our joint motion is in order. How about this afternoon at 2:00 eastern?

866-906-9888 pass code 518-4986

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

Fwd: FW: KIUC discovery issue

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:40 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kristin Henry** <kristin.henry@sierraclub.org>
Date: Tue, Jun 12, 2012 at 12:31 PM
Subject: Re: FW: KIUC discovery issue
To: Kurt Boehm <KBoehm@bkllawfirm.com>
Cc: Shannon Fisk <sfisk@earthjustice.org>, Philip Hayet <philhaye@concentric.net>, Michael Kurtz <MKurtz@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>

We can confirm that I am seeing the same problems with 1a, 2a, 2b, 3, and 5 listed below. However, I cannot comment on the others at this point.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

PRIVILEGE AND CONFIDENTIALITY NOTICE
This message is intended only for the use of the individual or entity to which it is addressed and may contain information that is

On Tue, Jun 12, 2012 at 8:58 AM, Kurt Boehm <KBoehm@bkllawfirm.com> wrote:
>
> Shannon and Kristin- Phil Hayet asked me if you would confirm with your consultants that they are having the same issues (described below) with Big Rivers' data?
>
>
>
> Thanks
>
>
>
> Kurt J. Boehm, Esq.
>
> BOEHM, KURTZ & LOWRY
>
> 36 East Seventh Street, Suite 1510
>
> Cincinnati, Ohio 45202
>
> office: 513-421-2255
>
> mobile: 513-290-6683
>
> fax: 513-421-2764
>
>
>
> From: Kurt Boehm
> Sent: Monday, June 11, 2012 5:40 PM
> To: 'Jim Miller'; 'tkamuf@smsmlaw.com'
> Cc: Michael Kurtz; 'Brown, David'; Philip Hayet; Lane Kollen
> Subject: KIUC discovery issue
>
>
>
> Jim and Tyson-
>
> KIUC's consultants have identified several problems with the data supplied by Big Rivers in response to KIUC's First Set of Data Requests. Please address these problems at the earliest possible time.
>
> Below is a description of each problem followed by KIUC's requested action by Big Rivers to rectify the problem:
>
> 1. The April 26, 2012 CD provided input and output data associated with the Company's Financial Models. The following problems were encountered. The Company's Base Case Financial Model was found in:

>
> Financial Forecast (2012-2026) Base Case (No Env. Comp.) 02-.xls
>
> a) As stated in KIUC's Question 1 from our first set of DRs, some of the cell entries in the Financial Model spreadsheet point to spreadsheets that were not supplied. Question 1 requested the Company to supply all spreadsheets that were referenced but had not been supplied to that point. For example, the Worktab PCM, Cell N77 in the above file pointed to another spreadsheet (Big Rivers 2012-2026 (CAIR) Base Case exhibits determin (2-2-12).xlsx) that was not provided. That cell referenced market price data for the month of Jan 2012. BR's DR response stated "Please see the CD Big Rivers filed May 29, 2012, in response to the May 11, 2012, letter from KIUC's counsel to Big River's counsel." The May 29th CD still did not contain the referenced spreadsheets, and it was not clear what file on the May 29th CD BR wanted us to refer to.
>
> b) However, production cost results were supplied by ACES on the May 24 CD in other files that can be matched up to some degree to the results found in the Financial Model spreadsheets. For example, the file associated with the Base Case from May 24th is Big Rivers.15Year.CAIR Base Case.xlsm.
>
> c) Still there are some values in the Base Case Financial Model spreadsheet that cannot be matched precisely. For example, VO&M and SO2 Tons do not appear to match exactly. Most likely it is because ACES performed some calculation in the spreadsheets that we were not given, most likely related to splitting out costs and other results between Big Rivers and Henderson Municipal Power and Light. Without the missing spreadsheets, we don't know all of the additional calculations that ACES performed.
>
> KIUC Request: Please direct KIUC to the referenced spread sheets or properly comply with KIUC Q1.1 and supply all other spreadsheets that were referenced from within each of the Financial Model spreadsheets.
>
> 2) PACE Global supplied two of the files that were on the May 29th CD, and one could not be opened properly:
>
> PACE_Big Rivers Data Request Outputs_120524.xlsx
>
> a) An error message appeared in trying to open this file indicating that Excel found unreadable content in the file. After allowing Excel to try to recover from this error, Excel reported a message stating, "Replaced Part: /xl/worksheets/sheet3.xml part with XML error. The name in the end tag of the element must match the element type in the start tag. Line 2, column 17076013.
>
> b) After that message went away the file opened, two worktabs were found in the spreadsheet:
>
> Output Stochastic Energy Prices- This contains annual market price values ($/MWH - onpeak, offpeak, all hours) for 200 iterations for the years 2012 - 2030. It is not clear what the iterations were and how this information was factored into the evaluations that ACES performed, and there is no documentation that explains that. It would be more clear if ACES gave us fully populated input database files.
>
> Output Hourly Energy Prices - This worktab was completely blank. It is possible that it was blank because of the error that was encountered in opening the file.
>
> KIUC Request: Please re-send a working file PACE_Big Rivers Data Request Outputs_120524.xlsx, which includes market price data.
>
> 3. It appears that the file ACES used containing market price data was - Copy of 2012-26 hrly energy price forecast for PCM (1-18-12) nominal.xlsx. However, there was a problem with this file, as it was unreadable, and Excel indicated that the file was corrupted and could not be opened.
>
> KIUC Request: Please resend a working file.
>
> 4. It appears that the Company did not supply the ACES input assumptions and output results for the Buy and Buy No Smelter Load cases.
>

> There is a very specific Excel spreadsheet for each of the two cases that appear to be missing, and some associated folders appear to be missing.
>
> a) For the "Buy" case, the spreadsheet missing is Big Rivers.15Year.CSAPR By Gen.VarLimits.xlsm.
>
> b) For the "Buy No Smelter Load" case, the spreadsheet missing is Big Rivers.15Year.CSAPR By Gen.VarLimits NoSmelters.xlsm
>
> KIUC Request: For each of those cases, please provide either the location or a working file with the associated folders identified as Assumptions, Data, and Exhibits. There appears to be two files supplied that are very close in the name to the above spreadsheet names, but not identical. KIUC is concerned that unless we have files with the exact name, we may not be looking at the correct files.
>
> 5. On the CD supplied May 29, 2012, Big Rivers supplied the following file - (C-M by eq) sens 2 exh. det. Rev 1 no smltrs 021412.xlsx - This file can't be opened, first Excel reported it had unrecoverable data, then Excel stated it was corrupt.
>
> KIUC Request: Please supply a working file.
>
>
>
> Thank you in advance for your efforts in rectifying this situation.
>
> Kurt
>
>
>
> Kurt J. Boehm, Esq.
>
> BOEHM, KURTZ & LOWRY
>
> 36 East Seventh Street, Suite 1510
>
> Cincinnati, Ohio 45202
>
> office: 513-421-2255
>
> mobile: 513-290-6683
>
> fax: 513-421-2764
>
>
>
>

Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:43 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kurt Boehm** <KBoehm@bkllawfirm.com>
Date: Tue, Jun 12, 2012 at 8:56 AM
Subject: RE: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063
To: "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>
Cc: "dbrown@stites.com" <dbrown@stites.com>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>

I am forwarding the below email to the parties prior to the 2pm call because it may come up in our discussion.

