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Via Courier

April 22nd, 2013

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

Re: Docket Case No. 2012-00578

Dear Mr. Derouen:

Enclosed for the filing are an original and ten copies of the *ALEXANDER DESHA, TOM VIERHELLER, BEVERLY MAY, AND THE SIERRA CLUB'S RESPONSE TO KENTUCKY POWER COMPANY'S DATA REQUESTS* and a certificate of service in docket 2012-00578 before the Kentucky Public Service Commission. This filing contains no confidential information.

Sincerely,

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
APR 23 2013
PUBLIC SERVICE
COMMISSION

IN THE MATTER OF: APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	Case No. 2012-00578

ALEXANDER DESHA, TOM VIERHELLER, BEVERLY MAY, AND THE SIERRA CLUB'S RESPONSE TO KENTUCKY POWER COMPANY'S DATA REQUESTS

April 22, 2013

VERIFICATION

The undersigned, Tim Woolf, being duly sworn deposes and says he is the Vice President of Synapse Energy Economics, Inc., that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Tim Woolf

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tim Woolf, this the 22 day of April 2013

Notary Public

My Commission Expires: 7-27-18

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

Intervenors Alexander Desha, Tom Vierheller, Beverly May, and Sierra Club (collectively "Environmental Intervenors") hereby submit their responses and objections to Kentucky Power Company's ("KPC") Data Requests.

GENERAL OBJECTIONS

A. Environmental Intervenors object to Requests that are 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 as a trade secret and/or as confidential and proprietary commercial and financial information.

D. Environmental Intervenors object to Requests that seek information that is protected by the First Amendment

E. Environmental Intervenors object to Requests that are overly broad, unduly burdensome, oppressive, or 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 KPC's Request, which are only of marginal value to KPC. Kentucky Civil Rule 26.02.

F. 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.

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

H. Environmental Intervenors do not admit the validity of any legal or factual contention asserted or assumed in the text of any Request.

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

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

1. Please refer to the testimony of Mr. Woolf, Exhibit TW-3, page 3, regarding Efficiency Vermont's 2008 results:

(a) How much (percent of the total claimed) of the reduction in energy use is attributable to residential conversion from incandescent to compact fluorescent light bulbs ("CFLs")?

(b) What baseline technology are the residential CFLs measured against?

(c) For calendar year 2008 and any other year that Sierra Club has the information, what percentage of residential electric consumption in Vermont is attributable to lighting?

(d) What percentage of the residential savings resulted from the early replacement of end-use appliances?

(e) What percentage of the total claimed savings is attributable to business lighting measures?

(f) What baseline technology or technologies were used to measure the business savings for lighting measures?

(g) What was the net-to-gross ratio used by Efficiency Vermont to determine residential lighting savings in 2008?

(h) What was the net-to-gross ratio used by Efficiency Vermont to determine business lighting savings in 2008?

(i) What was the assumption of annual hours of use per CFL bulb used by Efficiency Vermont in 2008?

Response:

(a) – (i) Mr. Woolf did not review the details of Efficiency Vermont's 2008 programs in preparing his testimony, as he neither cited nor directly relied on Efficiency Vermont's 2008 programs in his testimony. Instead, results from those programs were cited in a document that Mr. Woolf cited in his testimony.

End-use specific savings by Efficiency Vermont in 2008 can be found in the 2008 Annual Report and Savings Report, available at
http://www.efficiencyvermont.com/about_us/information_reports/annual_reports.aspx

Net-to-gross ratios by end-use and annual hours of use per CFL bulb used by Efficiency

Vermont can be found in the Technical Reference Manual report developed by Efficiency Vermont. A portion of the Technical Reference Manual is publicly available on-line at http://www.veic.org/Libraries/Resumes/TechManualEVT.sflb.ashx

Note that the rest of report is proprietary, but may be available by contacting Efficiency Vermont.

2. Please refer to the testimony of Mr. Woolf, Exhibit TW-3, page 4, regarding California's "nearly 2%" reduction achieved in 2007:

(a) How much (percent of the total claimed) of the reduction in energy use is attributable to residential conversion from incandescent to compact fluorescent lighbulbs ("CFLs")?

(b) What baseline technology are the residential CFLs measured against?

(c) For calendar year 2007 and any other year that Sierra Club has the information, what percentage of residential electric consumption in California is attributable to lighting?

(d) What percentage of the residential savings resulted from the early replacement of end-use appliances?

(e) What percentage of the total claimed savings is attributable to business lighting measures?

(f) What baseline technology or technologies were used to measure the business savings for lighting measures?

(g) What was the net-to-gross ratio used by California to determine residential lighting savings in 2007?

(h) What was the net-to-gross ratio used by California to determine business lighting savings in 2007?

(i) What was the assumption of annual hours of use per CFL bulb used California in 2007?

(j) Are these results claimed or final evaluated results?

Response:

(a) – (j) Mr. Woolf did not review the details of California's 2007 programs in preparing his testimony, as he neither cited nor directly relied on California's 2007 programs in his testimony. Instead, results from those programs were cited in a document that Mr. Woolf cited in his testimony

End-use specific savings as well as net-to-gross ratio for lighting-related savings can be found in Section 4.2. of the *2006-2008 Energy Efficiency Evaluation Report* prepared by the California

Public Utilities Commission, available at
http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/EM+and+V/2006-2008+Energy+Efficiency+Evaluation+Report.htm

Additional measure specific data can be found in California DEER (Database for Energy Efficient Resources), available at http://www.energy.ca.gov/deer/

3. Is Sierra Club familiar with the *2006-2008 Energy Efficiency Evaluation Report* published in 2010 by the California Public Utility Commission?

(a) If so, please describe the evaluated results relative to the results reported for California on page 4 of Exhibit TW-3 of the testimony of Mr. Woolf.

(b) What was the resultant net-to-gross value for CFLs?

(i) How does this value compare to the net-to-gross assumption in the results for California reported on page 4 of Exhibit TW-3 of the testimony of Mr. Woolf?

(c) What was the resultant annual hours of use per CFL?

(i) How does this value compare to the net-to-gross assumption in the results for California reported on page 4 of Exhibit TW-3 of the testimony of Mr. Woolf?

Response

(a) Mr. Woolf is familiar with the report. A summary of the evaluation results that compare the evaluated results with reported results is presented in the following table taken from page xi in the executive summary of the report. The table below presents net savings impact relative to state savings goals for the reported savings and the evaluated savings. However, it is not clear whether the savings reported on page 4 of Exhibit TW-3 corresponds to the kWh savings results for the 2006-2008 program cycle presented in this table.

	kWh		kW		Therms	
Program Cycle	**Reported**	**Evaluated**	**Reported**	**Evaluated**	**Reported**	**Evaluated**
2002-2003	118%	104%	104%	86%	98%	81%
2004-2005	127%	79%	133%	75%	182%	55%
2006-2008	151%	62%	122%	55%	117%	50%

(b) According to Table 22 of the report on page 95 of the report, gross-kWh and net-kWh for CFL fixture are 55% and 53% of the reported savings respectively.

(i) The CA report cited apparently does not report the net-to-gross assumption used.

(c) The annual hours of use per CFL are apparently not provided in the report.

4. Is Sierra Club familiar with the *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond*, prepared for the California Public Utilities Commission and made available in March of 2012? If so, please describe the levels of "maximum achievable" savings attributable to utility-sponsored programs as a percent of forecast consumption in each of the years 2013-2020.

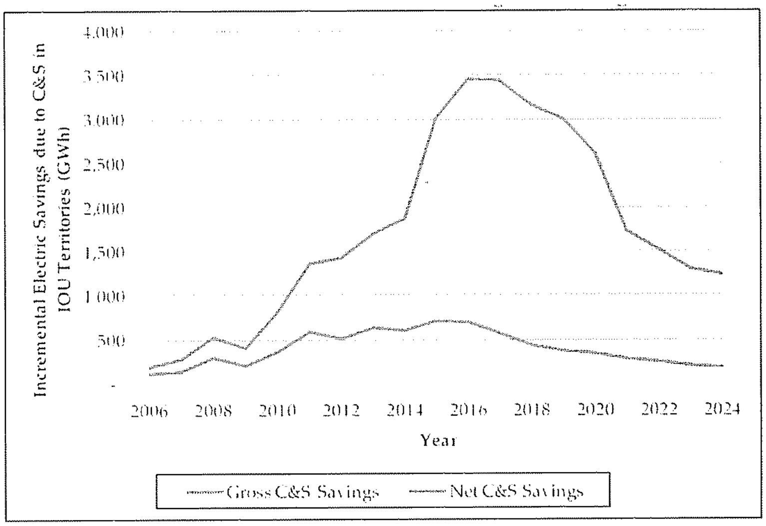
Response

Yes. Before describing the study result, it is important to note that the study results (i.e., achievements and projections for California) are not very relevant to Kentucky for two main reasons. First, California has the most aggressive building codes and standards in the country, which reduce the potential for savings from ratepayer-funded efficiency programs. In contrast, Kentucky building codes and standards are much less aggressive than those adopted in California (ACEEE State Score Card 2012, Table ES-1.) Second, California is likely to have more free riders than other states because it has promoted energy efficiency measures for a longer period of time and therefore has transformed more of the efficiency market.

The California study projected about 2,100 GWh of incremental annual "market potential" (i.e., "maximum achievable potential") in 2016, which is attributable to utility-sponsored programs (See Figure 6, page 10). This level of savings represents approximately 1% of total consumption in the state (See Figure 8 for total state consumption, page 12). This savings level consists of savings for a few technology types by sector as well as the utilities' efforts attributable to new codes and standards. The study also projects annual gross and net savings for codes and standards, the latter of which represents savings attributable to the utility efforts (See the figure below taken from Figure 4 on page 8 of the report). The figure below reveals that the savings attributable to codes and standards that utilities cannot claim (the difference between the gross and net savings) are very large, approximately 3,000 GWh in 2016. Together with the utility program potential, the total potential equals about 5,000 GWh, which exceeds 2% of the forecasted annual consumption in that year. This means that if California did not have aggressive codes and standards, the level of the market potential for the utilities would have been much higher, getting closer to 2% per year because as presented in Appendix Volume II (Table 13, page 138) the study also reveals that the impact from the state's codes and standards is significant.[1]

[1] The study projects energy savings from codes from the following four codes and standards categories: (a) On-the-Books Standards, (b) Future Title 20, (c) Future Title 24, and (d) Future Federal Appliance. Among them, the future federal appliance standard which includes the impact of the EISA is not as significant as the others. On a cumulative basis through 2024, the net impact from the EISA standard for California that utilities can claim is only about 3.6% of the total net energy savings from codes and standards (i.e., 267 GWh over 7,396 GWh). While some of the existing standards may have overlaps with the EISA, it is likely that that are plenty of new savings opportunities beyond the EISA.

Incremental Annual Gross and Net C&S Program Savings for all IOUs (GWh)



5. Please refer to the testimony of Mr. Woolf, Exhibit TW-4.

(a) What part of the 23% of economic potential savings described in the McKinsey & Company report would best be effected by utility-sponsored programs?

(b) Please describe the difference between economic potential and market potential.

(c) What discount rate did McKinsey use in their analysis to determine economic potential?

(d) What was the average cost of energy used in the determination of economic potential?

(e) What part of the 23% of economic potential savings described would best be effected through codes and standards?

(f) What part of the 23% of economic potential savings described would best be effected through tax incentives?

(g) What percentage of end-use savings comes from the industrial sector?

(h) Does the McKinsey study exclude "mining operations" from its analysis?

(i) What percentage of the "Electrical Devices and Small Appliances" potential does McKinsey feel would be in the purview of utility-sponsored efficiency programs?

(j) What discount rates does McKinsey suggest are necessary for energy efficiency investment in the residential, commercial, and industrial sectors?

(k) In Sierra Club's opinion, what will be the average cost of energy, comparable to the McKinsey & Company assumption?

Response

(a), (e), (f), & (i) The study does not allocate savings among different policy tools, even though it does describe such policy tools including utility programs, codes and standards. The extent to which the economic potential can be allocated to utility-sponsored programs generally depends on the aggressiveness of building codes and appliance standards. For example, given that California has some of the most aggressive codes and standards in the nation, the economic energy efficiency potential available for California investor owned utilities naturally become smaller than what is available in other states on a relative term (See response to SC-KPC-4). This means that, for example, a relatively small portion of the total state economic energy efficiency potential may be available for California utilities, but a relatively large portion of Kentucky's economic energy efficiency may be available for Kentucky utilities.

Further, note that the savings potential estimated by McKinsey take into account the impact of the federal EISA lighting and appliance standard. This means that McKinsey's potential estimate is above and beyond the savings expected from the EISA standard.

Please see Attachment SC-KPC-5 for additional information regarding the assumptions in the McKinsey study.

(b) Market potential represents achievable potential, which is a subset of economic potential. Economic potential takes into account the cost-effectiveness of energy efficiency measures and programs without taking into account any barriers regarding measure adaptation by consumers and program implementation. In contrast, market potential takes into account such barriers.

(c) A 7% discount rate. See Exhibit B of the study on page vi.

(d) The McKinsey study stated it "values energy saved at Census-division industrial retail rates from AEO 2008, because it serves as a central value that is publicly available and well understood." (page 118)

(g) The savings associated with the industrial sector accounts for 17% of the total savings in 2020. The table below presents a summary of the results of the McKinsey study by sector.

McKinsey's Estimates for U.S. Electric Energy Savings Potential in 2020

	BAU energy use (TWh)	Electric savings (TWh) savings	Savings as % of sector use	Savings as % of total use
RES	1,510	390	26%	36%
COM	1,660	510	31%	47%
IND	1,050	190	18%	17%
All	4,220	1,090	26%	100%

(h) Yes, the McKinsey study excluded the mining industry from its analysis (page 115 of the study). However, the study identified the technical savings potential for the mining industry from some other studies, which ranges from 60% to 95%, mostly related to on-site transportation, reducing what is transported and increasing efficiency of how it is transported. (page 82 of the study). However, most of this potential would be available from greenfield facilities, as opposed to existing facilities.

(j) It is not clear what rates McKinsey would suggest for these sectors.

(k) The Sierra Club does not have an opinion on the average cost of energy comparable to the McKinsey & Company assumption.

6. Throughout his testimony, Mr. Woolf claims that energy consumption savings may be achieved through the use of energy efficiency and DSM measures. For each such claim, please identify the standard or technology that establishes the baseline against which the savings are calculated.

(a) For each standard identified, please identify whether that standard is currently applicable in Kentucky Power's service area.

Response

When Mr. Woolf makes a general claim that ratepayer-funded energy efficiency and DSM programs can achieve energy savings, he is referring to the savings that can be achieved relative to the electricity system in the absence of the programs. Therefore, the baseline against which the savings can be calculated is the electricity system peak and energy demands in the absence of the programs.

(a) In preparing his testimony Mr. Woolf did not conduct a detailed assessment of Kentucky Power's peak and energy demands in the absence of energy efficiency or DSM programs. Mr. Woolf's conclusions regarding the potential efficiency savings in Kentucky Power's service territory are based on

- a review of the Company's DSM planning assumptions;
- a review of the 2009 EPRI Study that the Company relied upon in its planning assumptions;
- a comparison of the Company's projected savings relative to those of AEP-East;
- a review of the 2007 study entitled "An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential," prepared by Kentucky Pollution Prevention Center and the American Council for an Energy-Efficient Economy;
- a comparison with energy efficiency savings achieved in other states and by other utilities; and
- Mr. Woolf's extensive experience in reviewing energy efficiency in other states and provinces.

See Attachment SC-KPC-6(a) for "An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential," prepared by Kentucky Pollution Prevention Center and the American Council for an Energy-Efficient Economy.

7. In what year were T-12 lighting fixtures last allowed to be sold in the U.S.?

Response

It is my understanding that T-12 lighting fixtures are still allowed to be sold in the US until the current inventories of T-12 bulbs in all stores are exhausted. However, T-12 magnetic ballasts are no longer produced as of July 1, 2010, and many T12 lamps started to be phased out starting in July 2012.

See
http://nuwnotes1.nu.com/apps/clm/eventcalendar.nsf/0/6feae9ce87dcb7968525770a0074d8ea/$FILE/Lighting%20phaseout%20optimized.pdf

8. In what years are the EISA lighting standards for screw-in lights effective?

Response

The EISA lighting standards set minimum lumen per watt efficacy levels (approximately 25 to 30% less power than the traditional incandescent bulbs), which took effect in 2012, and is scheduled to cover four types of bulbs (100W, 75W, 60W, and 40W incandescent bulbs) over time through 2014. After this period, it has a schedule to improve the lighting efficiency to 45 lumens per watt (the current CFL-equivalent level) in 2020. See the following documents:

- "FACT SHEET: General Service Incandescent Lamp Provisions Contained in EISA 2007," available at http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/lighting_legislation_fact_sheet_03_13_08.pdf
- "Residential Lighting Programs and Federal Minimum Lighting Standards: An Overview for Regulators," available at http://www.energystar.gov/ia/partners/manuf_res/LightingfactsheetFinal.pdf

9. In Sierra Club's opinion, specifically as it pertains to CFLs, should utilities continue to provide financial incentives for general service CFL bulbs when the only alternative bulbs are more expensive?

Response

Yes. While the potential energy savings from CFLs diminished due to the EISA lighting standards, CFLs can still provide significant amounts of energy savings over the new baseline. In general, lighting remains one of the most cost-effective energy efficiency measures. For example, see the following reports:

- NEEP. *Northeast Residential Lighting Strategy*, March 2012, available at http://neep.org/regional-initiatives/residential-lighting-2/lighting-strategy
- Lara Ettenson and Noah Long 2010. "Market Transformation and Resource Acquisition: Challenges and Opportunities in California's Residential Efficiency Lighting Programs", proceedings of the 2010 ACEEE Summer Study on Energy, page 6-51 to 6-63. See Attachment SC-KPC-9.
- Navigant Consulting. *Analysis to Update Energy Efficiency Potential, Goals, and Targets for 2013 and Beyond*, prepared for the California Public Utilities Commission, March 2012. (Referenced in the Company's Data Request SC-KPC-4.)

10. In Sierra Club's opinion, what benchmark or standard should T-8 lighting retrofits be measured against, prospectively?

Response

It is my understanding that T-8 lamps have become a practical baseline for new lighting replacement, given the EISA standard has eliminated the production of most types of T-12 lamps in 2012. Accordingly, now energy efficiency choices have become super T-8, T-5 lightings, and LED linear tubes. See for example a description of a lighting program offered by Efficiency Vermont at http://www.efficiencyvermont.com/stella/filelib/SuperT8%20Fact%20Sheet%20Revised%2011-20-06%20Final.pdf

11. For calendar year 2012 and any other year that Sierra Club has the information, what percentage of Kentucky's residential electricity consumption is attributable to lighting?

(a) For each year that Sierra Club has information regarding the percentage of Kentucky's residential electricity consumption that is attributable to lighting, please identify the source of that information.

(b) Please provide copies of all documents used to identify the percentage of Kentucky's residential electricity consumption that is attributable to lighting.

(c) Please provide all spreadsheets, work papers, calculations, analyses, and calculations relating to, reviewed by, consulted, that were performed, consulted or relied upon by Sierra Club to identify the percentage of Kentucky's residential electricity consumption that is attributable to lighting. The requested information should be provided in an electronic format, with formulas intact and visible, and no pasted values.

(d) If the percentage of lighting end-use is less in Kentucky than in Vermont or California, would an identical reduction in the amount of lighting result in a lower or higher overall percentage reduction?

<u>Response</u>

(a), (b) & (c) Mr. Woolf does not have information regarding the percentage of residential electricity consumption that is attributable to lighting. This information was not necessary in preparation of his testimony. Mr. Woolf's conclusions regarding the efficiency potential are relevant regardless of the precise percentage of residential consumption attributable to lighting, because all states have some level of residential consumption attributable to lighting, and there are many energy efficiency opportunities available from residential end-uses other than lighting.

(d) If the percentage of lighting electricity consumption relative to total electricity consumption is less in Kentucky than in Vermont or California, then by definition an <u>identical percentage</u> reduction in the amount of electricity used for lighting would result in a smaller percentage reduction in total electricity consumption.

12. Please identify all studies, reports, analyses or other documents since 2008 that Sierra Club is aware of that demonstrate achieving greater than 0.5% annual energy consumption savings for DSM measures other than lighting upgrades.

Response

There are a number of energy efficiency program administrators which have achieved or are planning greater than 0.5% savings since 2008 including lighting upgrades.

For example, Efficiency Vermont saved nearly 2.5 percent of sales in 2008, and about 2 percent of sales in annual savings in 2010 and 2011. In 2011, non-lighting related savings account for 30% of the total savings, which is also equal to about 0.6% of total annual consumption.

Many states are planning to achieve annual efficiency savings that are significantly greater than 0.5% of retail sales, even with the EISA lighting standards in place. Mr. Woolf is aware of at least three such states.

- Massachusetts is planning to save 2.5%, 2.55%, and 2.6% by 2013, 2014 and 2015, respectively. D.P.U. 12-100 through D.P.U. 12-111, Approval of Massachusetts Program Administrator's 2013-2015 Three-Year Energy Efficiency Plan, January 31, 2013, p 17.

- Rhode Island is planning to achieve savings levels that are comparable to Massachusetts' levels.

- Michigan has a requirement for utilities to save at least 1.0% of sales per year. See http://www.michigan.gov/documents/mpsc/2012_EO_Report_404891_7.pdf; and http://aceee.org/sector/state-policy/michigan

13. Please refer to page 31, lines 15-31 of Mr. Woolf's testimony. Does Sierra Club agree that the Company's April 10, 2013 application seeking Commission approval of the Renewable Energy Purchase Agreement for Biomass Energy Resources between ecoPower Generation-Hazard LLC and Kentucky Power Company will add renewable resources to the Company's portfolio? If the answer to this data request is anything but an unqualified "yes," please provide each fact relied upon by Sierra Club in failing to answer with an unqualified "yes."

Response

The Sierra Club notes that the Renewable Energy Purchase Agreement (REPA) was not included in the Company's economic analysis of the Mitchell purchase. The Sierra Club agrees that that the application states that the contract is for "renewable energy" that will be eligible for producing renewable energy credits (RECs). The Sierra Club has not evaluated whether the REPA will involve renewable energy or will in fact qualify for RECs. Subject to those qualifications and assuming the REPA will produce RECs, the answer to this question is "yes," this would be the type of renewable resource that should have been included in the Company's economic analysis of the Mitchell purchase. Again, assuming the purchase agreement does indeed involve renewable energy, it would help the Company meet future energy and capacity needs, and would be an important addition to the portfolio of resources that could be procured as an alternative to the Mitchell purchase.

14. Please refer to page 32 of the testimony of Tim Woolf. Please provide a copy of the 2012 Synapse Energy Economics study entitled "Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky."

<u>Response</u>

Please see Attachment SC-KPC-14.

15. Please identify whether Mr. Woolf reviewed any studies or other materials or performed any evaluations relating to whether specific renewable resources will be available for the Company to meet a portion of its capacity and energy requirements upon the retirement of Big Sandy Unit 2 in June 2015. Please identify and provide copies of each study or other materials responsive to this request.

Response

Mr. Woolf did not review any studies or other materials relating to whether specific renewable resources will be available for the Company to meet a portion of its capacity and energy requirements.

Mr. Woolf's conclusion that the Company should have assessed renewable resources as part of the economic analysis of the Mitchell purchase was based upon his extensive experience with integrated resource planning practices.

Mr. Woolf's conclusion that there are likely to be renewable resources available in the region is based upon a review of the studies cited on pages 31 and 32 of his testimony, as well as his extensive experience with renewable resource assessment in general.

16. Please refer to pages 22 – 23 of the testimony of Tim Woolf where Mr. Woolf cites to a report prepared by the Brattle Group (the executive summary of which was attached as Exhibit TW-5) to support his claims that Kentucky could reduce its peak demand by 2019 by up to 18 percent depending on the level of demand response implementation. The report included as Exhibit TW-5 contains no state-specific analyses. Please identify and provide all documents used by Mr. Woolf to support his claim that peak demand in Kentucky could be reduced as described in his testimony. Add what we can. FERC documents, TVA study, ACEEE studies in the region.

Response

Please see Attachment SC-KPC-16, which includes Appendix A to the Brattle study. Kentucky-specific results are presented on page 117 to 118 of the report.

Attachment SC-KPC-16 also includes several studies of the potential for energy efficiency and demand response to reduce peak demand in states in the region.

17. Please identify whether Mr. Woolf reviewed any studies or other materials or performed any evaluations regarding the potential effectiveness of DSM measures in Kentucky Power's service area. Please identify and provide copies of each study or other materials responsive to this request.

Response

In preparing his testimony Mr. Woolf did not review any studies or materials regarding the potential effectiveness of DSM measures specifically in Kentucky Power's service area, other than the materials provided by the Company in this docket.

Also, please see response to SC-KPC-6(a) for a summary of the materials that Mr. Woolf did review regarding the potential for efficiency savings in Kentucky.

18. Please identify whether Mr. Woolf reviewed any studies or other materials or performed any evaluations regarding the potential effectiveness of DSM measures for utilities whose customers' average incomes are similar to the average income of Kentucky Power's customers. Please identify and provide copies of each study or other materials responsive to this request.

Response

In preparing his testimony Mr. Woolf did not review any studies or materials regarding the potential effectiveness of DSM measures specifically in Kentucky Power's service area, other than the materials provided by the Company in this docket.

Mr. Woolf did rely upon one study specifically addressing the potential cost-effectiveness of DSM measures in Kentucky. See response to SC-KPC-6(a).

19. Please identify whether Mr. Woolf reviewed any studies or other materials or performed any evaluations regarding the potential effectiveness of DSM measures for steep slope, Central Appalachian mining operations. Please identify and provide copies of each study or other materials responsive to this request.

<u>Response</u>

In preparing his testimony Mr. Woolf did not review any studies or materials regarding the potential effectiveness of DSM measures in Kentucky Power's service area specifically, other than the materials provided by the Company in this docket.

Mr. Woolf did rely upon one study specifically addressing the potential cost-effectiveness of DSM measures in Kentucky. See response to SC-KPC-6(a). That study finds that there are significant cost-effective efficiency savings available in Kentucky, including the industrial sector in Kentucky (see pages 18-20).

20. Please refer to page 26, lines 26-27 of the testimony of Tim Woolf. Please identify and provide all support, including any documents reviewed, for Mr. Woolf's conclusion that "the Company has an obligation to provide DSM services to all of its customers, including industrial customers, in order to offer them one of the best means of reducing their electric bills."

Response

Mr. Woolf did not rely upon any specific documents to support this statement. It is widely accepted that energy efficiency offers customers one of the best means of reducing their electric bills and, therefore, is an important part of achieving a least cost resource plan. It is also widely accepted that electric utilities have an obligation to offer DSM services to all customer types, including industrial customers. Mr. Woolf is not aware of any utilities that offer energy efficiency programs to residential and commercial customers, but not to industrial customers.

21. Please refer to page 31, lines 12-14 of the testimony of Tim Woolf. Please identify and provide all support, including any documents reviewed, for Mr. Woolf's conclusion that "An economic assessment of renewable resources in 2012, in light of the Big Sandy retirement, would very likely find more cost competitive renewable resource potential than the Company found in 2009."

Response

This conclusion is based upon two important developments that occurred between 2009 and 2012.

First, in 2009 the Company was not expecting the Big Sandy unit to retire, and therefore did not face a need for capacity like to does today. With a much greater need for capacity in the near-term on the Company's system, it is likely that renewable resources would be more cost competitive for the Company.

Second, since 2009 many coal plants in the region, and in the US, have been required to install control technologies to comply with evolving environmental requirements. Several companies have retired coal plants instead of installing the control technologies. These changes have resulted in increased operating costs and reduced availability of coal generation. It is likely that renewable resources would be more cost competitive in an environment where coal generation is less available and more expensive.

22. Please refer to page 45, lines 24-31, and page 46, lines 1-15 of the testimony of Tim Woolf.

(a) Please identify which of the assets identified by Mr. Woolf as demonstrating the current market value of coal plants should have been considered by the Company in the review advocated by Mr. Woolf at page 45.

(b) For each such asset please identify and provide all facts and documents supporting Mr. Woolf's contention that the asset is comparable to the Mitchell Generating Station.

Response

As indicated in the testimony, Mr. Woolf did not conduct an "assessment of the details of these recent power plant sales, but even a cursory review of information provided in the recent trade press indicates that the price of the Mitchell purchase is likely to be well above its market value." The coal plants referred to sold for roughly 22 to 23 percent of the per kW price that the Company is paying for the Mitchell purchase.

(a) Mr. Woolf relied upon trade press articles for information on these coal plant sales. These are noted in footnotes 4 and 5 on page 46 of his testimony.

He also relied upon an August 2012 memo prepared by Synapse Energy Economics. It is provided as Attachment SC-KPC-22(a).

He also relied upon a Bloomberg trade press article regarding the recent reduction in asset values for coal plants. This article can be found at http://www.bloomberg.com/news/2012-06-24/coal-plant-plunge-threatens-billions-in-pollution-spend.html.

(b) Note that the plants in the recent power plant sales are comparable to Mitchell in that they are coal-fired steam plants, are relatively old, and have recently installed scrubbers.

23. Please refer to page 46, lines 1-15 of the testimony of Tim Woolf. With respect to the Dominion and Exelon transactions referenced in that portion of the testimony, please provide for each transaction the following:

(a) All documents reviewed or used by Mr. Woolf in his analysis of the transactions.

(b) All spreadsheets, work papers, calculations, analyses, and calculations relating to, reviewed by, consulted, that were performed, consulted or relied upon by Mr. Woolf with respect to the identified transactions. The requested information should be provided in an electronic format, with formulas intact and visible, and no pasted values.

(c) All internal and external Sierra Club reports which relate to the generation plants sold by Exelon and Dominion referenced on page 46, lines 1-15 of Mr. Woolf's Direct Testimony ("Maryland Generation Plants").

(d) All Sierra Club press releases which relate to the Maryland Generation Plants, either as individual generating units or as collective portfolios.

(e) A list of all litigation filed since 2003 where Sierra Club was a party involving the Maryland Generation Plants. For each identified case, please identify the date, other parties to the case, the forum, and the outcome and provide a description of Sierra Club's positions in the lawsuits and claims for relief.

Response

(a) & (b) As indicated in the testimony, Mr. Woolf did not conduct an "assessment of the details of these recent power plant sales, but even a cursory review of information provided in the recent trade press indicates that the price of the Mitchell purchase is likely to be well above its market value." The coal plants referred to sold for roughly 22 to 23 percent of the price that the Company is paying for the Mitchell purchase.

See also response to SC-KPC-22(a).

(c) Sierra Club objects to this request as vague and unlikely to result in information relevant to this proceeding. Subject to the specific and general objections, see Attachment SC-KPC-23(c).

(d) See attachment SC-KPC-23(c).

(e) Sierra Club did not participate as a party in any litigation involving the Maryland Generation Plants. Sierra Club did participate as intervenors in the Maryland PSC docket regarding the Exelon Constellation merger, where it argued for retirement of those facilities.

24. Please refer to page 45, lines 24-31, and page 46, lines 1-15 of the testimony of Tim Woolf. Please identify any transactions noted or reviewed by Mr. Woolf in connection with the preparation of the identified testimony that were not included in the identified testimony. Individually, for each such transaction, please provide the following information:

(a) All documents reviewed or used by Mr. Woolf in his analysis of the transactions that were not included;

(b) All spreadsheets, work papers, calculations, analyses, and calculations relating to, reviewed by, consulted, that were performed, consulted or relied upon by Mr. Woolf with respect to the transactions that were not included. The requested information should be provided in an electronic format, with formulas intact and visible, and no pasted values.

(c) A detailed explanation of the basis for the decision not to include each transaction.

Response

(a), (b) & (c) Mr. Woolf did not review any other coal plant transactions in preparation of his testimony.

25. Is Mr. Woolf aware of the Sierra Club's efforts to force the early retirement of two of the three Maryland Generation Plants sold by Exelon described on page 46, lines 1-9 of his Direct Testimony?

(a) Does Mr. Woolf contend that the Sierra Club's campaign to force the retirement of two of the three Maryland Generation Plants sold by Exelon affects the market price of those plants? If the answer to this data request is anything other than an unqualified "yes," please state each fact upon which Mr. Woolf relies in support of his answer.

Response

In preparing his testimony Mr. Woolf did not make any assumptions or contentions about the factors that lead to the market price of the coal plants cited.

There are many factors that can affect the market price of a coal plant, including but not necessarily limited to: prevailing and expected natural gas prices; prevailing and expected coal prices; the age of the plant; the potential costs of complying with current and future environmental regulations; as well as local, regional and national environmental campaigns such as the Sierra Club's campaign.

Furthermore, as noted on Exelon's August 9, 2012 press release:

> The sale was required by the Federal Energy Regulatory Commission (FERC), U.S. Department of Justice (DOJ) and the Maryland Public Service Commission as part of Exelon's merger agreement. The transaction, which is subject to approval by FERC and DOJ, is expected to close in the fourth quarter of 2012.[2]

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[2] Available at: http://www.exeloncorp.com/newsroom/PR_20120809_EXC_Mdcoalplantsale.aspx.

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Item No. 26

26. Please refer to page 46, lines 5-7 of the testimony of Tim Woolf. Please provide a unit-specific breakdown of the $1 billion retrofit investments. As part of the breakdown, please provide the type of environmental upgrade installed, the cost of each upgrade and the date the upgrade was placed in service.

Response

As indicated in the testimony, Mr. Woolf did not conduct an "assessment of the details of these recent power plant sales, but even a cursory review of information provided in the recent trade press indicates that the price of the Mitchell purchase is likely to be well above its market value." The coal plants referred to sold for roughly 22 to 23 percent of the price that the Company is paying for the Mitchell purchase.

See also response to SC-KPC-22(a), including the attachment to that response.

List of Attachments

Attachment SC-KPC-5. McKinsey memo comparing their study to EPRI's.

Attachment SC-KPC-6(a). "An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential," prepared by Kentucky Pollution Prevention Center and the American Council for an Energy-Efficient Economy

Attachment SC-KPC-9. Lara Ettenson and Noah Long 2010. "Market Transformation and Resource Acquisition: Challenges and Opportunities in California's Residential Efficiency Lighting Programs", proceedings of the 2010 ACEEE Summer Study on Energy.

Attachment SC-KPC-14. Synapse RPS Potential Study.

Attachment SC-KPC-16. Appendix A to Brattle Study.

Attachment SC-KPC-22(a). Synapse 8/29/2012 memo on Excelon's coal plant sale.

Attachment SC-KPC-23(c). Sierra Club Press Releases.

CERTIFICATE OF SERVICE

I certify that I mailed a copy of Alexander Desha, Tom Vierheller, Beverly May, and The Sierra Club's Response To Kentucky Power Company's Data Requests Information by first class mail on April 22nd, 2013 to the following:

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ATTACHMENTS

SC Responses to

KPC-5

EPRI and McKinsey Reports on Energy Efficiency: A Comparison

The Electric Power Research Institute (EPRI) and McKinsey & Company recently released separate reports on the topic of energy efficiency in the United States. McKinsey's Unlocking Energy Efficiency in the U.S. Economy released in July 2009 analyzes the NPV-positive potential for energy efficiency, identifies barriers to capturing that energy efficiency opportunity, and explores the solutions that could address those barriers. EPRI's Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S. released in January 2009 provides analysis of the Technical and Economic potential for energy efficiency, then uses historical energy efficiency program performance to estimate Maximum Achievable and Realistic Achievable Potential for energy efficiency.

Despite differences in methodology and potential sizing, both reports are in agreement on the following key messages:

- Energy efficiency offers a vast low-cost energy source for the U.S.
- Significant and persistent barriers to energy efficiency exist and will need to be addressed on multiple levels to stimulate demand for energy efficiency measures
- New sources of no- and low-carbon energy generation will still be necessary in conjunction with energy efficiency as part of a portfolio of energy solutions.

EPRI and McKinsey reports approach the question of energy efficiency from different perspectives. EPRI focuses on understanding existing programs and best practices to capture energy efficiency and analyzing likely achievability based on current experience. McKinsey focuses on understanding the opportunity available, and exploring ways to significantly change the status quo in ways that will overcome the significant barriers currently facing the energy efficiency opportunity.

Additionally, EPRI and McKinsey employ different methodologies, with differences in scope, technologies considered, and assumptions in characteristics of these technologies. These factors lead to differences in the sizing of the energy efficiency potential. Comparing EPRI's estimate for Economic potential of 473 TWh in the year 2020 to McKinsey's estimate for NPV-positive potential of 1080 TWh for the same year yields the following four sources of difference[1]:

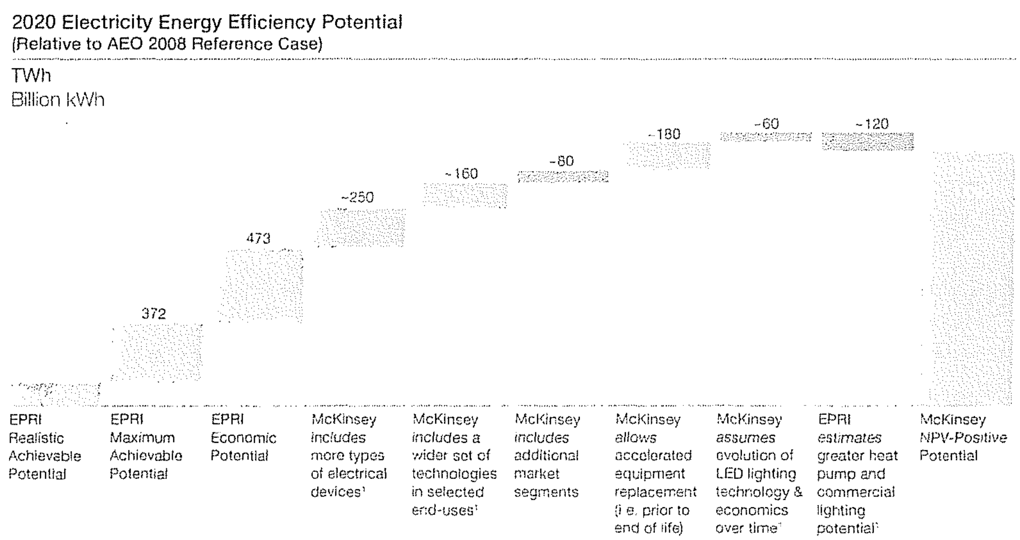
- *McKinsey report addresses additional end-uses of energy.* The McKinsey report included within its scope additional sources of end-use energy consumption, such as: community infrastructure (e.g., street lighting, traffic lighting, water distribution facilities, waste water treatment plants and telecom infrastructure); additional industrial processes; additional categories included in residential and commercial electronic devices and small appliances; and additional commercial and residential building shell measures. These differences in scope (which on the chart include the additional market segments, additional types of electrical devices, and a wider set of technologies utilized in some end-uses) account for 490 TWh of the higher potential in the McKinsey report.
- *McKinsey report allows accelerated deployment of energy-efficient technology prior to end of life.* If the energy savings produced by an efficiency measure would fully pay for itself (i.e., total levelized cost including capital, operation and maintenance, and energy costs of the new measure is less than the current stock's levelized energy cost only), then the current stock is replaced with the new technology in McKinsey's methodology, but not in EPRI's calculations. For example, McKinsey allows an incandescent bulb to be replaced with a CFL or LED without waiting for the incandescent bulb to reach its natural end of life replacement cycle if this cost-effectiveness test is met. This acceleration drives an additional 180 TWh in the potential found in the McKinsey report. (Note: this is in essence a timing difference between the two

1 [illegible]

reports, as both methodologies would ultimately recognize cost effective savings to the extent they use similarly efficient technologies)

- *EPRI report applies existing technology performance and economics, while McKinsey report assumes advancement of technology and economics over time* The EPRI report utilizes current, verifiable, technology cost and efficiency data through the forecast horizon The McKinsey report, in contrast, uses datasets from the National Energy Modeling System that factor in conservative technology cost and efficiency improvements overtime. In general, this means that technologies decrease in cost over time in the McKinsey methodology (e.g., LED light bulbs will be more expensive in the near-term, and trend down over time with manufacturing scale and expected deployment, as well as improvements in their technology). This difference in underlying data accounts for another 60 TWh of increased potential found in the McKinsey report.
- *EPRI report uses more aggressive assumptions in the technology characteristics of some technologies, a lower discount rate, and customer-specific retail rates to value the energy saved.* The calculation of economic potential requires assumptions in the discount rate, the value of energy saved, and the technology characteristics of the measures being utilized. EPRI uses a 5% discount rate while McKinsey employs a 7% discount rate, which has the effect of making measures generally more economic in EPRI's analysis. In addition, McKinsey employs industrial retail rates as a proxy for the avoided cost of energy, while EPRI uses customer-specific (i.e., participant) retail rates. Lastly, for some technologies (e.g., heat pumps and commercial lighting), EPRI has differing technology assumptions that make these measures economic, driving additional potential from the McKinsey report, which does not consider these technologies economic. Contrary to the prior three differences, this difference causes EPRI to find a higher potential than the potential found in the McKinsey report. These differences in methodology drive an increase in the potential found by EPRI of 120 TWh

Comparison between EPRI and McKinsey energy efficiency potential values, year 2020



ATTACHMENTS

SC Responses to

KPC-14

Synapse
Energy Economics, Inc.

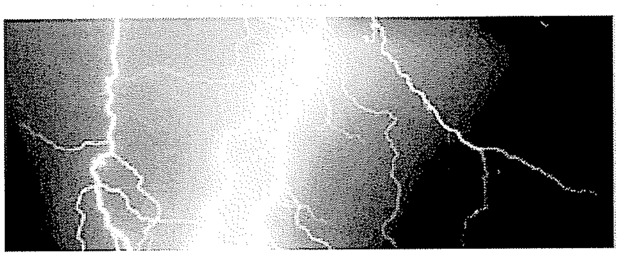
Potential Impacts of a Renewable and Energy Efficiency Portfolio Standard in Kentucky

Prepared for the Mountain Association for Community Economic Development & the Kentucky Sustainable Energy Alliance

January 12, 2012

AUTHORS

Rick Hornby, Dr. David White, Dr. Tommy Vitolo, Tyler Comings, and Kenji Takahashi



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1. Executive Summary

Legislation being introduced in the Kentucky General Assembly proposes to establish a Renewable and Energy Efficiency Portfolio Standard (REPS) for utilities in the state. The Mountain Association for Community Economic Development (MACED) and the Kentucky Sustainable Energy Alliance (KySEA) retained Synapse Energy Economics, Inc. (Synapse) to estimate the potential impacts of establishing such a standard. The study estimates the impacts of a REPS on Kentucky's portfolio of electricity resources, on average electric bills, and on the state's economy.