Kurt

From: Kurt Boehm
Sent: Monday, June 11, 2012 5:40 PM
To: 'Jim Miller'; 'tkamuf@smsmlaw.com'
Cc: Michael Kurtz; 'Brown, David'; Philip Hayet; Lane Kollen
Subject: KIUC discovery issue

Jim and Tyson-

KIUC's consultants have identified several problems with the data supplied by Big Rivers in response to KIUC's First Set of Data Requests. Please address these problems at the earliest possible time.

Below is a description of each problem followed by KIUC's requested action by Big Rivers to rectify the problem:

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a) As stated in KIUC's Question 1 from our first set of DRs, some of the cell entries in the Financial Model spreadsheet point to spreadsheets that were not supplied. Question 1 requested the Company to supply all spreadsheets that were referenced but had not been supplied to that point. For example, the Worktab PCM, Cell N77 in the above file pointed to another spreadsheet (Big Rivers 2012-2026 (CAIR) Base Case exhibits determin (2-2-12).xlsx) that was not provided. That cell referenced market price data for the month of Jan 2012. BR's DR response stated "Please see the CD Big Rivers filed May 29, 2012, in response to the May 11, 2012, letter from KIUC's counsel to Big River's counsel." The May 29th CD still did not contain the referenced spreadsheets, and it was not clear what file on the May 29th CD BR wanted us to refer to.

b) However, production cost results were supplied by ACES on the May 24 CD in other files that can be matched up to some degree to the results found in the Financial Model spreadsheets. For example, the file associated with the Base Case from May 24th is Big Rivers.15Year.CAIR Base Case.xlsm.

c) Still there are some values in the Base Case Financial Model spreadsheet that cannot be matched precisely. For example, VO&M and SO2 Tons do not appear to match exactly. Most likely it is because ACES performed some calculation in the spreadsheets that we were not given, most likely related to splitting out costs and other results between Big Rivers and Henderson Municipal Power and Light. Without the missing spreadsheets, we don't know all of the additional calculations that ACES performed.

KIUC Request: Please direct KIUC to the referenced spread sheets or properly comply with KIUC Q1.1 and supply all other spreadsheets that were referenced from within each of the Financial Model spreadsheets.

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a) An error message appeared in trying to open this file indicating that Excel found unreadable

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Output Stochastic Energy Prices- This contains annual market price values ($/MWH - onpeak, offpeak, all hours) for 200 iterations for the years 2012 - 2030. It is not clear what the iterations were and how this information was factored into the evaluations that ACES performed, and there is no documentation that explains that. It would be more clear if ACES gave us fully populated input database files.

Output Hourly Energy Prices - This worktab was completely blank. It is possible that it was blank because of the error that was encountered in opening the file.

KIUC Request: Please re-send a working file PACE_Big Rivers Data Request Outputs_120524.xlsx, which includes market price data.

3. It appears that the file ACES used containing market price data was - Copy of 2012-26 hrly energy price forecast for PCM (1-18-12) nominal.xlsx. However, there was a problem with this file, as it was unreadable, and Excel indicated that the file was corrupted and could not be opened.

KIUC Request: Please resend a working file.

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KIUC Request: Please supply a working file.

Thank you in advance for your efforts in rectifying this situation.

Kurt

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

office: 513-421-2255

mobile: 513-290-6683

fax: 513-421-2764

From: Nguyen, Quang D (PSC) [mailto:QuangD.Nguyen@ky.gov]
Sent: Tuesday, June 12, 2012 8:51 AM

To: Michael Kurtz; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; James Giampietro; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG)
Cc: dbrown@stites.com; Kurt Boehm; Raff, Richard (PSC)
Subject: RE: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

The contact number for the informal conference is (502) 564-9110. Conference Access Code: 5643941.

From: Nguyen, Quang D (PSC)
Sent: Tuesday, June 12, 2012 7:50 AM
To: 'Michael Kurtz'; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; 'James Giampietro'; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG)
Cc: dbrown@stites.com; Kurt Boehm; Raff, Richard (PSC)
Subject: RE: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

All –

Please advise as to your availability today at 2pm, EDT, for a telephonic informal conference to discuss the status of the discovery issue and the procedural schedule. I will forward the call in information shortly.

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 11, 2012 5:06 PM
To: jmiller@smsmlaw.com; DeRouen, Jeff (PSC); Nguyen, Quang D (PSC); Burns, Faith (PSC); Raff, Richard (PSC); tkamuf@smsmlaw.com; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; 'James Giampietro'
Cc: dbrown@stites.com; Kurt Boehm
Subject: Joint Motion to Stay Procedural Schedule, Docket No. 2012-00063

Counsel, attached please find the JOINT MOTION TO STAY PROCEDURAL SCHEDULE of KIUC, SIERRA CLUB and ATTORNEY GENERAL filed in the above-referenced matter. Hard copies will follow by regular, U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

Fwd: Modeling

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:39 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Kristin Henry** <kristin.henry@sierraclub.org>
Date: Thu, Jun 14, 2012 at 4:48 PM
Subject: Modeling
To: Michael Kurtz <MKurtz@bkllawfirm.com>

Hi Mike

I talked to Synapse and, on further thought, they decided that we do not need to have access to the modeling files for this case. Sierra Club doesn't have enough money to pay for modeling this time, so they said that it is okay if they don't see the files. They said that they have been talking to Phil and will continue to talk to Phil about possible approaches to re-running the model.

Thanks for even considering my request.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
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415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

SIERRA CLUB

KIUC's Supplemental Data Requests to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:36 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, Jun 22, 2012 at 1:54 PM
Subject: KIUC's Supplemental Data Requests to BREC, Docket No. 2012-00063
To: "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>
Cc: Kurt Boehm <KBoehm@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Jody Kyler <jkyler@bkllawfirm.com>, "sbaron@jkenn.com" <sbaron@jkenn.com>

Counsel, attached pleas find KIUC'S SUPPLEMENTAL SET OF DATA REQUESTS TO BIG RIVERS ELECTRIC CORPORATION in .Word and .Pdf format for filing in the above-referenced matter. Hard copies will follow by regular, U.S. Mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

Supplemental Set of Data Requests FINAL.docx
48K

KIUC Supplemental Data Requests to BREC.pdf
235K

SIERRA CLUB

Docket No. 2012-00063- Status of Discovery Issue

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:34 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Tyson Kamuf** <tkamuf@smsmlaw.com>
Date: Fri, Jun 22, 2012 at 2:01 PM
Subject: RE: Docket No. 2012-00063- Status of Discovery Issue
To: Kurt Boehm <KBoehm@bkllawfirm.com>, Jim Miller <jmiller@smsmlaw.com>
Cc: dbrown@stites.com, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, Jody Kyler <jkyler@bkllawfirm.com>, Philip Hayet <philhaye@concentric.net>, Lane Kollen <lkollen@jkenn.com>

Kurt and Mike:

As you know, we received from you this afternoon the Non-Disclosure Agreement and Non-Disclosure Certificate signed by Phil Hayet. ACES will now provide Mr. Hayet access to the database. ACES thinks the easiest way for Mr. Hayet to access the database is for Ventyx to release the database directly to Mr. Hayet. ACES has already told Ventyx that it can do so. If Mr. Hayet prefers, ACES has also posted the database on a password protected FTP site, and ACES can provide Mr. Hayet the password.

With regard to Kurt's email below, on the June 12 call, we did not agree that ACES would re-run every scenario. ACES did, however, ask Ventyx to use the stripped-down database to run a scenario to verify that the stripping down of the database did not create any errors or eliminate any necessary information. Ventyx did so, and Ventyx's results were within one-tenth of one percent of ACES' results. This fulfills our commitments made on the June 12 call to provide a working database.

Tyson Kamuf

Sullivan, Mountjoy, Stainback & Miller, P.S.C.

100 St. Ann Street, P.O. Box 727

Owensboro, Kentucky 42302-0727

tkamuf@smsmlaw.com

(270) 926-4000

(270) 683-6694 fax

From: Kurt Boehm [mailto:KBoehm@bkllawfirm.com]
Sent: Thursday, June 21, 2012 1:22 PM
To: Jim Miller; Tyson Kamuf
Cc: dbrown@stites.com; Raff, Richard (PSC); 'Nguyen, Quang D (PSC)'; Michael Kurtz; Cook, Larry (KYOAG); James, Matt (KYOAG); Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica; James Giampietro; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Jody Kyler; Philip Hayet; Lane Kollen
Subject: Docket No. 2012-00063- Status of Discovery Issue

Jim and Tyson-

This is an update concerning KIUC's effort to get the "stripped down database" from ACES and the PAR model from Ventyx as discussed on the June 12, 2012 conference call with the parties and Staff.

We have been coordinating with Ventyx, given they were doing the work to strip down the database, and we knew

they had been in turn coordinating with ACES. Our assumption is that all of the work is being performed in accordance with the agreement we reached on the June 12 call. Last week, KIUC consultant Phil Hayet coordinated with Ventyx to meet at their offices today, June 21, 2012, to obtain the PAR model and the stripped down database. We assumed that ACES would have given Ventyx the green light to release the stripped down database at that time. This had to be cancelled as details concerning the confidentiality agreement have not been finalized, and work on the database has not been completed as per our agreement from the conference call.

When Mr. Hayet attempted to finalize details yesterday regarding the software and database, he learned that two critical items were still outstanding. 1) Run definitions had not been provided by ACES, and in fact did not exist, and 2) no runs had been performed to evaluate whether or not the stripped down database would reproduce the results that ACES had generated and that were filed in testimony.

With regard to the first item, without the run definitions for each case that ACES performed, neither Ventyx nor Mr. Hayet would be able to know how to recreate the ACES runs. This is because the database has many modeling elements located within it, and a proper run definition is required to select the appropriate subset of elements to create the desired run. As of late yesterday, it was Mr. Hayet's understanding that ACES created some document that they supplied to Ventyx, from which the run definitions could be created.

With regard to the second item, as of late yesterday, no runs had been made to prove that all of the runs that ACES had made previously run could be recreated exactly. While we are certainly hopeful that the runs can be reproduced exactly, problems often crop up with this type of work that have to be worked through, and our agreement with Big Rivers was that the data supplied would definitely reproduce the results ACES had previously produced. That was confirmed by Tyson on the June 12 conference call. The mere fact that ACES had to create a written document to tell Ventyx how to recreate the run definitions means that no runs have been performed to validate that the Big Rivers results could be recreated exactly.

It may be possible that since last night ACES has verified that all of the cases can be successfully reproduced using the stripped down database, however, we are not aware of the status. We still need to be supplied with the database once the appropriate validation has been completed, and we need to re-schedule with Ventyx for installation. We request that Big Rivers provide us with a plan to complete these steps as quickly as possible, if they have not been completed already.

We are aware that the confidentiality agreement must be signed before Mr. Hayet may be provided with the database, and we are working to complete that today.

Thanks,

Kurt

Kurt J. Boehm, Esq.

BOEHM, KURTZ & LOWRY

36 East Seventh Street, Suite 1510

Cincinnati, Ohio 45202

office: 513-421-2255

mobile: 513-290-6683

fax: 513-421-2764

SIERRA CLUB

Case No. 2012-00063 Big Rivers

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:35 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Fri, Jun 22, 2012 at 2:42 PM
Subject: Case No. 2012-00063 Big Rivers
To: Jim Miller <jmiller@smsmlaw.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, Michael Kurtz <MKurtz@bkllawfirm.com>, Kurt Boehm <KBoehm@bkllawfirm.com>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, joe@jchilderslaw.com
Cc: "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, James Giampietro <james.giampietro@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>

Attached please find the Public Version of the Attorney General's 2nd Set of Data Requests to Big Rivers, which was filed with the PSC yesterday. Hard copies of both the confidential and non-confidential versions were also mailed to the parties on June 21, 2012.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

12-63 brec ag public supp dr.pdf
711K

SIERRA CLUB

Fwd: Hayet Power System Consulting

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:38 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, Jun 22, 2012 at 8:20 AM
Subject: RE: Hayet Power System Consulting
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Wayne Harris <WayneH@acespower.com>
Cc: Jim Miller <jmiller@smsmlaw.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, "Brown, David" <DBROWN@stites.com>, Kurt Boehm <KBoehm@bkllawfirm.com>, Jody Kyler <jkyler@bkllawfirm.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, Shannon Fisk <sfisk@earthjustice.org>, Kristin Henry <kristin.henry@sierraclub.org>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Michael Kurtz
Sent: Friday, June 22, 2012 10:56 AM
To: 'Wayne Harris'
Cc: 'Jim Miller'; 'Tyson Kamuf'; 'Brown, David'; Kurt Boehm; Jody Kyler; Hans, Jennifer (KYOAG); Shannon Fisk; Kristin Henry; Nguyen, Quang D (PSC)

Subject: RE: Hayet Power System Consulting

Mr. Harris.

We took the NDA you sent last night and accepted all changes. We have red lined the attached off of that. You understand that the model outputs will be treated as public, just as Big Rivers has treated the model outputs. We have made clear in the attached that model inputs (such as fuel costs, market price assumptions) used by ACES will only be disclosed to the Commission and to those parties who have signed a confidentiality agreement with Big Rivers.

We trust that this now addresses your concerns.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Wayne Harris [mailto:WayneH@acespower.com]
Sent: Thursday, June 21, 2012 9:35 PM
To: Michael Kurtz
Cc: 'Jim Miller'; 'Tyson Kamuf'
Subject: RE: Hayet Power System Consulting

Mr. Kurtz:

Please find our redline and clean versions of the proposed Non-Disclosure Agreement and Certificate. It is my understanding that the parties to your case have addressed model inputs and outputs in another agreement to

which APM is not a party, or alternatively you may choose to subsequently address those issues within the parameters of your case. Accordingly, APM will not address those matters in this Non-Disclosure Agreement.

Hopefully we have made some progress and will be able to complete this document tomorrow. Please advise me at your earliest convenience.

Sincerely,

Wayne Harris
Chief Counsel
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032
Email: wayneh@acespower.com
Tele.: (317) 344-7017

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Thursday, June 21, 2012 5:12 PM
To: Wayne Harris
Cc: 'Brown, David'; Kurt Boehm; Jody Kyler; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Nguyen, Quang D (PSC); Hans, Jennifer (KYOAG); Shannon Fisk; Kristin Henry
Subject: RE: Hayet Power System Consulting

Mr. Harris.

We respect the desire of ACES to safeguard its proprietary data base. However, you need to recognize that that data base was relied upon by Big Rivers in its environmental surcharge application and the Commission and parties must have reasonable access to it.

We have taken your proposed NDA and have made the attached changes. Fundamentally, Mr. Hayet will be the only person having access to and using the data base. We expect that the model outputs resulting from the data base use will be treated as public information, just as Big Rivers has treated the model outputs. However, we will treat the data base input assumptions such as market price forecasts, fuel prices, etc. as confidential. Such information will only be provided to the Commission and the parties under seal.