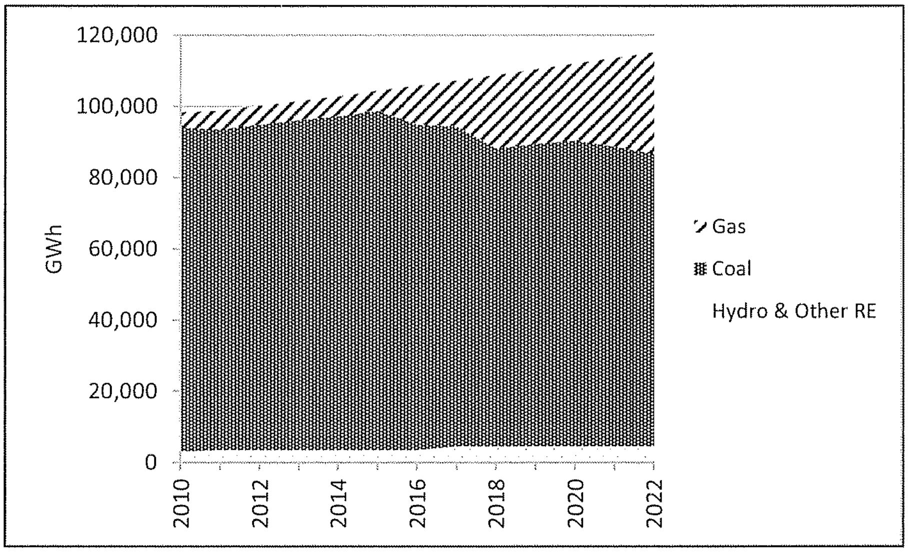
Proposed REPS. The study assumes the goals of the REPS would be to promote energy independence and security by diversifying the state's generating mix, stabilizing long-term energy prices, and creating high-quality jobs and business opportunities. It assumes the REPS would require all utilities in the state to meet specific portions of their retail load through energy efficiency (EE) and from renewable energy (RE) respectively. The assumed required cumulative reductions from EE begin at 0.25 percent in 2014 and increase to 10.25 percent of aggregate retail load by 2022. The assumed required cumulative portions of retail load to be met from RE begin at 2.25 percent in 2014 and increase to 12.5 percent by 2022.

Study Methodology. The study estimates various impacts of the proposed REPS over the ten year period 2013 – 2022 using a scenario approach. It then projects supply mix and average electric bills under a Business-as-Usual (BAU) scenario, i.e., a future without a REPS, and under a REPS scenario. The study develops the REPS scenario by estimating the cost of achieving the EE reductions and of acquiring the RE resources required under the REPS legislation. Finally, the study calculates the incremental impacts of the REPS scenario relative to the BAU scenario in terms of the state's electricity supply portfolio, average electric bills, and economic activity. All values are expressed in constant 2010$ unless noted otherwise.

The BAU scenario and the REPS scenario are based on a number of common assumptions. Both scenarios are based on the same projection of retail electric requirements excluding the effects of EE, which is an average annual rate of growth of 1.5% over the study period. Second, both are based on the same projections of electricity resource capital and operating costs, including projected long-term prices for coal and natural gas. Third, both scenarios assume Kentucky utilities will comply with new, more stringent regulations of various air emissions that are currently scheduled to take effect in 2016. Finally, both scenarios assume that carbon emissions from all generating units, both existing and new, will be subject to regulation beginning in 2018 at a cost per ton of $15 (2010$). Given the uncertainty regarding the timing and magnitude of future regulation of carbon, Appendix C of the study presents an estimate of the summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022.

BAU scenario. Historically almost all of Kentucky's annual supply of electric energy has been coal-fired generation. For example, in 2010 Kentucky met over 92% of its annual retail electric requirements from coal-fired generation. The BAU scenario projects that coal-fired generation would decline but would continue to supply the majority of the state's annual electric energy requirements, as indicated in Figure 1-1. For example, the study projects that generation from coal would account for approximately 71% of the state's supply in 2022. The decline in coal-fired generation is due to generation from new gas-fired units projected to replace older coal units scheduled to retire starting 2016 and to meet load growth. Under the BAU scenario Kentucky utilities are projected to meet less than 5% of annual retail electric requirements from resources other than coal and natural gas.

Figure 1-1. BAU scenario annual electricity requirements and sources

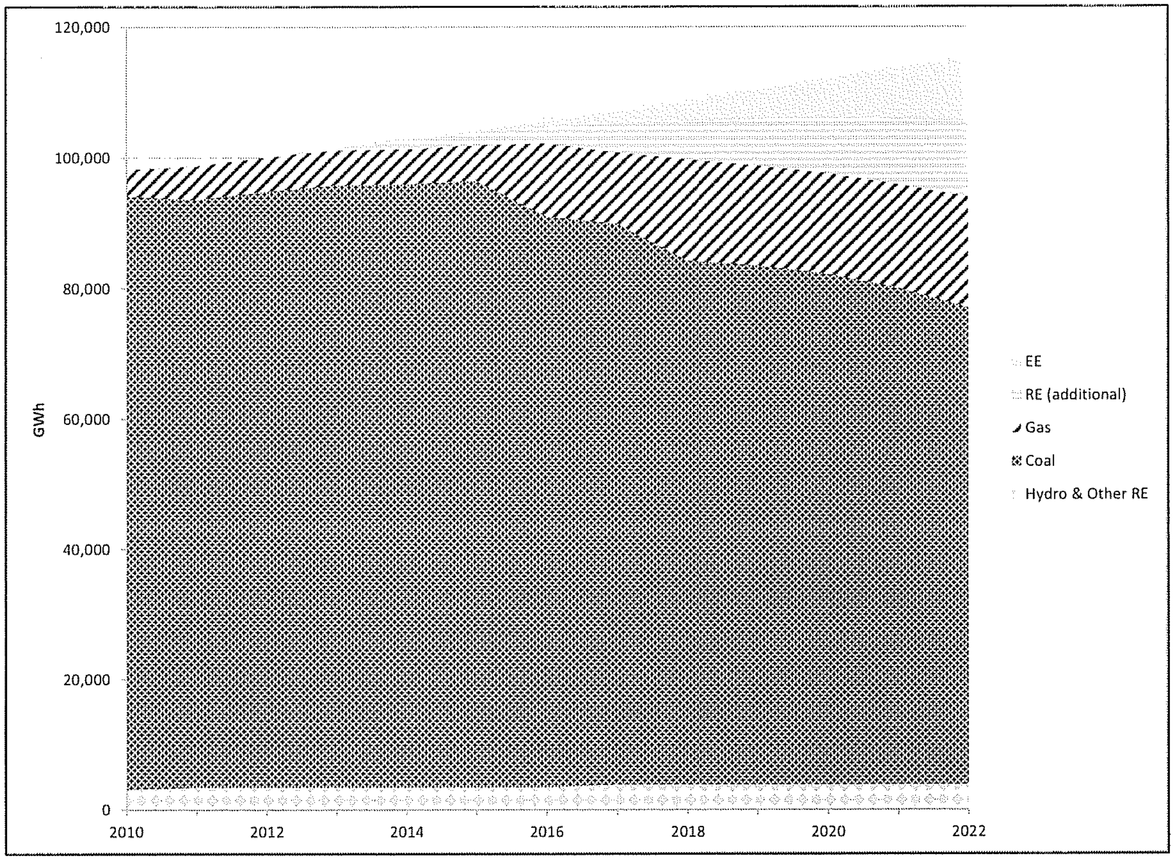


Average electricity prices and average electric bills are projected to increase substantially under the BAU, primarily due to the capacity costs of new gas-fired units and the higher costs of generation from those units (i.e., production costs). For example, the BAU scenario projects state-wide average residential bills would increase approximately 47 percent, in constant dollars, between 2010 and 2022.

The marginal, or avoided, cost of electricity under the BAU scenario is projected to double over the study period, from less than 4 cents/kWh in 2012 to approximately 9 cents/kWh by 2022. This increase is again attributable to the projected costs of adding and dispatching new gas-fired capacity as well as to the projected cost of complying with carbon regulation from 2018 onward.

REPS Scenario. The REPS scenario estimates the impacts of meeting total annual retail electricity requirements using greater levels of EE and RE than under the BAU scenario. The additional quantities of EE and RE would displace some of the generation from natural gas and coal projected under the BAU scenario. Under the REPS scenario, Kentucky would have a more diverse electricity resource portfolio, as illustrated in Figure 1-2. For example, the state's dependence on coal would decrease to approximately 63% of total annual requirements by 2022. This diversification of the state's generating mix has the potential to produce a number of benefits beyond those examined in this report, including mitigation of operational and financial risks.

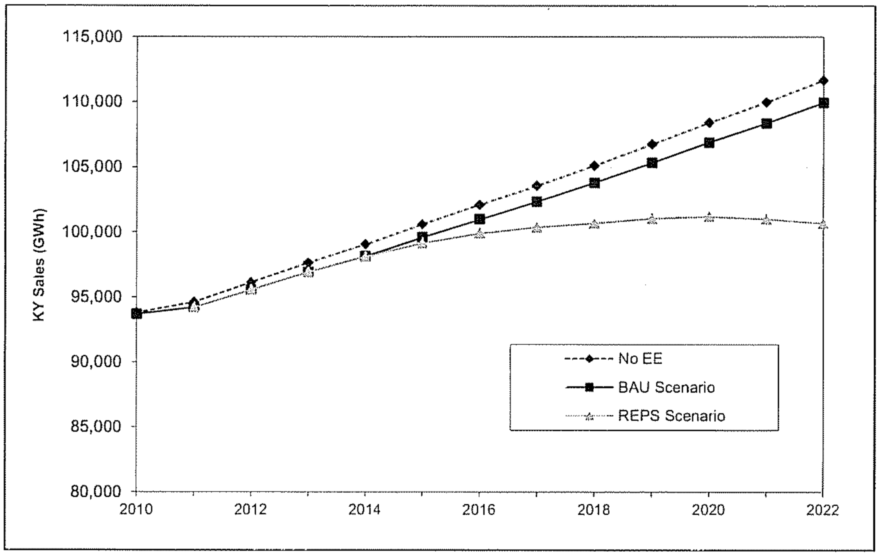
Figure 1-2. REPS scenario annual electricity requirements and sources



Additional EE reductions under REPS scenario. Our analyses project that, by 2015, cumulative reductions from EE required under a REPS would be large enough to offset incremental growth in annual electric sales. The potential for EE to flatten annual sales after 2015 is illustrated in Figure 1-3 (below).

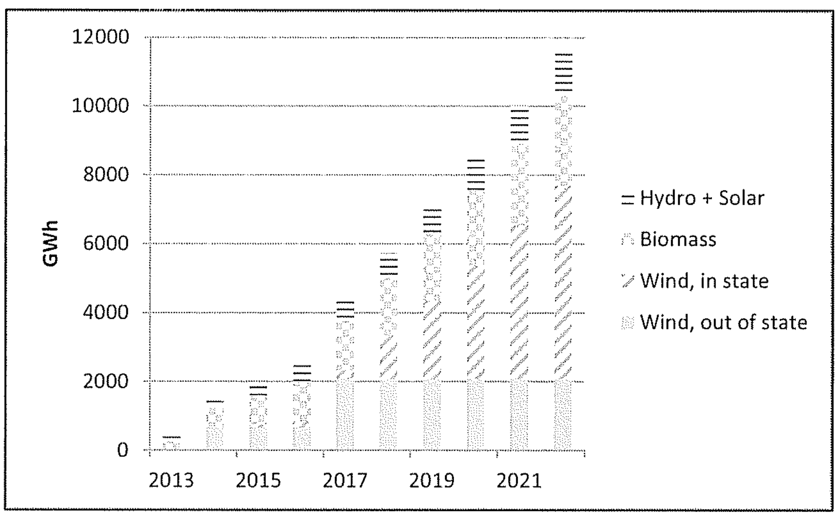
By capping annual retail sales, those EE reductions would reduce the quantity of new peaking capacity needed over the study period as well as reduce the quantity of annual generation required from new gas-fired plants. The study estimates these EE reductions could be achieved at levelized costs ranging between 3 cents/kWh and 4 cents/kWh, considerably less than the avoided costs projected under the BAU scenario.

Figure 1-3. Total annual sales without EE, BAU scenario, and REPS scenario



Additional RE generation under REPS scenario. The study projects that Kentucky could eventually acquire the majority of the additional RE generation required under the REPS scenario from in-state resources, primarily biomass and wind. The study projects that Kentucky utilities would acquire a portion of their required RE as wind energy imported from out-of-state, particularly during the initial years when in-state resources are being developed. The study assumes utilities would satisfy the solar RE requirement through a combination of solar water heating installations at customer sites and large-scale photovoltaic (PV) projects. Figure 1-4 illustrates the mix of projected additional RE sources.

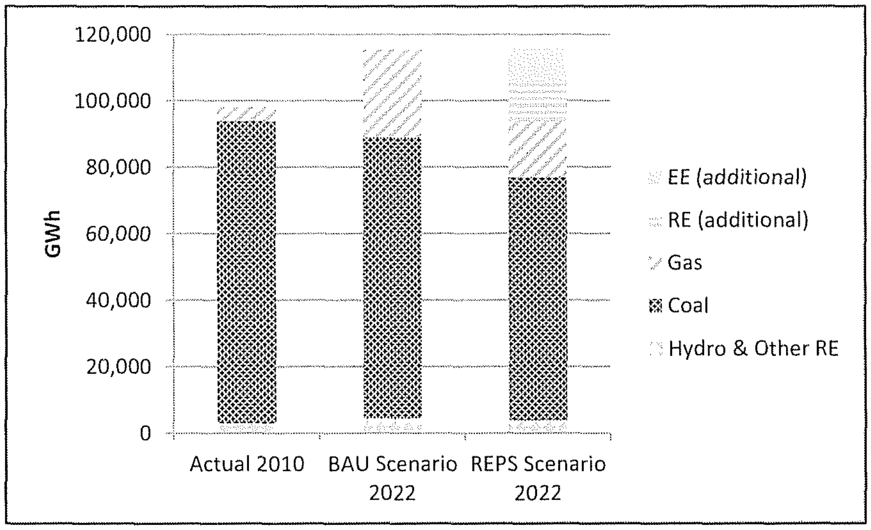
Figure 1-4. Mix of additional RE under REPS scenario



The cost of electricity from RE varies by RE resource and project scale. The study projects that the total cost of generation from new RE projects, i.e. capital plus variable production, will become increasingly competitive with generation from new natural gas units and existing coal units over time due to increases in the costs of carbon emissions and decreases in the costs of RE technologies.

Impact of REPS on Kentucky electricity resource portfolio. The study projects that the REPS would lead to a more diverse electricity resource portfolio. For example, by 2022 the state's utilities would be achieving reductions from EE equivalent to 10.2 percent of annual retail sales and acquiring generation from RE equivalent to 12.5 percent of annual sales. Those quantities of EE and RE would enable the state to reduce its dependence on generation from coal and natural gas for its total annual energy requirements in 2022 from 71 percent and 25 percent under the BAU scenario to 63 percent and 15 percent under the REPS scenario, as indicated in Figure 1-5. Kentucky would have 15% less emissions of carbon dioxide under the REPS scenario than under the BAU scenario as a result of these increased quantities of EE and RE.

Figure 1-5. Annual electricity requirements and sources in 2022 - REPS versus BAU



Impact of REPS on electric bills. The study indicates that the REPS would lead to lower electric bills over time. If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to lower electric bills, although the savings would be less.

The study projects electric bills will increase under the REPS scenario, but by lesser amounts than under the BAU scenario. For example, the study projects annual bills will be approximately 8 to 10 percent lower under the REPS scenario in 2022 than under the BAU scenario, as indicated in Table 1-1. The lower average bills in that year are primarily due to the fact that, under the REPS scenario, retail customers are projected to use approximately 8 percent less electricity on average than under the BAU scenario due to reductions from EE. After 2022 the study projects that average bills would continue to be less under the REPS scenario, as the cost of electricity from

RE is projected to continue declining relative to the cost of electricity from coal-fired and natural gas generation.

Table 1-1. Annual electricity bills in 2022 - REPS versus BAU

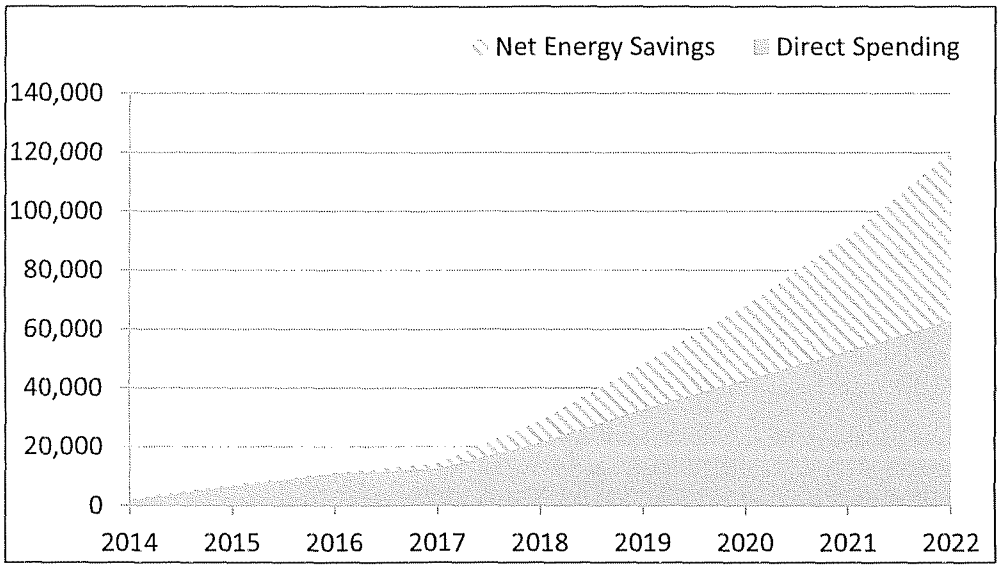
Average Electric Rates ($/kWh) (2010$)	2010	BAU Scenario 2022	REPS Scenario 2022	REPS Scenario vs BAU Scenario
Total (All Sectors)	$0.067	$0.101	$0.102	1%
Residential	$0.086	$0.120	$0.121	1%
Commercial	$0.079	$0.113	$0.114	1%
Industrial	$0.051	$0.085	$0.085	0%
Average Electric Bills ($) (2010$)	**2010**	**BAU Scenario 2022**	**REPS Scenario 2022**	**REPS Scenario vs BAU Scenario**
Residential	$1,249	$1,834	$1,657	-10%
Commercial	$5,198	$7,658	$7,067	-8%
Industrial	$325,409	$557,989	$513,178	-8%

Impact of REPS on Kentucky economy. The study estimates that a REPS would lead to a net increase in employment and business opportunities in Kentucky. In other words the expenditures on additional reductions from EE and additional RE generation required under a REPS would create more economic activity and employment in Kentucky than the electric generation from coal and natural gas that the additional EE and RE would displace. If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to a net increase in employment and business opportunities in Kentucky, although those net increases would be somewhat smaller.

Complying with the EE targets will require expenditures on materials and equipment to improve the efficiency of residences, businesses, and factories, while complying with the RE targets will require expenditures on construction and operation of RE projects. The net positive impact of these expenditures is attributable to three major factors. First, the portion of total expenditures that would remain in Kentucky is projected to be higher for EE and RE than for generation from coal and natural gas. Second, the EE and RE projects are expected to be more labor-intensive than generation from coal and natural gas, and thus are projected to create more jobs per dollar spent. Finally, the additional quantities of EE and RE are projected to result in lower electric bills over time, leaving Kentuckians with more discretionary income available to spend on other goods and services, which in turn would produce additional economic impacts.

The study projects a REPS would create over 28,000 net additional job-years in Kentucky by 2022. (Employment impacts are in job-years since the duration of some jobs is limited, e.g. a RE construction project, while the duration of other jobs is longer-term, e.g. programs to install EE measures). The major sources of these incremental job-years are capital and operating expenditures on EE measures and RE facilities ($159 million in 2022) as well as electric customer spending of the amounts they saved on their electric bills, i.e., spending of their net energy savings from energy efficiency ($970 million in 2022). Figure 1-6 presents the projected cumulative net job-year impacts in Kentucky.

Figure 1-6. Cumulative net job-year impacts in Kentucky from a REPS



The study projects the net incremental impacts of a REPS on Kentucky by 2022 would include an increase in personal income of nearly $1 billion and an increase in Gross State Product of $1.5 billion. Those projections are reported in Table 1-2.

Table 1-2. Annual net economic impacts in Kentucky from a REPS

Economic Impacts	2017	2020	2022	Cumulative Total
Job-years	3,190	19,958	28,539	***120,140***
Personal Income (2010$ millions)	$119	$765	$1,088	***$4,634***
Gross State Product (2010$ millions)	$118	$1,004	$1,474	***$6,038***

2. Introduction

Kentucky has historically relied upon coal from mines in the state for the majority of its electricity generation. For example, in 2010 over 92% of the state's electricity production was from coal-fired generation, with approximately 67% of the coal used to generate that electricity produced in Kentucky.[1,2] Over the past several years various reports have identified energy efficiency and renewable energy as resources that could help Kentucky diversify its electricity supply portfolio, control its future electricity costs, and create jobs for Kentuckians.

Legislation being introduced in the Kentucky General Assembly proposes to establish a Renewable and Energy Efficiency Portfolio Standard (REPS). The expected goals of the legislation would be to:

1) Promote energy independence and security by diversifying the portfolio of energy sources used for generating electricity for Kentucky electric customers;
2) Stabilize long-term energy prices and encourage economic growth; and
3) Create high-quality jobs, training, business, and investment opportunities in the Kentucky energy sector.

This study assumes that the legislation would be designed to achieve those three goals by requiring all utilities in the state to meet specific portions of their retail load through reductions from EE and generation from RE, respectively. The study assumes required cumulative reductions from EE would begin at 0.25 percent in 2014 and increase to 10.25 percent of aggregate retail load by 2022. It assumes the required cumulative portions of retail load to be met from RE would begin at 2.25 percent in 2014 and increase to 12.5 percent by 2022.

Diversifying the state's generating mix through development of additional EE and RE has the potential to produce a number of benefits beyond those examined in this report, including mitigation of operational and financial risks. The benefits of meeting future electricity requirements through a diverse mix of cost-effective resources, including EE and new RE, in addition to traditional supply side resources have been recognized for several years at both the federal and state level, for example the Energy Policy Act of 2005 (EPAct) and *Intelligent Energy Choices for Kentucky's Future.*[3] [4]

MACED and KySEA retained Synapse to estimate the potential impacts of establishing a REPS. Synapse provides research, testimony, reports, and regulatory support on electric industry regulatory and environmental issues to consumer advocates, environmental organizations, regulatory agencies and energy offices at the state and federal level throughout the United States. For example, the American Council for an Energy Efficient Economy (ACEEE) has relied upon

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1 EIA state energy profile for Kentucky and EIA *Electric Power Monthly*
2 Synapse analysis of EIA coal statistics, report DOE/EIA-0584(2009) updated February 3, 2011
3 EPAct 2005 Title XII Electricity, Subtitle E, Amendments to PURPA §1251(a)

4 Beshear, Steven L. and Peters, Leonard, Intelligent Energy Choices for Kentucky's Future, Kentucky Energy and Environment Cabinet, November 2008

Synapse estimates of avoided electricity costs for its clean energy studies of Ohio, North Carolina, South Carolina, Arkansas, Virginia, and Pennsylvania.

The study provides an initial quantitative estimate of the approximate magnitude and direction, i.e., positive or negative, of several key impacts of the proposed REPS. The study estimates these in terms of state-wide impacts measured relative to a future without a REPS. Thus, the study is providing high level projections recognizing that the specific impacts of a REPS will vary by utility. Analyzing the impact of a REPS on individual or specific Kentucky utilities was beyond the scope of work of this study. The study estimates the impact of a REPS on Kentucky using state-wide data augmented by utility-specific data and projections where relevant and public. It estimates these impacts using a methodology that other parties could use to estimate the impacts of a REPS on individual Kentucky utilities.

A. Kentucky Electricity Market

Kentucky is served by more than 50 retail electricity service providers and has a complex wholesale electricity market. According to statistics from the United States Energy Information Administration (EIA), in 2009 Kentucky was served by 58 retail providers consisting of four investor-owned utilities (IOUs) and 54 cooperatives and public entities. The four IOUs, i.e., Louisville Gas and Electric (LG&E), Kentucky Utilities (KU), Duke Energy Kentucky, and Kentucky Power, accounted for about half of the state's electricity sales in that year, and about half of the in-state generation. The cooperatives and public entities accounted for the remaining sales and in-state generation.

Historically the annual quantity of electricity generated in Kentucky has closely matched the state's annual retail sales. According to EIA statistics the state has been a small net exporter of power.

Almost all of the in-state generation has been from coal units and approximately 67% of the coal those units consumed to generate that electricity was produced in Kentucky. In contrast, Kentucky's electric sector is not the dominant market for coal produced in Kentucky, accounting for only approximately 26% of the state's annual coal production. The majority of coal mined in Kentucky, approximately 74%, is sold to out-of-state markets and to Kentucky's industrial sector.[5]

The state's utilities appear to have limited potential to sell, or buy, power in the inter-state market. Most retail electric service providers in Kentucky are not currently members of the major wholesale electricity markets operated by the Mid-West Independent System Operator (MISO) or PJM. The potential to export or import power is subject to the availability of adequate transmission, with the existing major inter-state transmission lines in Kentucky running primarily north and south.

B. Study approach

The purpose of the study is to estimate the impacts of a REPS for a given set of explicit assumptions about the future. The study estimates the state-wide average impacts of a REPS on Kentucky's portfolio of electricity resources, on average electric bills, and on the state's economy over a ten year period, 2013 to 2022. It uses a scenario approach to estimate these impacts. As

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[5] ibid.

such the study provides a "what if" analysis rather than a detailed forecast of Kentucky's electricity supply.

The study developed its estimates of these impacts in the following major steps:

- Develop common assumptions applicable to both the BAU scenario and the REPS scenario, including assumptions regarding electricity resource costs and environmental regulations based upon national trends;
- Develop projections for the BAU scenario including future retail electric requirements, electric supply, average rates, and average bills. These projections are based upon Kentucky electric sector statistics and public planning documents of Kentucky utilities;
- Develop projections for the REPS scenario including future retail electric requirements, electric supply, average rates, and average bills. To develop the REPS scenario the study estimates the cost of achieving the EE reductions and RE generation required under the REPS legislation. These estimates draw upon prior reports that have addressed the potential impact of increasing reliance on EE and RE in Kentucky as well as the most recent estimates of EE and RE potential and costs relevant to Kentucky; and
- Calculate the incremental impacts of the REPS scenario relative to the BAU scenario on Kentucky's portfolio of electricity resources, on state-wide average electric bills, and on the state's economy.

As with every forecast, the projections for the BAU and REPS scenarios are subject to uncertainty because the key assumptions underlying those projections are subject to uncertainty. Those key assumptions include projections of future electricity sales, natural gas prices, and regulation of carbon dioxide emissions. Each of the study's key assumptions is specified explicitly in order to enable parties to test the sensitivity of the BAU and REPS scenario projections to different values for key input assumptions.

The balance of the report is organized as follows:

- Chapter 3 describes the key common assumptions applicable to both scenarios and then describes the projections of electricity supply, average rates, and average bills for the BAU scenario;
- Chapter 4 describes the EE and RE assumptions specific to the REPS scenario and then provides the projections of electricity supply, average rates, and average bills for that scenario;
- Chapter 5 describes the analysis of net economic impacts of a REPS;
- Chapter 6 summarizes the incremental impacts of a REPS;
- Appendix A provides the references used to prepare the report;
- Appendix B provides key results for the BAU and REPS scenarios; and
- Appendix C provides summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022.

3. Business as Usual Scenario

The BAU scenario assumes a future without a REPS. The projections for the BAU scenario provide the quantitative reference points against which the study will measure the incremental impacts of the REPS scenario. Those projections include electric resource costs, electric supply mix, average rates, average bills, and avoided costs for each year of the study period.

This chapter begins by describing the modeling framework and key common assumptions applicable to both the BAU scenario and the REPS scenario. It then describes the projections of electricity supply, average rates, and average bills for the BAU scenario.

A. Modeling Framework and Common Assumptions

The study develops projections of the capacity mix, energy mix, production costs, average rates, and average bills on a state-wide basis under the BAU scenario and the REPS scenario using an Electricity Costing Model (ECM) developed by Synapse.[6] The ECM is an annual production costing model implemented in Excel. It calculates the total revenue requirements for electricity service that utilities and/or resource owners would seek to recover from ratepayers for a given set of input assumptions. Revenue requirements consist of the annual amount required to recover the variable cost of producing electricity each year plus the cost of recovering capital investments including a return on those investments. Key input assumptions include projected retail energy requirements, both annual energy and peak demand, reserve margin, mix and characteristics of existing capacity, projected capacity retirements and additions, projected fuel prices, and projected environmental compliance costs.

The study developed a BAU scenario independently of the two scenarios presented in the Kentucky Department for Energy Development and Independence (DEDI) projections for several reasons.[7] First, the ECM requires numerous input assumptions and Synapse did not have access to all of the input assumptions that the DEDI used to develop its two scenarios. Second, Scenario A of the DEDI projection assumes construction of an Advanced Super Critical Pulverized coal plant while Scenario B implicitly assumes that Henry Hub gas prices will double in real terms between 2010 and 2020.[8] Synapse did not consider either of those two assumptions to be reasonable for a BAU scenario during the study period.

The base year of our analysis is 2010; this is the most recent year for which a complete set of statistics for Kentucky's electric sector were available from the EIA. All monetary values are reported in constant 2010 year dollars unless noted otherwise. The analysis begins in 2011 and ends in 2025, a study period of 15 years. The study focuses in particular on the ten-year period from 2013 through 2022, during which the REPS bill would be implemented.

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[6] Synapse developed the initial version of the ECM in order to provide the ACEEE with these projections for its clean energy studies of Ohio, North Carolina, South Carolina, Arkansas, Virginia and Pennsylvania.

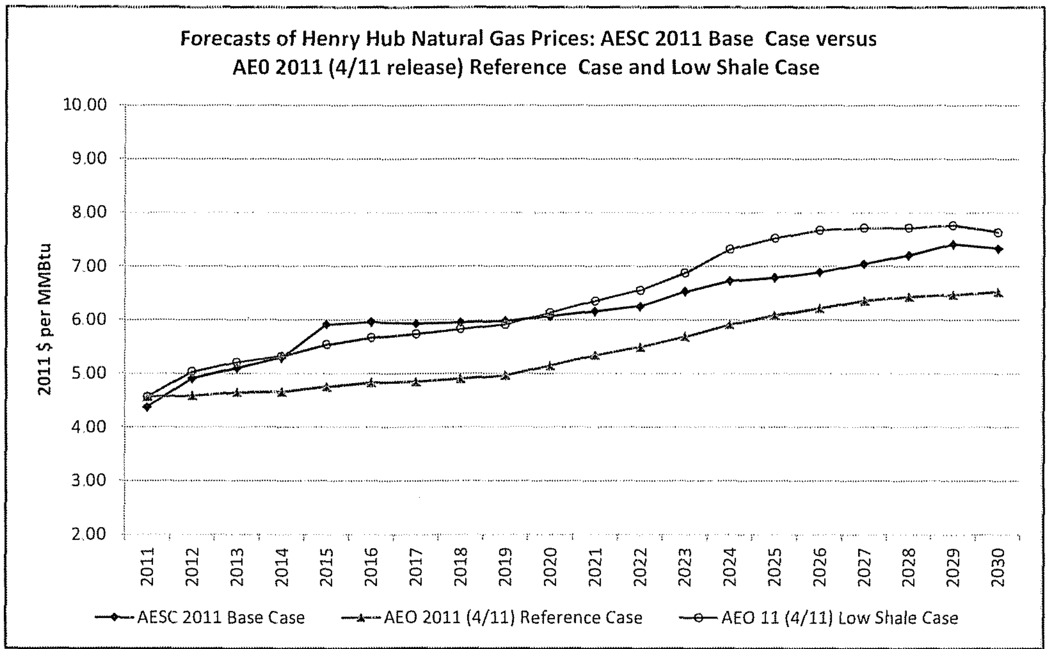
[7] Patrick, Aron et al. *Kentucky Electricity and Natural Gas Price and Consumption Forecasts to 2035*. DEDI. August 9, 2011.

[8] Ibid. Table 5. Implied by increase in industrial customer retail prices from \$5.30 in 2010 to \$10.03 in 2020 (2010\$/MMBtu)

The analysis assumes inflation at 2.00% per year, discount rates of 8.0% nominal and 5.88% real, income tax rates of 35% federal and 6.0% Kentucky, and a property tax rate at 0.5% per annum of initial plant cost.

Fuel Prices. The study assumes coal prices will remain close to current levels over the study period based upon EIA reference case projections in Annual Energy Outlook 2011 (AEO2011).[9] The study assumes that the price of natural gas delivered to gas-fired units in Kentucky, the burner-tip price, will increase from $5.29/MMBtu in 2010 to approximately $6.50/MMBtu (in 2010$) by 2022. The largest component of that price is the projected Henry Hub price, with the other component being an estimate of the basis differential between the Henry Hub price and Kentucky.[10] The projection of Henry Hub prices underlying the study's burner-tip prices is drawn from *Avoided Energy Supply Costs in New England: 2011 Report* (AESC 2011), a report Synapse prepared for a group of efficiency program administrators in New England. That projection received considerable scrutiny during the development of AESC 2011. The study's projected Henry Hub prices are lower than those implied in the DEDI projection but within the range of Henry Hub prices that LG&E/KU considered in their April 2011 CPCN filing and also within the range of Henry Hub price projections the EIA analyzed in AEO 2011, as indicated in Figure 3-1.

Figure 3-1. Projections of Henry Hub prices



9 _____. *Annual Energy Outlook 2011*. U.S. Energy Information Agency. April 2011. http://www.eia.gov/forecasts/aeo/

10 Hornby, Rick et al. *Avoided Energy Supply Costs in New England: 2011 Report*. Synapse Energy Economics. July 2011. www.synapse-energy.com

Particulate, Sulfur Dioxide and Nitrogen Oxide Emission Compliance Costs. The United States Environmental Protection Agency (EPA) is in the process of implementing tighter regulations of emissions of various air pollutants including particulate matter, ozone, sulfur dioxide, and nitrogen oxides. The changes include revisions to several National Ambient Air Quality Standards (NAAQS), a Cross-State Air Pollution Rule (CSAPR), and proposed standards for hazardous air pollutants (HAPS). These new tighter regulations are currently scheduled to take effect in 2016. Our study assumes that Kentucky utilities will comply with these new, more stringent regulations by December 2015. The study assumes that some existing coal units have the necessary control technology required to comply, some units will require major capital investments in new control technology in order to comply, and some units will be retired.

The study's projections of capacity costs under the BAU and REPS scenarios do not include capital costs that Kentucky utilities might incur in order to enable their existing coal units to comply with the tighter environmental regulations scheduled to take effect in 2016. In addition to the difficulty of obtaining estimates of those capital costs for each coal unit in Kentucky, the study assumed those costs would be relatively unavoidable under both scenarios because the utilities would make those capital investments between 2012 and 2015 and would be able to recover them in full through a special environmental surcharge.

Carbon Dioxide Emission Compliance Costs. There is considerable uncertainty regarding the timing and design of future federal regulation of carbon emissions. However, Synapse considers it reasonable to assume that some form of carbon regulation will occur during the planning horizon covered by this study. A number of electric utilities apparently share that expectation, as they have assumed a cost for complying with carbon emission regulation in long-term plans filed in the last year. Those utilities include Delmarva Delaware, Ameren Missouri, PacifiCorp, TVA, Duke Energy Ohio, Georgia Power, and Duke Energy Carolinas.[11] This study assumes that emissions of carbon dioxide from all generating units in Kentucky, both existing and new, will be subject to federal regulation beginning in 2018 at a cost of compliance of $15 per ton of carbon.[12] Figure 3-2 plots that carbon dioxide assumption relative to the assumptions used by most of those electric utilities for their reference or medium cases.

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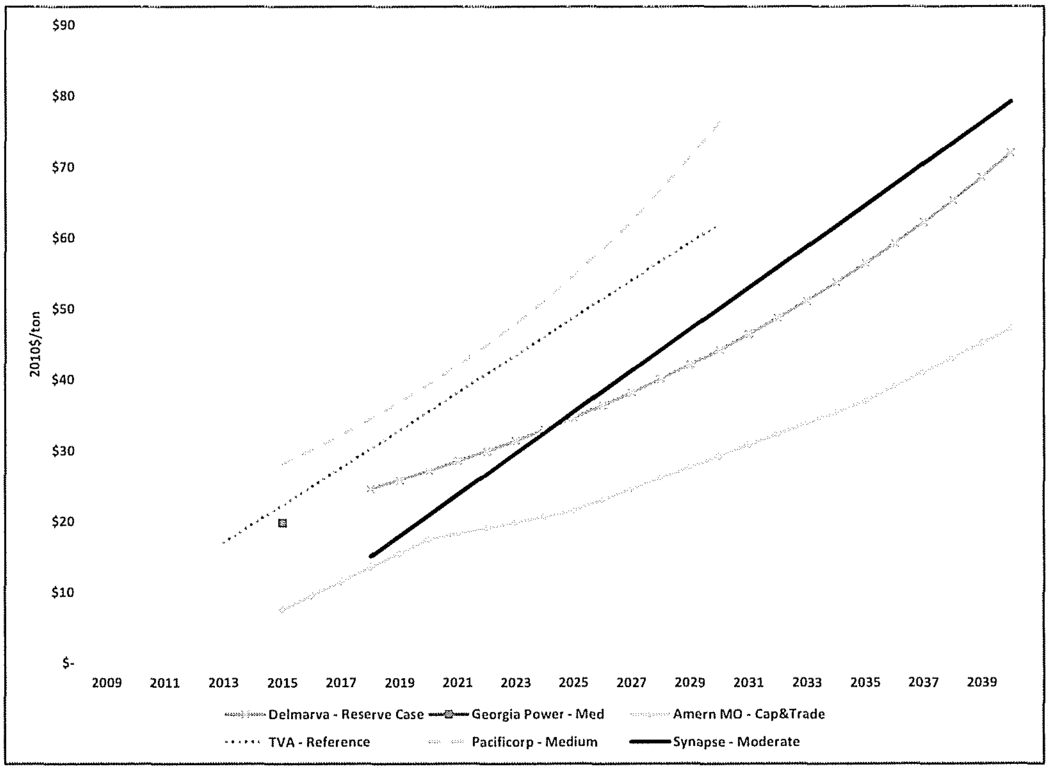
[11] COMMENTS OF INTERVENORS NATURAL RESOURCES DEFENSE COUNCIL AND SIERRA CLUB ON THE 2011 JOINT INTEGRATED RESOURCE PLAN OF KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC . CASE NO. 2011-00140. November 23, 2011. Page 10.

[12] Johnston, Lucy et al. Synapse 2011 CO2 Price Forecasts, February 2011, mid-case

Figure 3-2 Projections of Carbon Dioxide Prices (2010$)



Given the uncertainty regarding the timing and magnitude of future regulation of carbon, the study also includes an estimate of the impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022. The summary impacts from that analysis are presented in Appendix C.

B. Projection of Retail Electricity Requirements

The study projects retail electricity requirements in terms of annual sales and aggregate peak demand. The study develops a projection of state-wide annual electricity sales for each of the three major sectors, i.e., residential, commercial, and industrial. It also develops a projection of the aggregate peak demand from all three sectors. It begins by developing a projection of requirements assuming no reductions from EE. From that projection it develops projections of retail sales for the BAU scenario and the REPS scenario by deducting the reductions from EE assumed in each of those scenarios.

The projection of state-wide sales with no reductions from EE assumes that all utilities in the state will have approximately the same rate of growth as LG&E/KU have projected for their service territory, prior to the impact of their proposed EE. [13] LG&E/KU assume their annual retail sales will

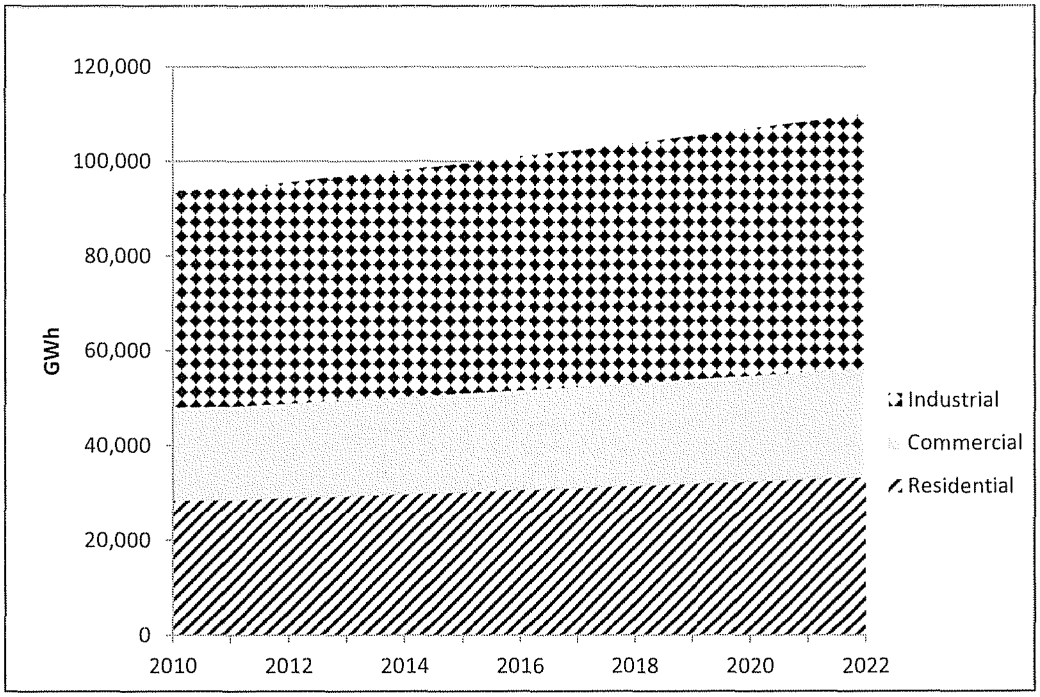
[13] LG&E/KU Integrated Resource Plan (IRP), April 2011, Table 6.(1)-1, page 6-4

rebound in 2011 and 2012 from their 2009 and 2010 recession levels and will increase steadily thereafter.