We hope that you find the attached NDA acceptable.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Wayne Harris [mailto:WayneH@acespower.com]
Sent: Wednesday, June 20, 2012 6:26 PM
To: Michael Kurtz
Subject: RE: Hayet Power System Consulting

Mr. Kurtz:

I reviewed your proposed Non-Disclosure Agreement and find that certain aspects do not pertain to ACES Power Marketing. We are not a party to this proceeding. Our interests in safeguarding the database that we are willing to provide to your client's consultant are paramount. Our company has expended significant capital in the creation of the database and uses this database as a mechanism for making profits. We therefore regard the database a proprietary and an ACES Power Marketing trade secret. We will require accountability for anyone having access to the database. We are willing to provide the database to the consultant who is licensed by Ventyx to use the PaR software in conjunction with our database. I have designed our Non-Disclosure Agreement to meet these objectives.

Please review this revised version and call me with any questions or concerns.

Sincerely,

Wayne Harris
Chief Counsel
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032
Email: wayneh@acespower.com
Tele.: (317) 344-7017

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]

Sent: Wednesday, June 20, 2012 2:36 PM
To: Wayne Harris
Subject: RE: Hayet Power System Consulting

Mr. Harris.

We have reviewed the Non-Disclosure Agreement you sent yesterday. It is fundamentally different than the Non-Disclosure Agreement between Big Rivers and KIUC, the Attorney General and the Sierra Club in the environmental surcharge proceeding. We have therefore modeled KIUC's agreement with ACES on the Big Rivers Agreement.

The ACES database is central to Big Rivers carrying its burden of proof in this case. The procedural schedule recently adopted by the Commission assumes that the information in the possession of ACES will be provided promptly. We therefore hope to have this worked out with ACES very soon.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Wayne Harris [mailto:WayneH@acespower.com]
Sent: Tuesday, June 19, 2012 12:04 PM
To: Michael Kurtz
Subject: Hayet Power System Consulting

Mr. Kurtz:

I represent ACES Power Marketing LLC. It is my understanding that you are counsel for KIUC and that you or KUIC has retain Phil Hayet of Hayet Power System Consulting with regard to the case currently before the Kentucky Public Service Commission under Case No. 2011-00401, and captioned as "*In the Matter of: Application of Kentucky Power Company For Approval Of Its 2011 Environmental Compliance Plan, For Approval Of Its Amended Environmental Cost Recovery Surcharge Tariff, And For the Grant Of A Certificate Of Public Convenience And Necessity For The Construction And Acquisition Of Related Facilities*". It is further my understanding that Hayet Power System Consulting desires to have access to the Big Rivers' portion of ACES Power Marketing's Ventyx Planning & Risk (PaR) proprietary database for use exclusively in the aforementioned case after Hayet Power System Consulting has obtained a license from Ventyx.

As may have been communicated to you by counsel for Big Rivers, APM is willing to disclose the Big Rivers portion of the ACES Power Marketing's Ventyx Planning & Risk (PaR) proprietary database to Hayet Power System Consulting and Phil Hayet, subject to: (1) the execution by Hayet Power System Consulting and Phil Hayet of the attached Non-Disclosure Agreement and Non-Disclosure Certification; and (2) verification that Hayet Power System Consulting has executed a license agreement with Ventyx for the Planning & Risk (PaR) software.

Please review the attachments and advise me at your convenience of your client's/expert's approval to these terms.

Sincerely,

Wayne Harris
Chief Counsel
ACES Power Marketing LLC
4140 West 99th Street
Carmel, IN 46032
Email: wayneh@acespower.com
Tele.: (317) 344-7017

Think before you print

NOTICE: This email message and any attachments are for the sole and confidential use of the intended recipients and may contain proprietary and/or confidential information which may be privileged or otherwise protected from disclosure. Any unauthorized review, use, disclosure or distribution is strictly prohibited. If you are not the intended recipient, please contact the sender by reply email and delete the original message from your computer system and destroy any copies of the message as well as any attachments and notify me immediately at (317) 344-7000.

Think before you print

Redlined NDA - Between Hayet and ACES Power Marketinga.docx
26K

SIERRA CLUB

2012-00063 [PUBLIC] Ben Taylor & Sierra Club's 3rd Data Request to Big Rivers

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:32 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Cook, Larry (KYOAG)** <larry.cook@ag.ky.gov>
Date: Wed, Jun 27, 2012 at 10:28 AM
Subject: RE: 2012-00063 [PUBLIC] Ben Taylor & Sierra Club's 3rd Data Request to Big Rivers
To: James Giampietro <james.giampietro@sierraclub.org>, "Kurt J. Boehm" <kboehm@bkllawfirm.com>, jmiller@smsmlaw.com, tkamuf@smsmlaw.com, dbrown@stites.com, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, Philip Hayet <philhaye@concentric.net>, Lane Kollen <lkollen@jkenn.com>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, Jody Kyler <jkyler@bkllawfirm.com>
Cc: Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>

FYI, the AG will not have any modeling-related DRs for BREC.

Yours,

Larry Cook

From: James Giampietro [mailto:james.giampietro@sierraclub.org]
Sent: Wednesday, June 27, 2012 1:21 PM
To: Kurt J. Boehm; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; dbrown@stites.com; Raff, Richard (PSC); Nguyen, Quang D (PSC); Michael Kurtz; James, Matt (KYOAG); Hans, Jennifer (KYOAG); Philip Hayet; Lane Kollen; Cook, Larry (KYOAG); Howard, Dennis (KYOAG); Jody Kyler
Cc: Kristin Henry; Shannon Fisk; Joe Childers; Ruben Mojica
Subject: 2012-00063 [PUBLIC] Ben Taylor & Sierra Club's 3rd Data Request to Big Rivers

Attached please find a cover letter and the PUBLIC version of Sierra Club's 3rd Data Request to Big Rivers in both .PDF and .DOC formats. Paper copies will be delivered to the Commission and mailed out to parties today. In a few minutes a confidential version of this data request will be emailed to those who have singed the confidentiality agreement.

--

James Giampietro

Sierra Club Environmental Law Program

85 2nd Street, 2nd Floor

San Francisco CA, 94105

Office: (415)977-5638

Fax: (415)977-5793

SIERRA CLUB

KIUC's Third Set of Data Requests to BREC, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:30 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Wed, Jun 27, 2012 at 2:08 PM
Subject: KIUC's Third Set of Data Requests to BREC, Docket No. 2012-00063
To: "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Raff, Richard (PSC)" <Richard.Raff@ky.gov>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, Kristin Henry <kristin.henry@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>, Joe Childers <childerslaw81@gmail.com>, Ruben Mojica <ruben.mojica@sierraclub.org>, James Giampietro <james.giampietro@sierraclub.org>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>
Cc: Kurt Boehm <KBoehm@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Jody Kyler <jkyler@bkllawfirm.com>, "sbaron@jkenn.com" <sbaron@jkenn.com>

Counsel, attached please find KIUC'S THIRD SET OF DATA REQUESTS TO BIG RIVERS ELECTRIC CORPORATION in .Word and .Pdf format for filing in the above-referenced matter. Hard copies will follow by regular, U.S. Mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

KIUC 3rd Set of Data Requests, #2012-00063.pdf
115K

Third Set of Data Requests FINAL.docx
33K

SIERRA CLUB

Fwd: Motion to Compel

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:10 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Wed, Jun 6, 2012 at 12:54 PM
Subject: RE: Motion to Compel
To: Kristin Henry <kristin.henry@sierraclub.org>
Cc: Michael Kurtz <MKurtz@bkllawfirm.com>, "Brown, David" <DBROWN@stites.com>, Philip Hayet <philhaye@concentric.net>, Shannon Fisk <sfisk@earthjustice.org>, Jody Kyler <jkyler@bkllawfirm.com>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>

Kristin:

I apologize, but the pleading has been filed. Electronic delivery will be forthcoming shortly. Joe Childers electronically signed for you and Shannon.

Thank you.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Wednesday, June 06, 2012 3:45 PM
To: Hans, Jennifer (KYOAG)
Cc: Michael Kurtz; Brown, David; Philip Hayet; Shannon Fisk; Jody Kyler; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)

Subject: Re: Motion to Compel

I had a few minor edits if it hasn't gone out yet. Also, please sign for me.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

On Wed, Jun 6, 2012 at 11:54 AM, Hans, Jennifer (KYOAG) <jennifer.hans@ag.ky.gov> wrote:

I have signed, and we will file and send copies to docket list by regular mail today. When I receive a stamped copy, I will scan and circulate it to all counsel by email today.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, June 06, 2012 2:19 PM
To: 'Brown, David'; Philip Hayet
Cc: Hans, Jennifer (KYOAG); Shannon Fisk; Jody Kyler; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG);

Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

Same

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Brown, David [mailto:DBROWN@stites.com]
Sent: Wednesday, June 06, 2012 2:18 PM
To: Philip Hayet
Cc: Michael Kurtz; Hans, Jennifer (KYOAG); Shannon Fisk; Jody Kyler; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: Re: Motion to Compel

Jennifer - please sign my name to the final.

David Brown

Sent from my iPhone

On Jun 6, 2012, at 1:56 PM, "Philip Hayet" <philhaye@concentric.net> wrote:

> Mike,
>
> I am reviewing it right now.
>
> Phil
>
> **From:** Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
> **Sent:** Wednesday, June 06, 2012 1:49 PM

To: 'Hans, Jennifer (KYOAG)'; Brown, David; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

You have my permission. David may be out of pocket for a while, but I'm sure is fine to sign for him if he does not respond personally.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Hans, Jennifer (KYOAG) [mailto:jennifer.hans@ag.ky.gov]
Sent: Wednesday, June 06, 2012 1:52 PM
To: Michael Kurtz; Brown, David; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

I can file it today. I am happy to sign for you and David if I have both of your permissions, and I see where Joe has already signed on behalf of the Sierra Club.

Great effort everyone!

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, June 06, 2012 1:41 PM
To: 'Brown, David'; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

All.

Here is what should be considered the final version of the motion, plus the referenced letter. I can overnight from my office. Jennifer, if it is convenient you could sign for the parties and file today. Either way. Let me know.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Brown, David [mailto:DBROWN@stites.com]

Sent: Wednesday, June 06, 2012 9:38 AM
To: Michael Kurtz; Shannon Fisk
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

I think the additions by the Sierra Club are very fine. There are a few editing comments that i will send momentarily.

David

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, June 06, 2012 9:17 AM
To: 'Shannon Fisk'; Brown, David
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG)
Subject: RE: Motion to Compel

All.

Shannon/Kristen.

Thank you for the additions. I think the motion is very compelling. I would like to file it today. I will accept all changes and then make final clean ups. I don't think affidavits are essential and I don't want to delay, so I will remove those references.

Jennifer, we would like to have the AG sign on if you give the go ahead.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Shannon Fisk [mailto:sfisk@earthjustice.org]

Sent: Tuesday, June 05, 2012 10:47 PM
To: Brown, David; Michael Kurtz
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org
Subject: RE: Motion to Compel

Thanks, Mike and David, for drafting this. Attached are some proposed edits and additions from Kristin and me. Please let us know if you have any questions, concerns, etc.

Shannon

From: Brown, David [mailto:DBROWN@stites.com]
Sent: Tuesday, June 05, 2012 1:30 PM
To: Michael Kurtz
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; Shannon Fisk
Subject: RE: Motion to Compel

Mike and All - attached is a clean and marked copy of the original draft that came out last night. Sorry it turned out so messy. What I have tried to do is (i) make it a joint motion, (ii) explain the process and the main issue up front, and (iii) give the Commission the option to issue a subpoena althoguh ACES is in Indiana. The rest of the editing is mainly to eliminate repetition and keeping the focus on the main issue. Mike, I'll leave this up to you. Also I thought I saw some comment from you but they did not make it into this draft.

David

David C. Brown
Stites & Harbison, PLLC
400 W. Market Street
Suite 1800
Louisville, KY 40202-3352
Direct Dial: (502) 681-0421
Fax: (502) 779-8251
dbrown@stites.com

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Tuesday, June 05, 2012 11:48 AM
To: Brown, David
Cc: Jody Kyler; philhaye@concentric.net; kristin.henry@sierraclub.org; sfisk@earthjustice.org
Subject: Re: Motion to Compel

David. Please send your changes to Kristen and Shannon also. Hopefully we will file a joint motion.

Sent from my iPad

On Jun 5, 2012, at 11:41 AM, "Brown, David" <DBROWN@stites.com> wrote:

Mike - I have revisions to suggest and will get thsoe to you in a bit. I think we need to put the precise issue up front.

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Tuesday, June 05, 2012 10:36 AM
To: Brown, David; Jody Kyler
Subject: Fwd: Motion to Compel

Sent from my iPhone

Begin forwarded message:

From: Philip Hayet <philhaye@concentric.net>
Date: June 5, 2012 7:57:36 AM EDT
To: Michael Kurtz <MKurtz@bkllawfirm.com>, 'Lane Kollen' <lkollen@jkenn.com>
Subject: RE: Motion to Compel

Mike,

Here are my changes. If you would like to discuss please call my cell at
770-855-1815. I may not be immediately available but will be able to call
back. I will be back in the office tomorrow.

Thanks,

Phil

-----Original Message-----
From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 04, 2012 10:51 AM
To: 'Lane Kollen'; 'Philip Hayet'
Subject: FW: Motion to Compel

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com

-----Original Message-----
From: Jody Kyler

Sent: Sunday, June 03, 2012 6:10 PM
To: Michael Kurtz
Subject: Motion to Compel

Mike,

Attached is a draft Motion to Compel in the Big Rivers' Environmental Surcharge case. I will probably review the Motion again, but wanted to get
you something now since I will likely be in the Columbus hearing Monday and
Tuesday and at Kentucky new lawyer training on Wednesday and Thursday. I
based the information in the May 11, 2012 letter on the e-mails I reviewed,
but you may want to verify that I quoted the final letter actually sent on May 11, 2012 accurately.

Thanks,

Jody

SIERRA CLUB

Fwd: Big Rivers Modeling Case 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:17 AM
To: James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Mon, Jun 4, 2012 at 2:32 PM
Subject: RE: Big Rivers Modeling Case 2012-00063
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>
Cc: Brenton Meese <Brenton.Meese@ventyx.abb.com>, Jim Miller <jmiller@smsmlaw.com>, dbrown@stites.com, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, joe@jchilderslaw.com, childerslaw@yahoo.com, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>, Kurt Boehm <KBoehm@bkllawfirm.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>, Albert Yockey <Albert.Yockey@bigrivers.com>, Roger.Hickman@bigrivers.com, briana@acespower.com, johnst@acespower.com, Joseph McLeer <Joseph.McLeer@ventyx.abb.com>, Shannon Fisk <sfisk@earthjustice.org>, Christopher Leung <cleung@earthjustice.org>, kristin.henry@sierraclub.org

Counsel:

This is just to advise you that Assistant Attorney General Matt James also joined me on this call. Matt has signed the Confidentiality Agreement supplied by counsel for Big Rivers.