The study projects that annual sales and aggregate peak demand under the BAU scenario will each increase at an annual average rate of approximately 1.5% per year over the study period. This projection reflects our estimates of reductions from EE for those Kentucky utilities who offer EE programs. For example, the BAU forecast projects a total state-wide cumulative annual reduction from EE under the BAU scenario of approximately 2,000 GW in 2025, or 1.7% of annual sales forecast for that year. This projection is based on our review of public data on EE programs of Kentucky utilities. LG&E/KU have projected reductions from their EE programs equal to 4.8% of 2025 sales. The state's other utilities do not appear to be projecting any material reductions from EE.

The BAU scenario projection of electricity sales by sector is presented in Figure 3-3. This projection assumes that each major customer sector, i.e., residential, commercial, and industrial, would account for the same proportion of total sales in the future as it did on average between 2008 and 2010. During that period the residential, commercial, and industrial sectors respectively accounted for 30%, 21% and 49% of total annual retail sales in the state.[14] The BAU scenario projection assumes that the number of customers in each sector will grow at 1.1% per year, the average annual rate of total customer growth between 1990 and 2009.

Figure 3-3. BAU scenario - Forecast of annual electricity sales by sector



[14] Industrial sales as a percentage of total sales in all sectors are about twice the national average.

The average annual rate of growth projected under the BAU scenario, at 1.5%, is less than the actual average rate of state-wide load growth from 2000 to 2010 (1.8%). However, that projection is higher than the state-wide average rate of load growth the DEDI has projected for the period 2010 through 2035 (0.7%).[15] The fact that the study projects a higher average annual rate of growth for the BAU scenario than the DEDI report may be attributable to several factors, including a shorter forecast period than the DEDI report, i.e. through 2022 rather than through 2035, and no reflection of the impact of price elasticity on retail load.

C. Projection of Electricity Resources and Costs

The study developed the BAU scenario projection of electricity resource mix and costs in two steps. In step one the study determined the quantity of total capacity required each year to meet peak demand plus losses and a reserve margin. In years in which the total of existing capacity plus planned additions were less than the total quantity of capacity required to ensure reliable service, Synapse added generic capacity to the ECM. In step two the study estimated the quantity of total annual generation required each year to meet annual sales plus losses, i.e. total annual retail electric requirements. Synapse used the ECM to calculate the quantity of generation from each category of capacity each year and the annual costs of producing that generation. The study also developed a projection of avoided electricity costs.

Step One - Ensure Adequate Capacity

In order to ensure reliable service, Kentucky utilities must have sufficient capacity to meet each year's forecast of peak demand plus a reserve margin. Our analysis of capacity requirements for the BAU scenario revealed the following key points:

- LG&E/KU assume a 55% load factor in their April 2011 IRP. Our study assumes a 60% load factor because industrial load, the customer class with the highest load factor, accounts for 50% of total sales in the state but only 28% of LG&E/KU total sales. With a 60% load factor, and a 15% reserve margin as LG&E/KU assume in their April 2010 IRP,, our analysis of EIA statistics for Kentucky in 2010 indicates that Kentucky met 94% of its reserve margin requirement in 2010 with capacity located in-state and 6% with capacity located out-of-state;[16]
- Approximately 824 MW of hydro capacity is currently available and an additional 130 MW is scheduled to be in-service by 2017. Under the REPS, generation from hydro built after 1992 would quality as RE. Therefore the study assumes that 57.8 MW of existing hydro and all of the proposed hydro would qualify as RE;[17]
- LG&E/KU plan to retire at least 800 MW of older coal units by 2016. They have concluded that it is not economic to install new emission controls on those units in order to comply

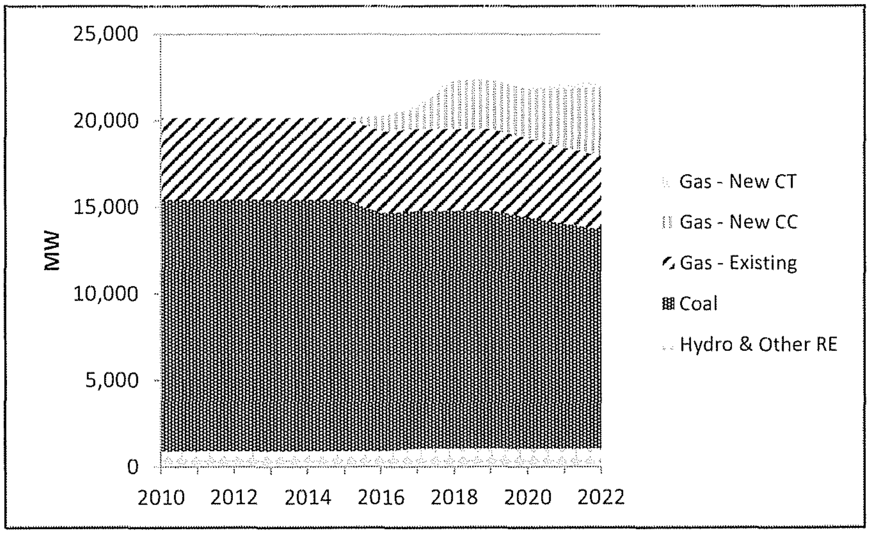
[15] Patrick, Aron et al. *Kentucky Electricity and Natural Gas Price and Consumption Forecasts to 2035.* DEDI. August 9, 2011.
[16] Reliance on out-of-state capacity would be lower with a higher average load factor &/or lower reserve margin
[17] The 57.8 MW equals hydro capacity reported in Form EIA 860 Annual Electric Generator Report for 2009 minus capacity reported for 1990, since report for 1992 was not available.

with the more stringent limits on emissions scheduled to take effect in 2016 under NAAQS, CSAPR, and HAPs;

- LG&E/KU plan to add 907 MW of gas-fired combined cycle units in 2016 and another 907 MW in 2018 to replace the units retiring in 2016 and to meet growth in peak demand; and
- Further capacity additions will be needed from 2017 onward to maintain the reserve margin in response to projected growth in peak demand and annual energy.

Synapse added capacity to the Electricity Costing Model (ECM) by specifying the timing, quantity, type, capital cost, and operating characteristics of each capacity addition. Under the BAU scenario we assume these generic capacity additions will be a mix of new natural gas combined-cycle (NGCC) capacity and new natural gas combustion turbine (NGCT) capacity. Figure 3-4 presents the projection of capacity in Kentucky for the BAU scenario resulting from these analyses.

Figure 3-4. BAU scenario - Forecast of capacity in Kentucky



Synapse developed assumptions regarding capital cost and operating characteristic of each category of new capacity based upon its review of various cost projections and on the assumptions for new capacity the EIA used to prepare AEO 2011.

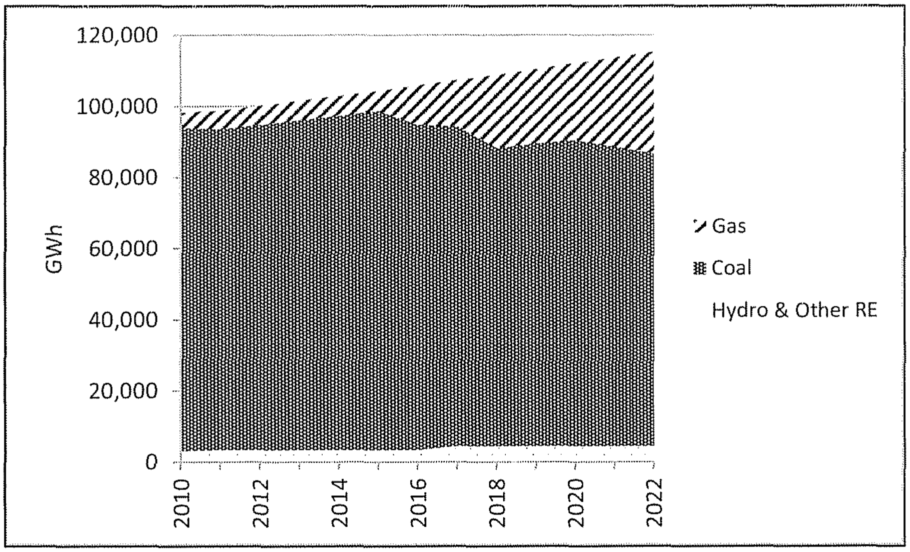
Step Two - Calculate Annual Generation from Each Category of Capacity

The ECM estimates the annual quantity of generation required from each category of capacity to meet the projected annual retail requirements for the year and calculates the annual cost of producing that generation. The ECM estimates the quantity of generation from each category of capacity, existing and new, based upon an analysis of historic load and operating patterns, including capacity factors. For example, if load increases by 1% in a year with no increase in capacity, the model increases the annual generation from each category of capacity by 1% to meet the increase. In a year in which some quantity of existing capacity is retired and new units are added, the remaining reduced quantity of existing capacity is dispatched at its historic capacity factor and the new capacity is dispatched at a capacity factor based on general industry experience.

The ECM calculates the unit cost of generating electricity from each category of capacity, referred to as the production cost, in $ per MWh, based upon numerous input assumptions. These assumptions include the quantity, efficiency, and non-fuel variable production cost of each category of existing capacity available each year.[18] The study derived those assumptions from an analysis of base year and historical data for existing generating units in Kentucky. Two other key assumptions are fuel prices and carbon emission costs.

Figure 3-5 presents the generation mix for the BAU scenario based upon those assumptions. Kentucky's reliance on coal generation is projected to decline under the BAU scenario, from over 92% in 2010 to 71% in 2022. This decline is due to the retirement of several older coal units starting in 2016 and their replacement by gas-fired NGCC units.

Figure 3-5. BAU scenario - annual electricity requirements and sources



Annual Avoided Cost of Electricity Supply

The annual avoided cost of electricity supply associated with this scenario is an estimate of the costs that all retail customers could avoid paying if less electricity was required from the resources projected under this scenario. The ECM calculates the avoided cost of electricity supply based upon the costs of the marginal, or avoidable, sources of capacity and generation.

- Prior to 2015 the avoidable capacity resource is new NGCT, and the avoidable generation is primarily production from existing coal units. Thus, the avoided cost during this period

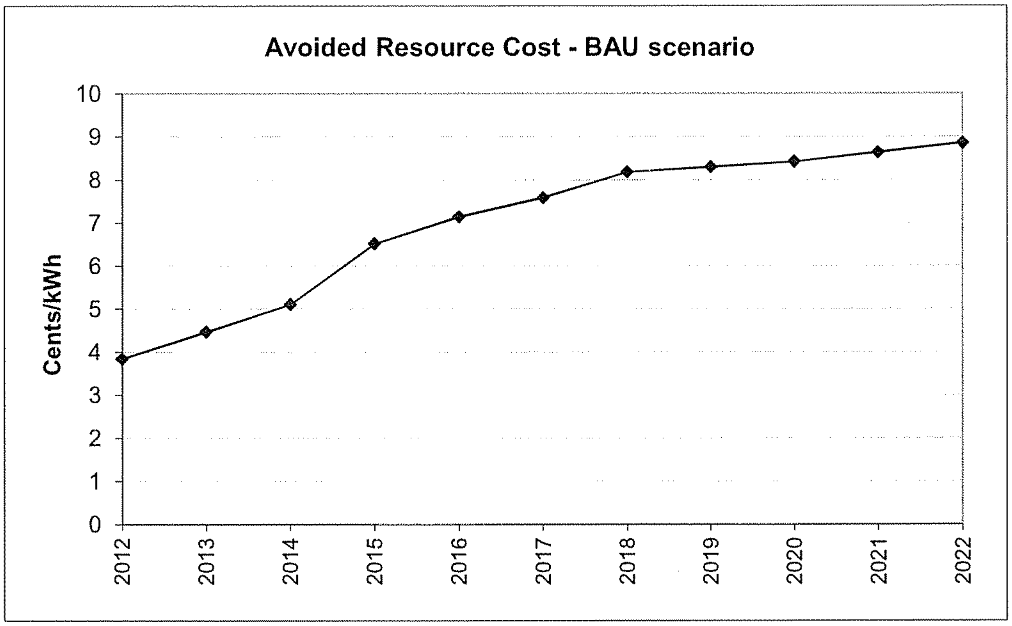
[18] The efficiency with which a generating unit converts fuel into electricity is referred to as its heat rate.

reflects the average operating costs of coal-fired generation and the levelized capital cost of a new NGCT.

- From 2016 onward the avoidable capacity resources are a mix of new NGCC and new NGCT, while the avoidable generation is production from those new gas units. Thus, from 2016 onward the avoided cost reflects the levelized capital cost of the mix of projected new NGCC and NGCT units and the average operating costs of new gas-fired generation.

As indicated in Figure 3-6, under the BAU scenario the total annual avoided cost of electricity supply, capacity plus generation, is projected to increase from approximately 4 cents/kWh in 2012 to approximately 9 cents/kWh in 2022.

Figure 3-6. BAU scenario – avoided electricity resource cost



D. Projection of Average Retail Rates and Average Retail Bills

The study projects state-wide average rates, and state-wide average bills, by sector for each year. These projections are indicative approximations, not forecasts of precise rates or bills. First, as noted earlier, the projections are state-wide averages; actual rates and bills will vary by utility. Second, the projections of system average rates are essentially the total projected revenue requirements in a year divided by total projected retail sales in that year. The projected average rates by sector are derived from the system average rate by applying the historical ratio of each sector's rate to the system average rate. In contrast, development of precise estimates of specific rates by utility requires a detailed allocation of utility revenue requirements among rate classes and the calculation of various type of charges, e.g., customer charges ($/month), demand charges ($/kW), energy charges ($/kWh), and surcharges or riders. Finally, the projected state-wide average bills by sector in a year equal the projected average rates by sector in that year multiplied by the projected annual electricity sales per customer by sector each year.

State-Wide Average Retail rates

The state-wide average rate in each year equals the total projected costs utilities would seek to recover from retail customers in that year divided by projected annual electricity sales in that year. Our analyses assume utilities would seek to recover four major types of costs each year:

- Transmission and distribution (T&D) costs,
- Annual fixed costs of existing generating capacity,
- Annual fixed costs of new generating capacity, and
- Annual production costs.

The study projects the first two types of costs, i.e., T&D and existing generating capacity, based upon an analysis of historical costs and historical rates. The study assumes that Kentucky utilities will need to recover the same amount of those projected costs in the BAU scenario and the REPS scenario.

The study projects the last two types of costs, i.e., fixed costs of new generating capacity and production costs, based upon the ECM outputs for each scenario. The projection of fixed costs of new generating capacity and of production cost for the BAU scenario is different from the projections for the REPS scenario.

Table 3-1 presents the BAU scenario projections of average rates by sector and electric bills by sector. These projections are in 2010 constant dollars.

Table 3-1. BAU scenario - Forecast average rates and bills by sector

Average Electric Rates ($/kWh) (2010$)	2010	2015	2020	2022	Increase from 2010
Total (All Sectors)	$0.067	$0.070	$0.095	$0.101	50%
Residential	$0.086	$0.088	$0.114	$0.120	40%
Commercial	$0.079	$0.081	$0.106	$0.113	43%
Industrial	$0.051	$0.053	$0.078	$0.085	67%
Average Electric Bills ($) (2010$)	**2010**	**2015**	**2020**	**2022**	**Increase from 2010**
Residential	$1,249	$1,319	$1,727	$1,834	47%
Commercial	$5,198	$5,384	$7,185	$7,658	47%
Industrial	$325,409	$342,448	$513,290	$557,989	71%

The study projects that average retail rates will increase substantially by 2022 under the BAU scenario. For example, the study projects that system-wide average rates would be 50% higher in 2022 than in 2010 under the BAU scenario, while residential rates would increase by 40%. These projected increases are somewhat higher than, but consistent with, the magnitude of increases in state-wide average electricity prices that the Kentucky DEDI has projected for the period 2010 through 2020 under Scenario B.[19]

The study projects average residential bills to increase by 47% between 2010 and 2022. This projected increase reflects the combined effect of a projected 40% increase in rates and a projected 5% increase in annual use per residential customer over that period.

The increases in rates and bills projected under the BAU scenario are conservative because, as noted earlier, they do not reflect the capital costs that some Kentucky utilities, such as LG&E/KU, will incur by 2015 in order to retrofit certain of their existing coal units to comply with tighter emission regulations.

[19] Patrick, Aron et al. *Kentucky Electricity and Natural Gas Price and Consumption Forecasts to 2035.* DEDI. August 9, 2011. Table 3.b.

4. REPS Scenario

The REPS scenario assumes a future in which Kentucky utilities achieve reductions from EE and acquire generation from RE according to the annual targets specified in the REPS. As a result, the REPS scenario meets the projection of total annual retail electricity requirements using a different mix of electricity resources than the BAU scenario, which leads to a different projection of average rates and average bills.

This chapter provides a general description of the key assumptions and methodology the study used to develop the REPS scenario projections, and reports those projections. The study develops the REPS scenario in four steps:

1. Calculate the additional reductions from EE and generation from RE required under the REPS scenario,
2. Estimate the cost of acquiring the additional reductions from EE,
3. Estimate the cost of acquiring the additional generation from RE, and
4. Develop projections of electric resource costs, electric supply mix, average rates, and average bills.

A. Additional EE and RE required under the REPS scenario

The REPS bill specifies the total reductions from EE and generation from RE required each year as percentages of average retail sales in the previous two years. The bill refers to that average as a "rolling baseline."

The study estimated the additional reductions from EE and generation from RE required under the REPS scenario by calculating the aggregate quantities of EE and RE required to comply with the REPS bill, and then subtracting the quantities of qualifying EE and RE projected under the BAU scenario. These estimates represent the additional quantities of EE and RE that Kentucky utilities would have to achieve, over and above the quantities projected in the BAU scenario, in order to comply with the REPS.

Table 4-1 provides the development of these estimates of additional reductions from EE and generation from RE. Note that:

- The rolling baseline, reported in column d, is developed from the projections of annual retail requirements presented in columns a through c;
- The additional reductions from EE required under the REPS scenario, reported in column h, is developed from the rolling baseline, the REPS aggregate requirements presented in column e, and the qualifying EE projected under the BAU scenario in column g; and
- The additional generation from RE required under the REPS scenario, reported in column m, is developed from the rolling baseline, the REPS aggregate requirements presented in column j, and the qualifying RE projected under the BAU scenario in column l.

Table 4-1. Additional EE and RE required under REPS

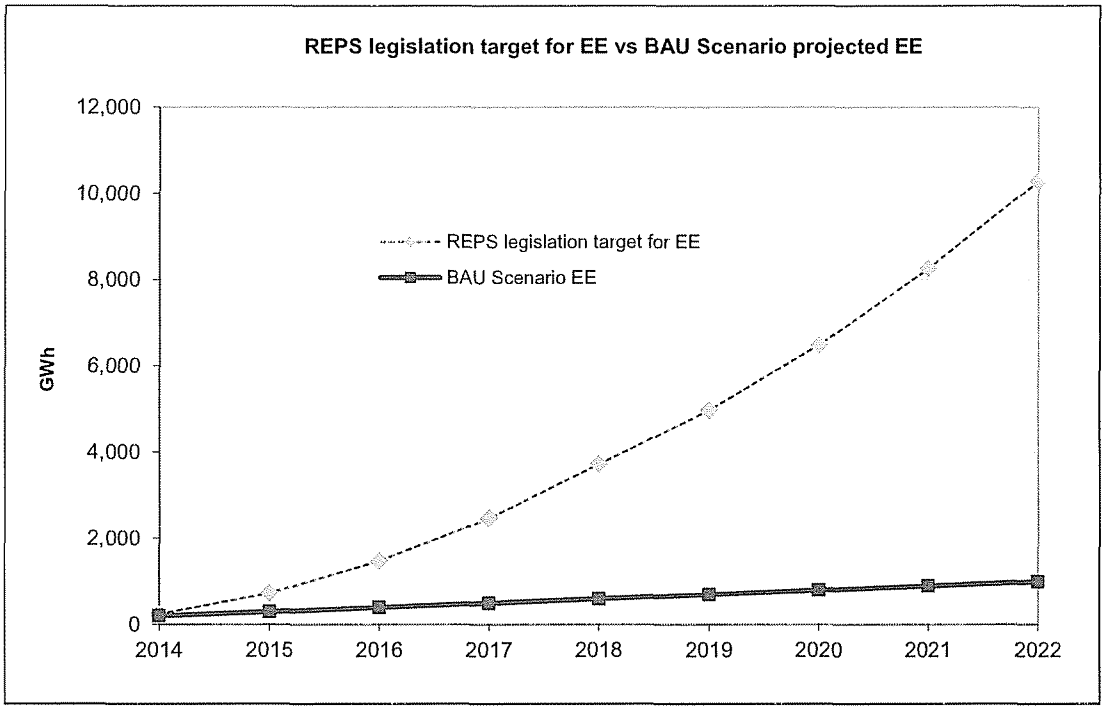
Year	Sales Forecast (GWh)				Additional EE Required under REPS Scenario (GWh)					Additional RE Required under REPS Scenario (GWh)			
	BAU Scenario	BAU Scenario without incremental EE after 2013	REPS scenario	Rolling Baseline (Average of sales in prior 2 years)	REPS Legislation Requirement for EE		Incremental EE in BAU Scenario	Additional EE under REPS Scenario	Cumulative EE	REPS Legislation Requirement for RE		Eligible RE in BAU scenario	Additional RE under REPS Scenario
Column	a	b	c	d	e	f	g	h	i	j	k	l	m
2010	93,686	93,794	93,686										
2011	94,203	94,605	94,203										
2012	95,558	96,132	95,558										
2013	96,916	97,642	96,916										
2014	98,130	98,330	98,089	96,237	0.25%	241	200	41	241	2.25%	2,165	685	1,480
2015	99,571	99,868	99,140	97,502	0.50%	488	97	390	728	2.25%	2,194	685	1,509
2016	100,976	101,370	99,903	98,615	0.75%	740	97	642	1,468	2.25%	2,219	685	1,534
2017	102,341	102,833	100,370	99,521	1.00%	995	97	898	2,463	5.50%	5,474	1104	4,370
2018	103,793	104,387	100,672	100,136	1.25%	1252	102	1,150	3,715	5.50%	5,508	1104	4,404
2019	105,333	106,027	101,056	100,521	1.25%	1257	100	1,156	4,971	5.50%	5,529	1104	4,425
2020	106,897	107,691	101,207	100,864	1.50%	1513	100	1,413	6,484	9.25%	9,330	1104	8,226
2021	108,369	109,263	101,010	101,132	1.75%	1770	100	1,670	8,254	9.25%	9,355	1104	8,251
2022	109,948	110,942	100,666	101,108	2.00%	2022	100	1,922	10,276	12.50%	12,639	1104	11,535

a, b	BAU scenario sales forecast
c	2010 to 2013 equals column a, *BAU Scenario*.
	2014 onward equals column b, *BAU Scenario without BAU incremental EE after 2013, minus column i, cumulative EE*
d	average of prior two years from column c, *REPS Scenario*
f	column d * column e
g	BAU scenario sales forecast
h	column f minus column g
k	column d * column j
l	BAU scenario projected generation mix
m	column k minus column l

B. Cost of Additional EE Reductions

Under the REPS scenario Kentucky utilities would have to achieve much greater reductions from EE than under the BAU scenario. The projected additional reductions are reported in Table 4-1 (above) and plotted in Figure 4-1.

Figure 4-1. Additional EE required under REPS



Fortunately, Kentucky has a tremendous potential for cost-effective EE, despite the Commonwealth's relatively low electricity prices. To date Kentucky utilities have not pursued EE as actively and aggressively as those in other states. For example, Kentucky ranked 37th in the nation for efficiency policies and programs according to the *ACEEE 2011 State Energy Efficiency Scorecard*. According to the ACEEE Scorecard Kentucky utilities, on average, achieved annual savings relative to sales of 0.07% in 2009. In contrast, the top fifteen states achieved annual savings ranging from 0.68% to 1.64%, i.e., the annual reductions from EE achieved by utilities in those states were ten to twenty times greater than the annual reductions achieved by Kentucky utilities.[20]

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[20] Sciortino, Michael et al. *The 2011 State Energy Efficiency Scorecard*. American Council for An Energy Efficient Economy. October 2011. Table 8.

Table 4-2 presents our assumptions for the unit cost of acquiring EE in Kentucky in the residential and C&I sectors, respectively.

Table 4-2. Estimated unit cost of energy efficiency in Kentucky (levelized ¢/kWh)

	RESIDENTIAL	C&I
Participant	1.8	1.4
Incentive	1.7	1.3
Program Administration	0.5	0.4
Total	4.0	3.0

Since the unit cost of acquiring EE varies by sector, we began the development of those unit costs by estimating the portions of additional EE that would be achieved from each sector each year. Based upon our review of the LG&E/KU April 2011 IRP and our experience in other states, we assume that through 2018 additional EE would be achieved primarily in the residential and commercial sectors, with a gradual ramp up in the quantity achieved in the industrial sector. From 2019 onward we assume each sector achieves the same percentage reduction in annual electricity use, i.e. the percentage specified in the draft bill.

Synapse developed estimates of the levelized unit cost of acquiring EE reductions in the residential sector and in the combined commercial and industrial sector (C&I) based primarily upon a review of prior reports prepared for Kentucky and states comparable to Kentucky. We checked those estimates against reports on the experience with efficiency throughout the United States over the past 20 years.

Our review covered two studies prepared for Kentucky, one study for Eastern Kentucky Power Cooperative, which covers a portion of Kentucky, and a 2009 report for Ohio. Table 4-3 provides estimates of the unit costs of acquiring EE based upon the costs in those reports. The total cost of acquiring EE consists of three major categories of costs – participant, incentives, and program administration. For those reports that provided only certain of those costs, we estimated the total cost based upon ACEEE statistics, which indicate an average composition of 45% participant costs, 42% incentives, and 13% administration costs.[21]

Table 4-3. Estimates of total unit cost of energy efficiency (levelized cents/kWh, 2010$)

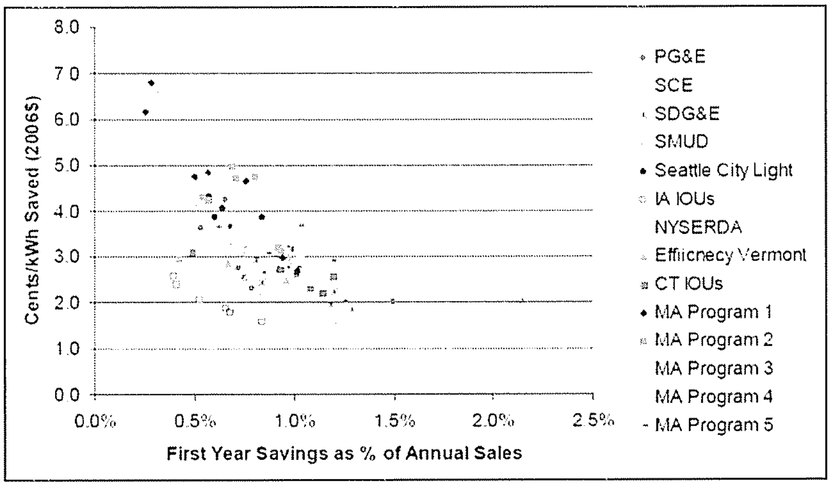
Study	Brown, et al. 2010	KPPC and ACEEE 2007	Zinga and McDonald 2008	ACEEE 2009
Region	KY	KY	EKPC	OH
Customer Sector				
Residential	4	n/a	4.1	3.4
Commercial	3.2	n/a	5.9	1.9
Industrial	1.5	3.7	4.4	2.7

The estimates of total unit costs for Kentucky presented in Table 4-3 are consistent with experience throughout the United States over the past 20 years. A 2009 ACEEE review of cost of saved energy from programs in 14 leading states found average program costs ranged from 1.5 cents/kWh to 3.4 cents/kWh,

[21] Friedrich, Katherine et al., *Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved through Utility-Sector Energy Efficiency Programs*. ACEEE 2009.

with an average of 2.5 cents/kWh.[22] That average equates to a total cost of approximately 4.5 cents/kWh when participant costs are included. The results of a Synapse study, summarized in Figure 4-2, indicate an average program cost of 2.6 cents/kWh (2010$), which indicates average total costs in the range of 4.7 cents/kWh (2010$).[23] That study indicates that the cost of saved energy declines at higher levels of annual savings, likely due to economies of scale and experience.

Figure 4-2. Variation in cost of energy efficiency with quantity of annual savings



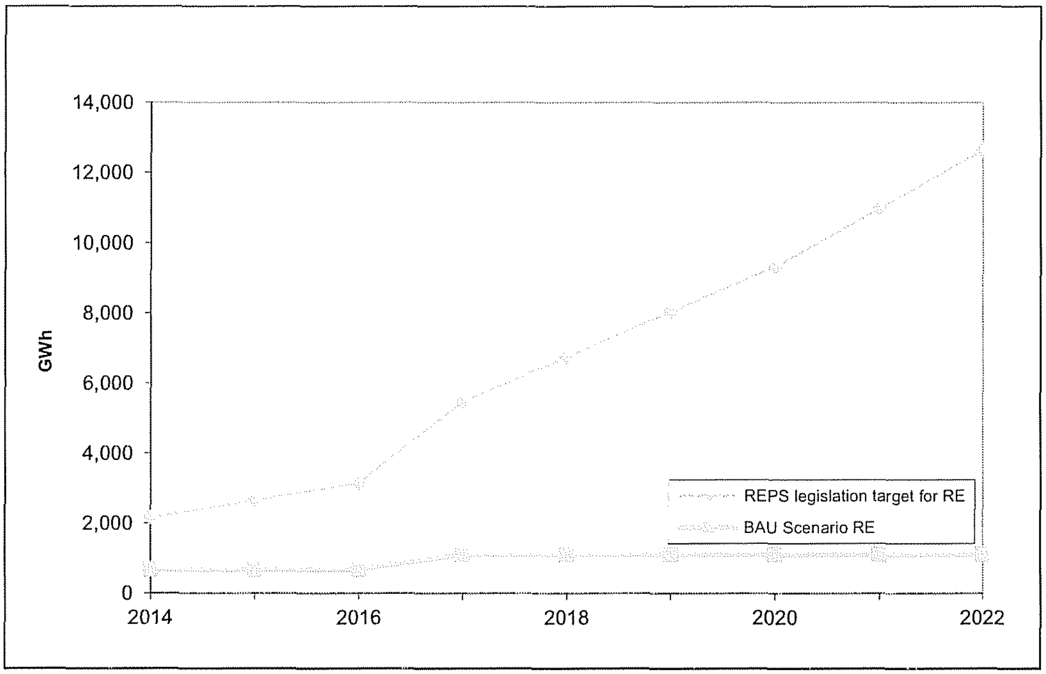
C. Cost of Additional RE Generation

Under the REPS scenario, Kentucky utilities would have to acquire much greater quantities of generation from RE than under the BAU scenario. The projected additional quantities are reported in Table 4-1 and plotted in Figure 4-3. The REPS legislation requires that a specific portion of that RE generation be met from solar resources. Our study refers to that portion as the "solar carve out."

[22] Ibid.

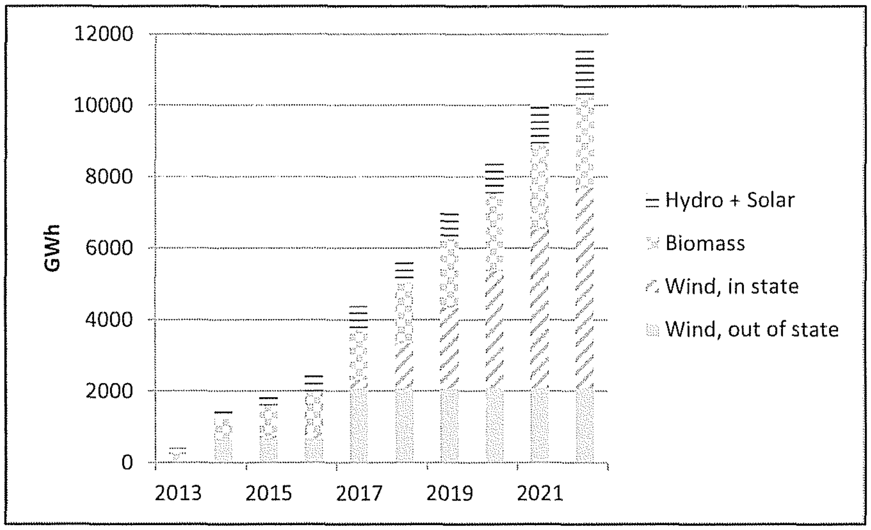
[23] Hurley, Doug et al. *Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts*. Synapse Energy Economics. August 2008.

Figure 4-3. Additional RE required under REPS



Our analyses indicate that Kentucky could eventually acquire the majority of these additional quantities from in-state resources. As indicated in Figure 4-4, the largest in-state RE resources are projected to be biomass and wind. The study estimates the remaining additional RE resources will be wind energy imported from out-of-state as well as hydro and solar RE developed in state.

Figure 4-4. Mix of additional RE in REPS Scenario



The study developed estimates of the quantity and cost of generation from each RE resource each year based upon a review of prior assessments of renewable energy resources in Kentucky and of renewable resources available to Kentucky from other states.

Biomass

Use of biomass for electric generation would require capital investments to install co-firing capability at various existing coal-fired plants, transportation infrastructure to deliver biomass to plants which add that co-firing capability, and projects to harvest various sources of biomass. Our analysis indicates that the costs of adding co-firing capability may be relatively modest and that the existing transportation infrastructure for delivery of coal may accommodate the delivery of biomass. However, adding co-firing capability and developing biomass transportation infrastructure will take time.

The major sources of biomass that could be harvested in sustainable quantities in Kentucky include logging residue, urban wood, trees that are not merchantable, underbrush, and short rotation woody crops such as hybrid poplar and willow.[24] The least expensive of those sources are logging residue and urban wood, which could be harvested to provide fuel at a price of approximately $2.50/MMBtu, while the cost of biomass from other sources is more expensive, in the order of $4.00/MMBtu. Those projected prices do not reflect the cost of transporting biomass to the coal plants with co-firing capability. Studies indicate that approximately 2600 GWh per year could be generated from biomass obtained at a fuel cost of $2.50/MMBtu, and an additional 3900 GWh could be generated each year at a biomass price of $4.00/MMBtu.[25,26]

Based on the relatively low capital costs required to add co-firing capability to existing coal fired units, we estimate the total levelized cost of generation from biomass at $2.50/MMBtu to be $0.028/kWh. Our study assumes that 100% of the less expensive biomass, i.e. logging residue and urban wood, would be used to generate electricity by 2022. That biomass represents approximately one-quarter of the total biomass that studies indicate could be harvested sustainably each year.[27]

Wind (in state)

The levelized cost of generation from wind turbines in Kentucky will vary based on several factors including turbine costs, meter hub height, capacity factor, and siting. Our study analyzed the potential for wind generation in Kentucky from wind turbines at two heights: units with an 80 meter hub height, and units with a 100 meter hub height. We estimate the total levelized cost of wind generation from 80 meter height units at $0.11/kWh and from 100 meter height units at $0.10/kWh based upon our review of the literature on the factors affecting the cost of wind generation in Kentucky. [28,29]

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[24] Anderson, Kristina et al. *Final Report from the Executive Task Force on Biomass and Biofuels Development in Kentucky*. Commonwealth of Kentucky. December 10, 2009. page 12.

[25] AEO 2011. Kentucky data. page 101

[26] Brown, Marilyn et al. *Renewable Energy in the South*. Southeast Energy Efficiency Alliance. December 2010.

[27] Logging residue plus urban wood represents 2.3 million dry tons per year out of a total biomass resource of 9.2 million dry tons per year.

[28] Zinga, Susan and McDonald, Andy. *A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative*. February 2008.

[29] Wiser, Ryan and Bolinger, Mark. *2010 Wind Technologies Market Report*. U.S. Department of Energy, June 2011.

Most assessments of wind potential to date have been limited to wind turbines with an 80 meter hub height. Our study assumes that 110 MW of wind turbines of that height will be installed by 2017. The annual generation from those units, at a 26% capacity factor, is projected to be 250 GWh/yr.

Assessments of wind potential from wind turbines with a 100 meter hub height are a relatively recent phenomenon nationally and completely new to Kentucky. However, the combination of falling prices for wind turbines and the development of 100 meter hub height wind turbines present a tremendous opportunity for Kentucky. At less than a 30% capacity factor, wind turbines of this size have the technical potential to generate more electricity than the state's annual retail electricity requirements.[30] While the economics of wind projects are certainly better the higher the capacity factor, more than a dozen wind projects out of 87 installed in 2009 had capacity factors below 30%.[31] Our study assumes that wind generation from 100 meter hub height units would begin to come online in 2020 in quantities sufficient to provide all of the incremental RE generation required to comply with the REPS in that year and thereafter.

This assumed pace of wind generation development is consistent with the recent experience in other states. For example, the pace of wind generation development in 12 states has averaged more than 250 MW/year over the past three years.[32]

Wind imports

The study assumes that Kentucky utilities could comply with the REPS by purchasing renewable electricity generated outside the state as long as that electricity is delivered to their customers. It is possible that utilities in Kentucky could enter into a power purchase agreement (PPA) for generation from RE with generators in the wholesale markets operated by MISO and PJM. The total delivered cost of that RE generation would be the price for generation under the PPA plus the transmission costs incurred to have that electricity delivered to its local distribution system.

Although the terms of PPAs are rarely disclosed, the study did gain some insight from the 2009 proceedings in case 2009-00545, in which the Kentucky PSC considered an application by Kentucky Power for authority to enter into a Renewable Energy Purchase Agreement with FPL Illinois Wind LLC. The PPA would have been for a 100 MW share of the Illinois based Lee-DeKalb Wind Energy Center for a 20-year term at the price of $43/MWh.[33] Furthermore, research by the US Department of Energy suggests that the cost to build wind projects in the Heartland (largely MISO) range from $30/MWh to $70/MWh, with a capacity weighted average of $48/MWh. These data points, when combined with the tremendous growth of wind generation and total wind resources in MISO, suggest that utilities in Kentucky could tap as much MISO wind as necessary for compliance without substantially impacting the price of supply. While limits on transmission could conceivably become a constraint, projects like the Grain Belt Express transmission project suggest that market forces will ensure sufficient transmission. Our study estimates the cost of imported wind generation at $72/MWh based on a conservative estimate

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30 ___. *Kentucky – Wind Resource Potential, 80m and 100m.*" National Renewable Energy Lab and AWS Truepower, February 2010.

31 Wiser, Ryan and Bolinger, Mark. *2010 Wind Technologies Market Report.* U.S. Department of Energy, June 2011. Figure 34 page 55.

32 Ibid.

33 ____. Order in Case No. 2009-00545. *APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF RENEWABLE ENERGY RESOURCES BETWEEN KENTUCKY POWER COMPANY AND FPL ILLINOIS WIND LLC. ENERGY PURCHASE AGREEMENT FOR WIND.* Commonwealth of Kentucky Public Service Commission. June 28, 2010

of wind costs in the Heartland of $60/MWh plus twenty percent for transmission to specific utilities in Kentucky.

Our study assumes that Kentucky utilities import sufficient quantities of wind generation from MISO to comply with their REPS requirements from 2014 through 2019. From 2020 onward we assume imports of wind generation remain at the 2019 level. Because wind developers typically seek a long term PPA, the study assumes any wind PPAs signed with MISO generation would be constant throughout the length of the study.

Solar

The REPS legislation defines solar resources that qualify as RE resources to include solar water heating and photovoltaics (PV).

Our analysis indicates significant potential in Kentucky for solar water heating as well as for large scale PV. (An example of large scale PV, also referred to as utility scale PV, would be a 10 MW or larger ground mounted installation.) Our study estimates the average cost of electricity from large scale PV units at $0.20/kWh based upon assumptions drawn from a recent Synapse projection of the cost of various sources of generation.[34] The study estimates the cost of solar water heating, expressed in terms of avoided electricity use, to range between $0.20/kWh and $0.22/kWh.

The 61 percent of Kentucky households who use electric hot water heaters represent 1,000,000 potential residential installations. They have a technical potential of 2700 GWh of avoided electricity use per year at a price of approximately $0.22/kWh. Commercial solar water heating offers fewer GWh of avoided electricity, but economies of scale offer a lower price; the technical potential is 1900 GWh at a price of approximately $0.20/kWh. Although solar water heating is less expensive than PV and there is sufficient solar water heating opportunity, the number of installations per year is limited by the ability to enroll customers and ramp up the number of installations per year. Our study assumes that one percent of the technical potential is installed each year, for both residential and commercial solar water heating. The potential achieved at that installation rate is not sufficient to fully comply with the solar carve out. Therefore the study assumes PV satisfies the remaining portion of the solar carve out. Some may consider the assumption of a one percent installation rate for solar water heating overly optimistic. However, if that level is not achieved, the shortfall could be achieved from PV without a significant material difference in total cost because the solar carve out is small relative to the total generation required from RE.

Like other states, the achievable potential for PV in Kentucky is limited primarily by cost. With an ever changing set of state and federal subsidies available for PV and a rapidly decreasing price per watt, estimating the "sticker price" of a solar project is difficult. What remains clear is that the price of electricity from PV is higher than other forms of renewable electricity available to Kentucky.

D. REPS Scenario Projections

The study develops the REPS scenario projection of electricity resource mix and costs using a process similar to that used for the BAU scenario.

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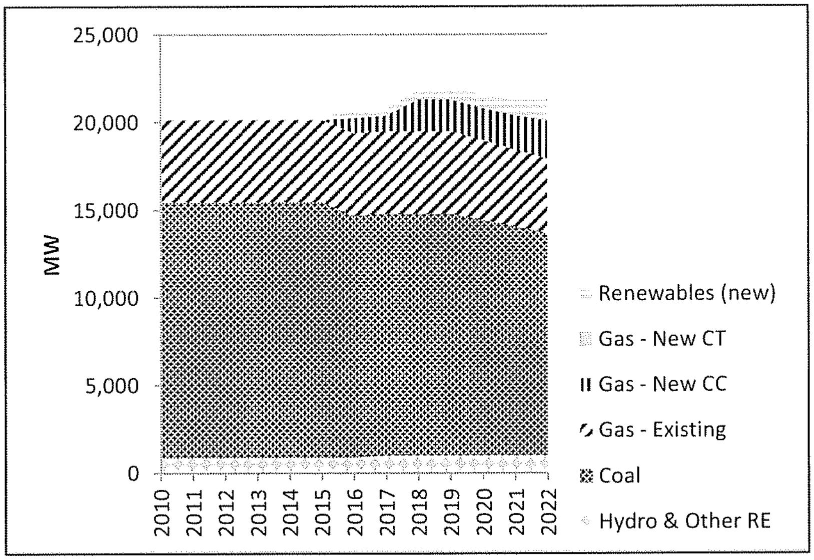
[34] Keith, Geoffrey et al. *Toward a Sustainable Future for the US Power Sector: Beyond Business as Usual 2011. Synapse Energy Economics*. November 2011. www.synapse-energy.com.