Thank you.

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 04, 2012 9:49 AM
To: 'Kristin Henry'

Cc: Brenton Meese; Jim Miller; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com; briana@acespower.com; johnst@acespower.com; Joseph McLeer; Shannon Fisk; Christopher Leung
Subject: RE: Big Rivers Modeling Case 2012-00063

Kristen.

Yes, the call is today at 5:00 eastern. 866-906-9888 pass code 518-4986

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Monday, June 04, 2012 12:06 AM
To: Michael Kurtz
Cc: Brenton Meese; Jim Miller; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com; briana@acespower.com; johnst@acespower.com; Joseph McLeer; Shannon Fisk; Christopher Leung
Subject: Re: Big Rivers Modeling Case 2012-00063

Mike,

I just wanted to confirm that the call-in information is the same for the new 5:00 pm time.

Thanks,

Kristin Henry

On Wed, May 30, 2012 at 6:03 AM, Michael Kurtz <MKurtz@bkllawfirm.com> wrote:

Everyone.

Thank you for the response. It looks like Monday June 4 at 11:00 am Eastern is the best time. Please use the following call in number: 866-906-9888 pass code 518-4986

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Brenton Meese [mailto:Brenton.Meese@ventyx.abb.com]

Sent: Tuesday, May 29, 2012 9:11 PM

To: Jim Miller; Michael Kurtz; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com
Cc: briana@acespower.com; johnst@acespower.com; Joseph McLeer

Subject: RE: Big Rivers Modeling Case 2012-00063

The Ventyx project manager, Joe McLeer, is very constrained next Monday as he will be at a client site in New Brunswick, Canada.

It is possible that Joe can attend if the call can take place at 11:00am Eastern or thereabouts. We would like to request that an (800) dial-in number be issued with the meeting notice. Please include him on any invitation. Thanks.

BRENTON MEESE
Executive Account Manager
(O) 678.825.1467
(M) 404.964.8882

VENTYX
an ABB company
www.ventyx.com

From: Jim Miller [mailto:jmiller@smsmlaw.com]
Sent: Tuesday, May 29, 2012 6:31 PM
To: Michael Kurtz; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com
Cc: Brenton Meese; briana@acespower.com; johnst@acespower.com
Subject: RE: Big Rivers Modeling Case 2012-00063

All:

Big Rivers can participate in a call on Monday as requested by ACES.

Jim

-----Original Message-----
From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Tue 5/29/2012 3:32 PM
To: Jim Miller; dbrown@stites.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); joe@jchilderslaw.com; childerslaw@yahoo.com; kristin.henry@sierraclub.org; Nguyen, Quang D (PSC); Burns, Faith (PSC); Kurt Boehm; Tyson Kamuf; Lane Kollen; Philip Hayet; Albert Yockey; Roger.Hickman@bigrivers.com
Cc: 'Brenton.Meese@ventyx.abb.com'; 'briana@acespower.com'; 'johnst@acespower.com'
Subject: Big Rivers Modeling Case 2012-00063

Counsel,

After having explored the option of our going to ACES Power Marketing's ("ACES") office to make KIUC's production cost runs, we have now decided to obtain a PAR model license from Ventyx, and will make our own runs. This email is going to all parties involved in providing the software, data and results, including Big Rivers, Ventyx, and ACES Power Marketing,

Mr. Hayet is coordinating with Ventyx to acquire a license to access the same tools (EnerPrise database/Microsoft SQL) that ACES uses to run the PAR model. Mr. Hayet is aware this will require certain hardware and software requirements, which he will arrange for with Ventyx. Mr. Hayet will also work with Ventyx to install the software with the goal of being able to reproduce ACES' results on his own computer. In order to do that, Mr. Hayet understands from Ventyx, that early coordination between ACES, Ventyx, and me will be required.

We suggest that we arrange a conference call for tomorrow if at all possible, between Mr. Hayet, Ventyx, and ACES (and whoever else would be appropriate) to discuss the technical details to help smooth the way, and to minimize unnecessary delays. For example, one question that will have to be answered is whether ACES will provide a database containing just the Big Rivers data, or a large database with all of the companies that it models in it, including Big Rivers. This will be important for us to know what we will have to do to install the model. We are also aware that Ventyx would likely have other questions as well that will have to be answered.

We are targeting the week of June 11th to install the software, so we would like to work through all of the details prior to that.

We would like to have this call tomorrow or Thursday if at all possible so that we can clear Ventyx to proceed with the process and we can finalize the license We would like to ask ACES, Ventyx, Mr. Hayet, and anyone else who wants to be on the call, to indicate times that you are not available on Wednesday and on Thursday, and we will find a time that will hopefully work for everyone.

Thank you for your assistance.

Mike

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com

--

Kristin Henry
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85 Second Street
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SIERRA CLUB

Fwd: BREC Environmental Complinace

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:59 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jun 4, 2012 at 3:07 PM
Subject: RE: BREC Environmental Complinace
To: Shannon Fisk <sfisk@earthjustice.org>, "Brown, David" <DBROWN@stites.com>, Philip Hayet <philhaye@concentric.net>, Kristin Henry <kristin.henry@sierraclub.org>
Cc: Christopher Leung <cleung@earthjustice.org>

Supporting statement or affidavit would be good. Yes, specific examples would be good also. We really need to explain why this information is critical in a big picture way. This could all be resolved with one email from BREC requesting the ACES release the information.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Shannon Fisk [mailto:sfisk@earthjustice.org]
Sent: Monday, June 04, 2012 6:02 PM
To: Michael Kurtz; 'Brown, David'; 'Philip Hayet'; 'Kristin Henry'
Cc: Christopher Leung
Subject: RE: BREC Environmental Complinace

Mike,

I was just thinking the same thing. I will discuss with Kristen, and then we'll get back to you soon.

I gave your motion a quick review and one thought on this is whether you want to include a supporting statement from Phil and/or our expert if we sign on explaining that they always get this sort of information in these types of proceedings. In addition, do we want to add a specific example of how having the specific modeling files, including the various vectors and switches, can be important (the 20% demand vector issue from the Big Sandy proceeding is one such example).

Shannon

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Monday, June 04, 2012 5:50 PM
To: Shannon Fisk; 'Brown, David'; 'Philip Hayet'; 'Kristin Henry'
Subject: BREC Environmental Complinace

Shannon/Kristen.

It appears that KIUC and Sierra Club are in agreement with respect to the discovery impasse. I think a joint motion to compel would carry the most weight with the Commission. A draft motion is attached. If you want to go jointly, then please review and make any improvements you think appropriate. I think we should file something sooner rather than later.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

SIERRA CLUB
FOUNDED 1892

Fwd: BREC

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:10 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Tue, Jun 5, 2012 at 12:22 PM
Subject: BREC
To: "philhaye@concentric.net" <philhaye@concentric.net>, Shannon Fisk <sfisk@earthjustice.org>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, David Brown <DBROWN@stites.com>

Phil can you prepare a short affidavit that mimics the technical assertions in the motion. Shannon can you have your expert do the same?