Since the RE targets are expressed as a percent of annual sales, Synapse derived the quantity of each category of new RE capacity that would have to be added to the ECM in each year from the quantity of annual generation projected from that RE resource. Because wind and solar capacity cannot be dispatched in the same manner as traditional fossil fuel capacity, Synapse assumed load carrying capacities of 20% for in-state wind and solar and zero for wind imports when calculating the effective capacity available from each resource for reliability purposes. Figure 4-5 presents the capacity mix for the REPS scenario resulting from these analyses.

Figure 4-5. REPS scenario - Forecast capacity in Kentucky



In the REPS scenario, the ECM begins by using the reductions from EE and the generation from RE and then dispatches each remaining category of capacity available in each year in the same manner as in the BAU scenario. Figure 4-6 plots the additional EE and generation mix for the REPS scenario resulting from those assumptions. Note that the state's reliance on coal generation under the REPS scenario declines to 63% of its total annual energy requirements in 2022 due to displacement of generation from existing coal units by additional EE and RE resources.

Figure 4-6. REPS scenario – annual electricity requirements and sources

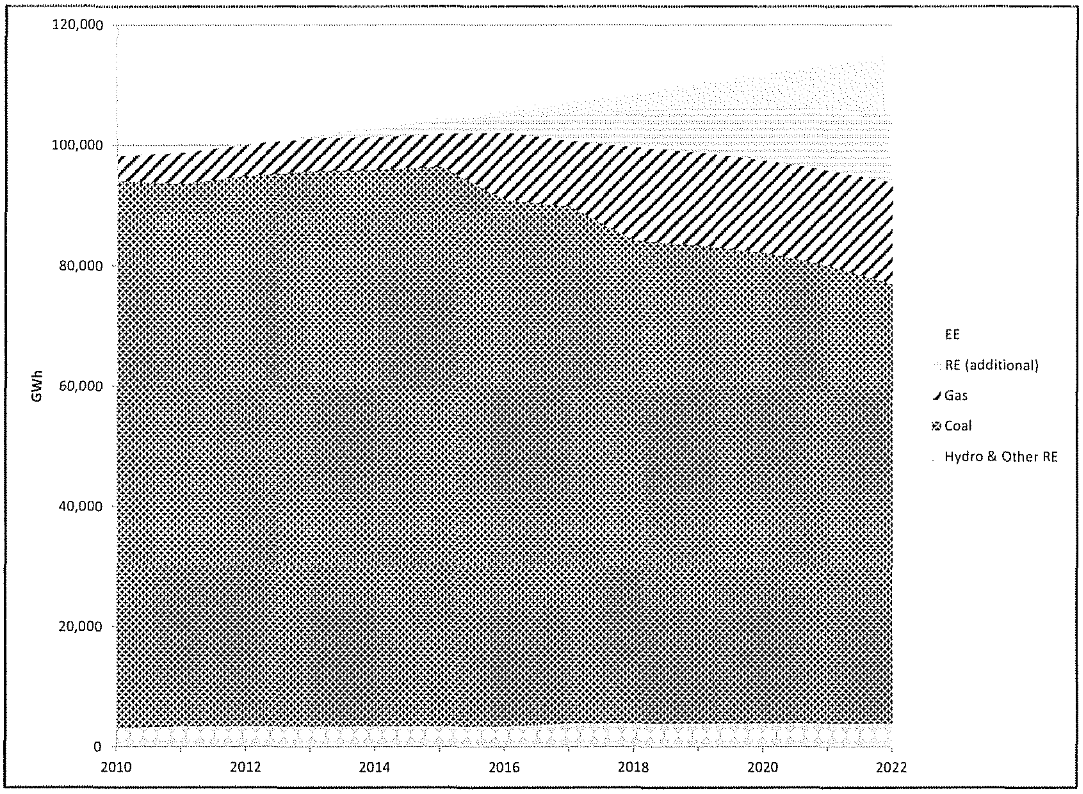


Table 4-4 presents the projections of average rates and average bills by sector for the REPS scenario.

Table 4-4. REPS scenario – Projected average rates and average bills by sector

Average Electric Rates ($/kWh) (2010$)	**2010**	**2015**	**2020**	**2022**	**2022 versus 2010**
Total (All Sectors)	$0.067	$0.070	$0.096	$0.102	51%
Residential	*$0.086*	*$0.089*	*$0.114*	*$0.121*	41%
Commercial	$0.079	$0.081	$0.107	$0.114	44%
Industrial	$0.051	$0.054	$0.079	$0.085	68%
Average Electric Bills ($) (2010$)	**2010**	**2015**	**2020**	**2022**	**2022 versus 2010**
Residential	$1,249	$1,292	$1,611	$1,657	33%
Commercial	$5,198	$5,392	$6,850	$7,067	36%
Industrial	$325,409	$344,740	$489,393	$513,178	58%

The study projects that average rates (in constant 2010 dollars) will increase slightly more under the REPS scenario over the period 2010 to 2022 than under the BAU scenario. The increase is driven by the fixed costs of T&D and existing generating capacity, common to both scenarios, Kentucky utilities would recover from a smaller quantity of annual sales under the REPS scenario. The magnitude of the increase is offset by savings in the absolute amount of incremental capacity costs and production costs that Kentucky utilities would have to recover as a result of the incremental EE and RE.

For example, the study projects that average residential rates (in constant dollars) would increase by 41% under the REPS scenario over the period 2012 to 2022 as compared to 40% under the BAU scenario. However, the study projects that average bills will increase by lesser amounts under the REPS scenario than under the BAU scenario over this period, primarily because customers will be using less electricity on average. For example, average residential bills are projected to increase by 33% over that period as compared to 47% under the BAU scenario.

If one assumes no regulation of carbon in Kentucky until after 2022 our analyses indicate that a REPS would still lead to lower electric bills. The reductions in electric bills would be less since customers would not be avoiding payment of carbon costs. The summary results from that analysis are presented in Table C-1 of Appendix C.

5. Impacts of a REPS on Kentucky's Economy

One of the key goals of the proposed REPS legislation is to "... create high-quality jobs, training, business, and investment opportunities in the Kentucky energy sector." Increased expenditures on EE and RE would generate increased economic activity in Kentucky directly as well as through various multiplier effects. The direct impacts would be additional jobs and increased business earnings resulting from increased expenditures on the production, sale, installation, and maintenance of materials and equipment required to achieve reductions from EE and to generate electricity from RE. In addition, there would be increased jobs and business earnings resulting from the multiplier effect of the direct expenditures as well as from the spending of any savings on electricity bills on other Kentucky goods and services.

Increased expenditures on EE and RE are not only expected to increase economic activity, they are generally expected to create more economic activity than expenditures on the electricity generation they would displace (e.g., generation for coal and natural gas). In other words increased expenditures on EE and RE are expected to have net positive economic impacts. The expectation of a net positive impact is based on several factors. First, EE and some forms of RE are projected to be less expensive in the long-term than electric generation from coal and natural gas. Second, typically a higher percentage of the total dollars spent on energy efficiency and renewable energy remain in the local economy than dollars spent on those traditional sources of electric generation. Finally, energy efficiency and renewable energy projects tend to be more labor-intensive than traditional generation, and thus typically create more jobs per dollar spent.

This chapter describes our estimate of the net incremental economic impact of the proposed REPS on Kentucky over the study period. The net incremental economic impact measures the difference between economic activity under the REPS scenario and under the BAU scenario. It is an estimate of "net" incremental impact because it reports the increase in economic activity from investments in additional quantities of EE and RE under the REPS scenario minus the decrease in economic activity due to the displacement of some electricity generation from coal and natural gas that would have otherwise occurred under the BAU scenario.

A. Expenditures on Electricity Resources and Change in Electricity Bills

Our study estimated the net incremental economic impact of the REPS on Kentucky based upon two major outputs of the ECM analyses of the BAU scenario and the REPS scenario. The first major output was net incremental expenditures on electric capacity, generation and efficiency resources in Kentucky. The second major output was the net change in electricity bills. The study uses those two outputs from the ECM as inputs to its economic models, IMPLAN and JEDI.

The ECM provides the expenditures to generate electricity from Kentucky resources and to reduce electricity use in Kentucky as capital costs plus operation and maintenance (O&M) costs in each year. The study calculates the net expenditure each year as expenditures under the REPS scenario minus expenditures under the BAU scenario. Thus, that net amount consists of two major components, an increase in capital and O&M expenditures associated with the acquisition of additional quantities of EE and RE under the REPS scenario and decrease in expenditures on generation from new natural gas units and existing coal units. The largest components of the increase are capital and O&M expenditures of $3.0 billion on EE, $5.4 billion on in-state wind, and $1.8 billion on solar while the decreases in capital plus O&M expenditures on new natural gas units and existing coal units are $5.7 billion and $ 2.1 billion respectively. Those projected changes in expenditures are reported in Table 5-1. The cumulative total net incremental capital and O&M expenditure in Kentucky through 2022 is $3.0 billion.

Table 5-1. Incremental capital and O&M expenditures (REPS scenario minus BAU)

Annual Expenditures (2010$ million)	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***TOTAL***
Energy Efficiency	$12	$130	$210	$292	$371	$367	$448	$530	$610	*$2,970*
Hydro	$0	$50	$50	$51	$28	$28	$29	$24	$24	*$285*
Wind (in-state)	$0	$86	$87	$88	$935	$949	$962	$1,120	$1,135	*$5,363*
Biomass	$25	$32	$39	$46	$52	$58	$62	$65	$69	*$449*
Solar	$234	$158	$159	$161	$178	$180	$182	$264	$266	*$1,782*
Natural Gas	-$14	-$24	-$228	-$799	-$796	-$405	-$765	-$1,223	-$1,418	*-$5,672*
Coal	-$40	-$65	-$111	-$116	-$155	-$266	-$395	-$443	-$528	*-$2,119*
Total	***$218***	***$367***	***$207***	*($277)*	***$614***	***$911***	***$523***	***$337***	***$159***	***$3,058***

The net expenditures include the costs of EE programs, costs of construction and operation of new RE facilities, and the reduction in expenditures on coal and natural gas generation due to the additional EE and RE. There is a reduction in expenditures on natural gas because less new gas capacity is built under the REPS scenario and there is less generation from natural gas. The reduction in expenditures on coal is attributable to the reduction in generation from existing coal units as compared to the BAU scenario, and a corresponding reduction in production and use of Kentucky coal associated with that reduction in generation. (Note that this estimate may over-state the reduction in coal-related expenditures, since Kentucky mines may sell the coal not used for electric generation in other markets.)

The second key input to the economic modeling was net incremental changes in electricity bills. Those net changes are reported in Table 5-2. The changes in bills are reported for the residential sector and the commercial/industrial sector since those sectors treat those changes differently. Residents re-spend savings elsewhere in the local economy, while business re-invest savings to increase their competitive position and increase their bottom line.

Table 5-2. Net incremental change in annual electricity bills (REPS scenario minus BAU)

Aggregate Change in Electricity Bills (2010$ million)	***2014***	***2015***	***2016***	***2017***	***2018***	***2019***	***2020***	***2021***	***2022***	***TOTAL***
Residential	-$7	$6	$24	$55	$123	$152	$198	$263	$341	*$1,154*
Commercial & Industrial	-$15	-$7	$12	$55	$197	$261	$349	$477	$630	*$1,959*
Total	***-$21***	***-$1***	***$36***	***$109***	***$320***	***$413***	***$547***	***$741***	***$970***	***$3,113***

If one assumes no regulation of carbon in Kentucky until after 2022 our analyses indicate that that the cumulative total net incremental capital and O&M expenditure in Kentucky through 2022 would be higher and the reduction in bills would be lower. Net direct expenditures are higher because the additional expenditures on EE and RE would be much the same but the decrease in expenditures on gas- and coal-fired generation would be less since those two amounts would not include carbon costs. The reduction in bills would be lower since customers would not be avoiding payment of carbon costs, as noted earlier. Those summary results are presented in Tables C-2 and C-3 of Appendix C.

B. Net Economic Impacts on Kentucky

This study estimates the net incremental impact of the proposed REPS on Kentucky's economy in terms of dollars (i.e., personal income, gross state product) and employment. Employment impacts are expressed in job-years since the duration of some jobs is limited (e.g. a RE construction project), while the duration of other jobs is longer-term (e.g. programs to install EE measures).

Each of those metrics is a function of three categories of economic activity, i.e., direct impacts, indirect impacts, and induced impacts. For example, total personal income from expenditures on EE is equal to personal income from direct impacts plus from indirect impacts plus from induced impacts. Direct economic impacts typically measure direct spending on goods and services (e.g., direct spending on construction or on purchases of equipment). The other two categories of impacts, indirect and induced, reflect the "multiplier" or ripple effect of direct economic impacts throughout the economy. Indirect impacts measure spending on local supplies and services by the firms that are providing the direct activity, while induced impacts measure the spending of wages earned by the workers involved in the direct activity as well as the workers providing the supporting supplies and services.

The net incremental dollar impact of the proposed REPS on Kentucky is equal to the net direct impacts from the EMS analyses plus indirect and induced impacts, i.e., the multiplier effects. The net incremental employment impact of the proposed REPS on Kentucky is equal to the job-years from the direct expenditures plus job-years from the indirect and induced impacts.

The study projected these dollar and employment impacts using IMPLAN, an input-output model, with augmentation for RE resources from the National Renewable Energy Laboratory JEDI model. The IMPLAN model uses industry and region-specific data sets describing the purchases of consumers and industries, as well as flows of goods and services between regions, to estimate indirect and induced impacts for a given set of direct expenditures. IMPLAN has built-in assumptions regarding the portion of each industry's supplies that are provided in-state and the portion of household spending that remains in-state. Synapse augmented the standard IMPLAN assumptions for the electricity industry by using JEDI to develop distinct coefficients for each renewable technology. Those coefficients are a more detailed and accurate estimate of the components of expenditures for each category of RE, such as manufacturing, installation, O&M and the composition of those components such as labor, raw materials, manufactured equipment, and services. By using these RE specific coefficients, and by calibrating the IMPLAN coefficients for Kentucky, the study was able to use IMPLAN to estimate the spin-off effects in Kentucky of new industry-specific activity by estimating the activity of suppliers required for that activity (indirect impacts) and the re-spending of workers' wages in the state's economy (induced impacts). The study also used IMPLAN to estimate the induced impacts from changes in annual electricity bills.

Dollar Impacts

The REPS is projected to have a positive net incremental impact on personal income and Gross State Product (GSP) in Kentucky as shown in Table 5-3. The incremental economic activity associated with the

REPS is projected to generate accumulative $4.6 billion in personal income and $6.0 billion in GSP for Kentucky over the study period.

Table 5-3. Net impacts on Kentucky economy (2010$ millions)

Economic Impacts	2017	2020	2022	Cumulative Total
Personal Income	$119	$765	$1,088	*$4,634*
Gross State Product	$118	$1,004	$1,474	*$6,038*

Employment Impacts

The REPS is also projected to have a positive net incremental impact on employment in Kentucky, as shown in Table 5-4. By 2022 the study projects a net increase of over 28,000 job-years, i.e., net of a reduction in job-years associated with electricity generation from new natural gas units and existing coal units. This projection consists of approximately 9,700 net direct job-years and approximately 18,800 net job-years from indirect and induced activity in Kentucky. The major sources of these incremental job-years are capital and operating expenditures on EE measures and RE facilities ($159 million in 2022) as well as electric customer spending of the amounts they saved on their electric bills, i.e., spending of their net energy savings from energy efficiency ($970 million in 2022).

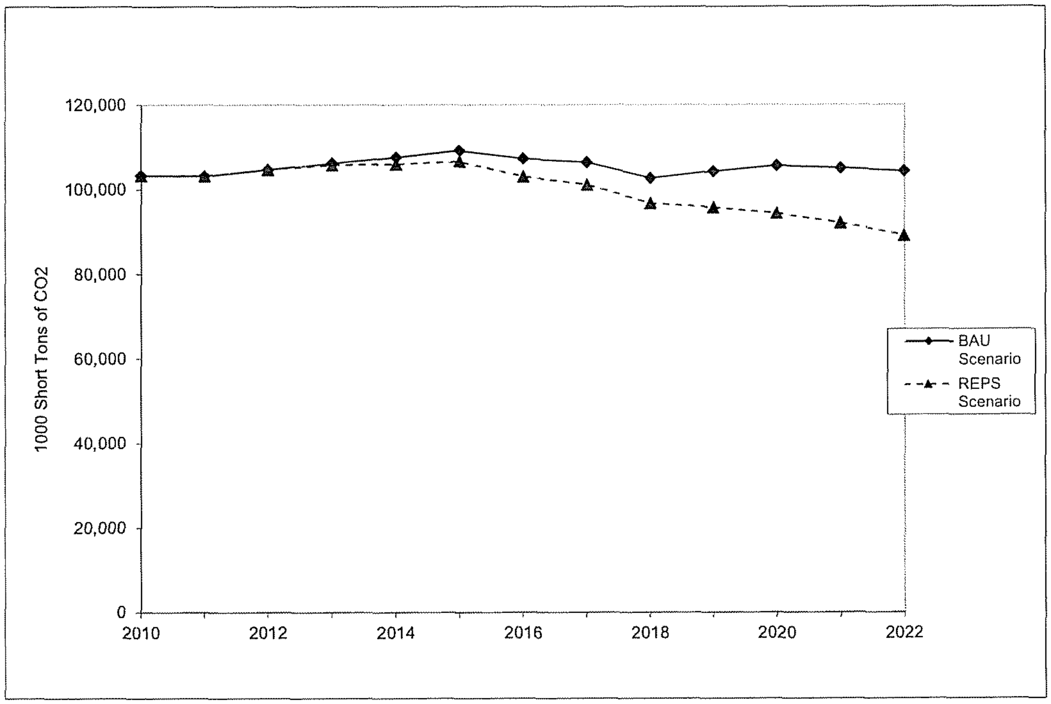
The net additional 9,700 direct job-years consists of over 12,500 job-years associated with acquiring additional EE and RE offset by a reduction of 2,500 job-years associated with less construction and operation of new natural gas units and a reduction of nearly 300 job-years associated with less generation from existing coal units.

Table 5-4. Net job-years in Kentucky by major electricity resource by year

Direct	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*
RE & EE	1,661	3,532	4,423	5,326	9,028	9,018	9,935	11,568	12,478
Natural Gas	-2	-3	-1,009	-3,103	-2,123	-53	-1,383	-2,533	-2,482
Coal	-24	-38	-65	-68	-90	-154	-230	-258	-307
Sub-Total	**1,636**	**3,491**	**3,348**	**2,156**	**6,815**	**8,811**	**8,322**	**8,777**	**9,688**
Indirect and Induced									
RE & EE	504	1,592	2,658	4,404	10,621	12,487	15,475	20,084	24,874
Natural Gas	-20	-35	-857	-2,770	-2,243	-593	-1,805	-3,058	-3,302
Coal	-208	-333	-572	-599	-800	-1,368	-2,034	-2,284	-2,720
Sub-Total	**276**	**1,225**	**1,229**	**1,035**	**7,578**	**10,525**	**11,636**	**14,742**	**18,851**
Direct, Indirect, and Induced									
RE & EE	2,166	5,124	7,081	9,730	19,649	21,505	25,410	31,651	37,351
Natural Gas	-22	-38	-1,867	-5,873	-4,366	-647	-3,188	-5,591	-5,785
Coal	-232	-370	-637	-666	-890	-1,522	-2,264	-2,542	-3,027
Total	**1,912**	**4,716**	**4,578**	**3,190**	**14,393**	**19,336**	**19,958**	**23,518**	**28,539**

The cumulative job-years from Table 5-4 amount to 120,000 over the study period. The cumulative job-years by year are shown in Figure 5-1, which illustrates the timing of impacts from new spending and net

Figure 6-2. Annual carbon dioxide emissions in 2022 - REPS versus BAU



B. Electricity Bills

The REPS would lead to lower increases in electric bills over time. Table 6-1 provides comparison of the changes in average rates and average electric bills through 2022 under the BAU scenario and the REPS scenario, respectively.

Table 6-1. Annual electricity bills in 2022 - REPS versus BAU

Average Electric Rates ($/kWh) (2010$)	2010	BAU Scenario 2022	REPS Scenario 2022	REPS Scenario vs BAU Scenario
Total (All Sectors)	$0.067	$0.101	$0.102	1%
Residential	$0.086	$0.120	$0.121	1%
Commercial	$0.079	$0.113	$0.114	1%
Industrial	$0.051	$0.085	$0.085	0%
Average Electric Bills ($) (2010$)	**2010**	**BAU Scenario 2022**	**REPS Scenario 2022**	**REPS Scenario vs BAU Scenario**
Residential	$1,249	$1,834	$1,657	-10%
Commercial	$5,198	$7,658	$7,067	-8%
Industrial	$325,409	$557,989	$513,178	-8%

Under the REPS scenario, average rates are projected to be 1% higher than under the BAU scenario by 2022. However, average annual bills under the REPS scenario are projected to be 8% to 10% lower. The lower average bills in that year are primarily due to the fact that retail customers will be using approximately 8 percent less electricity on average than under the BAU scenario due to load reductions from EE. After 2022, the study indicates that average bills will be even less under the REPS scenario than under the BAU scenario as carbon regulation continues to drive the cost of electricity from natural gas and coal up and improvements in technology continues to drive the cost of electricity from RE down.

If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to lower electric bills. The reductions in electric bills would be less since customers would not be avoiding payment of carbon costs. Those summary results are presented in Table C-1 of Appendix C.

C. Economic Impacts

The study estimates that a REPS would lead to a net increase in employment and business opportunities in Kentucky. In other words, the expenditures on additional reductions from EE and additional RE generation required under a REPS would create more economic activity and employment in Kentucky than the electric generation from new natural gas units and from existing coal units displaced by the additional EE and RE.

EE will require expenditures on materials and equipment to improve the efficiency of residences, businesses, and factories, while RE will require expenditures on construction and operation of RE projects. The net positive impact of these expenditures is attributable to three major factors. First, the portion of total expenditures that would remain in Kentucky is projected to be higher for EE and RE than for generation from coal and natural gas. Second, the EE and RE projects are expected to be more labor-intensive than generation from coal and natural gas, and thus are projected to create more jobs per dollar spent. Finally, the additional quantities of EE and RE are projected to result in lower electric bills over time, leaving Kentuckians with more discretionary income available to spend on other goods and services, which in turn would produce additional economic impacts.

The REPS is projected to have a positive net incremental impact on personal income, GSP, and employment in Kentucky. The incremental economic activity associated with the REPS is projected to generate a cumulative $4.6 billion in personal income and $6.0 billion in GSP for Kentucky over the study period. The REPS is also projected to lead to a net increase of over 28,000 job-years, i.e., net of a reduction in job-years associated with electricity generation from new natural gas units and existing coal units. This projection consists of approximately 9,700 net direct job-years and approximately 18,800 net job-years from indirect and induced activity in Kentucky. The major sources of these incremental job-years are installation of EE measures, construction of RE facilities, and electric customer spending of the amounts they saved on their electric bills. These summary results are shown in Table 6 2.

Table 6-2. Net impacts on Kentucky economy

Economic Impacts	2017	2020	2022	Cumulative Total
Job-years	3,190	19,958	28,539	***120,140***
Personal Income (2010$ millions)	$119	$765	$1,088	***$4,634***
Gross State Product (2010$ millions)	$118	$1,004	$1,474	***$6,038***

If one assumes no regulation of carbon in Kentucky until after 2022, our analyses indicate that a REPS would still lead to a net increase in employment and business opportunities in Kentucky, although those net increases would be somewhat smaller. Those summary results are presented in Tables C-4 and C-5 of Appendix C.

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Appendix B. Tables of Key Results

TABLE B-1 BAU Scenario Requirements, Sources and Supply Price

All costs in constant 2010 dollars.

CASE:	BAU Scenario											
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Retail Sales Forecast												
Retail Energy	GWh	95,558	96,916	98,130	99,571	100,976	102,341	103,793	105,333	106,897	108,369	109,948
Retail Demand	MW	18,181	18,439	18,670	18,944	19,212	19,471	19,747	20,041	20,338	20,618	20,919
Supply Forecast												
Capacity Requirement	MW	21,923	22,235	22,513	22,844	23,166	23,479	23,812	24,166	24,525	24,862	25,225
Capacity Sources												
Hydro & Other RE	MW	893	893	893	893	893	1,023	1,023	1,023	1,023	1,023	1,023
Coal	MW	14,553	14,553	14,553	14,553	13,753	13,753	13,753	13,753	13,389	13,025	12,662
Gas - Existing	MW	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,558	4,401	4,244
Gas - New CC	MW	0	0	0	1	909	1,251	2,862	2,862	2,862	3,402	4,030
Gas - New CT	MW	1	1	1	2	3	117	352	352	352	532	741
Renewable (additional)	MW	0	0	0	0	0	0	0	0	0	0	0
Sub-total In-State Capacity	MW	20,162	20,162	20,162	20,164	20,273	20,859	22,705	22,705	22,184	22,383	22,699
Out-of-State Capacity	MW	1,761	2,073	2,351	2,680	2,893	2,620	1,107	1,461	2,341	2,479	2,526
Total Capacity Provided	MW	21,923	22,235	22,513	22,844	23,166	23,479	23,812	24,166	24,525	24,862	25,225
Energy Requirement	GWh	100,198	101,622	102,895	104,406	105,879	107,311	108,833	110,448	112,088	113,632	115,287
Energy Sources												
Hydro & Other RE	GWh	3,445	3,445	3,445	3,445	3,445	4,472	4,472	4,472	4,472	4,472	4,472
Coal	GWh	91,442	92,747	93,914	95,293	91,416	89,959	83,798	85,057	85,965	84,257	82,205
Gas	GWh	5,293	5,411	5,517	5,649	10,999	12,860	20,544	20,899	21,631	24,883	28,590
Renewable (additional)	GWh	0	0	0	0	0	0	0	0	0	0	0
Sub-total In-State Generation	GWh	100,180	101,604	102,876	104,387	105,860	107,291	108,813	110,428	112,068	113,611	115,266
Out-of-State Generation	GWh	18	19	19	19	19	20	20	20	21	21	21
Total Energy Provided	GWh	100,198	101,622	102,895	104,406	105,879	107,311	108,833	110,448	112,088	113,632	115,287
Supply Price Forecast												
Average Production Cost	¢/kWh	5.31	5.33	5.36	5.40	5.58	5.72	7.34	7.64	7.93	8.25	8.56
Retail Margin	¢/kWh	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Average Retail Rate	¢/kWh	6.89	6.91	6.94	6.98	7.16	7.31	8.92	9.22	9.52	9.83	10.15

TABLE B-2 BAU Scenario Avoided Cost, Average Retail Rates and Average Electric Bills

All costs in constant 2010 dollars.

CASE:		BAU Scenario										
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Avoided Costs by costing period												
Avoided Resource Cost	¢/kWh	5.10	6.51	7.14	7.58	8.18	8.29	8.42	8.63	8.85	9.22	9.52
Avoided Capacity Cost	$/kW-yr	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00
	¢/kWh	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Avoided Energy Only Cost	¢/kWh	3.88	5.29	5.92	6.36	6.96	7.07	7.20	7.41	7.63	8.00	8.30
Average Retail Rates												
System-Wide average	¢/kWh	6.89	6.91	6.94	6.98	7.16	7.31	8.92	9.22	9.52	9.83	10.15
Residential	¢/kWh	8.73	8.75	8.77	8.82	8.99	9.15	10.77	11.07	11.36	11.68	11.99
Commercial	¢/kWh	8.00	8.02	8.05	8.10	8.27	8.43	10.05	10.34	10.64	10.95	11.27
Industrial	¢/kWh	5.21	5.23	5.26	5.31	5.48	5.62	7.23	7.53	7.83	8.14	8.46
Average Customer Bills (2010$)												
Residential	$/yr	1,295	1,302	1,308	1,319	1,350	1,377	1,625	1,676	1,727	1,780	1,834
Commercial	$/yr	5,280	5,309	5,335	5,384	5,517	5,632	6,735	6,960	7,185	7,417	7,658
Industrial	$/yr	333,811	336,054	338,329	342,448	354,950	364,340	470,667	491,971	513,290	535,362	557,989

TABLE B-3 REPS Scenario Requirements, Sources and Supply Price

All costs in constant 2010 dollars.

CASE:		REPS Scenario										
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Load Forecast												
Retail Energy	GWh	95,558	96,916	98,089	99,140	99,903	100,370	100,672	101,056	101,207	101,010	100,666
Retail Demand	MW	18,181	18,439	18,662	18,862	19,007	19,096	19,154	19,227	19,256	19,218	19,153
Supply Forecast												
Capacity Requirement	MW	21,923	22,235	22,504	22,745	22,920	23,027	23,096	23,185	23,219	23,174	23,095
Capacity Sources												
Hydro & Other RE	MW	893	893	893	893	893	1,023	1,023	1,023	1,023	1,023	1,023
Coal	MW	14,553	14,553	14,553	14,553	13,753	13,753	13,753	13,753	13,389	13,025	12,662
Gas - Existing	MW	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,715	4,558	4,401	4,244
Gas - New CC	MW	0	0	0	1	909	909	1,816	1,816	1,816	1,909	2,156
Gas - New CT	MW	1	1	1	2	3	3	3	3	3	34	116
Renewables (new)	MW	0	62	124	202	280	358	496	634	773	922	1,071
Sub-Total In-State Capacity	MW	20,162	20,224	20,286	20,366	20,553	20,761	21,806	21,945	21,562	21,314	21,271
Out-of-State Capacity	MW	1,761	2,011	2,218	2,379	2,367	2,266	1,290	1,240	1,657	1,860	1,824
Total Capacity Provided	MW	21,923	22,235	22,504	22,745	22,920	23,027	23,096	23,185	23,219	23,174	23,095
Energy Requirement	GWh	100,198	101,622	102,852	103,954	104,754	105,244	105,561	105,963	106,122	105,915	105,554
Energy Sources												
Hydro & Other RE	GWh	3,445	3,445	3,445	3,445	3,445	3,864	3,864	3,864	3,864	3,864	3,864
Coal	GWh	91,442	92,380	92,518	93,057	87,582	85,988	80,390	79,597	78,355	76,206	73,153
Gas	GWh	5,293	5,378	5,390	5,447	11,216	10,975	15,531	15,368	15,393	15,813	16,983
RE (additional)	GWh	0	401	1,480	1,986	2,491	4,397	5,756	7,115	8,490	10,012	11,535
Sub-Total In-State Generation	GWh	100,180	101,604	102,834	103,935	104,735	105,225	105,541	105,944	106,102	105,895	105,535
Out-of-State Generation	GWh	18	19	19	19	19	19	19	19	19	19	19
Total Energy Provided	GWh	100,198	101,622	102,852	103,954	104,754	105,244	105,561	105,963	106,122	105,915	105,554
Supply Price Forecast												
Average Production Cost	¢/kWh	5.31	5.34	5.39	5.45	5.65	5.79	7.35	7.68	8.00	8.32	8.63
Retail Margin	¢/kWh	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58
Average Retail Rate	¢/kWh	6.89	6.92	6.98	7.04	7.23	7.37	8.93	9.27	9.58	9.90	10.22

TABLE B-4 REPS Scenario Avoided Cost, Average Retail Rates and Average Electric Bills

All costs in constant 2010 dollars.

CASE:	REPS Scenario											
Category	Units	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Avoided Costs by costing period												
Avoided Resource Cost	¢/kWh	5.11	6.09	7.28	7.70	8.12	8.36	8.56	8.80	9.01	9.17	9.36
Avoided Capacity Cost	$/kW-yr	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00	64.00
	¢/kWh	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22	1.22
Avoided Energy Only Cost	¢/kWh	3.89	4.87	6.06	6.48	6.91	7.14	7.34	7.58	7.79	7.95	8.14
Average Retail Rates												
System-Wide average	¢/kWh	6.89	6.92	6.98	7.04	7.23	7.37	8.93	9.27	9.58	9.90	10.22
Residential	¢/kWh	8.73	8.76	8.82	8.86	9.05	9.20	10.77	11.12	11.44	11.77	12.10
Commercial	¢/kWh	8.00	8.04	8.09	8.15	8.33	8.48	10.05	10.39	10.71	11.03	11.36
Industrial	¢/kWh	5.21	5.24	5.30	5.37	5.57	5.71	7.26	7.57	7.88	8.19	8.50
Average Customer Bills (2010$)												
Residential	$/yr	1,267	1,276	1,285	1,292	1,314	1,327	1,541	1,580	1,611	1,635	1,657
Commercial	$/yr	5,280	5,319	5,360	5,392	5,498	5,559	6,533	6,707	6,850	6,966	7,067
Industrial	$/yr	333,811	336,599	340,410	344,740	356,455	363,176	458,093	474,524	489,393	501,857	513,178

Appendix C. Summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022

Given the uncertainty regarding the timing and magnitude of future regulation of carbon, this Appendix presents an estimate of the summary impacts of a REPS assuming no regulation of carbon in Kentucky until after 2022

Table C-1. Annual electricity bills in 2022, no carbon regulation - REPS versus BAU

Average Electric Rates ($/kWh) (2010$)	*2010*	BAU *Scenario* 2022	REPS Scenario 2022	REPS Scenario vs BAU Scenario
Total (All Sectors)	$0.067	$0.077	$0.080	3%
Residential	$0.086	$0.096	$0.099	3%
Commercial	$0.079	$0.089	$0.091	3%
Industrial	$0.051	$0.060	$0.062	3%
Average Electric Bills ($) (2010$)	**2010**	**BAU Scenario 2022**	**REPS Scenario 2022**	**REPS Scenario vs BAU Scenario**
Residential	$1,249	$1,466	$1,350	-8%
Commercial	$5,198	$6,020	$5,671	-6%
Industrial	$325,409	$398,623	$376,421	-6%

Table C-2. Incremental capital and O&M expenditures, no carbon regulation (REPS scenario minus BAU)

Annual Expenditures (2010$ million)	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*TOTAL*
Energy Efficiency	$12	$130	$210	$292	$371	$367	$448	$530	$610	*$2,970*
Hydro	$0	$50	$50	$51	$28	$28	$29	$24	$24	*$285*
Wind (in-state)	$0	$86	$87	$88	$935	$949	$962	$1,120	$1,135	*$5,363*
Biomass	$25	$32	$39	$46	$52	$58	$62	$65	$69	*$449*
Solar	$234	$158	$159	$161	$178	$180	$182	$264	$266	*$1,782*
Natural Gas	-$14	-$24	-$228	-$799	-$762	-$359	-$703	-$1,123	-$1,276	*-$5,288*
Coal	-$40	-$65	-$111	-$116	-$100	-$159	-$223	-$236	-$266	*-$1,315*
Total	***$218***	***$367***	***$207***	*($277)*	***$704***	***$1,064***	***$757***	***$644***	***$563***	***$4,246***

Table C-3. Net incremental change in annual electricity bills, no carbon regulation (REPS scenario minus BAU)

Aggregate Change in Electricity Bills (2010$ million)	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*	*TOTAL*
Residential	-$7	$6	$24	$55	$95	$104	$125	$167	$214	*$783*
Commercial & Industrial	-$15	-$7	$12	$55	$130	$151	$184	$261	$347	*$1,118*
Total	***-$21***	***-$1***	***$36***	***$109***	***$226***	***$256***	***$309***	***$428***	***$561***	***$1,901***

Table C-4. Net impacts on Kentucky economy, no carbon regulation (2010$ millions)

Economic Impacts	2017	2020	2022	Cumulative Total
Personal Income	$119	$646	$877	***$4,011***
Gross State Product	$118	$837	$1,174	***$5,157***

Table C-5. Net job-years in Kentucky by major electricity resource by year, no carbon regulation

Direct	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*2020*	*2021*	*2022*
RE & EE	1,661	3,532	4,423	5,326	9,028	9,018	9,935	11,568	12,478
Natural Gas	-2	-3	-1,009	-3,103	-2,118	-47	-1,375	-2,520	-2,464
Coal	-24	-38	-65	-68	-58	-93	-130	-137	-155
Sub-Total	**1,636**	**3,491**	**3,348**	**2,156**	**6,851**	**8,878**	**8,430**	**8,910**	**9,859**
Indirect and Induced									
RE & EE	504	1,592	2,658	4,404	8,787	9,448	10,871	14,065	17,004
Natural Gas	-20	-35	-857	-2,770	-2,193	-526	-1,714	-2,912	-3,094
Coal	-208	-333	-572	-599	-514	-820	-1,147	-1,214	-1,369
Sub-Total	**276**	**1,225**	**1,229**	**1,035**	**6,081**	**8,102**	**8,009**	**9,939**	**12,541**
Direct, Indirect, and Induced									
RE & EE	2,166	5,124	7,081	9,730	17,815	18,466	20,805	25,633	29,482
Natural Gas	-22	-38	-1,867	-5,873	-4,311	-573	-3,090	-5,432	-5,558
Coal	-232	-370	-637	-666	-572	-913	-1,277	-1,351	-1,524
Total	**1,912**	**4,716**	**4,578**	**3,190**	**12,932**	**16,980**	**16,439**	**18,850**	**22,400**

ATTACHMENTS

SC Responses to

KPC-16

APPENDIX A. STATE PROFILES

The following state profiles provide detailed information on the demand response potential projections for each state in the Assessment. The case studies presented in Chapter V of this report should be used as a guide for interpreting the results.

Some of the state profiles make reference to the "share of peak demand" that each sector contributes. This refers to the fraction of the entire state peak demand that is represented by that sector. In other words, if a state has peak demand of 10 GW and the residential class peak demand is 4 GW, the share of peak demand belonging to the residential class is 40 percent.

To provide context for interpreting the results, Table A-1 provides basic descriptive statistics for each of the states and the District of Columbia.

Also, in Table A-2 and Table A-3 are summaries of the potential peak reductions from demand response for 2014 (year five of the analysis horizon) and 2019 (year ten of the analysis horizon) for all states, as a fraction of the estimated summer peak demand without demand response. (In a few instances, estimated growth in peak demand between 2014 and 2019 exceeds estimated growth of demand response potential over the same period, causing the 2014 fraction to exceed the 2019 fraction)

Table A-1: Summary of Key Data by State

State	Total population	Number of accounts by rate class				System Peak Demand (MW)	Average peak load per customer (kW)				Annual average growth rate in peak (%)		CAC saturation for Residential sector (%)	AMI deployment in 2019 under EBAU scenario (%)
		Residential	Small C&I	Medium C&I	Large C&I		Residential	Small C&I	Medium C&I	Large C&I	Res	C&I		
Alabama	4,661,900	2,077,677	362,448	12,354	3,801	19,000	3.4	15.1	192	748	1.6	0.6	62	68
Alaska	686,293	266,671	45,183	3,270	62	1,417	0.9	4.5	80	1,029	0.4	0.2	3	21
Arizona	6,500,180	2,567,749	280,527	15,965	1,381	18,456	3.8	16.9	165	822	0.2	0.1	87	83
Arkansas	2,855,390	1,301,517	199,604	6,629	3,442	9,875	2.8	9.1	93	801	1.2	0.3	55	40
California	36,756,666	12,971,924	1,567,550	301,662	17,772	57,137	1.2	3.2	38	555	0.8	0.4	41	90
Colorado	4,939,456	2,068,055	282,139	88,021	1,531	10,837	1.5	1.9	40	901	0.9	0.1	47	43
Connecticut	3,501,252	1,449,983	141,998	11,261	8,044	7,524	1.6	3.9	63	206	0.9	0.4	27	52
Delaware	873,092	390,239	47,323	1,475	374	2,503	1.9	15.2	125	951	0.4	0.1	53	79
District of Columbia	591,833	206,047	24,506	1,842	1,229	2,403	1.6	9.5	158	745	1.5	0.1	56	100
Florida	18,328,340	8,615,249	921,368	224,874	9,195	49,453	3.1	2.9	40	696	0.2	0.6	91	74
Georgia	9,685,744	4,039,005	483,576	66,628	11,363	28,215	3.4	5.4	60	602	0.6	0.3	82	67
Hawaii	1,288,198	409,581	55,808	7,482	632	1,790	1.0	4.2	45	842	0.9	0.2	18	72
Idaho	1,523,816	647,581	65,923	55,692	928	4,962	2.9	3.9	31	636	0.4	0.1	67	69
Illinois	12,901,563	5,054,895	541,263	26,791	21,435	30,465	1.7	7.3	28	450	1.3	0.4	75	51
Indiana	6,376,792	2,734,788	286,888	65,468	8,038	22,890	2.4	6.3	52	798	1	0.3	74	40
Iowa	3,002,555	1,320,241	183,320	30,471	3,507	9,169	1.9	4.1	47	709	1.6	1.1	70	55
Kansas	2,802,134	1,213,189	221,809	10,962	7,594	8,630	2.8	6.4	44	318	1.3	0.5	84	29
Kentucky	4,269,245	1,918,247	272,458	27,771	3,050	18,889	3.0	10.5	176	959	1.3	0.4	76	33
Louisiana	4,410,796	1,870,160	196,805	89,052	3,192	16,332	3.5	14.6	39	771	1.6	0.4	75	40
Maine	1,316,456	693,400	75,666	13,927	1,065	2,812	0.8	2.0	30	571	0.7	0.4	14	54
Maryland	5,633,597	2,187,996	230,938	17,496	4,054	13,583	2.6	13.1	32	606	0.4	0.1	78	82
Massachusetts	6,497,967	2,631,568	367,459	22,605	4,510	12,695	1.0	6.0	24	642	0.8	0.4	13	26
Michigan	10,003,422	4,336,390	485,729	44,172	10,836	23,292	1.5	6.2	48	609	1.2	0.4	57	69
Minnesota	5,220,393	2,283,083	189,477	75,091	10,044	14,123	1.7	3.2	42	327	1.3	1.1	51	46
Mississippi	2,938,618	1,222,047	228,202	1,565	2,228	9,835	3.5	8.8	78	1,215	1.6	0.6	75	42
Missouri	5,911,605	2,670,172	347,394	25,739	4,651	17,362	3.1	5.0	110	748	1.3	0.7	88	45
Montana	967,440	456,112	103,892	890	238	2,991	1.6	12.3	157	1,101	1.3	0.2	42	22
Nebraska	1,783,432	787,312	178,123	10,854	2,889	5,771	2.6	4.5	128	291	1.6	1.1	83	19
Nevada	2,600,167	1,079,306	145,469	4,497	1,963	7,538	3.1	12.1	112	931	0.2	0.1	87	25
New Hampshire	1,315,809	600,399	102,868	831	1,875	2,539	1.1	4.7	32	306	0.2	0.4	13	45
New Jersey	8,682,661	3,414,289	461,304	10,998	10,375	17,273	2.2	7.1	77	395	0.8	0.7	55	56
New Mexico	1,984,356	829,100	122,560	16,755	1,296	4,671	1.3	4.8	61	707	1.2	0.1	42	37
New York	19,490,297	6,855,544	958,009	66,351	5,265	33,809	1.3	5.7	81	820	0.8	0.3	17	42
North Carolina	9,222,414	4,128,231	619,832	29,169	3,277	26,548	3.2	5.6	168	1,373	0.5	0.3	84	47
North Dakota	641,481	310,222	54,365	2,211	699	2,379	2.2	9.7	129	614	1.6	1.1	51	34
Ohio	11,485,910	4,908,791	569,999	59,607	13,010	33,238	2.0	8.5	65	604	1.3	0.3	63	39
Oklahoma	3,642,361	1,629,818	243,831	30,398	3,097	11,919	3.3	3.8	70	778	1.2	0.1	84	41
Oregon	3,790,060	1,610,829	220,262	36,132	1,521	10,476	1.9	4.5	75	680	0.7	0.4	38	59
Pennsylvania	12,448,279	5,217,010	618,439	75,656	10,577	31,488	1.7	8.2	43	644	1.2	0.7	50	64
Rhode Island	1,050,788	432,307	48,623	8,614	864	1,785	1.0	2.7	32	393	0.8	0.4	12	25
South Carolina	4,479,800	2,028,361	326,244	15,666	2,327	16,947	3.6	7.6	172	1,696	1	0.3	84	37
South Dakota	804,194	355,714	66,375	658	875	2,128	2.2	9.3	87	402	1.6	1.1	71	27
Tennessee	6,214,888	2,660,110	428,663	30,312	3,735	22,475	3.9	11.5	186	376	1	0.6	81	29
Texas	24,326,974	9,397,317	1,269,490	411,961	5,756	72,723	3.3	3.7	47	2,086	0.3	0.3	80	71
Utah	2,736,424	911,744	103,864	16,754	791	5,742	1.6	4.9	86	1,322	0.4	0.1	42	23
Vermont	621,270	310,842	46,230	3,075	313	1,085	0.9	2.2	49	773	0.6	0.4	7	59
Virginia	7,769,089	3,170,126	369,208	32,352	7,886	22,412	2.5	4.6	88	708	0.7	0.3	50	46
Washington	6,549,224	2,762,275	345,256	26,145	3,568	18,538	1.8	6.5	110	771	0.6	0.4	29	46
West Virginia	1,814,468	855,919	135,823	11,181	1,199	6,916	2.3	6.3	78	1,431	1.6	0.1	50	45
Wisconsin	5,627,967	2,581,840	290,192	44,419	4,518	14,845	1.4	4.1	61	782	1.5	0.9	62	65
Wyoming	532,668	245,648	61,758	3,587	585	3,236	1.7	14.9	66	1,551	1.6	0.2	42	21

Table A-2: Potential Peak Demand Reduction by State (2014)

	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
Alabama	6%	10%	13%	17%
Alaska	0%	2%	2%	2%
Arizona	1%	5%	14%	22%
Arkansas	3%	13%	13%	14%
California	7%	7%	12%	16%
Colorado	4%	5%	6%	7%
Connecticut	17%	22%	23%	24%
Delaware	4%	7%	11%	15%
District of Columbia	8%	18%	18%	21%
Florida	5%	9%	13%	17%
Georgia	4%	12%	16%	19%
Hawaii	2%	5%	7%	9%
Idaho	1%	6%	11%	15%
Illinois	7%	9%	9%	9%
Indiana	5%	7%	8%	10%
Iowa	6%	9%	10%	12%
Kansas	3%	7%	8%	9%
Kentucky	2%	5%	6%	7%
Louisiana	0%	5%	6%	7%
Maine	17%	19%	20%	21%
Maryland	11%	14%	22%	28%
Massachusetts	7%	10%	11%	11%
Michigan	8%	13%	14%	15%
Minnesota	12%	13%	15%	16%
Mississippi	1%	7%	8%	9%
Missouri	1%	9%	11%	13%
Montana	0%	4%	4%	5%
Nebraska	10%	14%	14%	15%
Nevada	0%	9%	10%	12%
New Hampshire	4%	8%	8%	8%
New Jersey	4%	8%	9%	10%
New Mexico	1%	6%	6%	7%
New York	8%	9%	10%	11%
North Carolina	5%	10%	10%	11%
North Dakota	1%	5%	6%	6%
Ohio	1%	11%	12%	12%
Oklahoma	0%	9%	10%	10%
Oregon	0%	3%	6%	9%
Pennsylvania	7%	11%	14%	16%
Rhode Island	7%	10%	11%	11%
South Carolina	4%	9%	10%	11%
South Dakota	1%	6%	6%	6%
Tennessee	5%	8%	9%	9%
Texas	1%	8%	12%	16%
Utah	8%	12%	13%	14%
Vermont	8%	9%	10%	11%
Virginia	1%	6%	7%	8%
Washington	0%	4%	5%	7%
West Virginia	3%	10%	10%	11%
Wisconsin	1%	5%	6%	7%
Wyoming	0%	6%	7%	7%

Table A-3: Potential Peak Demand Reduction by State (2019)

	Business-as-Usual	Expanded BAU	Achievable Participation	Full Participation
Alabama	5%	10%	15%	21%
Alaska	0%	2%	5%	7%
Arizona	1%	5%	18%	28%
Arkansas	2%	13%	17%	21%
California	6%	7%	13%	17%
Colorado	3%	5%	12%	17%
Connecticut	16%	21%	26%	29%
Delaware	4%	7%	13%	19%
District of Columbia	7%	18%	17%	20%
Florida	5%	9%	18%	25%
Georgia	3%	12%	18%	25%
Hawaii	2%	5%	8%	11%
Idaho	1%	6%	14%	21%
Illinois	6%	8%	12%	15%
Indiana	5%	7%	13%	18%
Iowa	5%	8%	13%	17%
Kansas	2%	7%	13%	17%
Kentucky	1%	5%	11%	18%
Louisiana	0%	5%	12%	18%
Maine	16%	19%	22%	24%
Maryland	11%	13%	24%	32%
Massachusetts	7%	10%	14%	17%
Michigan	8%	12%	14%	16%
Minnesota	12%	13%	16%	19%
Mississippi	1%	7%	13%	19%
Missouri	1%	9%	14%	19%
Montana	0%	4%	9%	14%
Nebraska	9%	13%	19%	24%
Nevada	0%	9%	18%	26%
New Hampshire	3%	8%	10%	13%
New Jersey	4%	8%	12%	18%
New Mexico	1%	6%	11%	15%
New York	7%	9%	13%	17%
North Carolina	4%	10%	17%	25%
North Dakota	1%	5%	10%	14%
Ohio	1%	11%	14%	17%
Oklahoma	0%	9%	14%	19%
Oregon	0%	3%	9%	14%
Pennsylvania	7%	10%	15%	19%
Rhode Island	7%	10%	13%	16%
South Carolina	4%	9%	17%	23%
South Dakota	1%	6%	12%	17%
Tennessee	4%	8%	17%	24%
Texas	1%	8%	15%	21%
Utah	7%	12%	18%	23%
Vermont	7%	8%	11%	13%
Virginia	1%	6%	11%	16%
Washington	0%	4%	9%	12%
West Virginia	3%	10%	13%	18%
Wisconsin	1%	5%	8%	11%
Wyoming	0%	6%	9%	12%

Alabama State Profile

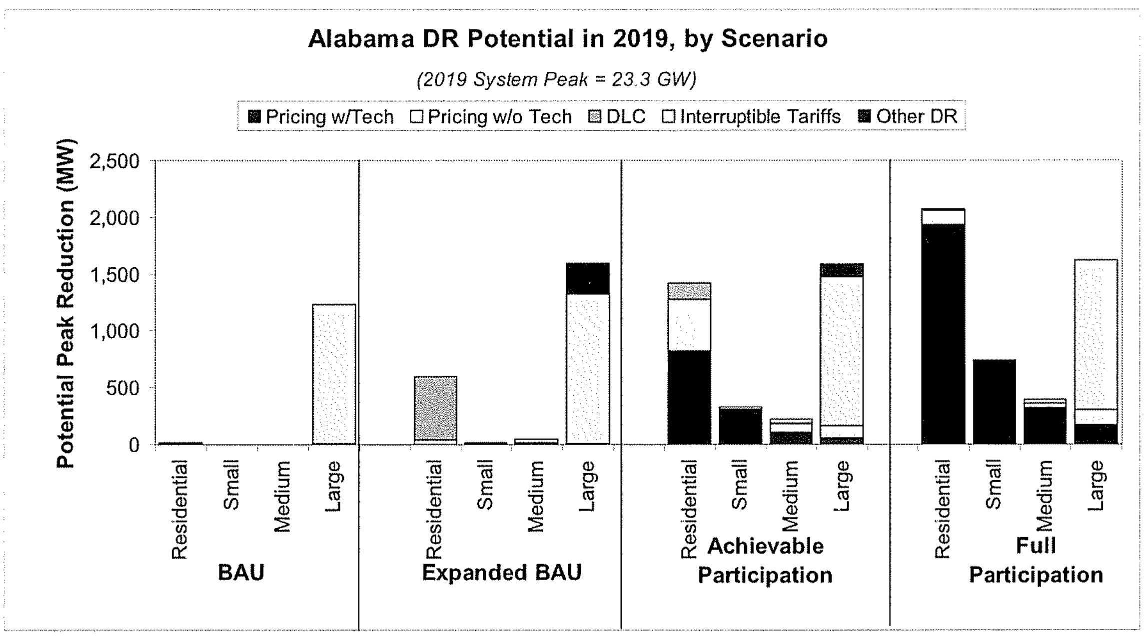
Key drivers of Alabama's demand response potential estimate include: higher-than-average residential CAC saturation of 62 percent, a customer mix that has an above average share of peak demand in the Small C&I class (31%), a moderate amount of existing Interruptible Tariffs for the Large C&I class, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state. Most of the growth potential in demand response comes from the Residential class.

BAU: Alabama's existing demand response comes primarily from a large Interruptible Tariff program for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through two sources. There is the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. In addition, there is a lot of growth potential for DLC in the Residential class due higher-than-average residential CAC saturation.

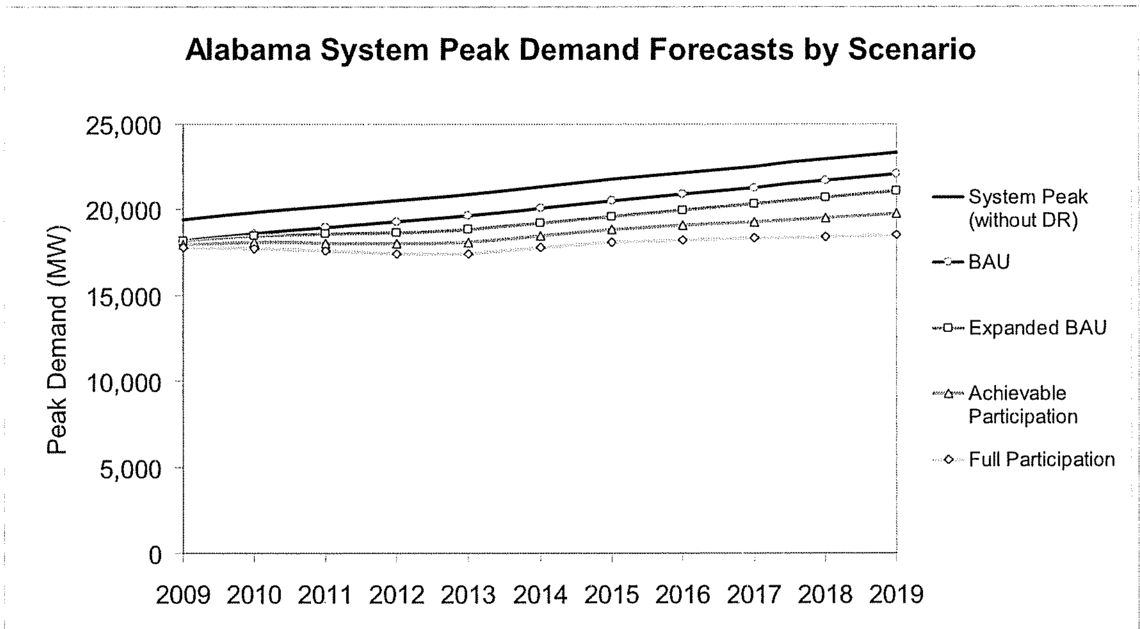
Achievable Participation: High CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is not significantly higher than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation in the Residential class drives the increase in impacts. The growth in impacts from the base BAU scenario are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Alabama, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	10	0.0%	10	0.0%
Automated/Direct Load Control	16	0.1%	0	0.0%	0	0.0%	0	0.0%	16	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	1,224	5.2%	1,224	5.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	16	0.1%	0	0.0%	0	0.0%	1,234	5.3%	1,250	5.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	42	0.2%	1	0.0%	8	0.0%	10	0.0%	61	0.3%
Automated/Direct Load Control	559	2.4%	13	0.1%	9	0.0%	0	0.0%	581	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	271	1.2%	271	1.2%
Total	601	2.6%	15	0.1%	50	0.2%	1,592	6.8%	2,258	9.7%
Achievable Participation										
Pricing with Technology	825	3.5%	312	1.3%	110	0.5%	58	0.2%	1,305	5.6%
Pricing without Technology	453	1.9%	17	0.1%	73	0.3%	105	0.5%	648	2.8%
Automated/Direct Load Control	145	0.6%	3	0.0%	4	0.0%	0	0.0%	152	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	112	0.5%	112	0.5%
Total	1,422	6.1%	333	1.4%	221	0.9%	1,586	6.8%	3,562	15.3%
Full Participation										
Pricing with Technology	1,929	8.3%	730	3.1%	322	1.4%	169	0.7%	3,150	13.5%
Pricing without Technology	130	0.6%	9	0.0%	36	0.2%	136	0.6%	310	1.3%
Automated/Direct Load Control	16	0.1%	0	0.0%	0	0.0%	0	0.0%	16	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	33	0.1%	1,311	5.6%	1,345	5.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,074	8.9%	739	3.2%	391	1.7%	1,616	6.9%	4,821	20.6%



Alaska State Profile

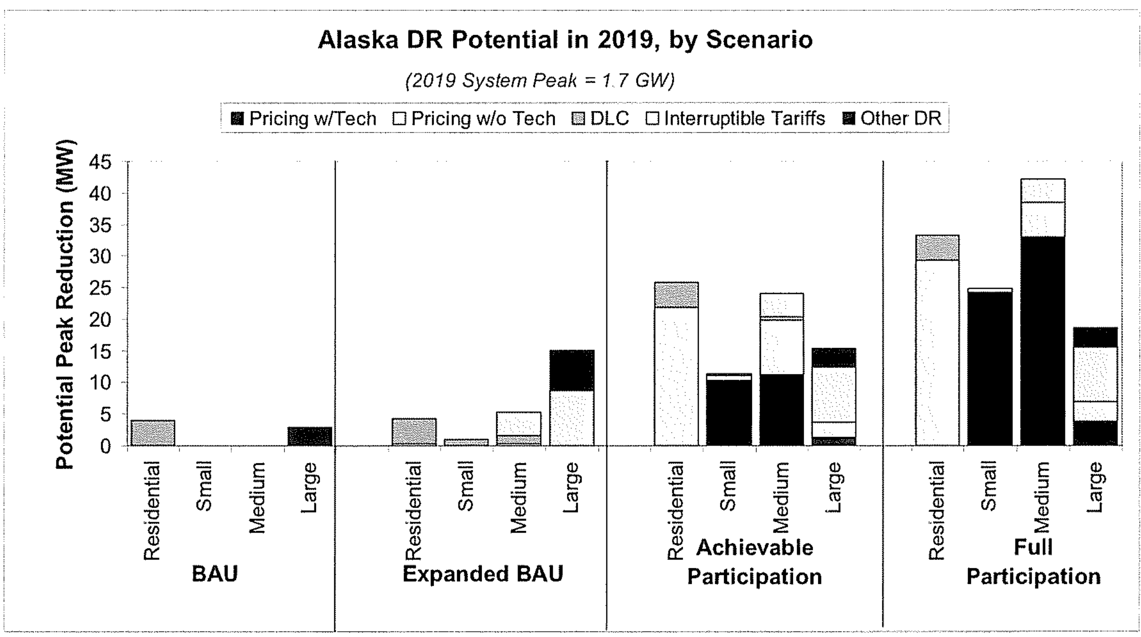
Key drivers of Alaska's demand response potential estimate include: very low residential CAC saturation, a customer mix that has an above average share of peak demand in the Small and Medium C&I classes (26% and 34%, respectively), a small amount of existing demand response, and the expectation that it will deploy AMI at a lower-than-average rate. Enabling technologies are cost effective for all C&I classes in the state, but not for the residential class.

BAU: Alaska's existing demand response comes from two sources. In the Residential class, there is a small amount of non-air conditioning DLC, and in the Medium C&I class, there is a small amount of Other DR.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs programs for the Large C&I class, which currently do not exist in the state. Within the Large C&I class, demand response is split between Interruptible Tariffs and Other DR. The only other substantial growth in demand response comes from Interruptible Tariffs in the Medium C&I class.

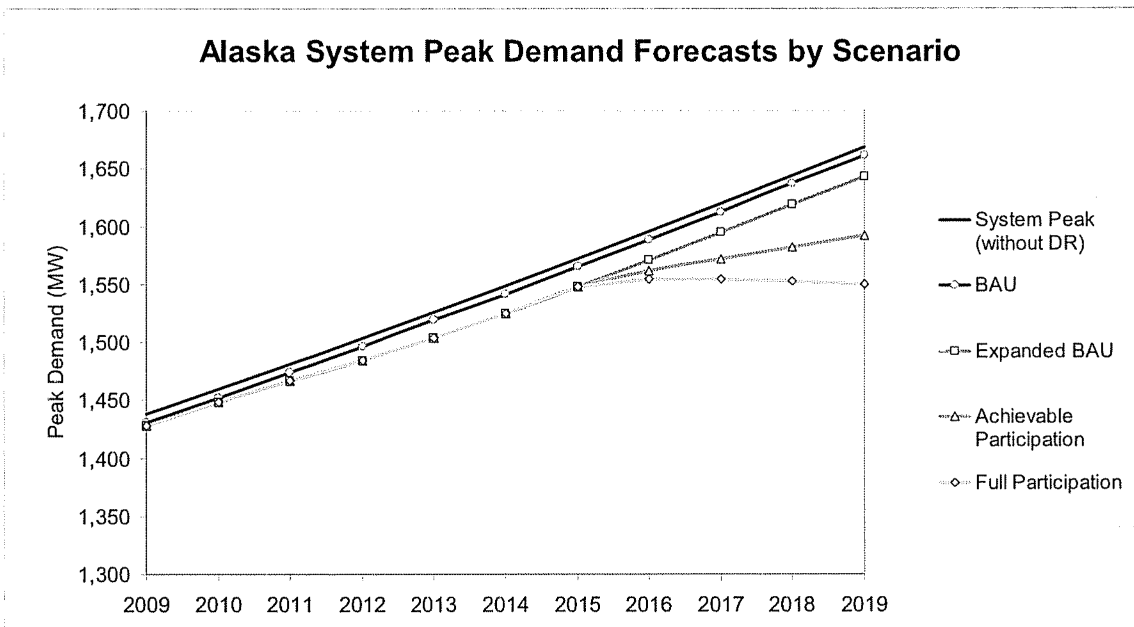
Achievable Participation: A significant increase in demand response potential comes from dynamic pricing with and without enabling technology. However, for the Large C&I class specifically, demand response potential does not change significantly from Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. Since enabling technology did not prove to be cost-effective in the Residential sector, all of the pricing impacts are without enabling technology.

Full Participation: Similar to the Achievable Participation scenario, a significant increase in demand response potential comes from dynamic pricing. The majority of the statewide impacts come from pricing with enabling technologies, which are cost-effective for all customer classes except Residential.



Total Potential Peak Reduction from Demand Response in Alaska, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	4	0.2%	0	0.0%	0	0.0%	0	0.0%	4	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	4	0.2%	0	0.0%	0	0.0%	3	0.2%	7	0.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	4	0.2%	1	0.1%	1	0.1%	0	0.0%	6	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	6	0.4%	6	0.4%
Total	4	0.3%	1	0.1%	5	0.3%	15	0.9%	26	1.5%
Achievable Participation										
Pricing with Technology	0	0.0%	10	0.6%	11	0.7%	1	0.1%	23	1.4%
Pricing without Technology	22	1.3%	1	0.0%	9	0.5%	2	0.1%	34	2.0%
Automated/Direct Load Control	4	0.2%	0	0.0%	1	0.0%	0	0.0%	5	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	26	1.6%	11	0.7%	24	1.4%	15	0.9%	77	4.6%
Full Participation										
Pricing with Technology	0	0.0%	24	1.5%	33	2.0%	4	0.2%	61	3.7%
Pricing without Technology	29	1.8%	0	0.0%	5	0.3%	3	0.2%	38	2.3%
Automated/Direct Load Control	4	0.2%	0	0.0%	0	0.0%	0	0.0%	4	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	9	0.5%	12	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.2%	3	0.2%
Total	33	2.0%	25	1.5%	42	2.5%	19	1.1%	119	7.1%



Arizona State Profile

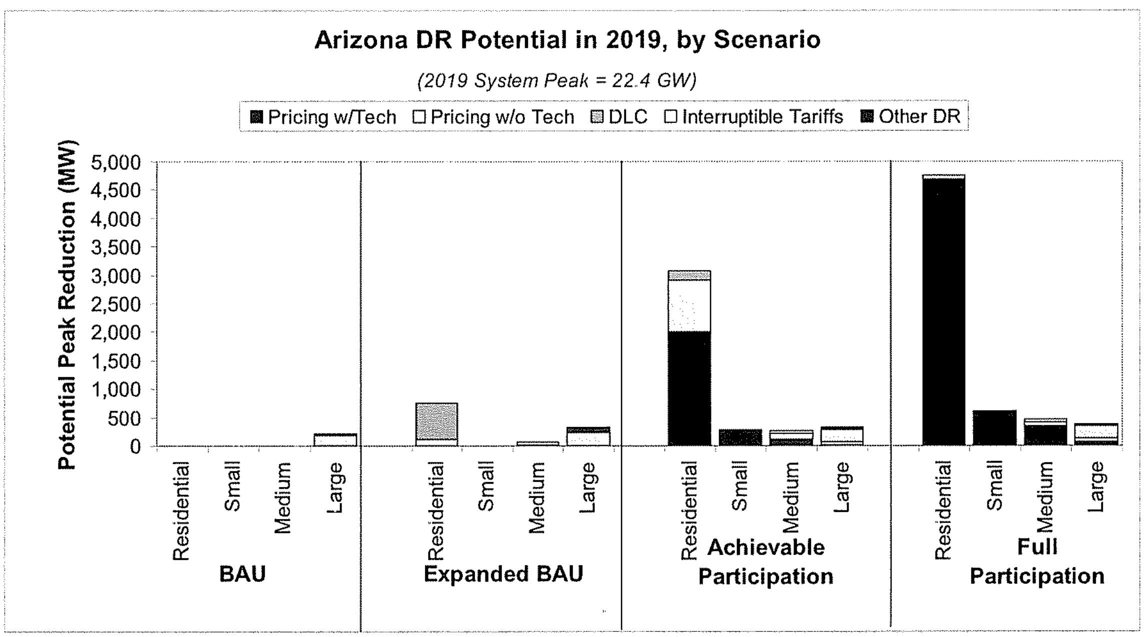
Key drivers of Arizona's demand response potential estimate include: higher-than-average residential CAC saturation of 87 percent, a customer mix that has an above average share of peak demand in the Residential and Small C&I classes (54% and 26%, respectively), a small amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state. This cost-effectiveness, high residential CAC saturation and a large proportion of customers in the Residential and Small C&I sectors means that control of CAC load will be the key driver of demand response growth in Arizona.

BAU: Arizona's existing demand response comes primarily from a small Interruptible Tariffs program for large C&I customers. Note that Arizona has the largest residential TOU program in the U.S., but for reasons described previously in the report, TOU rates are excluded as a demand response option in this analysis.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for the Residential class, which currently do not exist in the state. This growth is due to Arizona's high share of Residential load and high CAC saturation rate.

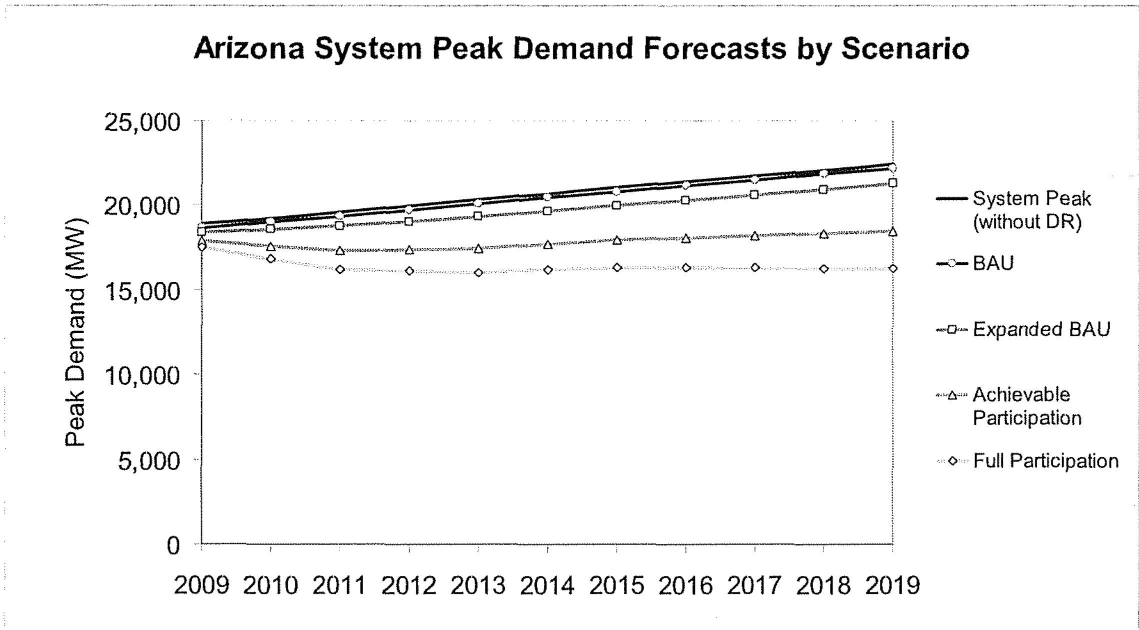
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the Residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Arizona, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	4	0.0%	0	0.0%	0	0.0%	0	0.0%	4	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	6	0.0%	184	0.8%	189	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.1%	30	0.1%
Total	4	0.0%	0	0.0%	6	0.0%	214	1.0%	223	1.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	114	0.5%	2	0.0%	11	0.1%	4	0.0%	130	0.6%
Automated/Direct Load Control	636	2.8%	6	0.0%	6	0.0%	0	0.0%	648	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	112	0.5%	112	0.5%
Total	750	3.3%	7	0.0%	74	0.3%	336	1.5%	1,166	5.2%
Achievable Participation										
Pricing with Technology	2,003	8.9%	254	1.1%	119	0.5%	24	0.1%	2,400	10.7%
Pricing without Technology	913	4.1%	17	0.1%	91	0.4%	44	0.2%	1,065	4.8%
Automated/Direct Load Control	166	0.7%	1	0.0%	3	0.0%	0	0.0%	170	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	47	0.2%	47	0.2%
Total	3,082	13.7%	273	1.2%	269	1.2%	334	1.5%	3,957	17.7%
Full Participation										
Pricing with Technology	4,685	20.9%	595	2.7%	349	1.6%	70	0.3%	5,698	25.4%
Pricing without Technology	67	0.3%	11	0.1%	58	0.3%	57	0.3%	193	0.9%
Automated/Direct Load Control	4	0.0%	0	0.0%	0	0.0%	0	0.0%	4	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	55	0.2%	220	1.0%	275	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.1%	30	0.1%
Total	4,755	21.2%	606	2.7%	462	2.1%	377	1.7%	6,200	27.7%



Arkansas State Profile

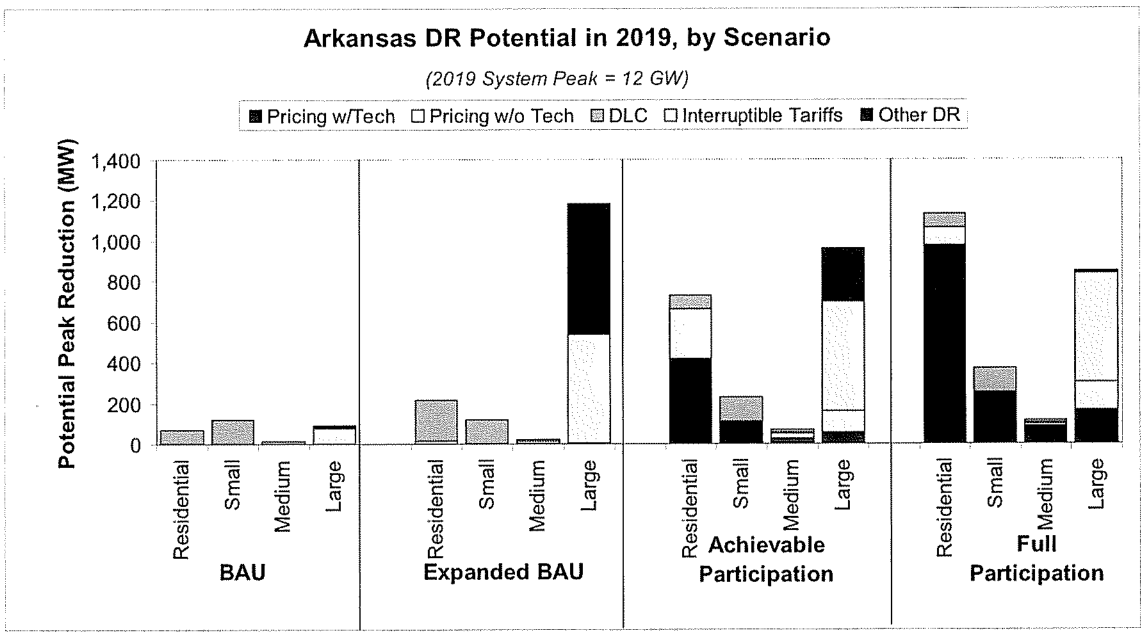
Key drivers of Arkansas's demand response potential estimate include: average residential CAC saturation of 55 percent, a customer mix that has an above average share of peak demand in the small and Large C&I classes (21% and 31%, respectively), a small amount of existing demand response, and the expectation that it will deploy AMI at a slightly lower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Arkansas's existing demand response comes from all customer classes, but none of these programs are that large. DLC in all but the Large C&I class contributes the majority of the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs and Interruptible Tariffs for the Large C&I class. This high growth is due to Arkansas's high share of Large C&I load.

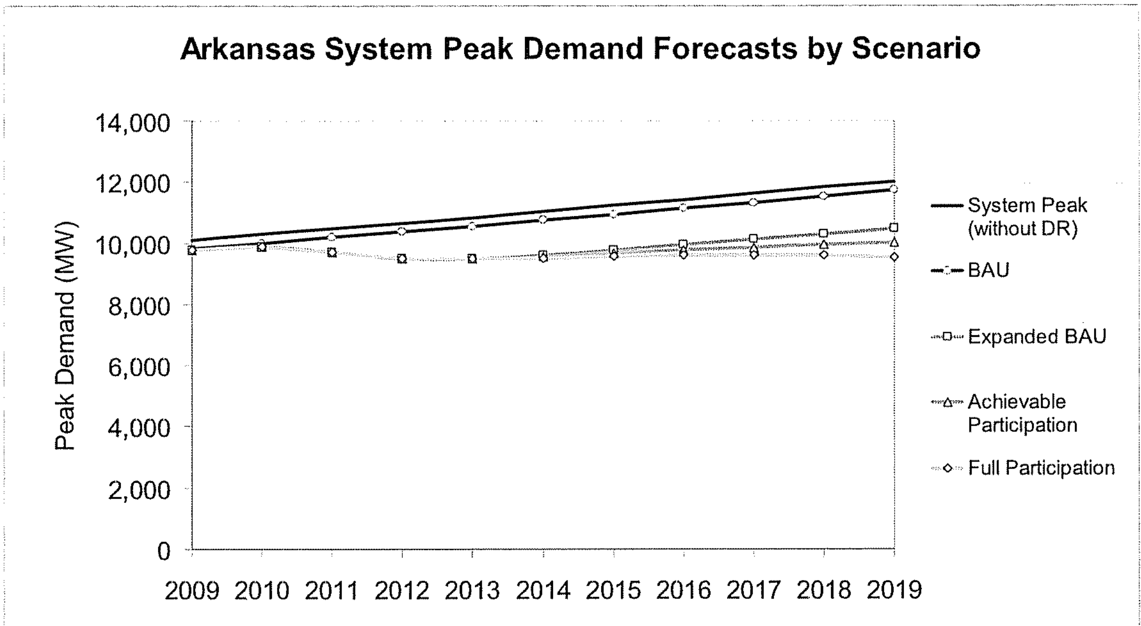
Achievable Participation: CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, CAC saturation drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes. Interruptible Tariffs in the Large C&I sector remain a significant portion of overall impacts and a key source of growth from BAU.



Total Potential Peak Reduction from Demand Response in Arkansas, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	79	0.7%	79	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	13	0.1%	13	0.1%
Total	69	0.6%	120	1.0%	13	0.1%	92	0.8%	295	2.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	13	0.1%	0	0.0%	1	0.0%	5	0.0%	19	0.2%
Automated/Direct Load Control	202	1.7%	120	1.0%	13	0.1%	0	0.0%	336	2.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	643	5.3%	643	5.3%
Total	215	1.8%	120	1.0%	23	0.2%	1,184	9.8%	1,543	12.8%
Achievable Participation										
Pricing with Technology	418	3.5%	106	0.9%	29	0.2%	57	0.5%	611	5.1%
Pricing without Technology	246	2.0%	6	0.0%	19	0.2%	104	0.9%	375	3.1%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	262	2.2%	262	2.2%
Total	733	6.1%	232	1.9%	70	0.6%	960	8.0%	1,996	16.6%
Full Participation										
Pricing with Technology	978	8.1%	248	2.1%	85	0.7%	167	1.4%	1,479	12.3%
Pricing without Technology	87	0.7%	3	0.0%	9	0.1%	135	1.1%	235	2.0%
Automated/Direct Load Control	69	0.6%	120	1.0%	13	0.1%	0	0.0%	202	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	536	4.5%	545	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	13	0.1%	13	0.1%
Total	1,134	9.4%	371	3.1%	117	1.0%	852	7.1%	2,474	20.6%



California State Profile

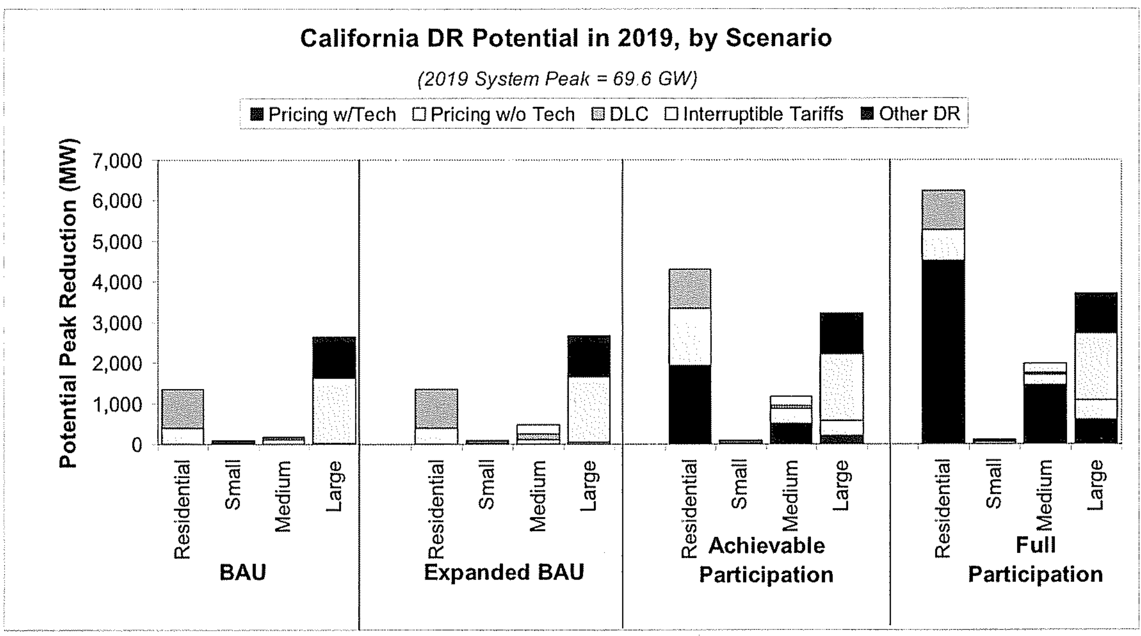
Key drivers of California's demand response potential estimate include: lower-than-average residential CAC saturation of 41 percent, a customer mix that has an above average share of peak demand in the Medium and Large C&I classes (50% combined), a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class.

BAU: California's existing demand response comes from three major sources – Interruptible Tariffs and Other DR in the Large C&I class and DLC in the Residential class. In addition, there is moderate demand response in place in the Small and Medium C&I classes, as well as some dynamic pricing.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class. This is due to California's high share of Large C&I load, which would also allow for significant growth in the existing Interruptible Tariff. Demand response potential in the Large C&I class is nearly the same as in the BAU scenario.

Achievable Participation: Dynamic pricing with technology in the Residential class drives a significant increase in demand response potential. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario.

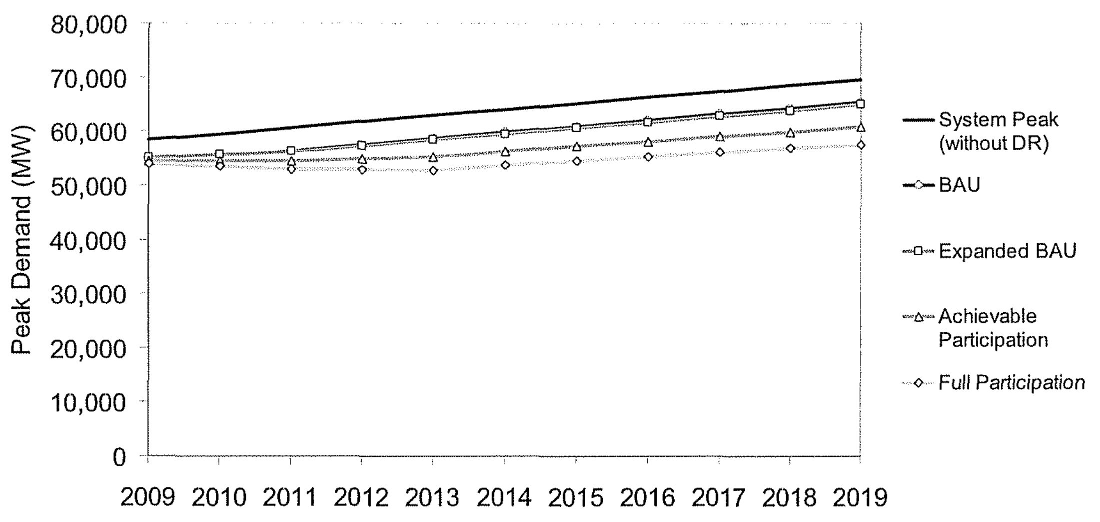
Full Participation: Similar to the Achievable Participation scenario, dynamic pricing with technology in the Residential sector drives a significant increase in demand response potential. Demand response potential in the Large C&I class is nearly the same as in the Achievable Participation scenario.