Sent from my iPad

SIERRA CLUB

Fwd: KIUC's Motion to Compel - Docket #2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 10:11 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Shannon Fisk** <sfisk@earthjustice.org>
Date: Tue, Jun 5, 2012 at 8:18 AM
Subject: RE: KIUC's Motion to Compel - Docket #2012-00063
To: Michael Kurtz <MKurtz@bkllawfirm.com>, Kristin Henry <kristin.henry@sierraclub.org>

Thanks, Mike. We'll look it over and get back to you.

From: Michael Kurtz [MKurtz@bkllawfirm.com]
Sent: Tuesday, June 05, 2012 11:00 AM
To: Kristin Henry; Shannon Fisk
Subject: KIUC's Motion to Compel - Docket #2012-00063

F.Y.I. Attached please find a current draft of KIUC's Motion to Compel for filing in the BREC environmental surcharge case.

Mike

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510
Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764
MKurtz@BKLlawfirm.com<mailto:MKurtz@BKLlawfirm.com>

SIERRA CLUB

Fwd: Joint Motion to Compel - Big Rivers - Case No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:50 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Hans, Jennifer (KYOAG)** <jennifer.hans@ag.ky.gov>
Date: Wed, Jun 6, 2012 at 1:18 PM
Subject: RE: Joint Motion to Compel - Big Rivers - Case No. 2012-00063
To: Kristin Henry <kristin.henry@sierraclub.org>

You are most welcome. Sorry that I missed your edits – good eye by the way. Unfortunately, we have a 3:00 pm EST mail drop that we had to make. I will get used to the time difference for you and other West Coasters eventually. ☺

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

From: Kristin Henry [mailto:kristin.henry@sierraclub.org]
Sent: Wednesday, June 06, 2012 4:10 PM
To: Hans, Jennifer (KYOAG)
Subject: Re: Joint Motion to Compel - Big Rivers - Case No. 2012-00063

Jennifer,

Thanks for taking care of this.

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

On Wed, Jun 6, 2012 at 1:13 PM, Hans, Jennifer (KYOAG) <jennifer.hans@ag.ky.gov> wrote:

Dear Counsel:

Please find attached a courtesy electronic copy of the Joint Motion of Kentucky Industrial Utility Customers, Inc., Ben Taylor and Sierra Club, and Attorney General to Compel or, in the alternative, to Issue Subpoena Duces Tecum, which was filed with the Commission today in the above-referenced docket. Please advise if you have any problems opening. Hard copies have been mailed today as indicated on the certificate of service.

Respectfully yours,

Jennifer Black Hans

Executive Director

Office of Rate Intervention

Office of the Attorney General

1024 Capital Center Drive

Frankfort, KY 40601

(502) 696-5453 (Rate Intervention)

(502) 696-5408 (Direct)

Fax: 502-573-1009

jennifer.hans@ag.ky.gov

SIERRA CLUB

Fwd: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:28 AM
To: Shannon Fisk <sfisk@earthjustice.org>, James Giampietro <james.giampietro@sierraclub.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Cook, Larry (KYOAG)** <larry.cook@ag.ky.gov>
Date: Thu, Jul 12, 2012 at 6:50 AM
Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063
To: Kurt Boehm <KBoehm@bkllawfirm.com>, Jim Miller <jmiller@smsmlaw.com>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Michael Kurtz <MKurtz@bkllawfirm.com>, Tyson Kamuf <tkamuf@smsmlaw.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, kristin.henry@sierraclub.org, sfisk@earthjustice.org, childerslaw81@gmail.com, cleung@earthjustice.org, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>
Cc: dbrown@stites.com, Jody Kyler <jkyler@bkllawfirm.com>

The AG will call in.

From: Kurt Boehm [mailto:KBoehm@bkllawfirm.com]
Sent: Thursday, July 12, 2012 9:32 AM
To: 'Jim Miller'; Nguyen, Quang D (PSC); Michael Kurtz; Tyson Kamuf; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); James, Matt (KYOAG); kristin.henry@sierraclub.org; sfisk@earthjustice.org; childerslaw81@gmail.com; James, Matt (KYOAG); cleung@earthjustice.org; DeRouen, Jeff (PSC)

Cc: dbrown@stites.com; Jody Kyler

Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Quang- KIUC is available at 1pm today.

[Quoted text hidden]

SIERRA CLUB

Fwd: KIUC's Direct Testimony and Exhibits, (Confidential and Non-Confidential), Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:26 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jul 23, 2012 at 1:41 PM
Subject: KIUC's Direct Testimony and Exhibits, (Confidential and Non-Confidential), Docket No. 2012-00063
To: "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, "jmiller@smsmlaw.com" <jmiller@smsmlaw.com>, "tkamuf@smsmlaw.com" <tkamuf@smsmlaw.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, "sfisk@earthjustice.org" <sfisk@earthjustice.org>, "childerslaw81@gmail.com" <childerslaw81@gmail.com>, "cleung@earthjustice.org" <cleung@earthjustice.org>, "DeRouen, Jeff (PSC)" <Jeff.DeRouen@ky.gov>
Cc: "dbrown@stites.com" <dbrown@stites.com>, Jody Kyler <jkyler@bkllawfirm.com>, Kurt Boehm <KBoehm@bkllawfirm.com>, "sbaron@jkenn.com" <sbaron@jkenn.com>, Lane Kollen <lkollen@jkenn.com>, Philip Hayet <philhaye@concentric.net>

Counsel, attached please find the DIRECT TESTIMONY AND EXHIBITS of LANE KOLLEN, and the PUBLIC VERSIONS of the DIRECT TESTIMONY AND EXHIBITS of PHILIP HAYET and STEPHEN J. BARON on behalf of KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC. for filing in the

above-referenced docket. I also attach the CONFIDENTIAL EXHIBITS filed under seal. Hard copies have been sent by regular, U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

5 attachments

Hayet Direct Testimony & Exhibits - (PUBLIC) FINAL.pdf
124K

Baron Direct Testimony & Exhibits (PUBLIC) - FINAL.pdf
608K

Kollen Direct Testimony & Exhibits FINAL.pdf
1808K

CONFIDENTIAL Hayet Direct Exhibits.pdf
40K

CONFIDENTIAL Baron Direct Exhibits.pdf
385K

Fwd: Big Rivers

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:25 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Fri, Jul 27, 2012 at 12:14 PM
Subject: Re: Big Rivers
To: Shannon Fisk <sfisk@earthjustice.org>
Cc: "Kristin Henry (kristin.henry@sierraclub.org)" <kristin.henry@sierraclub.org>

Thanks

Sent from my iPhone

On Jul 27, 2012, at 3:02 PM, "Shannon Fisk" <sfisk@earthjustice.org> wrote:

Mike,

Thanks for reaching out on this. Rachel is going to call Phil to discuss further. I'll keep you posted.

Shannon

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Friday, July 27, 2012 9:54 AM
To: Shannon Fisk; Kristin Henry
Cc: 'Brown, David'; Kurt Boehm; 'Philip Hayet'; '1-Lane Kollen'
Subject: Big Rivers

Shannon/Kristin.

Data requests to intervenors are due Monday. It may be helpful if we could coordinate. For example, perhaps you could ask us to re-run the financial model with some of your adjustments included.

Are either of you available for a conference call this afternoon to discuss. Say 2:00 eastern.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

SIERRA CLUB

Fwd: KIUC 1st Set of Data Requests to Sierra Club, Docket No. 2012-00063

Kristin Henry <kristin.henry@sierraclub.org> Fri, Aug 3, 2012 at 9:23 AM
To: James Giampietro <james.giampietro@sierraclub.org>, Shannon Fisk <sfisk@earthjustice.org>

Kristin Henry
Staff Attorney
Sierra Club
85 Second Street
San Francisco, CA 94105-3441
415.977.5716 phone
415.977.5793 fax
kristin.henry@sierraclub.org

---------- Forwarded message ----------
From: **Michael Kurtz** <MKurtz@bkllawfirm.com>
Date: Mon, Jul 30, 2012 at 10:06 AM
Subject: KIUC 1st Set of Data Requests to Sierra Club, Docket No. 2012-00063
To: Jim Miller <jmiller@smsmlaw.com>, "Nguyen, Quang D (PSC)" <QuangD.Nguyen@ky.gov>, Tyson Kamuf <tkamuf@smsmlaw.com>, "Hans, Jennifer (KYOAG)" <jennifer.hans@ag.ky.gov>, "Howard, Dennis (KYOAG)" <dennis.howard@ag.ky.gov>, "Cook, Larry (KYOAG)" <larry.cook@ag.ky.gov>, "James, Matt (KYOAG)" <Matt.James@ag.ky.gov>, "kristin.henry@sierraclub.org" <kristin.henry@sierraclub.org>, "sfisk@earthjustice.org" <sfisk@earthjustice.org>, "childerslaw81@gmail.com" <childerslaw81@gmail.com>, "cleung@earthjustice.org" <cleung@earthjustice.org>, "Burns, Faith (PSC)" <Faith.Burns@ky.gov>
Cc: Kurt Boehm <KBoehm@bkllawfirm.com>, Jody Kyler <jkyler@bkllawfirm.com>, "dbrown@stites.com" <dbrown@stites.com>

Counsel, attached please find KIUC's First Set of Data Requests to Sierra Club in .Word and .Pdf format filed in the above-referenced matter. Hard copies will follow by regular U.S. mail.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

2 attachments

1st Set of Data Requests to Sierra Club.docx
28K

KIUC 1st Set DR to Sierra Club.pdf
102K

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Two more e-mails to produce

Shannon Fisk <sfisk@earthjustice.org> Sun, Aug 5, 2012 at 10:28 PM
To: "james.giampietro@sierraclub.org" <james.giampietro@sierraclub.org>, "Ruben Mojica (ruben.mojica@sierraclub.org)" <ruben.mojica@sierraclub.org>
Cc: "Kristin Henry (kristin.henry@sierraclub.org)" <kristin.henry@sierraclub.org>

Please include the attached two e-mails with all of the ones that Kristin sent you for the responses to Big Rivers' requests number 15 and 16. Those are the only two e-mails I have with KIUC that Kristin wasn't included on.

Shannon Fisk
Earthjustice
156 William Street
Suite 800
New York, New York 10038
T: 212-791-1881 ext. 8239
C: 215-327-9922

www.earthjustice.org

Because the earth needs a good lawyer

---------- Forwarded message ----------
From: Michael Kurtz <MKurtz@bkllawfirm.com>
To: Shannon Fisk <sfisk@earthjustice.org>
Cc:
Date: Mon, 30 Jul 2012 08:29:47 -0700
Subject: RE: Discovery
Thanks Shannon. We are going to ask you the single question that Phil developed with Rachel.

Michael L. Kurtz, Esq.
BOEHM, KURTZ & LOWRY
36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202
Ph: 513.421.2255 Fax: 513.421.2764
E-mail: mkurtz@BKLlawfirm.com

-----Original Message-----
From: Shannon Fisk [mailto:sfisk@earthjustice.org]
Sent: Monday, July 30, 2012 10:31 AM
To: Michael Kurtz
Subject: Discovery

Mike, we'll be serving on you later today the discovery that we discussed last week.

Sent from my Samsung smartphone on AT&T

---------- Forwarded message ----------
From: Michael Kurtz <MKurtz@bkllawfirm.com>
To: Christopher Leung <cleung@earthjustice.org>
Cc: Shannon Fisk <sfisk@earthjustice.org>, Kim Walton <KWalton@bkllawfirm.com>, Sheila Fisk <SFisk@bkllawfirm.com>
Date: Thu, 12 Jul 2012 14:29:16 -0700
Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Chris.

Sorry. We will fix our certificate.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

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Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

E-mail: mkurtz@BKLlawfirm.com

From: Christopher Leung [mailto:cleung@earthjustice.org]
Sent: Thursday, July 12, 2012 10:22 AM
To: Michael Kurtz
Cc: Shannon Fisk
Subject: RE: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Hi Michael,

One small detail: The motion's certificate of service states that Shannon and I work at the Chicago office of the Natural Resources Defense Council. We actually both work at Earthjustice's New York office at the address listed below. Thanks.

Chris

Christopher Leung

Staff Attorney

Earthjustice

156 William Street, Suite 800

New York, New York 10038

T: 212-791-1881 x8235

F: 212-918-1556

www.earthjustice.org

From: Michael Kurtz [mailto:MKurtz@bkllawfirm.com]
Sent: Wednesday, July 11, 2012 4:51 PM
To: 'Nguyen, Quang D (PSC)'; jmiller@smsmlaw.com; tkamuf@smsmlaw.com; Hans, Jennifer (KYOAG); Howard, Dennis (KYOAG); Cook, Larry (KYOAG); James, Matt (KYOAG); kristin.henry@sierraclub.org; Shannon Fisk; childerslaw81@gmail.com; James, Matt (KYOAG); Christopher Leung; DeRouen, Jeff (PSC)
Cc: dbrown@stites.com; Jody Kyler; Kurt Boehm
Subject: KIUC Motion for Extension & Informal Conference, Docket No. 2012-00063

Counsel, attached pleas find KIUC's MOTION FOR EXTENSION OF TIME AND REQUEST FOR INFORMAL CONFERENCE filed in the above-referenced docket. Hard copies have been sent by regular, U.S. mail.

We have requested that the Commission schedule an informal conference tomorrow (July 12) in order to discuss this motion.

Michael L. Kurtz, Esq.

BOEHM, KURTZ & LOWRY

36 E. Seventh St., Suite 1510

Cincinnati, Ohio 45202

Ph: 513.421.2255 Fax: 513.421.2764

MKurtz@BKLlawfirm.com

Request No. 17

Please provide all emails, memos, and other documents, sent by Sierra Club to persons other than Big Rivers, the Kentucky Attorney General, Ventyx or KIUC since January 1, 2012, regarding this case or analyses performed relating to Big Rivers' environmental compliance options.

Response to Request No. 17 - Respondent: Kristin Henry, Sierra Club Counsel

Sierra Club objects to this request as it impinges on Sierra Club's First Amendment rights and privileges. Sierra Club also objects to this request as it seeks information that is protected by attorney client or work product protection. Subject to and without waiving the foregoing objections, Sierra Club states that there are no documents that are not subject to a legitimate claim of attorney-client privilege or work product protection responsive to this request.

Request No. 18

Please provide all emails, memos, and other documents, sent to Sierra Club from persons other than Big Rivers, the Kentucky Attorney General, Ventyx or KIUC since January 1, 2012, regarding this case or analyses performed relating to Big Rivers' environmental compliance options.

Response to Request No. 18 - Respondent: Kristin Henry, Sierra Club Counsel

Sierra Club also objects to this request as it impinges on Sierra Club's First Amendment rights and privileges. Sierra Club also objects to this request as it seeks information that is protected by attorney client or work product protection. Subject to and without waiving the foregoing objections, Sierra Club states that there are no documents that are not subject to a legitimate claim of attorney-client privilege or work product protection responsive to this request.