Total Potential Peak Reduction from Demand Response in California, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	391	0.6%	21	0.0%	108	0.2%	13	0.0%	532	0.8%
Automated/Direct Load Control	970	1.4%	36	0.1%	45	0.1%	0	0.0%	1,050	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.0%	1,626	2.3%	1,651	2.4%
Other DR Programs	0	0.0%	31	0.0%	0	0.0%	1,012	1.5%	1,043	1.5%
Total	1,361	2.0%	88	0.1%	177	0.3%	2,651	3.8%	4,276	6.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	391	0.6%	21	0.0%	108	0.2%	36	0.1%	556	0.8%
Automated/Direct Load Control	970	1.4%	42	0.1%	152	0.2%	0	0.0%	1,163	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	1	0.0%	1,012	1.5%	1,044	1.5%
Total	1,361	2.0%	94	0.1%	494	0.7%	2,674	3.8%	4,622	6.6%
Achievable Participation										
Pricing with Technology	1,931	2.8%	0	0.0%	500	0.7%	205	0.3%	2,636	3.8%
Pricing without Technology	1,400	2.0%	29	0.0%	382	0.5%	372	0.5%	2,184	3.1%
Automated/Direct Load Control	970	1.4%	36	0.1%	67	0.1%	0	0.0%	1,072	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	1	0.0%	1,012	1.5%	1,043	1.5%
Total	4,302	6.2%	96	0.1%	1,182	1.7%	3,215	4.6%	8,795	12.6%
Full Participation										
Pricing with Technology	4,518	6.5%	0	0.0%	1,462	2.1%	598	0.9%	6,578	9.4%
Pricing without Technology	757	1.1%	38	0.1%	243	0.3%	482	0.7%	1,521	2.2%
Automated/Direct Load Control	970	1.4%	36	0.1%	45	0.1%	0	0.0%	1,050	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	233	0.3%	1,626	2.3%	1,859	2.7%
Other DR Programs	0	0.0%	31	0.0%	0	0.0%	1,012	1.5%	1,043	1.5%
Total	6,245	9.0%	105	0.2%	1,983	2.8%	3,719	5.3%	12,052	17.3%

California System Peak Demand Forecasts by Scenario



Colorado State Profile

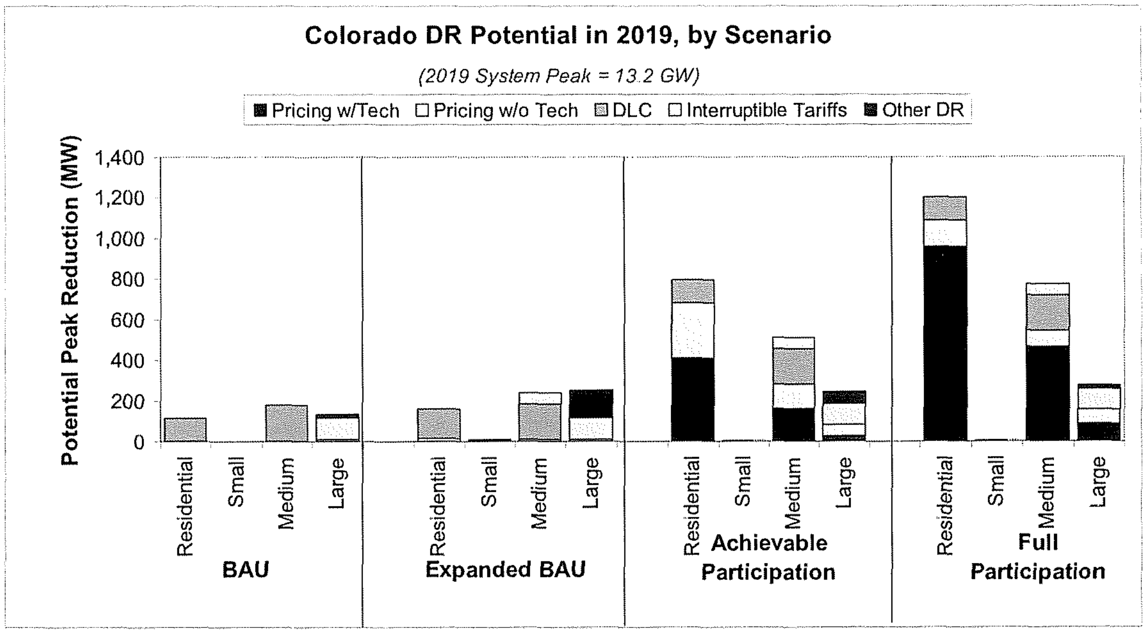
Key drivers of Colorado's demand response potential estimate include: lower-than-average residential CAC saturation of 47 percent, a customer mix that has an above average share of peak demand in Medium and Large C&I (57% combined), a moderate amount of existing demand response, and the expectation that it will deploy AMI at a slightly lower-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class.

BAU: Colorado's existing demand response comes primarily from DLC for Residential and Medium C&I customers. An Interruptible Tariff program for Large C&I customers also contributes significantly to the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class. In addition, the Medium C&I class provides some Interruptible Tariffs demand response.

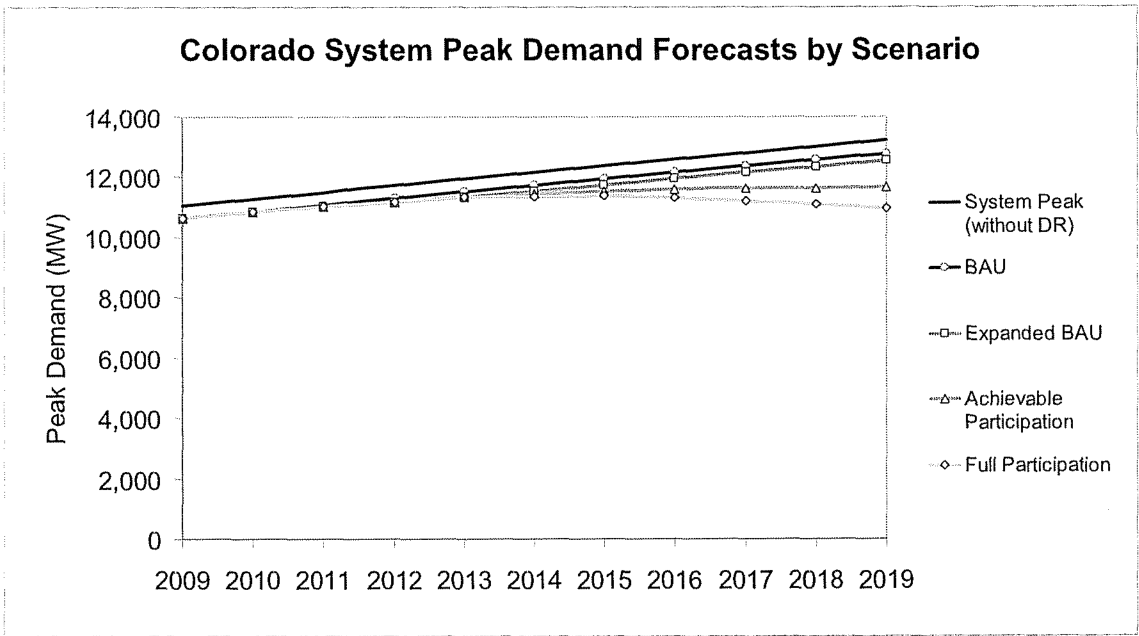
Achievable Participation: The Residential class and a large proportion of customers in the Medium C&I sector drive a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, customers in the Residential and Medium C&I sectors drive the increase in impacts. The impacts are dominated by pricing with enabling technology for Residential and Medium C&I customers.



Total Potential Peak Reduction from Demand Response in Colorado, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	1	0.0%	0	0.0%	11	0.1%	12	0.1%
Automated/Direct Load Control	114	0.9%	1	0.0%	177	1.3%	0	0.0%	292	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	104	0.8%	104	0.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	20	0.2%	20	0.2%
Total	114	0.9%	2	0.0%	177	1.3%	135	1.0%	428	3.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	15	0.1%	1	0.0%	8	0.1%	11	0.1%	34	0.3%
Automated/Direct Load Control	145	1.1%	7	0.1%	177	1.3%	0	0.0%	329	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	1.1%	140	1.1%
Total	159	1.2%	7	0.1%	237	1.8%	255	1.9%	659	5.0%
Achievable Participation										
Pricing with Technology	409	3.1%	0	0.0%	159	1.2%	29	0.2%	598	4.5%
Pricing without Technology	273	2.1%	3	0.0%	122	0.9%	53	0.4%	451	3.4%
Automated/Direct Load Control	114	0.9%	2	0.0%	177	1.3%	0	0.0%	293	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	0.4%	57	0.4%
Total	796	6.0%	5	0.0%	510	3.9%	244	1.8%	1,555	11.8%
Full Participation										
Pricing with Technology	958	7.3%	0	0.0%	465	3.5%	86	0.6%	1,509	11.4%
Pricing without Technology	128	1.0%	4	0.0%	77	0.6%	69	0.5%	279	2.1%
Automated/Direct Load Control	114	0.9%	1	0.0%	177	1.3%	0	0.0%	292	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	52	0.4%	104	0.8%	156	1.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	20	0.2%	20	0.2%
Total	1,200	9.1%	5	0.0%	772	5.8%	278	2.1%	2,256	17.1%



Connecticut State Profile

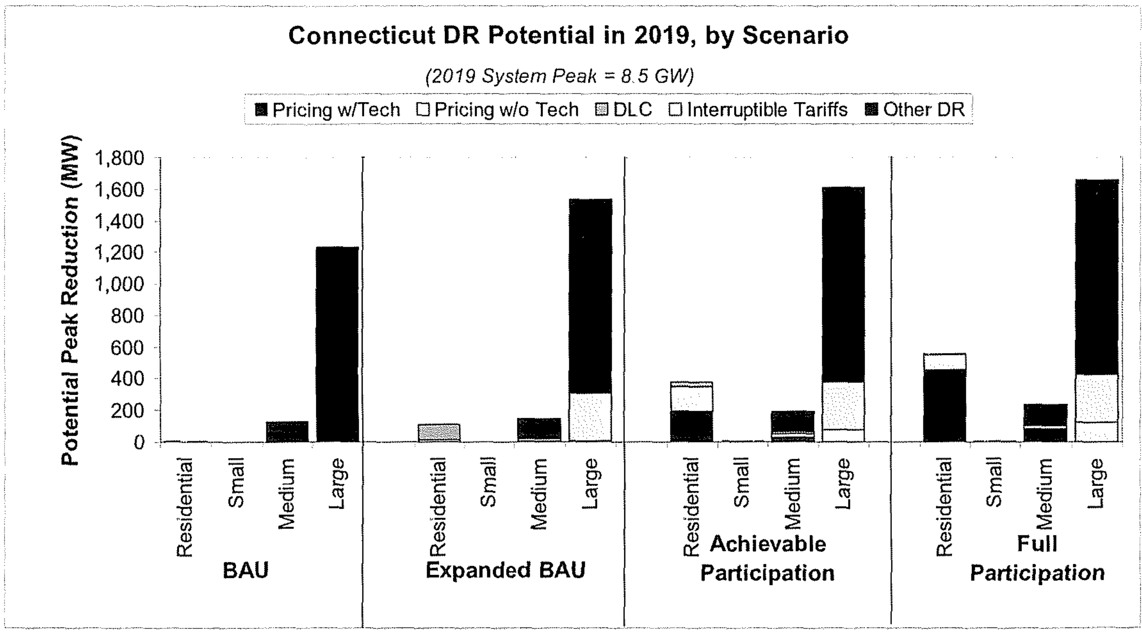
Key drivers of Connecticut's demand response potential estimate include: lower-than-average residential CAC saturation of 27 percent, a customer mix that has an above average share of peak demand in the Residential and Large C&I classes (45% and 31%, respectively), a large amount of existing demand response in the Medium and Large C&I sectors (especially Other DR), and the expectation that it will deploy AMI at a slightly lower-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small and Large C&I classes.

BAU: Connecticut's existing demand response comes primarily from Other DR for Medium and Large C&I customers, the bulk of which is in the ISO New England forward capacity market.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. This high growth is due to Connecticut's large share of Large C&I load.

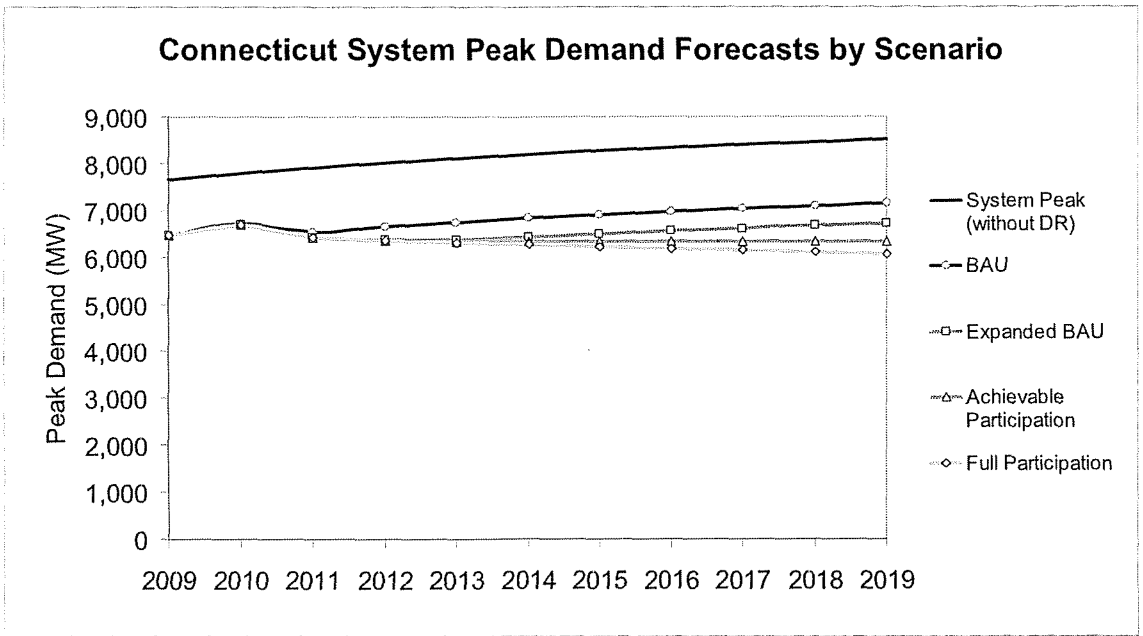
Achievable Participation: The Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario.

Full Participation: Similar to the Achievable Participation scenario, a large share of load in the Residential class drives the increase in impacts. Since CAC saturation is lower than average, the growth the Residential sector is not as much as is seen in hotter states for this scenario. The Large C&I class does not experience any growth in pricing with enabling technology because it is not cost effective for that class. Overall, the incremental increase in potential is small relative to the BAU.



Total Potential Peak Reduction from Demand Response in Connecticut, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	7	0.1%	0	0.0%	0	0.0%	0	0.0%	7	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	7	0.1%	0	0.0%	130	1.5%	1,233	14.5%	1,369	16.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	9	0.1%	0	0.0%	2	0.0%	3	0.0%	14	0.2%
Automated/Direct Load Control	104	1.2%	3	0.0%	4	0.1%	0	0.0%	111	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	113	1.3%	3	0.0%	146	1.7%	1,536	18.0%	1,798	21.1%
Achievable Participation										
Pricing with Technology	195	2.3%	0	0.0%	29	0.3%	0	0.0%	224	2.6%
Pricing without Technology	154	1.8%	3	0.0%	22	0.3%	75	0.9%	255	3.0%
Automated/Direct Load Control	27	0.3%	1	0.0%	2	0.0%	0	0.0%	29	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	376	4.4%	4	0.0%	193	2.3%	1,608	18.9%	2,181	25.6%
Full Participation										
Pricing with Technology	457	5.4%	0	0.0%	84	1.0%	0	0.0%	541	6.4%
Pricing without Technology	93	1.1%	4	0.0%	15	0.2%	125	1.5%	237	2.8%
Automated/Direct Load Control	7	0.1%	0	0.0%	0	0.0%	0	0.0%	7	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	303	3.6%	313	3.7%
Other DR Programs	0	0.0%	0	0.0%	130	1.5%	1,229	14.4%	1,360	16.0%
Total	557	6.5%	4	0.0%	239	2.8%	1,658	19.5%	2,458	28.9%



Delaware State Profile

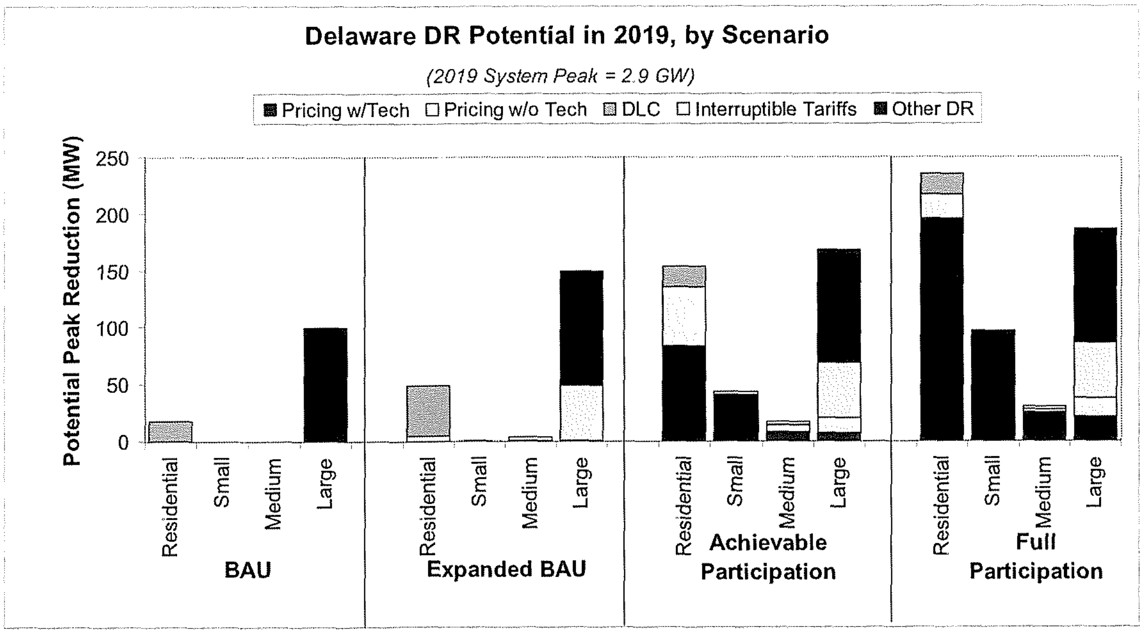
Key drivers of Delaware's demand response potential estimate include: average residential CAC saturation of around 55 percent, a customer mix that has an above average share of peak demand in the Small C&I class (36%), a moderate amount of existing demand response in the Large C&I class though Other DR, and the potential to deploy AMI at a faster-than-average rate. DLC and enabling technologies are cost effective for all customer classes in the state.

BAU: Delaware's existing demand response comes primarily from a large Other DR program for Large C&I customers. In addition, there is a moderate amount of DLC in the Residential class. Small and Medium C&I have any demand response.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for the Residential class and Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. Although Delaware has a large share of Small C&I load, there is not much growth in that customer class in this scenario.

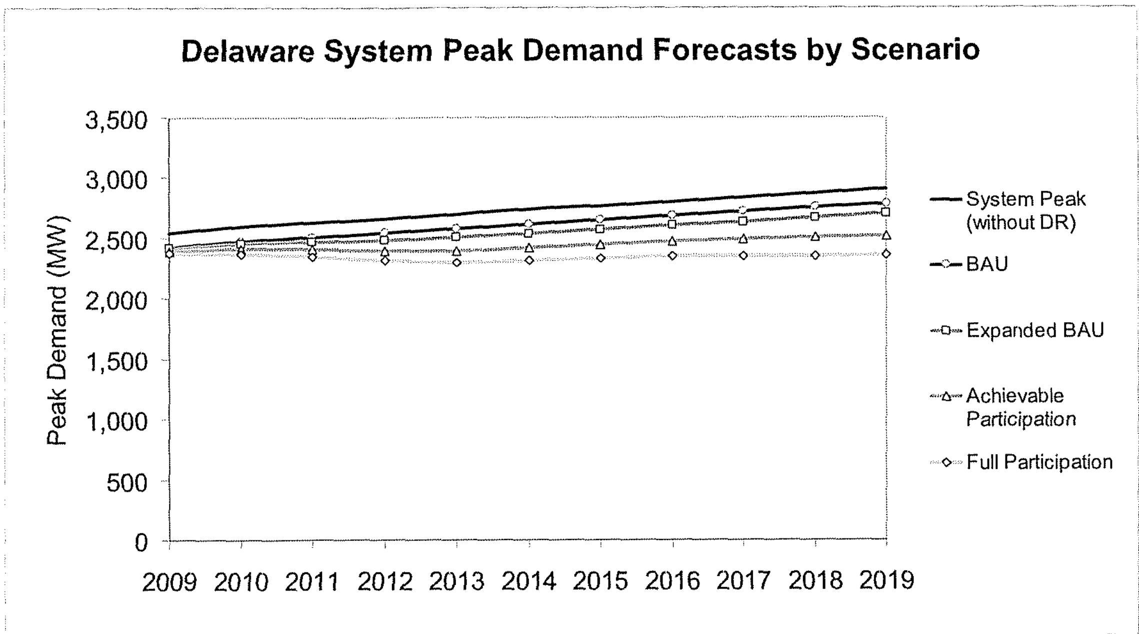
Achievable Participation: CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with enabling technology. The Small C&I class shows some growth through dynamic pricing with enabling technology.

Full Participation: Similar to the Achievable Participation scenario, residential CAC saturation combined with a large share of load in the Small C&I class drives the increase in impacts. Medium and Large C&I also show an increase due to pricing with enabling technology.



Total Potential Peak Reduction from Demand Response in Delaware, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	18	0.6%	0	0.0%	0	0.0%	100	3.4%	118	4.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	5	0.2%	0	0.0%	1	0.0%	1	0.0%	7	0.3%
Automated/Direct Load Control	44	1.5%	1	0.0%	0	0.0%	0	0.0%	46	1.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	50	1.7%	1	0.0%	4	0.1%	150	5.2%	204	7.0%
Achievable Participation										
Pricing with Technology	84	2.9%	41	1.4%	9	0.3%	7	0.2%	141	4.8%
Pricing without Technology	52	1.8%	2	0.1%	6	0.2%	13	0.5%	74	2.5%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	154	5.3%	44	1.5%	17	0.6%	169	5.8%	384	13.2%
Full Participation										
Pricing with Technology	196	6.7%	96	3.3%	25	0.9%	21	0.7%	338	11.6%
Pricing without Technology	22	0.8%	1	0.0%	3	0.1%	17	0.6%	43	1.5%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	48	1.7%	51	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	100	3.4%	100	3.4%
Total	235	8.1%	97	3.4%	30	1.0%	187	6.4%	550	18.9%



District of Columbia Profile

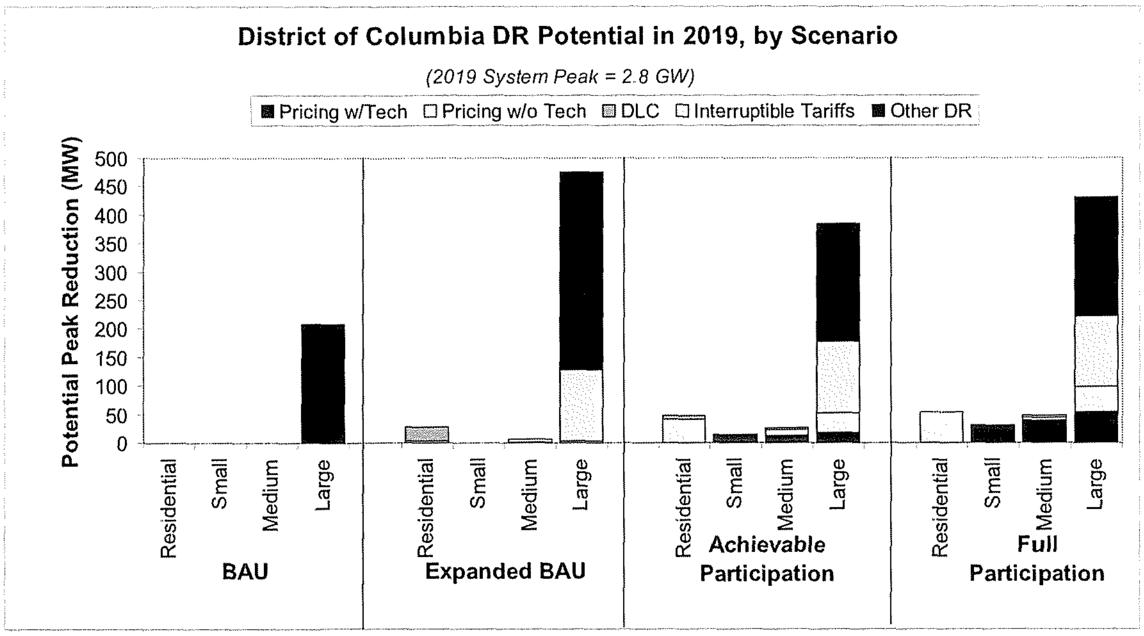
Key drivers of the District of Columbia's demand response potential estimate include: average residential CAC saturation of around 55 percent, a customer mix that has an above average share of peak demand in the Large C&I class (52%), a moderate amount of existing demand response in the Large C&I sector due to Other DR programs, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Residential class.

BAU: The District of Columbia's existing demand response comes entirely from Other DR for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Interruptible Tariffs for the Large C&I class, which currently do not exist in the state. Other DR expands substantially as well. This high growth is due to the District of Columbia's large share of Large C&I load.

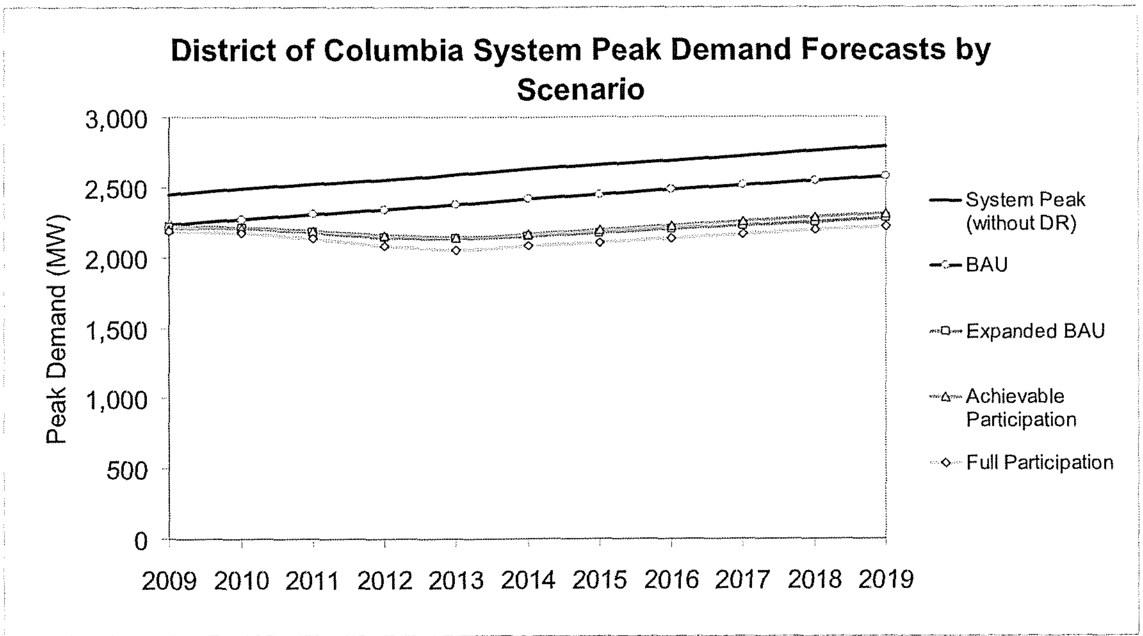
Achievable Participation: Large C&I demand response potential is lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR. This leads to lower demand response potential even though the other classes increase in demand response potential.

Full Participation: Similar to the Expanded BAU scenario, a large share of load in the Large C&I sector drives the increase in impacts. Since enabling technologies are not cost-effective for the Residential sector, the growth the Residential sector is not as much as is seen in other states for this scenario. C&I demand response potential is slightly higher than in the Achievable Participation scenario because of growth in pricing with and without enabling technology, which is cost-effective for all C&I sectors.



Total Potential Peak Reduction from Demand Response in District of Columbia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	3	0.1%	0	0.0%	1	0.1%	4	0.1%	8	0.3%
Automated/Direct Load Control	26	0.9%	0	0.0%	1	0.0%	0	0.0%	27	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	347	12.5%	347	12.5%
Total	29	1.0%	1	0.0%	6	0.2%	475	17.1%	511	18.3%
Achievable Participation										
Pricing with Technology	0	0.0%	13	0.5%	14	0.5%	19	0.7%	46	1.6%
Pricing without Technology	41	1.5%	1	0.0%	9	0.3%	34	1.2%	84	3.0%
Automated/Direct Load Control	7	0.2%	0	0.0%	0	0.0%	0	0.0%	7	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	47	1.7%	14	0.5%	27	1.0%	386	13.8%	474	17.0%
Full Participation										
Pricing with Technology	0	0.0%	31	1.1%	40	1.4%	54	2.0%	125	4.5%
Pricing without Technology	54	1.9%	0	0.0%	4	0.2%	44	1.6%	103	3.7%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	124	4.5%	128	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	209	7.5%	209	7.5%
Total	54	1.9%	32	1.1%	48	1.7%	431	15.5%	565	20.3%



Florida State Profile

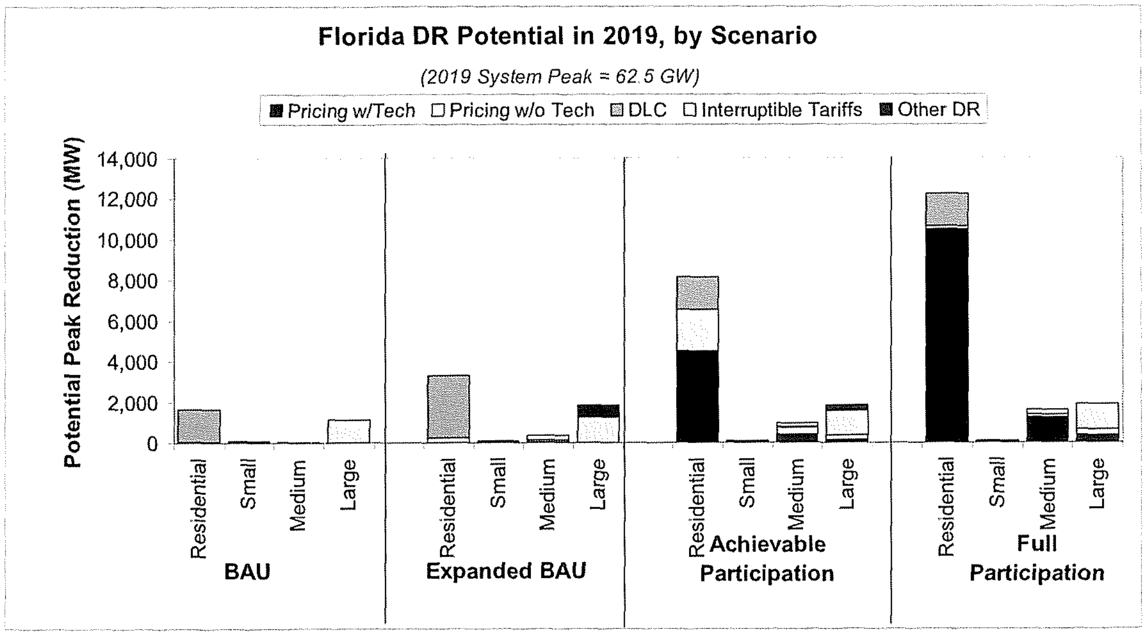
Key drivers of Florida's demand response potential estimate include: very high residential CAC saturation of 91 percent, a customer mix that has an above average share of peak demand in the Residential class (59%), a large existing residential DLC program, and the potential to deploy AMI at a faster-than-average rate. DLC is cost effective for all customer classes in the state. Enabling technologies are not cost effective for the Small C&I class. Florida's demand response potential is highly dependent on recruiting participants from the Residential class, as is shown in the Achievable and Full Participation scenarios.

BAU: Florida's existing demand response comes primarily from DLC in the Residential class and an Interruptible Tariffs program for Large C&I customers.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC for the Residential class. This is due to Florida's high share of Residential load. There is also growth in the Large C&I class due to Other DR.

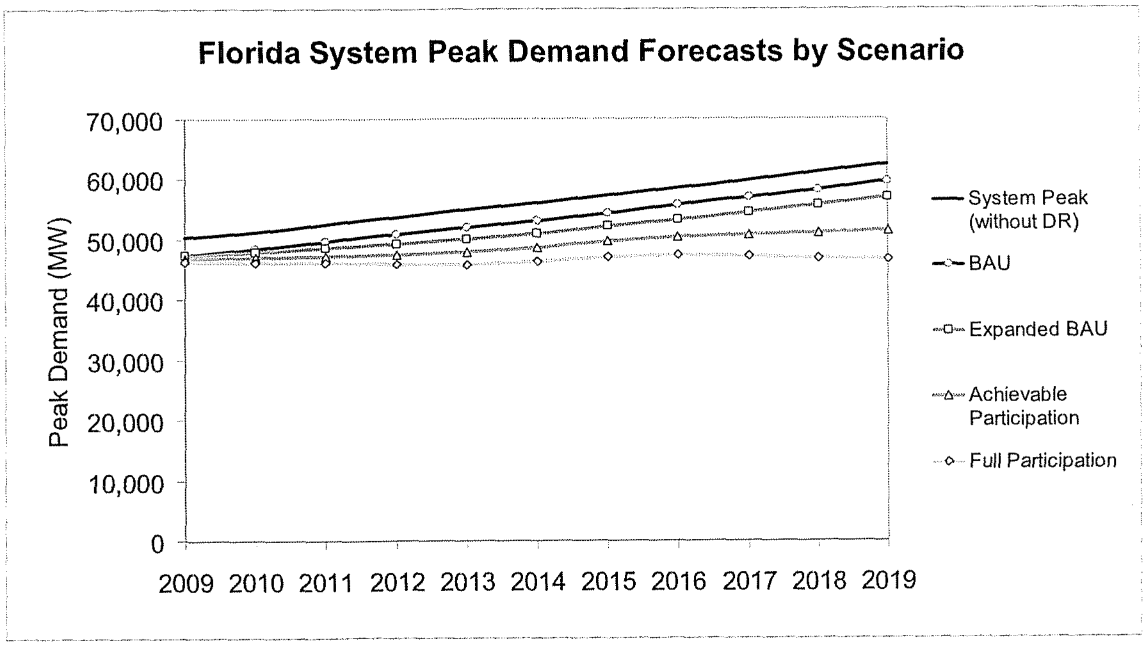
Achievable Participation: High CAC saturation in the Residential class drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the Residential class drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes except Small C&I.



Total Potential Peak Reduction from Demand Response in Florida, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	42	0.1%	0	0.0%	0	0.0%	0	0.0%	42	0.1%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	0	0.0%	0	0.0%	1,695	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	24	0.0%	1,163	1.9%	1,187	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,665	2.7%	73	0.1%	24	0.0%	1,163	1.9%	2,924	4.7%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	227	0.4%	1	0.0%	34	0.1%	18	0.0%	280	0.4%
Automated/Direct Load Control	3,091	4.9%	73	0.1%	125	0.2%	0	0.0%	3,289	5.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	574	0.9%	574	0.9%
Total	3,318	5.3%	74	0.1%	346	0.6%	1,833	2.9%	5,571	8.9%
Achievable Participation										
Pricing with Technology	4,494	7.2%	0	0.0%	432	0.7%	123	0.2%	5,049	8.1%
Pricing without Technology	2,037	3.3%	16	0.0%	288	0.5%	223	0.4%	2,564	4.1%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	52	0.1%	0	0.0%	1,747	2.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	238	0.4%	239	0.4%
Total	8,154	13.1%	89	0.1%	958	1.5%	1,825	2.9%	11,026	17.7%
Full Participation										
Pricing with Technology	10,513	16.8%	0	0.0%	1,264	2.0%	358	0.6%	12,135	19.4%
Pricing without Technology	133	0.2%	21	0.0%	139	0.2%	289	0.5%	582	0.9%
Automated/Direct Load Control	1,622	2.6%	73	0.1%	0	0.0%	0	0.0%	1,695	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	187	0.3%	1,242	2.0%	1,428	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	12,269	19.6%	94	0.2%	1,590	2.5%	1,889	3.0%	15,841	25.4%



Georgia State Profile

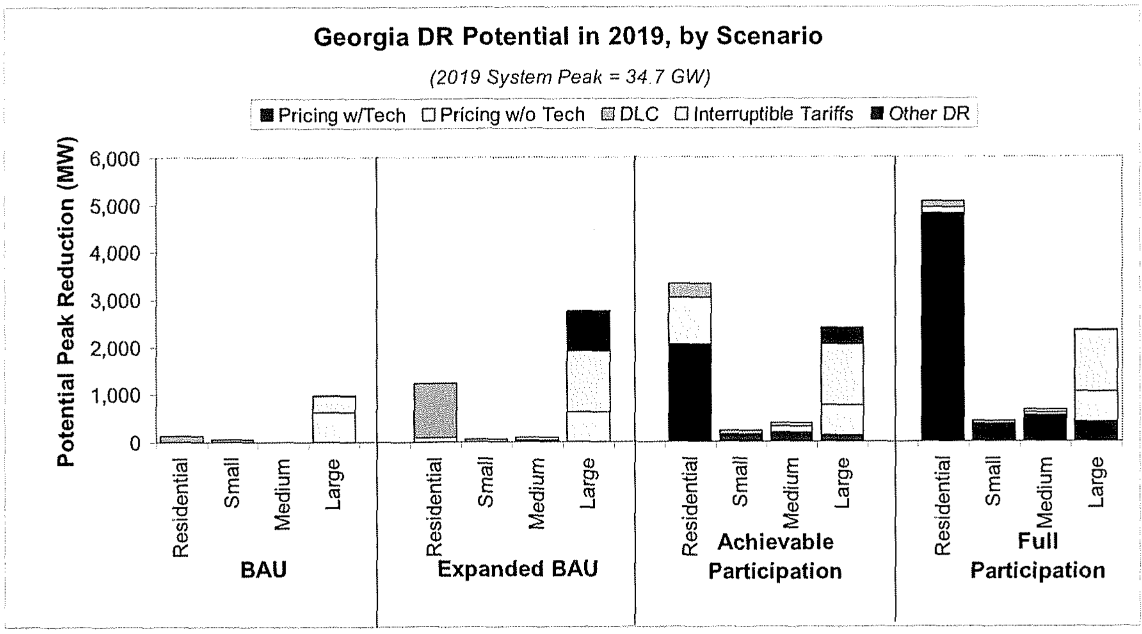
Key drivers of Georgia's demand response potential estimate include: higher-than-average residential CAC saturation of 82 percent, a customer mix that has an above average share of peak demand in the residential and Large C&I classes (50% and 25%, respectively), a moderate amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Georgia's existing demand response comes primarily from one of the largest RTP tariffs in the country for large C&I customers. An interruptible tariff program also contributes significantly to the total.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. This is due to Georgia's high share of Large C&I load, which would also allow for significant growth in the existing interruptible tariff. DLC also exhibits additional incremental potential in the Residential class as it is cost effective to implement.

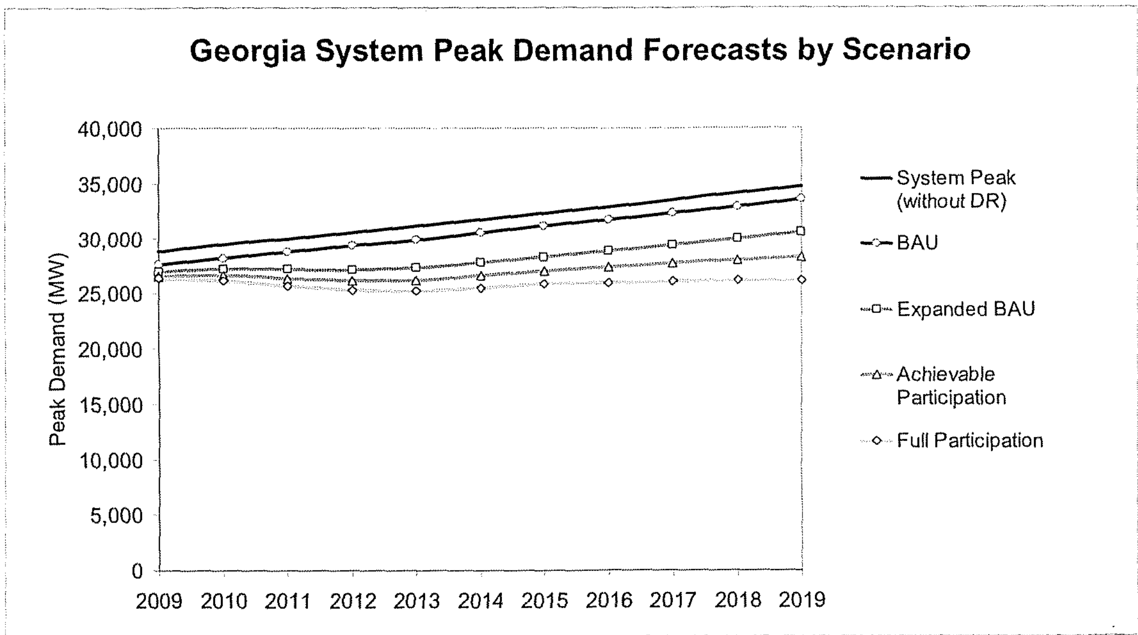
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes.



Total Potential Peak Reduction from Demand Response in Georgia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	2	0.0%	0	0.0%	628	1.8%	630	1.8%
Automated/Direct Load Control	130	0.4%	63	0.2%	2	0.0%	0	0.0%	196	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	332	1.0%	332	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	22	0.1%	22	0.1%
Total	130	0.4%	65	0.2%	2	0.0%	982	2.8%	1,179	3.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	95	0.3%	2	0.0%	14	0.0%	628	1.8%	739	2.1%
Automated/Direct Load Control	1,146	3.3%	63	0.2%	35	0.1%	0	0.0%	1,244	3.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	844	2.4%	844	2.4%
Total	1,241	3.6%	65	0.2%	106	0.3%	2,761	8.0%	4,174	12.0%
Achievable Participation										
Pricing with Technology	2,062	5.9%	155	0.4%	190	0.5%	143	0.4%	2,550	7.4%
Pricing without Technology	974	2.8%	9	0.0%	127	0.4%	628	1.8%	1,737	5.0%
Automated/Direct Load Control	296	0.9%	63	0.2%	14	0.0%	0	0.0%	374	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	353	1.0%	353	1.0%
Total	3,332	9.6%	227	0.7%	389	1.1%	2,414	7.0%	6,363	18.4%
Full Participation										
Pricing with Technology	4,823	13.9%	363	1.0%	557	1.6%	419	1.2%	6,161	17.8%
Pricing without Technology	114	0.3%	5	0.0%	61	0.2%	628	1.8%	807	2.3%
Automated/Direct Load Control	130	0.4%	63	0.2%	2	0.0%	0	0.0%	196	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	58	0.2%	1,290	3.7%	1,348	3.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	22	0.1%	22	0.1%
Total	5,066	14.6%	431	1.2%	678	2.0%	2,358	6.8%	8,534	24.6%



Hawaii State Profile

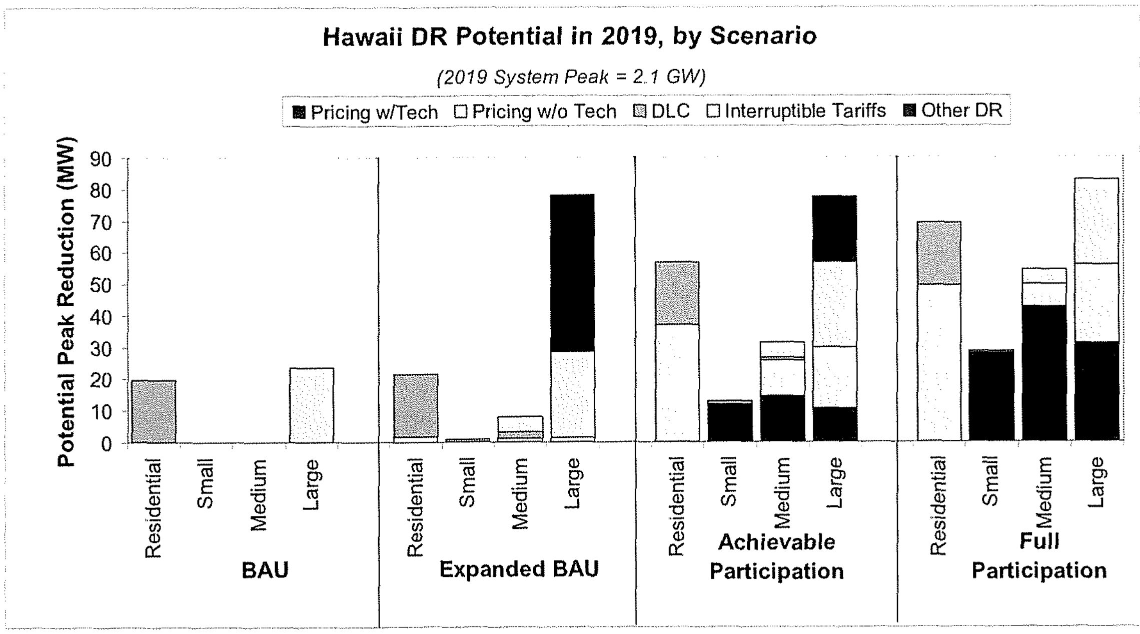
Key drivers of Georgia's demand response potential estimate include: very low CAC saturation of 17.6 percent, a customer mix that has an above average share of peak demand in the Large C&I (35%), a minimal amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all the C&I customer classes, however not for the Residential class.

BAU: Hawaii's existing demand response comes from DLC participation in the Residential class and Interruptible Tariff participation in the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven primarily by the Large C&I class. There is a significant increase in Interruptible Tariffs and the addition of Other DR programs. This is due to Hawaii's high share of Large C&I load.

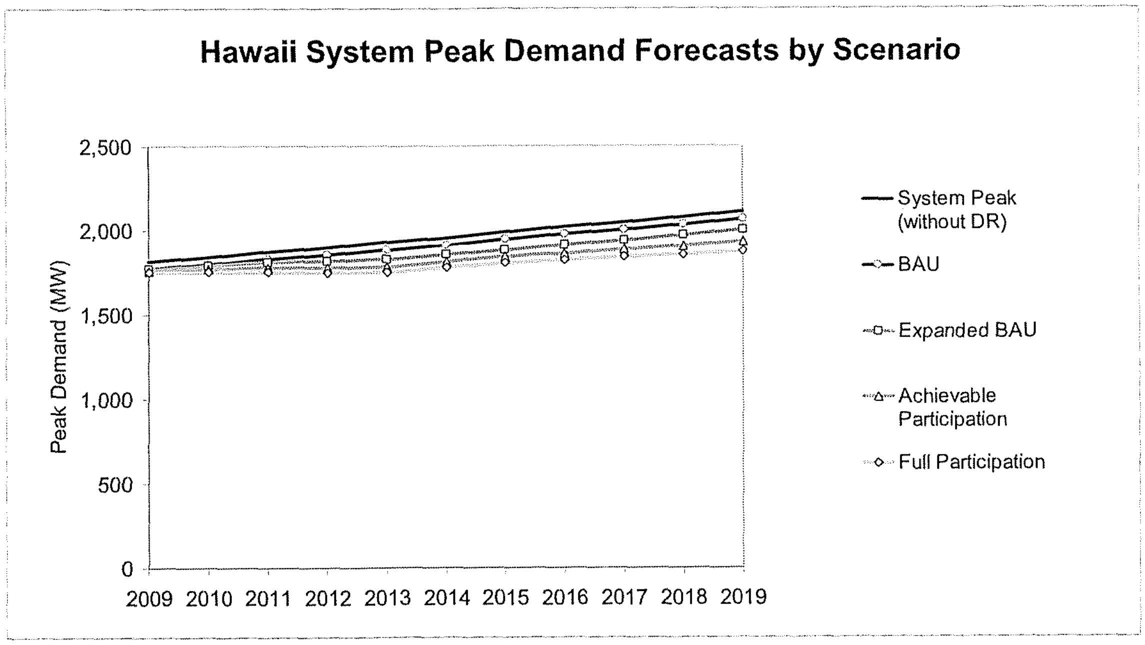
Achievable Participation: Though the Residential class is limited by a low CAC saturation and a lack of enabling technology, there is still growth in potential through pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR, while there is moderate growth in the Small and Medium C&I classes.

Full Participation: Similar to the Achievable Participation scenario, there is growing potential across the classes in dynamic pricing, though it is limited in the Residential class due to a lack of enabling technology. Finally, the Large C&I class still exhibits strong potential in Interruptible Tariffs.



Total Potential Peak Reduction from Demand Response in Hawaii, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	20	0.9%	0	0.0%	0	0.0%	0	0.0%	20	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	24	1.1%	24	1.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	20	0.9%	0	0.0%	0	0.0%	24	1.1%	44	2.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	1	0.1%	2	0.1%	5	0.2%
Automated/Direct Load Control	20	0.9%	1	0.0%	2	0.1%	0	0.0%	23	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	50	2.4%	50	2.4%
Total	22	1.0%	1	0.0%	8	0.4%	78	3.7%	109	5.2%
Achievable Participation										
Pricing with Technology	0	0.0%	12	0.6%	15	0.7%	11	0.5%	37	1.8%
Pricing without Technology	37	1.8%	1	0.0%	11	0.5%	19	0.9%	68	3.2%
Automated/Direct Load Control	20	0.9%	0	0.0%	1	0.0%	0	0.0%	21	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	21	1.0%	21	1.0%
Total	57	2.7%	13	0.6%	31	1.5%	78	3.7%	179	8.5%
Full Participation										
Pricing with Technology	0	0.0%	28	1.3%	43	2.0%	31	1.5%	102	4.8%
Pricing without Technology	49	2.3%	1	0.0%	7	0.3%	25	1.2%	82	3.9%
Automated/Direct Load Control	20	0.9%	0	0.0%	0	0.0%	0	0.0%	20	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	27	1.3%	32	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	69	3.3%	29	1.4%	54	2.6%	83	3.9%	235	11.2%



Idaho State Profile

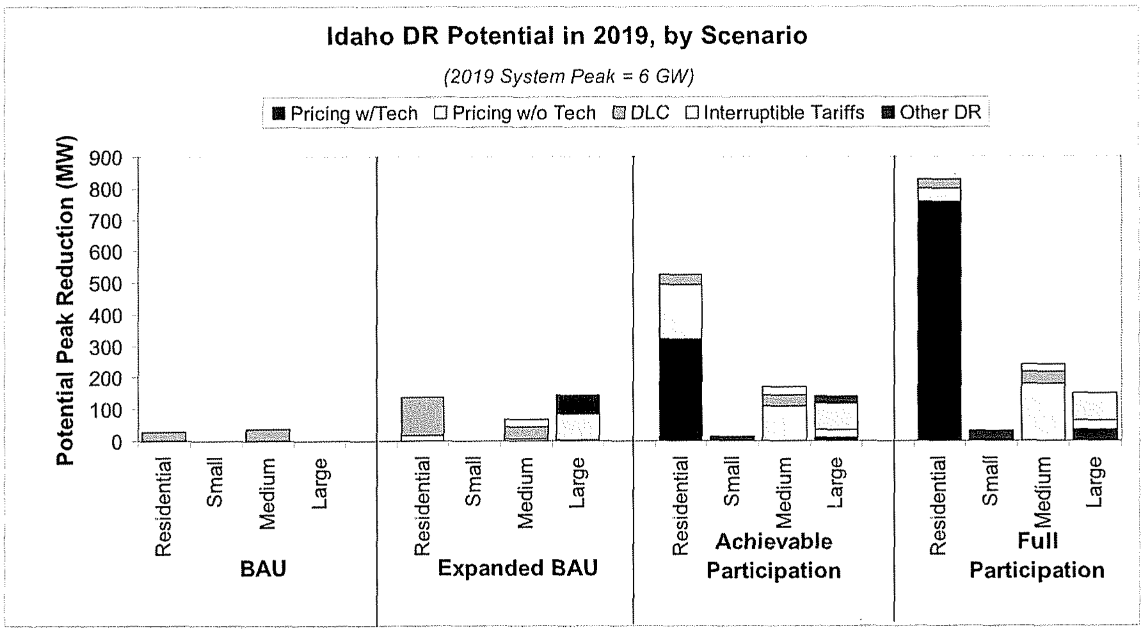
Key drivers of Idaho's demand response potential estimate significant residential CAC saturation of 66.5 percent, a customer mix that has an above average share of peak demand in the Medium C&I classes (39%), a minimal amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state except for the Medium C&I segment.

BAU: Idaho's existing demand response comes from DLC programs in the Residential and Medium C&I classes.

Expanded BAU: With a unique customer mix weighted towards the Residential and Medium C&I segments, growth in demand response impacts is spread across these two classes as well as in the Large C&I class. DLC potential has increased for the Residential class, while Interruptible Tariffs and Other DR make up the increase in potential found in the Medium and Large C&I classes.

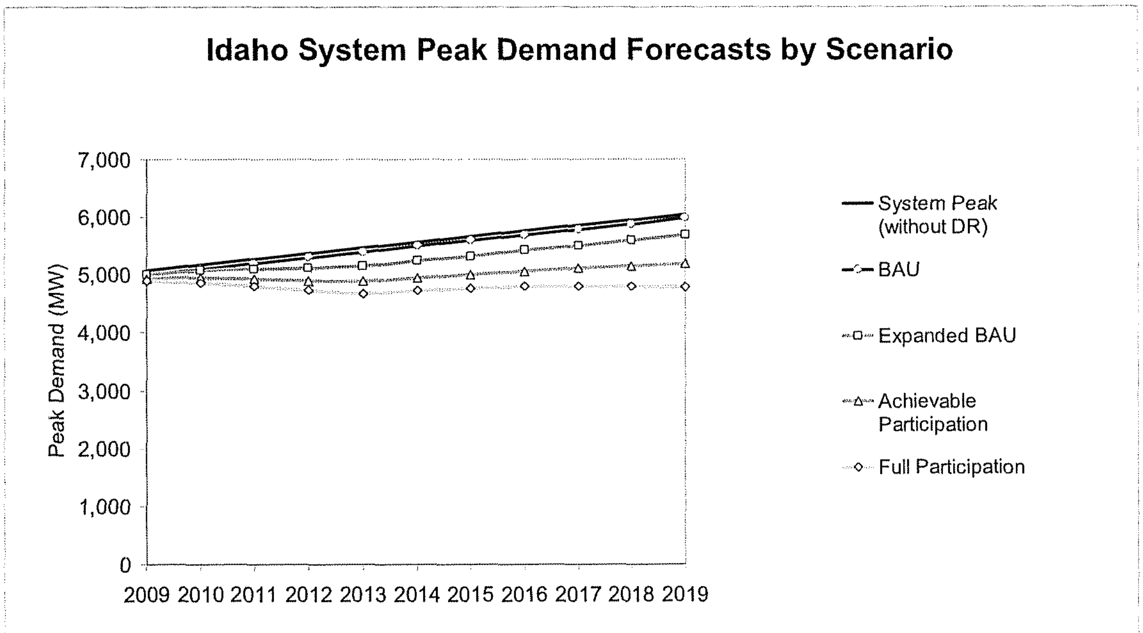
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. The size of the Medium C&I class contributes to the larger role that it plays in the state's total potential.

Full Participation: In the Full Participation scenario, the Residential class exhibits the most potential in dynamic pricing. The Medium and Large C&I classes have moderate increases from the same pricing programs, with potential from Other DR in the Large class dropping off due to an assumption that these customers would instead be enrolled in pricing programs. Potential from the Medium C&I class would be higher, but is mitigated by the lack of enabling technology for dynamic pricing.



Total Potential Peak Reduction from Demand Response in Idaho, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	16	0.3%	0	0.0%	6	0.1%	2	0.0%	24	0.4%
Automated/Direct Load Control	123	2.0%	1	0.0%	37	0.6%	0	0.0%	161	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	59	1.0%	59	1.0%
Total	139	2.3%	1	0.0%	69	1.1%	144	2.4%	354	5.9%
Achievable Participation										
Pricing with Technology	323	5.3%	14	0.2%	0	0.0%	13	0.2%	350	5.8%
Pricing without Technology	170	2.8%	1	0.0%	108	1.8%	23	0.4%	302	5.0%
Automated/Direct Load Control	32	0.5%	0	0.0%	37	0.6%	0	0.0%	69	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	24	0.4%	24	0.4%
Total	526	8.7%	15	0.3%	171	2.8%	144	2.4%	855	14.1%
Full Participation										
Pricing with Technology	757	12.5%	33	0.5%	0	0.0%	37	0.6%	826	13.7%
Pricing without Technology	41	0.7%	1	0.0%	180	3.0%	30	0.5%	252	4.2%
Automated/Direct Load Control	31	0.5%	0	0.0%	37	0.6%	0	0.0%	68	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.4%	84	1.4%	109	1.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	829	13.7%	33	0.6%	243	4.0%	150	2.5%	1,255	20.8%



Illinois State Profile

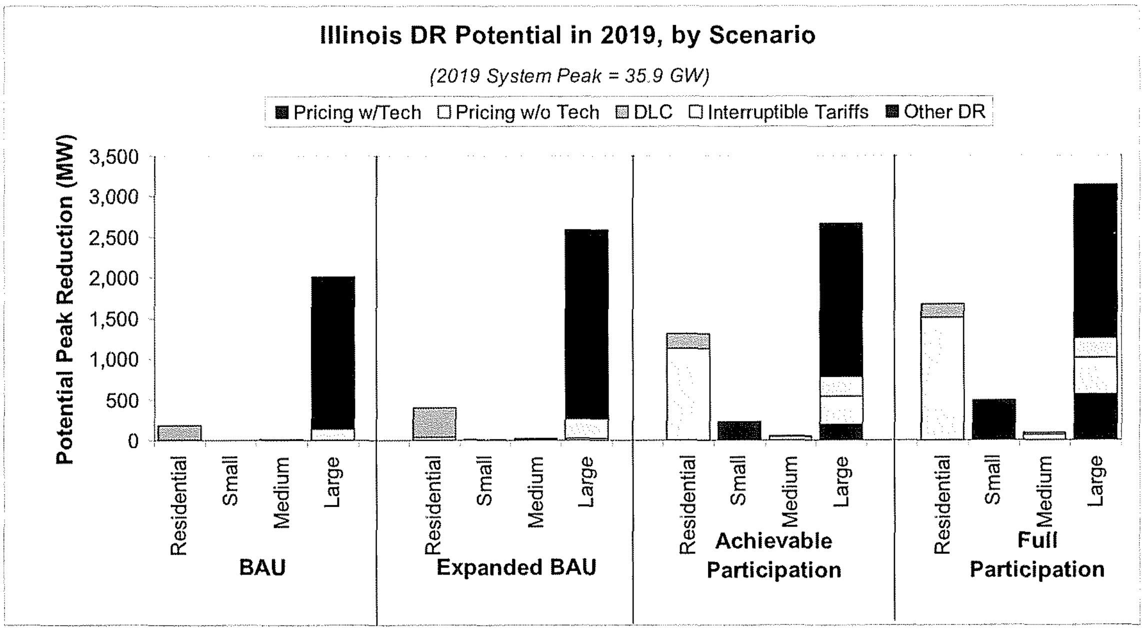
Key drivers of Illinois's demand response potential estimate include: higher-than-average residential CAC saturation of 75 percent, a customer mix that has an above average share of peak demand in the Large C&I class (42%), a moderate amount of existing demand response, and the potential to deploy AMI at a slightly faster-than-average rate. Enabling technologies are cost-effective only for the Small and Large C&I classes. DLC technology is cost-effective for all customer classes in the state.

BAU: Illinois's existing demand response comes primarily from its Large C&I class, namely in the Other DR category. The Residential class contributes minimally with DLC participation.

Expanded BAU: Growth in demand response impacts is driven primarily through the Other DR programs and Interruptible Tariffs for the Large C&I class. Residential DLC exhibits small growth in the existing DLC program.

Achievable Participation: High CAC saturation in the residential sector implies significant demand response potential through pricing programs, but this is realized without enabling technology as it is not cost-effective in this class in Illinois. It is, however, cost-effective for the Small and Large C&I classes, and this is reflected in the results. Large C&I demand response potential is slightly higher than in the Expanded BAU scenario due to higher assumed participation in pricing programs.

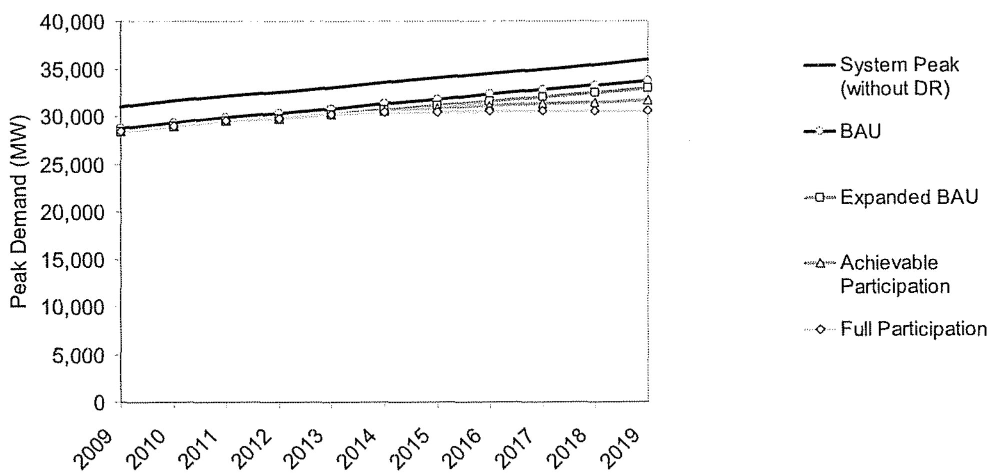
Full Participation: Potential increases relative to the Achievable Participation scenario due to impacts from pricing programs, limited somewhat by the lack of cost-effective enabling technology in the Residential and Medium C&I classes. The Large C&I class maintains strong potential from Interruptible Tariffs and Other DR as well.



Total Potential Peak Reduction from Demand Response in Illinois, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	178	0.5%	0	0.0%	0	0.0%	0	0.0%	178	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	10	0.0%	134	0.4%	144	0.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	179	0.5%	0	0.0%	10	0.0%	2,017	5.6%	2,206	6.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	39	0.1%	1	0.0%	2	0.0%	19	0.1%	61	0.2%
Automated/Direct Load Control	369	1.0%	10	0.0%	9	0.0%	0	0.0%	387	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,329	6.5%	2,329	6.5%
Total	407	1.1%	11	0.0%	26	0.1%	2,592	7.2%	3,036	8.5%
Achievable Participation										
Pricing with Technology	0	0.0%	210	0.6%	0	0.0%	192	0.5%	402	1.1%
Pricing without Technology	1,131	3.1%	13	0.0%	45	0.1%	349	1.0%	1,537	4.3%
Automated/Direct Load Control	178	0.5%	3	0.0%	4	0.0%	0	0.0%	184	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	1,309	3.6%	225	0.6%	63	0.2%	2,667	7.4%	4,265	11.9%
Full Participation										
Pricing with Technology	0	0.0%	492	1.4%	0	0.0%	561	1.6%	1,052	2.9%
Pricing without Technology	1,508	4.2%	8	0.0%	74	0.2%	452	1.3%	2,042	5.7%
Automated/Direct Load Control	178	0.5%	0	0.0%	0	0.0%	0	0.0%	178	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.0%	243	0.7%	258	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,883	5.2%	1,883	5.2%
Total	1,686	4.7%	499	1.4%	89	0.2%	3,139	8.7%	5,414	15.1%

Illinois System Peak Demand Forecasts by Scenario



Indiana State Profile

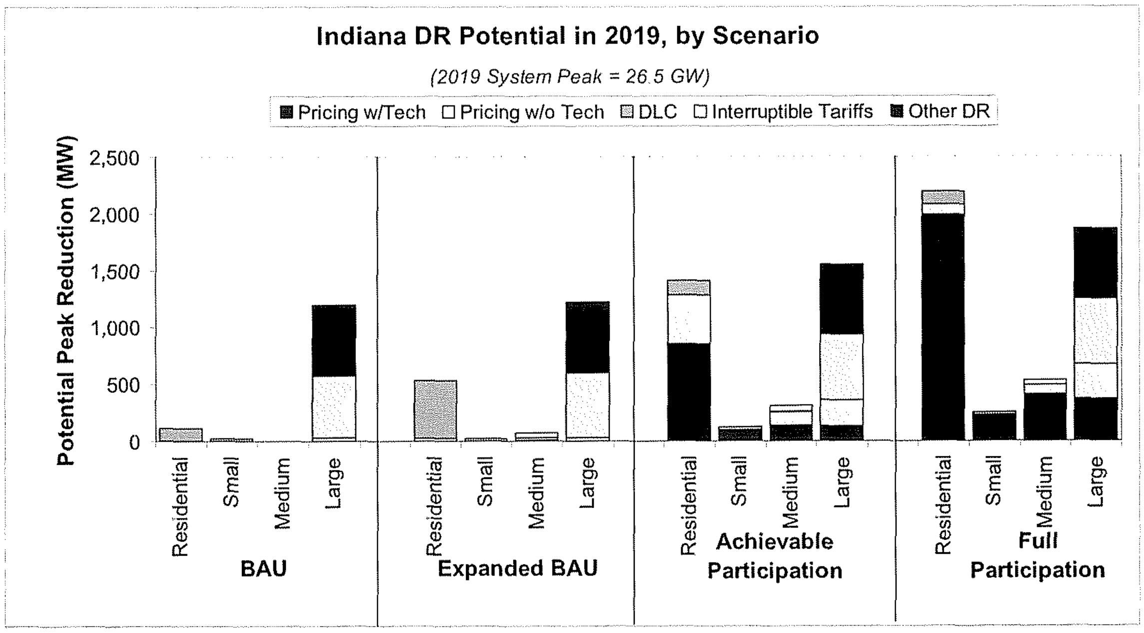
Key drivers of Indiana's demand response potential estimate include: higher-than-average residential CAC saturation of 74 percent, a customer mix that has an above average share of peak demand in the Large C&I class (35%), a moderate amount of existing demand response, and the potential to deploy AMI at an average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Indiana's existing demand response comes primarily from the Large C&I class. BAU demand response for this class is split between Interruptible Tariffs and Other DR.

Expanded BAU: Demand response potential for the Large C&I class remains largely unchanged. However, due to the high Residential CAC saturation, DLC potential in this class has grown significantly.

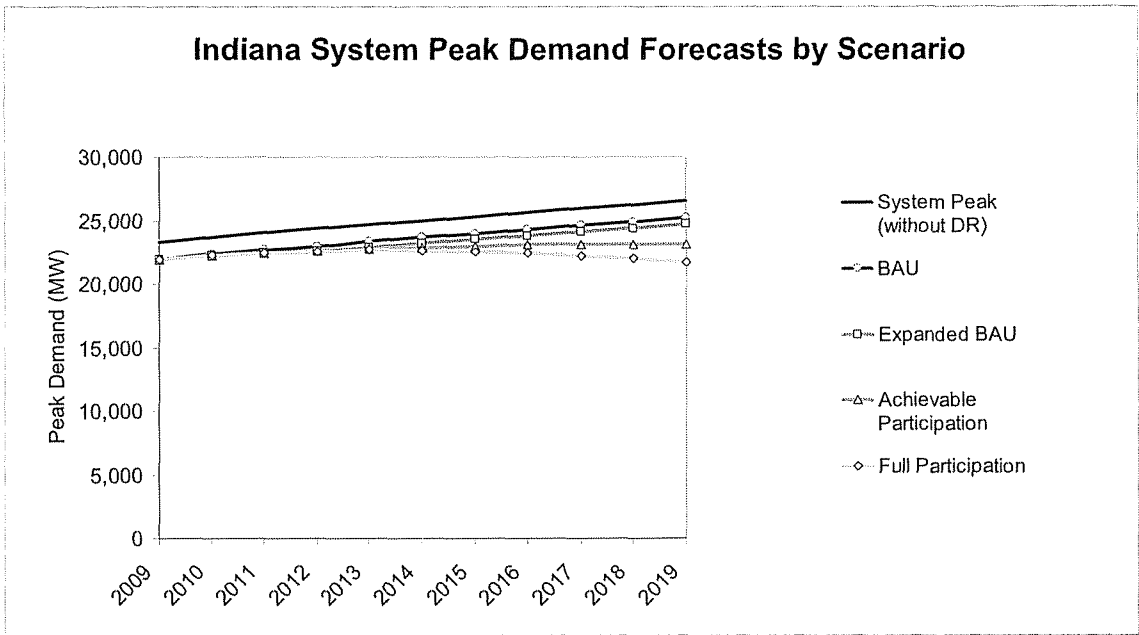
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. This is bolstered by the gains across the C&I classes due to pricing programs.

Full Participation: Continuing the trend from the Achievable Participation scenario, high CAC saturation in the residential sector and cost-effective enabling technology drive the increases in impacts from dynamic pricing programs. Potential in the C&I classes grows slightly as pricing program participation increases relative to the other scenarios.



Total Potential Peak Reduction from Demand Response in Indiana, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	29	0.1%	29	0.1%
Automated/Direct Load Control	116	0.4%	23	0.1%	0	0.0%	0	0.0%	139	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	549	2.1%	549	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	621	2.3%
Total	116	0.4%	23	0.1%	0	0.0%	1,199	4.5%	1,338	5.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	25	0.1%	0	0.0%	7	0.0%	29	0.1%	61	0.2%
Automated/Direct Load Control	512	1.9%	23	0.1%	24	0.1%	0	0.0%	559	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	622	2.3%
Total	537	2.0%	23	0.1%	78	0.3%	1,225	4.6%	1,863	7.0%
Achievable Participation										
Pricing with Technology	852	3.2%	96	0.4%	141	0.5%	128	0.5%	1,218	4.6%
Pricing without Technology	431	1.6%	6	0.0%	113	0.4%	232	0.9%	782	2.9%
Automated/Direct Load Control	131	0.5%	23	0.1%	10	0.0%	0	0.0%	163	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	622	2.3%
Total	1,414	5.3%	125	0.5%	311	1.2%	1,556	5.9%	3,407	12.8%
Full Participation										
Pricing with Technology	1,994	7.5%	225	0.8%	413	1.6%	373	1.4%	3,006	11.3%
Pricing without Technology	85	0.3%	3	0.0%	77	0.3%	301	1.1%	467	1.8%
Automated/Direct Load Control	116	0.4%	23	0.1%	0	0.0%	0	0.0%	139	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	47	0.2%	575	2.2%	622	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	621	2.3%	621	2.3%
Total	2,195	8.3%	252	0.9%	538	2.0%	1,870	7.0%	4,855	18.3%



Iowa State Profile

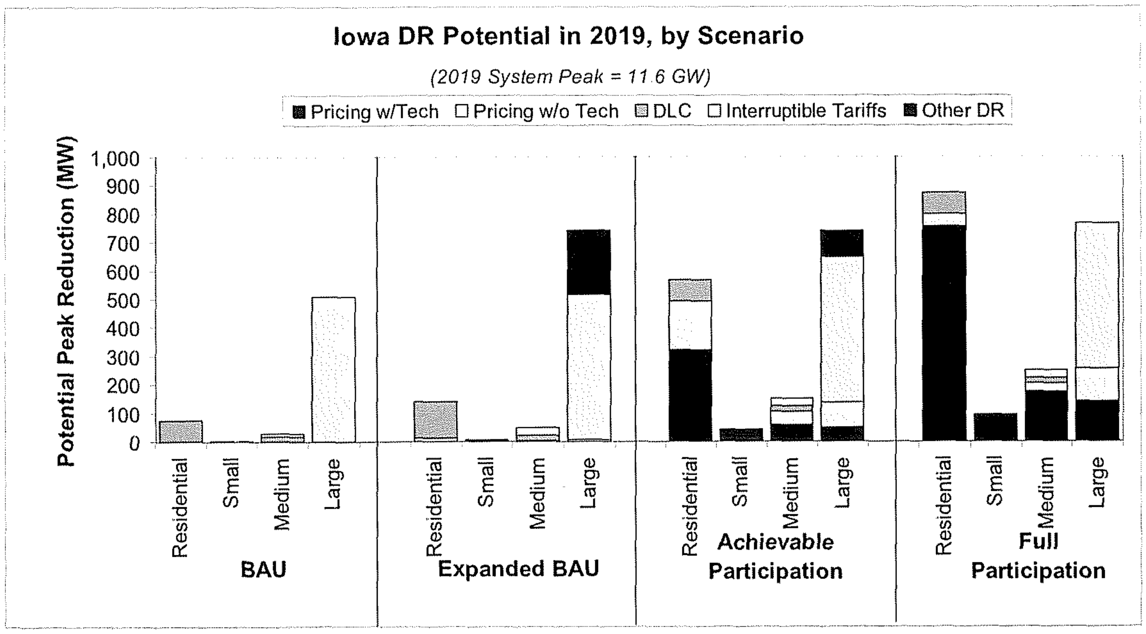
Key drivers of Iowa's demand response potential estimate include: higher-than-average residential CAC saturation of 70 percent, a customer mix that has an above average share of peak demand in the Large C&I class (34%), a small amount of existing demand response, and the potential to deploy AMI at a slightly faster-than-average rate. Enabling technologies are cost effective for all customer classes.

BAU: Iowa's existing demand response comes primarily from Interruptible Tariff and Pricing program participation in the Large C&I class. There is small DLC participation in the Residential and Medium C&I classes as well.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs and growth in Interruptible Tariffs participation for the Large C&I class, with slight growth in the Residential and Medium C&I classes contributing as well.

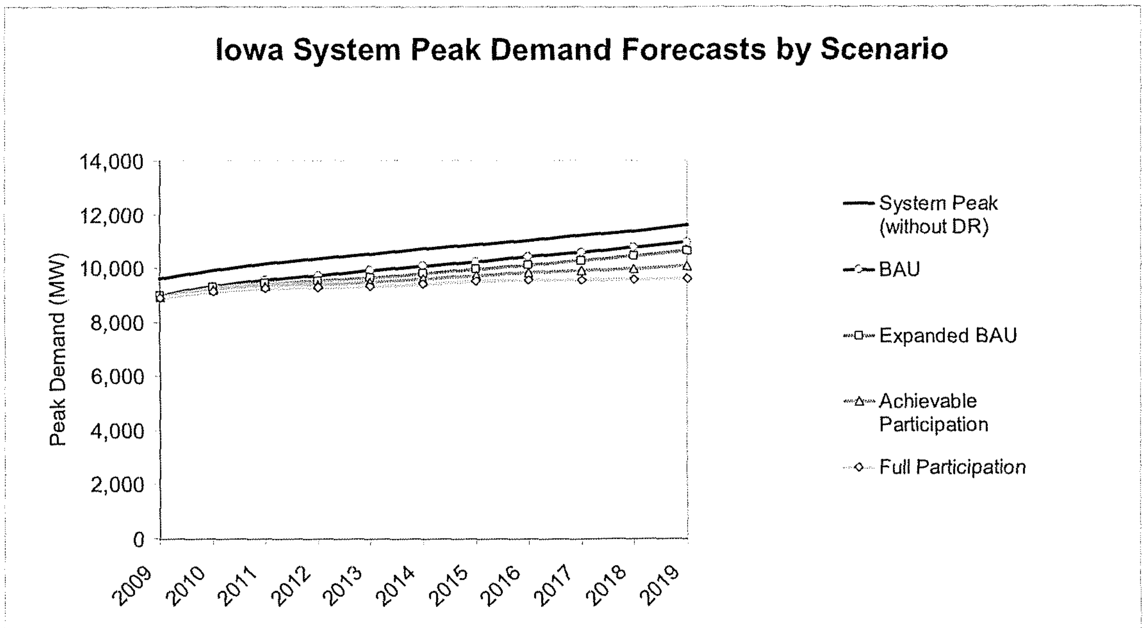
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing. The Small and Medium C&I classes show some potential, mainly through dynamic pricing. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, growth in the Residential class is driven by pricing with enabling technology. The Small and Medium C&I classes also exhibit an increase in dynamic pricing potential. With pricing making up a larger percentage of assumed participation in the Large C&I class, Other DR does not factor into the total impacts.



Total Potential Peak Reduction from Demand Response in Iowa, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	10	0.1%	510	4.4%	521	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	76	0.7%	2	0.0%	30	0.3%	510	4.4%	618	5.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	13	0.1%	0	0.0%	4	0.0%	5	0.0%	23	0.2%
Automated/Direct Load Control	129	1.1%	6	0.1%	19	0.2%	0	0.0%	154	1.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	230	2.0%	230	2.0%
Total	142	1.2%	6	0.1%	49	0.4%	745	6.4%	942	8.1%
Achievable Participation										
Pricing with Technology	323	2.8%	40	0.3%	59	0.5%	49	0.4%	471	4.1%
Pricing without Technology	171	1.5%	2	0.0%	47	0.4%	88	0.8%	309	2.7%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	94	0.8%	94	0.8%
Total	571	4.9%	44	0.4%	151	1.3%	742	6.4%	1,507	13.0%
Full Participation										
Pricing with Technology	755	6.5%	93	0.8%	173	1.5%	142	1.2%	1,164	10.1%
Pricing without Technology	43	0.4%	1	0.0%	32	0.3%	115	1.0%	191	1.6%
Automated/Direct Load Control	76	0.7%	2	0.0%	19	0.2%	0	0.0%	97	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	25	0.2%	510	4.4%	536	4.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	875	7.6%	97	0.8%	250	2.2%	767	6.6%	1,988	17.2%



Kansas State Profile

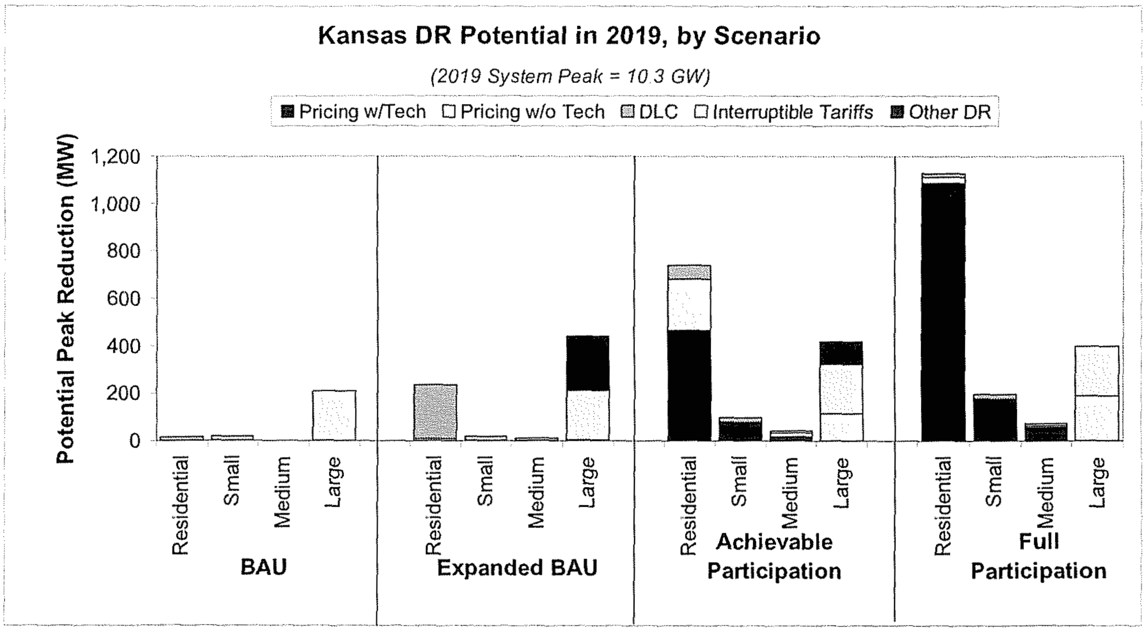
Key drivers of Kansas's demand response potential estimate include: higher-than-average residential CAC saturation of 83.7 percent, a customer mix that has a significant share of peak demand in the Residential and Large C&I classes (44% and 31%, respectively), a small amount of existing demand response, and the potential to deploy AMI at a slower-than-average rate. Enabling technologies are cost effective for all customer classes in the state except for the Large C&I class. DLC technology is cost-effective across all classes.

BAU: Kansas's existing demand response comes primarily from Interruptible tariffs in the Large C&I class and minimal DLC participation in the Residential and Small C&I classes.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state, as well as growth in the Large C&I class's Interruptible Tariff programs and the Residential class's DLC programs.

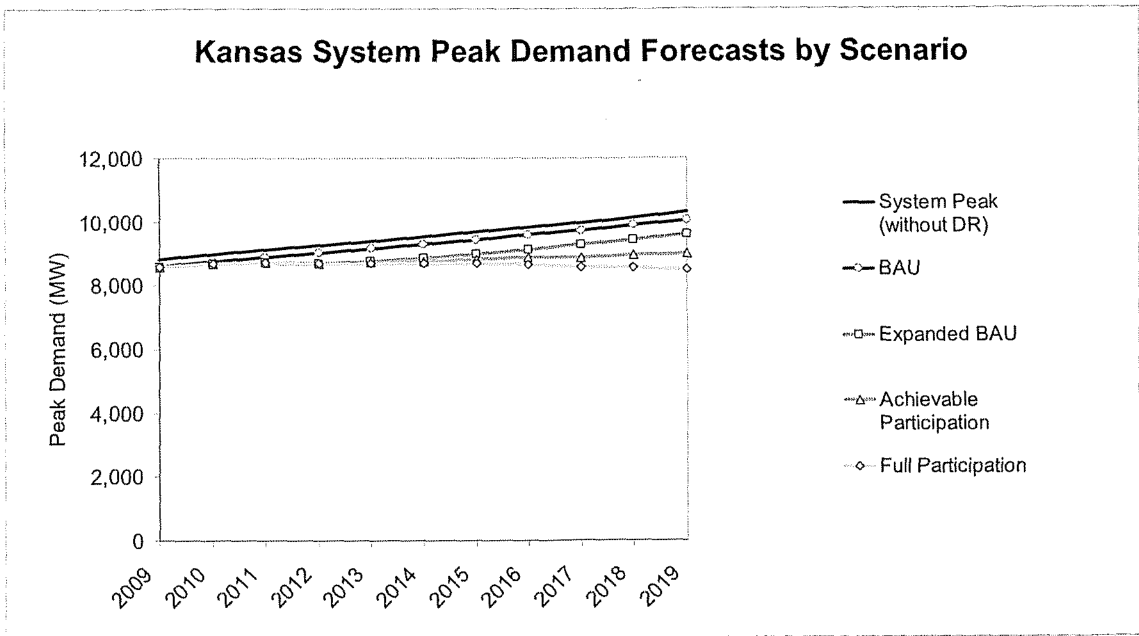
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing without technology relative to Other DR and Interruptible Tariffs.

Full Participation: High CAC saturation combined with a large share of load in the Residential sector drives the increase in impacts. With enabling technology being cost-effective for all but the Large C&I class, there are significant impacts in this category for the Small and Medium C&I classes. The Large C&I class contributes significantly through Interruptible Tariffs and pricing without enabling technology.



Total Potential Peak Reduction from Demand Response in Kansas, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	15	0.1%	19	0.2%	0	0.0%	0	0.0%	33	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	211	2.0%	211	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	15	0.1%	19	0.2%	0	0.0%	211	2.0%	244	2.4%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	9	0.1%	0	0.0%	1	0.0%	3	0.0%	13	0.1%
Automated/Direct Load Control	226	2.2%	19	0.2%	4	0.0%	0	0.0%	248	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	229	2.2%	229	2.2%
Total	236	2.3%	19	0.2%	11	0.1%	443	4.3%	708	6.9%
Achievable Participation										
Pricing with Technology	466	4.5%	75	0.7%	20	0.2%	0	0.0%	560	5.5%
Pricing without Technology	219	2.1%	5	0.0%	16	0.2%	113	1.1%	352	3.4%
Automated/Direct Load Control	57	0.6%	19	0.2%	1	0.0%	0	0.0%	78	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	0.9%	93	0.9%
Total	742	7.2%	98	1.0%	43	0.4%	417	4.1%	1,300	12.6%
Full Participation										
Pricing with Technology	1,089	10.6%	176	1.7%	58	0.6%	0	0.0%	1,322	12.9%
Pricing without Technology	24	0.2%	3	0.0%	11	0.1%	188	1.8%	225	2.2%
Automated/Direct Load Control	15	0.1%	19	0.2%	0	0.0%	0	0.0%	33	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	211	2.1%	218	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,127	11.0%	197	1.9%	75	0.7%	399	3.9%	1,798	17.5%



Kentucky State Profile

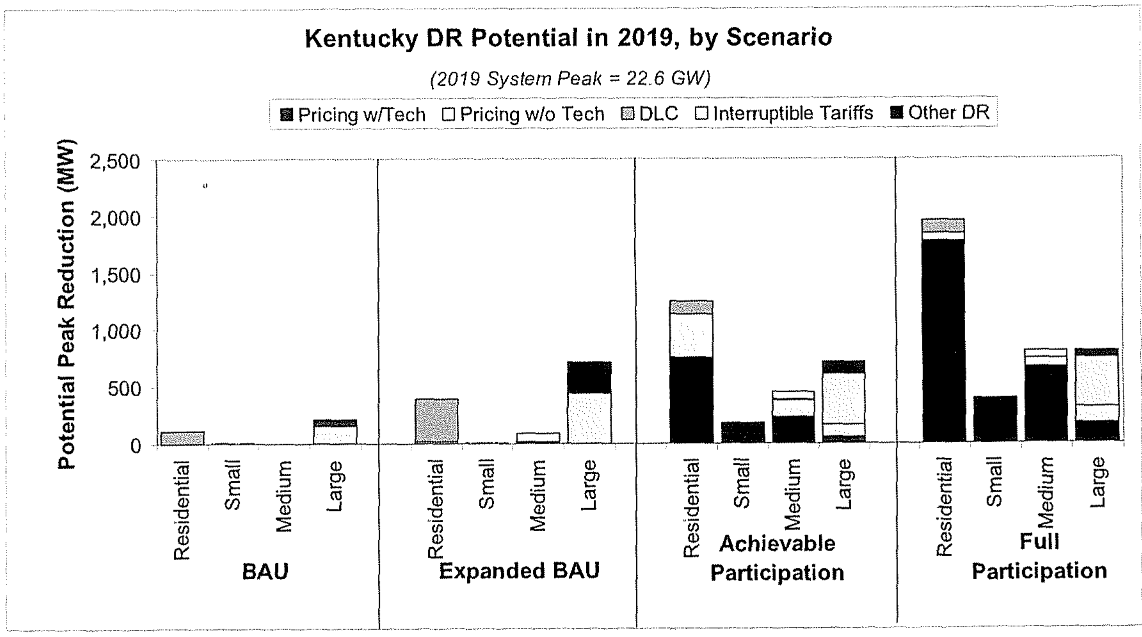
Key drivers of Kentucky's demand response potential estimate include: higher-than-average residential CAC saturation of 76 percent, a fairly typical customer mix with significant load in the Medium C&I class (30%), a minimal amount of existing demand response, and the potential to deploy AMI at a slightly slower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Kentucky's existing demand response comes from the Residential and Large C&I classes. DLC in the Residential class and an Interruptible Tariff in the Large C&I class make up most of the existing demand response, with Other DR in the Large C&I class also contributing.

Expanded BAU: Growth in demand response impacts is driven primarily through an increase in Other DR programs for the Large C&I class and growth in DLC for the Residential class. The Medium C&I class also gains demand response potential split mainly from an Interruptible Tariff.

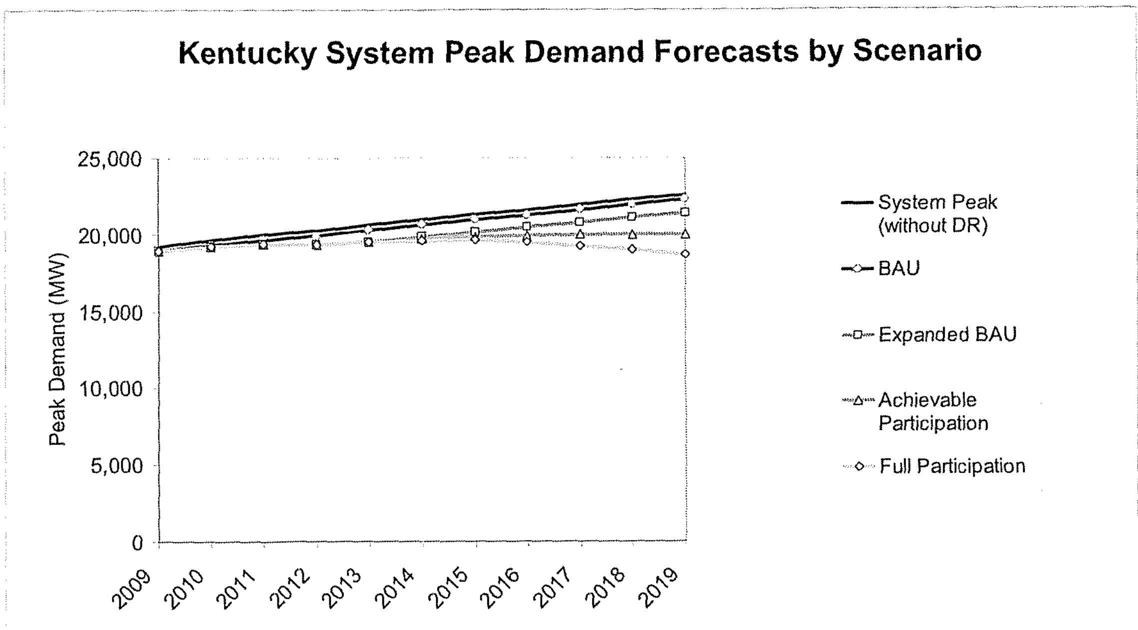
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR. There is also significant growth in demand response for the Small and Medium C&I classes driven by dynamic pricing programs

Full Participation: Residential class potential increases due to dynamic pricing. Overall, high CAC saturation across the Residential, Small C&I and Medium C&I classes drives the significant dynamic pricing potential, with the Large C&I class exhibiting significant potential in Interruptible Tariff programs.



Total Potential Peak Reduction from Demand Response in Kentucky, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	116	0.5%	6	0.0%	0	0.0%	0	0.0%	122	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	155	0.7%	155	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	56	0.2%	56	0.2%
Total	116	0.5%	6	0.0%	0	0.0%	211	0.9%	332	1.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	18	0.1%	0	0.0%	8	0.0%	4	0.0%	30	0.1%
Automated/Direct Load Control	377	1.7%	6	0.0%	12	0.1%	0	0.0%	394	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	272	1.2%	272	1.2%
Total	395	1.7%	6	0.0%	89	0.4%	713	3.2%	1,202	5.3%
Achievable Participation										
Pricing with Technology	759	3.4%	164	0.7%	227	1.0%	59	0.3%	1,209	5.4%
Pricing without Technology	377	1.7%	9	0.0%	151	0.7%	108	0.5%	645	2.9%
Automated/Direct Load Control	116	0.5%	6	0.0%	5	0.0%	0	0.0%	126	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	110	0.5%	111	0.5%
Total	1,251	5.5%	179	0.8%	452	2.0%	715	3.2%	2,596	11.5%
Full Participation										
Pricing with Technology	1,774	7.9%	383	1.7%	664	2.9%	174	0.8%	2,995	13.3%
Pricing without Technology	67	0.3%	5	0.0%	73	0.3%	140	0.6%	285	1.3%
Automated/Direct Load Control	116	0.5%	6	0.0%	0	0.0%	0	0.0%	122	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	69	0.3%	437	1.9%	506	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	56	0.2%	56	0.2%
Total	1,957	8.7%	394	1.7%	806	3.6%	807	3.6%	3,963	17.5%



Louisiana State Profile

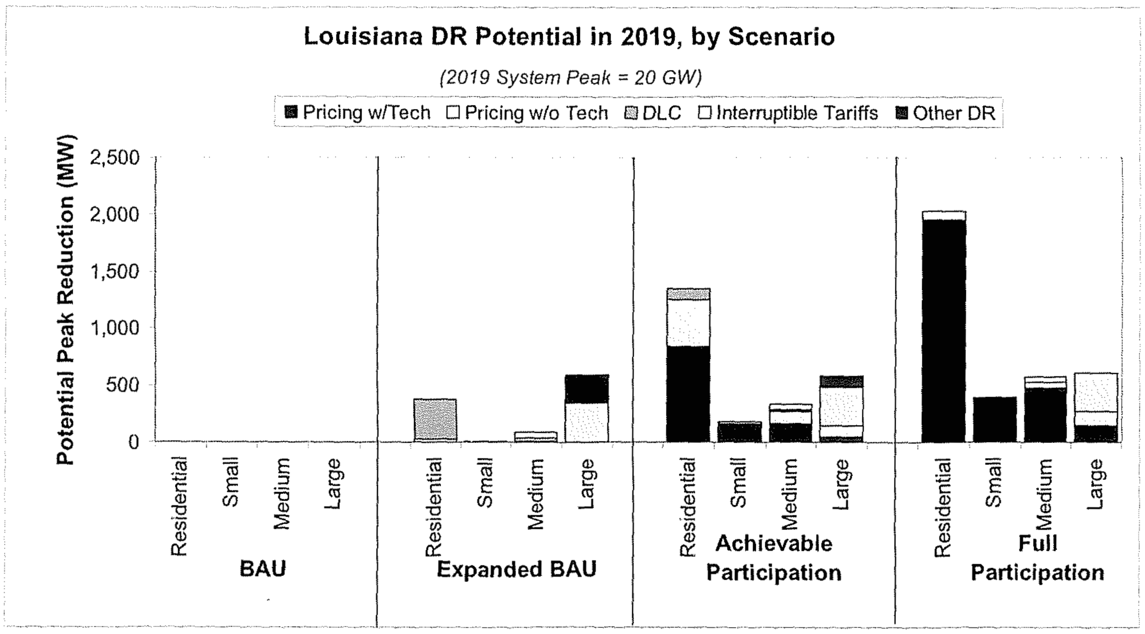
Key drivers of Louisiana's demand response potential estimate include: higher-than-average residential CAC saturation of 75.5 percent, an average customer mix, no existing demand response programs, and the potential to deploy AMI at a slightly slower-than-average rate. Enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: A review of the available data did not identify any existing demand response programs in Louisiana.

Expanded BAU: Growth in demand response impacts under this scenario are driven primarily through the addition of Other DR programs and Interruptible Tariffs for the Large C&I class, and a DLC program for the Residential class. The Residential class has much potential for DLC and dynamic pricing due to its high CAC saturation.

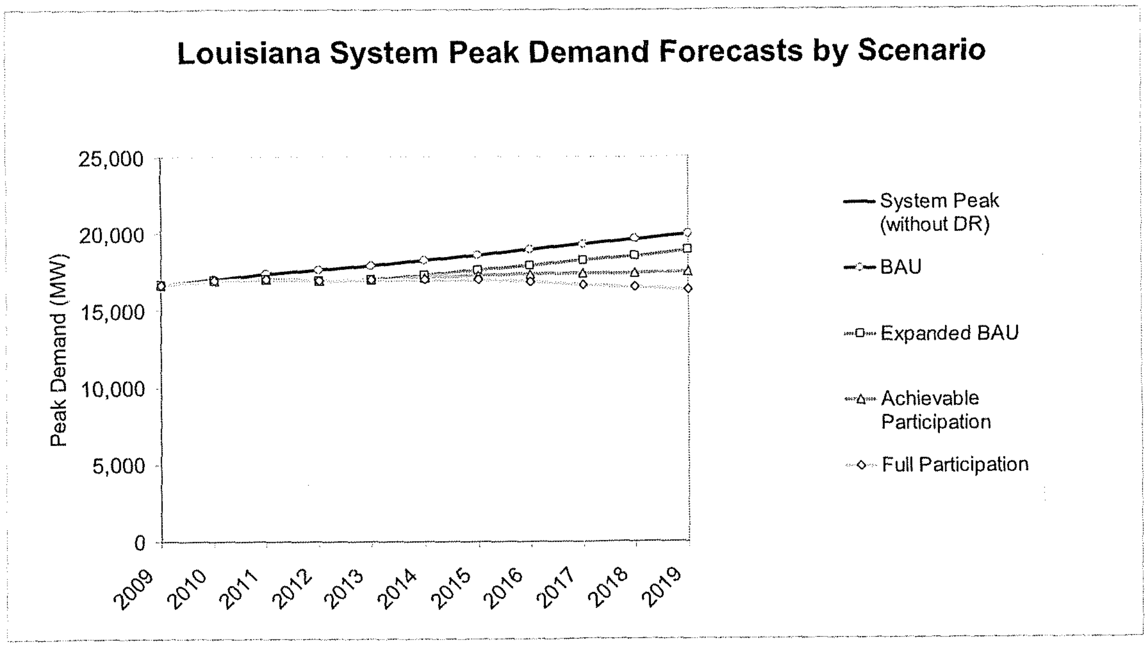
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing with and without enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a significant share of load in the Residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies, which are cost-effective for all customer classes. Lastly, an Interruptible Tariff in the Large C&I class contributes significantly to Louisiana's demand response potential under this scenario.



Total Potential Peak Reduction from Demand Response in Louisiana, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	24	0.1%	0	0.0%	7	0.0%	4	0.0%	35	0.2%
Automated/Direct Load Control	356	1.8%	4	0.0%	38	0.2%	0	0.0%	398	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	244	1.2%	244	1.2%
Total	380	1.9%	5	0.0%	94	0.5%	589	3.0%	1,068	5.4%
Achievable Participation										
Pricing with Technology	837	4.2%	168	0.8%	163	0.8%	51	0.3%	1,220	6.1%
Pricing without Technology	417	2.1%	9	0.0%	109	0.5%	93	0.5%	628	3.1%
Automated/Direct Load Control	91	0.5%	1	0.0%	15	0.1%	0	0.0%	107	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	99	0.5%	100	0.5%
Total	1,345	6.7%	179	0.9%	336	1.7%	585	2.9%	2,445	12.3%
Full Participation										
Pricing with Technology	1,959	9.8%	394	2.0%	477	2.4%	150	0.7%	2,979	14.9%
Pricing without Technology	74	0.4%	5	0.0%	53	0.3%	121	0.6%	252	1.3%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	49	0.2%	342	1.7%	391	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,033	10.2%	399	2.0%	579	2.9%	612	3.1%	3,622	18.1%



Maine State Profile

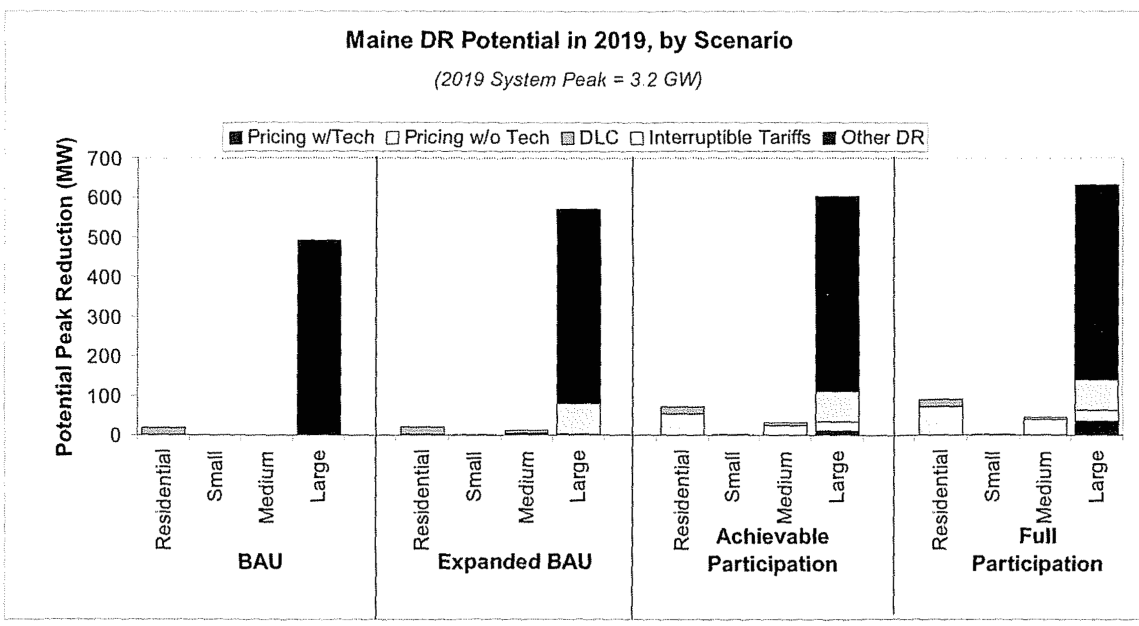
Key drivers of Maine's demand response potential estimate include: lower than average residential CAC saturation of 14%, above average share of peak demand (34%) in the Large C&I classes, and a large amount of existing demand response. Pricing with enabling technologies are only cost effective for the Large C&I class. DLC is cost effective for all classes.

BAU: Maine's existing demand response comes predominantly from the Large C&I class through participation in the ISO New England forward capacity market. These impacts account for over 60% of the total impacts under all scenarios, resulting in smaller incremental differences between BAU and the potential scenarios in comparison to most states.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of interruptible tariffs for the Large C&I class. This is due to Maine's above average share of Large C&I load, which would also allow for some growth in the Other DR category.

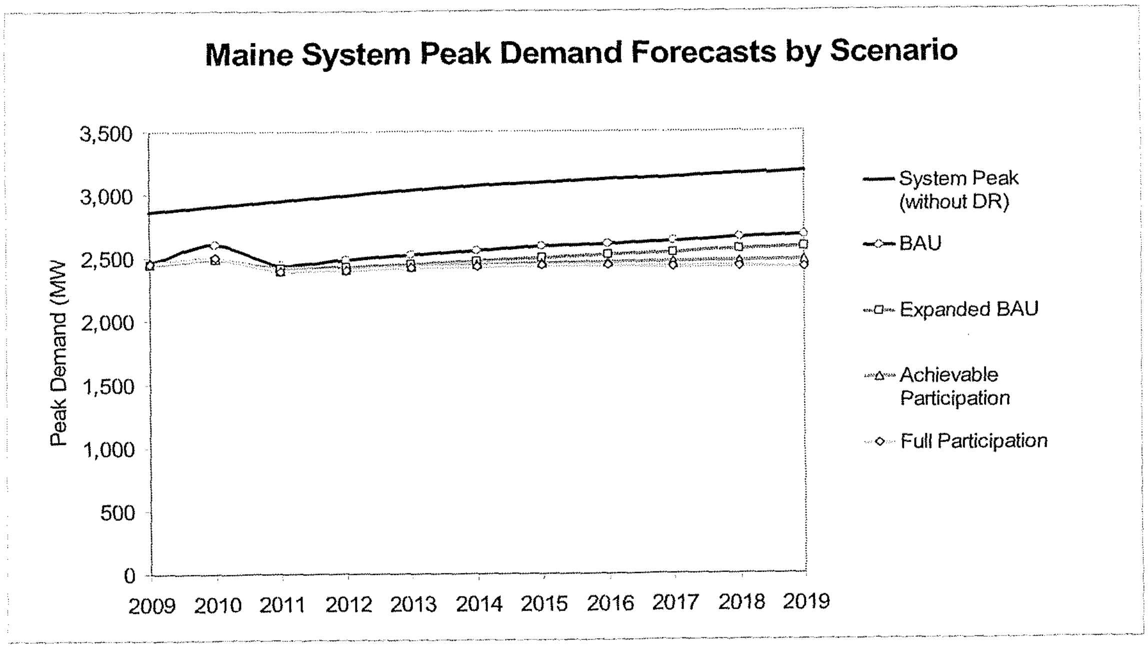
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology, which is cost effective for the Large C&I class, contributes additional potential for that customer group.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by pricing without enabling technologies for all customer classes. For the Large C&I class, pricing with enabling technology also contributes to the total potential.



Total Potential Peak Reduction from Demand Response in Maine, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	18	0.6%	0	0.0%	0	0.0%	492	15.4%	510	16.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	1	0.0%	1	0.0%	4	0.1%
Automated/Direct Load Control	18	0.6%	1	0.0%	5	0.2%	0	0.0%	25	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	20	0.6%	1	0.0%	12	0.4%	571	17.9%	604	19.0%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	12	0.4%	12	0.4%
Pricing without Technology	53	1.7%	1	0.0%	23	0.7%	21	0.7%	99	3.1%
Automated/Direct Load Control	18	0.6%	0	0.0%	2	0.1%	0	0.0%	21	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	72	2.2%	1	0.0%	31	1.0%	603	18.9%	706	22.2%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	34	1.1%	34	1.1%
Pricing without Technology	71	2.2%	1	0.0%	39	1.2%	28	0.9%	139	4.4%
Automated/Direct Load Control	18	0.6%	0	0.0%	0	0.0%	0	0.0%	18	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	5	0.2%	78	2.5%	83	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	492	15.4%	492	15.4%
Total	89	2.8%	1	0.0%	45	1.4%	631	19.8%	766	24.1%



Maryland State Profile

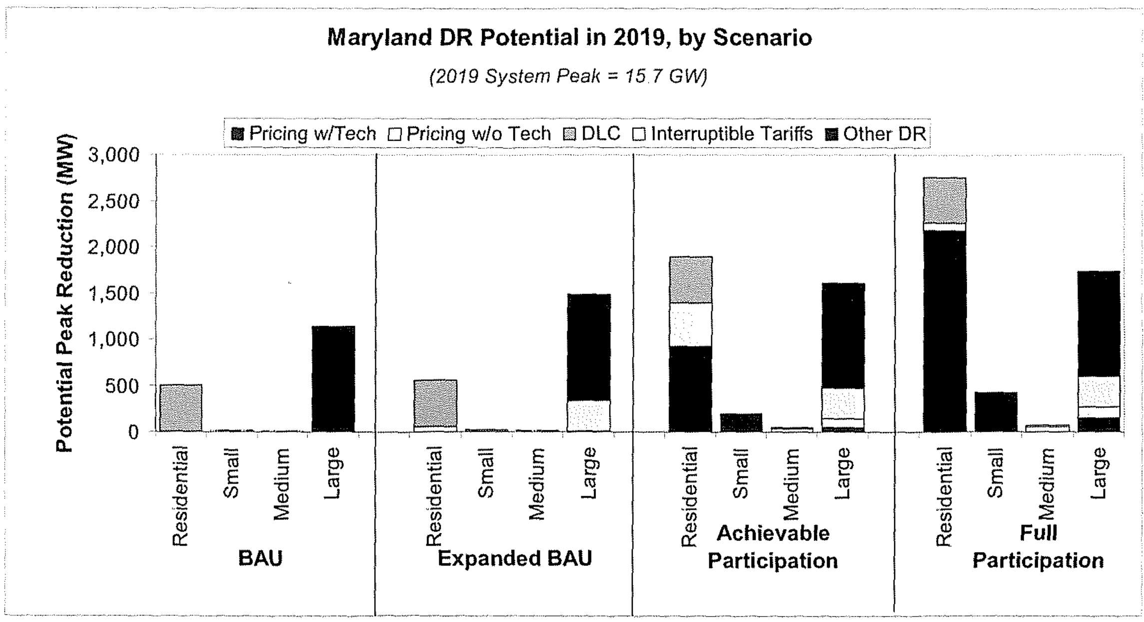
Key drivers of Maryland's demand response potential estimate include: higher-than-average residential CAC saturation of 78%, above average share of peak demand (48%) in the residential class, a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technologies are cost effective for all customer classes, except for the Medium C&I class. DLC is cost effective for all customer classes.

BAU: Maryland's existing demand response comes primarily from residential DLC and Other DR programs for Large C&I customers. The large impacts for Other DR are a due to participation in PJM demand response programs.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of interruptible tariffs for the Large C&I class. The rest of the increase in potential comes from dynamic pricing without enabling technology. Overall, the incremental increase relative to the BAU scenario is small because the state is already achieving significant impacts from non-pricing programs.

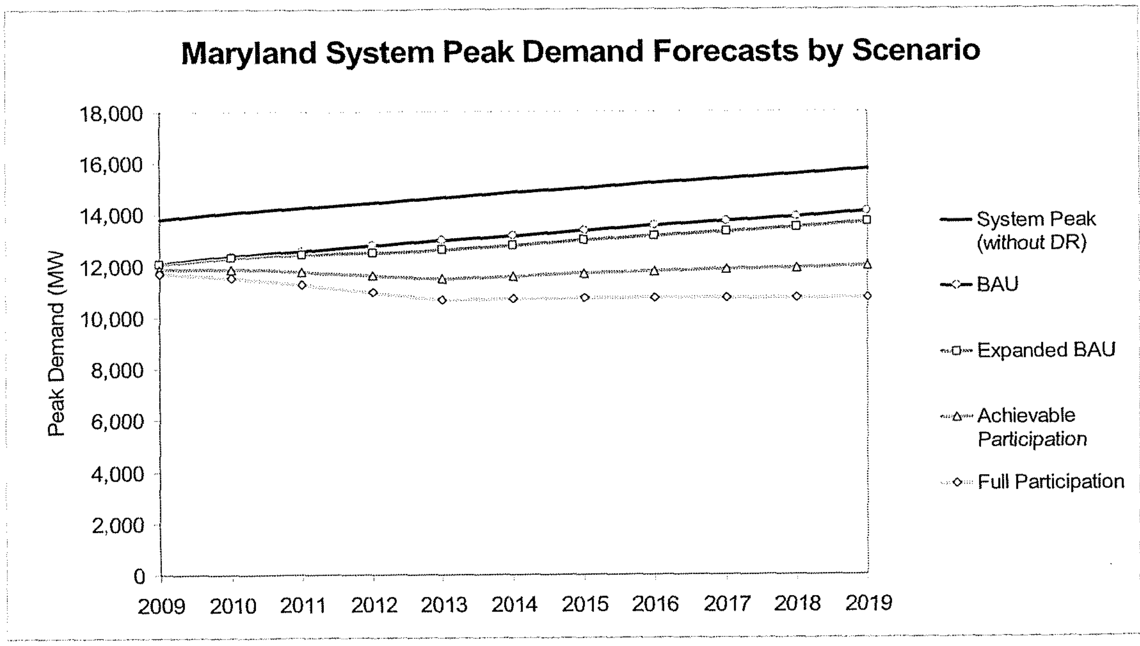
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Growth in dynamic pricing with enabling technologies occurs for all C&I customers except for Medium C&I, as this is the only class for which the option is not cost effective.

Full Participation: Relative to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies for all customer classes except for Medium C&I customers.



Total Potential Peak Reduction from Demand Response in Maryland, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	502	3.2%	13	0.1%	0	0.0%	0	0.0%	515	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	9	0.1%	0	0.0%	9	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	502	3.2%	13	0.1%	9	0.1%	1,143	7.3%	1,667	10.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	54	0.3%	1	0.0%	2	0.0%	8	0.1%	65	0.4%
Automated/Direct Load Control	502	3.2%	20	0.1%	5	0.0%	0	0.0%	528	3.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	556	3.5%	21	0.1%	19	0.1%	1,485	9.4%	2,081	13.2%
Achievable Participation										
Pricing with Technology	933	5.9%	173	1.1%	0	0.0%	50	0.3%	1,156	7.3%
Pricing without Technology	459	2.9%	10	0.1%	34	0.2%	91	0.6%	593	3.8%
Automated/Direct Load Control	502	3.2%	13	0.1%	2	0.0%	0	0.0%	517	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	1,894	12.0%	196	1.2%	47	0.3%	1,618	10.3%	3,755	23.8%
Full Participation										
Pricing with Technology	2,182	13.9%	405	2.6%	0	0.0%	146	0.9%	2,733	17.4%
Pricing without Technology	76	0.5%	5	0.0%	56	0.4%	118	0.7%	255	1.6%
Automated/Direct Load Control	502	3.2%	13	0.1%	0	0.0%	0	0.0%	515	3.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	334	2.1%	345	2.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,143	7.3%	1,143	7.3%
Total	2,760	17.5%	423	2.7%	68	0.4%	1,741	11.1%	4,991	31.7%



Massachusetts State Profile

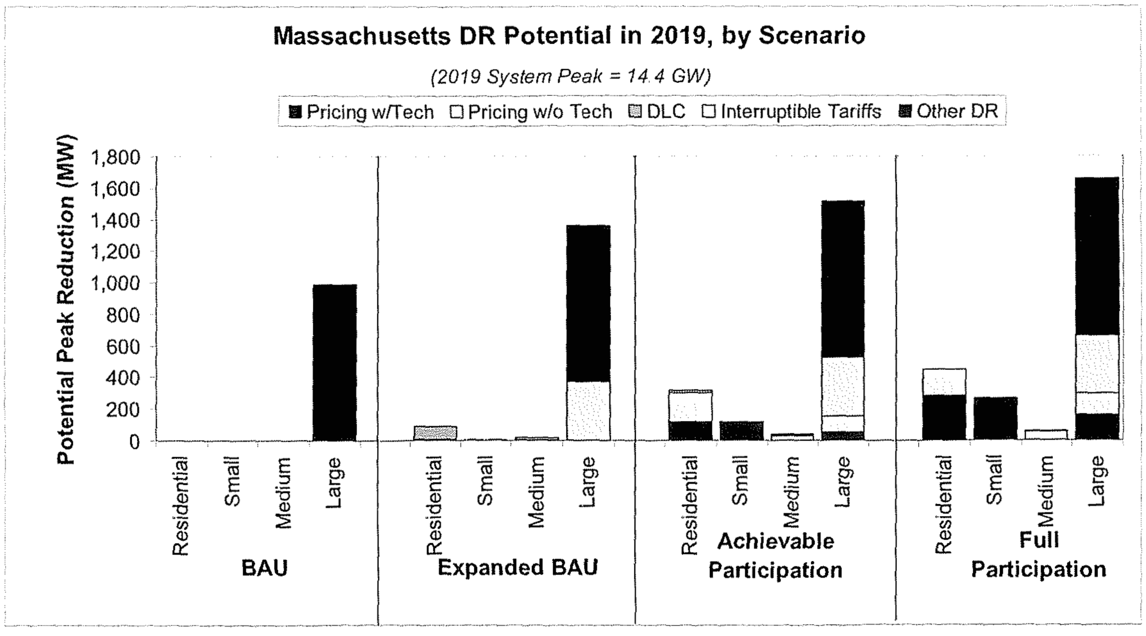
Key drivers of the Massachusetts demand response potential estimate include: significantly lower-than-average residential CAC saturation of 12.7 percent, a customer mix that has an above average share of peak demand in the Large C&I class, a moderate amount of existing Other DR, and an AMI deployment schedule that is anticipated to be slower-than-average. Enabling technologies are cost effective for all classes except the Medium C&I class; DLC technology is cost effective across all customer classes.

BAU: Massachusetts' existing demand response comes entirely from the Large C&I class, which currently has significant enrollment in Other DR, particularly ISO-NE programs.

Expanded BAU: The Expanded BAU scenario includes the addition of an interruptible tariff for the Large C&I class, which can have significant impact due to the high share of Large C&I peak demand in the customer mix. DLC program participation by the Residential class also contributes to Massachusetts' Expanded BAU scenario.

Achievable Participation: Low CAC saturation in the residential sector limits dynamic pricing potential. Furthermore, with enabling technology only cost effective in the Small and Large C&I classes, Other DR in the Large C&I class is still the dominant source of demand response potential.

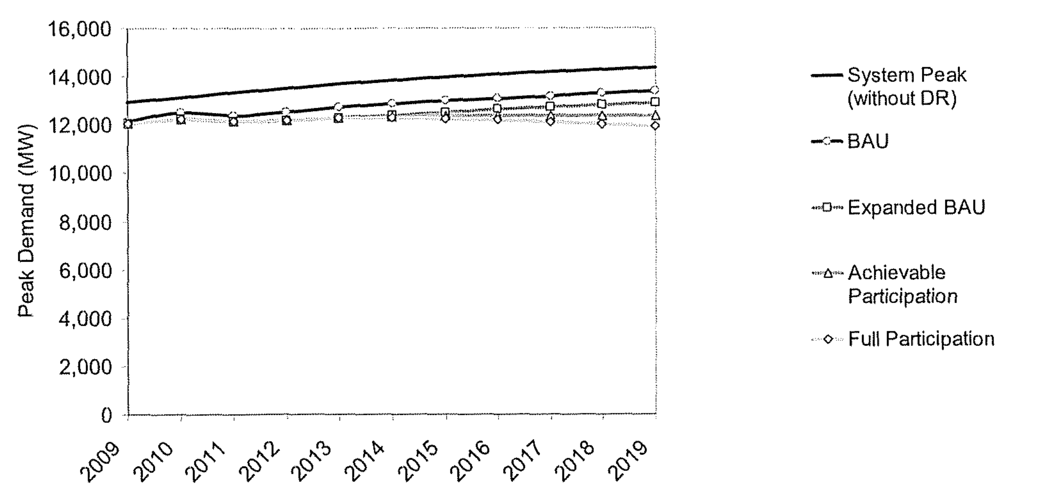
Full Participation: The Full participation scenario is similar to the Achievable Participation scenario, with incremental increases in dynamic pricing potential. The relatively low incremental difference between the BAU scenario and the Full Participation scenario is driven primarily by low CAC saturation and limited cost-effectiveness for enabling technology.



Total Potential Peak Reduction from Demand Response in Massachusetts, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	0	0.0%	1	0.0%	0	0.0%	990	6.9%	991	6.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.0%	1	0.0%	1	0.0%	3	0.0%	8	0.1%
Automated/Direct Load Control	85	0.6%	7	0.0%	8	0.1%	0	0.0%	101	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	90	0.6%	8	0.1%	16	0.1%	1,364	9.5%	1,478	10.3%
Achievable Participation										
Pricing with Technology	121	0.8%	111	0.8%	0	0.0%	56	0.4%	288	2.0%
Pricing without Technology	179	1.2%	7	0.0%	31	0.2%	101	0.7%	319	2.2%
Automated/Direct Load Control	22	0.2%	2	0.0%	3	0.0%	0	0.0%	27	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	322	2.2%	120	0.8%	42	0.3%	1,518	10.6%	2,002	13.9%
Full Participation										
Pricing with Technology	283	2.0%	260	1.8%	0	0.0%	163	1.1%	706	4.9%
Pricing without Technology	169	1.2%	4	0.0%	52	0.4%	131	0.9%	357	2.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	371	2.6%	379	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	990	6.9%	990	6.9%
Total	452	3.1%	264	1.8%	60	0.4%	1,655	11.5%	2,432	16.9%

Massachusetts System Peak Demand Forecasts by Scenario



Michigan State Profile

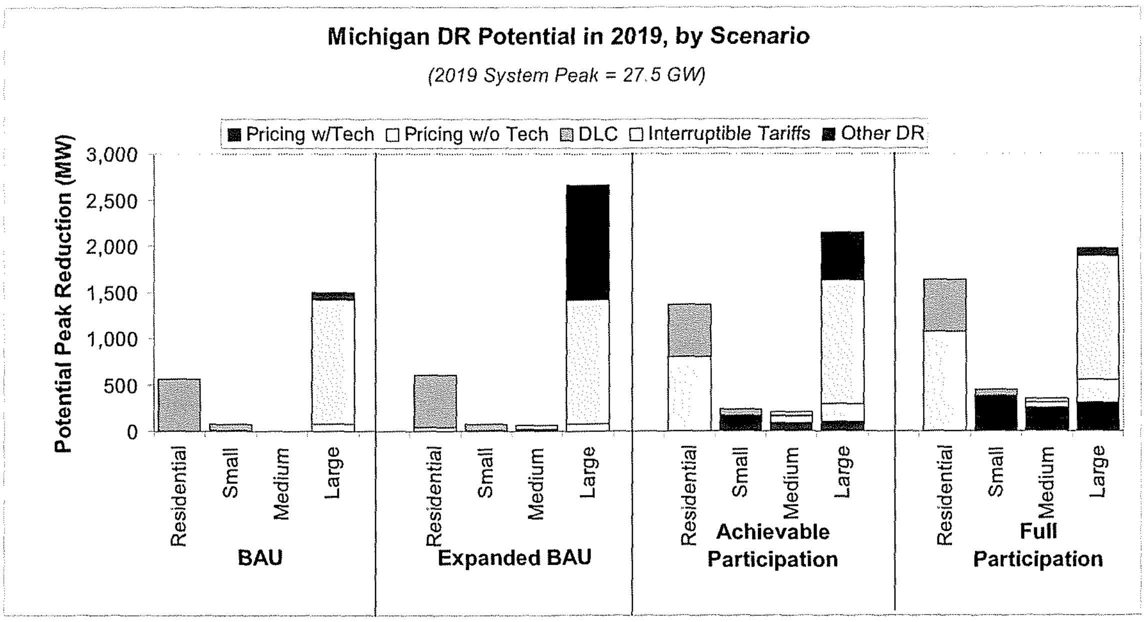
Key drivers of Michigan's demand response potential estimate include: above average residential CAC saturation of 57%, above average share of peak demand (37%) in the Large C&I classes, a large amount of existing demand response, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technologies are cost effective for all customer classes, except for the residential class. DLC is cost effective for all customer classes.

BAU: Michigan's existing demand response comes predominantly from interruptible tariffs for the Large C&I class and represents one of the largest interruptible loads in the country. Interruptible tariffs account for at least 30% of the total potential under all other scenarios. The state is also one of the few states that has a significant portion of price induced demand response.

Expanded BAU: Significant growth in Other DR is due to Michigan's above average share of Large C&I load. The rest of the impacts come from Pricing without technology and DLC for the other customer segments.

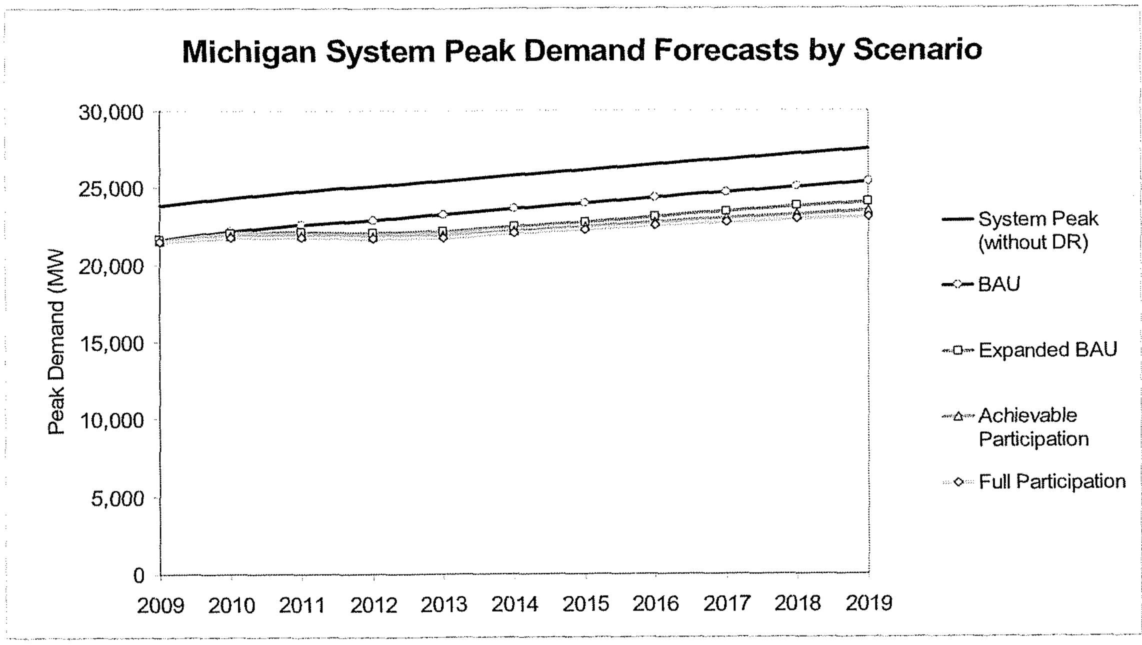
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology which is cost effective for all classes except for the residential sector, contributes additional potential for the C&I customers. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing without enabling technologies for all customer classes. The lower potential for Large C&I than in the other scenarios is due to participation changes within the different demand response options.



Total Potential Peak Reduction from Demand Response in Michigan, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	6	0.0%	0	0.0%	77	0.3%	83	0.3%
Automated/Direct Load Control	570	2.1%	69	0.3%	0	0.0%	0	0.0%	639	2.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	1,339	4.9%	1,341	4.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	0.3%	86	0.3%
Total	570	2.1%	75	0.3%	2	0.0%	1,502	5.5%	2,149	7.8%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	37	0.1%	6	0.0%	7	0.0%	77	0.3%	127	0.5%
Automated/Direct Load Control	570	2.1%	69	0.3%	18	0.1%	0	0.0%	657	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,245	4.5%	1,245	4.5%
Total	607	2.2%	75	0.3%	67	0.2%	2,661	9.7%	3,409	12.4%
Achievable Participation										
Pricing with Technology	0	0.0%	160	0.6%	88	0.3%	105	0.4%	352	1.3%
Pricing without Technology	801	2.9%	10	0.0%	70	0.3%	190	0.7%	1,071	3.9%
Automated/Direct Load Control	570	2.1%	69	0.3%	7	0.0%	0	0.0%	647	2.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	516	1.9%	516	1.9%
Total	1,371	5.0%	238	0.9%	207	0.8%	2,149	7.8%	3,965	14.4%
Full Participation										
Pricing with Technology	0	0.0%	373	1.4%	256	0.9%	306	1.1%	935	3.4%
Pricing without Technology	1,068	3.9%	6	0.0%	48	0.2%	246	0.9%	1,368	5.0%
Automated/Direct Load Control	570	2.1%	69	0.3%	0	0.0%	0	0.0%	639	2.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	42	0.2%	1,339	4.9%	1,380	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	86	0.3%	86	0.3%
Total	1,638	6.0%	448	1.6%	345	1.3%	1,977	7.2%	4,409	16.0%



Minnesota State Profile

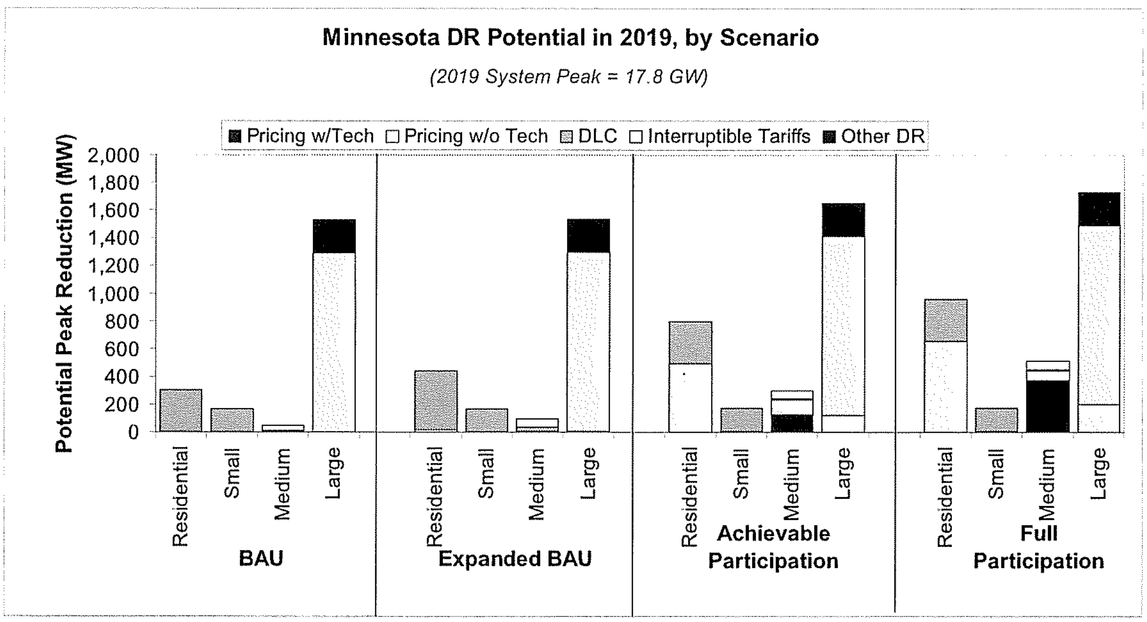
Key drivers of Minnesota's demand response potential estimate include: a substantial amount of existing demand response, above average share of peak demand (30%) in the Large C&I classes and a large residential base. Pricing with enabling technologies is not cost effective for all customer classes, except for the Medium C&I class. DLC is cost effective for all customer classes.

BAU: Minnesota's existing demand response comes primarily from interruptible tariffs and Other DR programs for Medium and Large C&I customers. The savings from interruptible tariffs account for at least 40% of the total impacts under all scenarios, resulting in smaller incremental differences between BAU and the potential scenarios in comparison to most states. The rest of the existing potential comes from direct load control programs for residential and Small and Medium C&I customers.

Expanded BAU: DLC and dynamic pricing without enabling technology account for the growth in potential. Since current participation levels in interruptible tariffs is substantially high, there is not much scope for growth in this program.

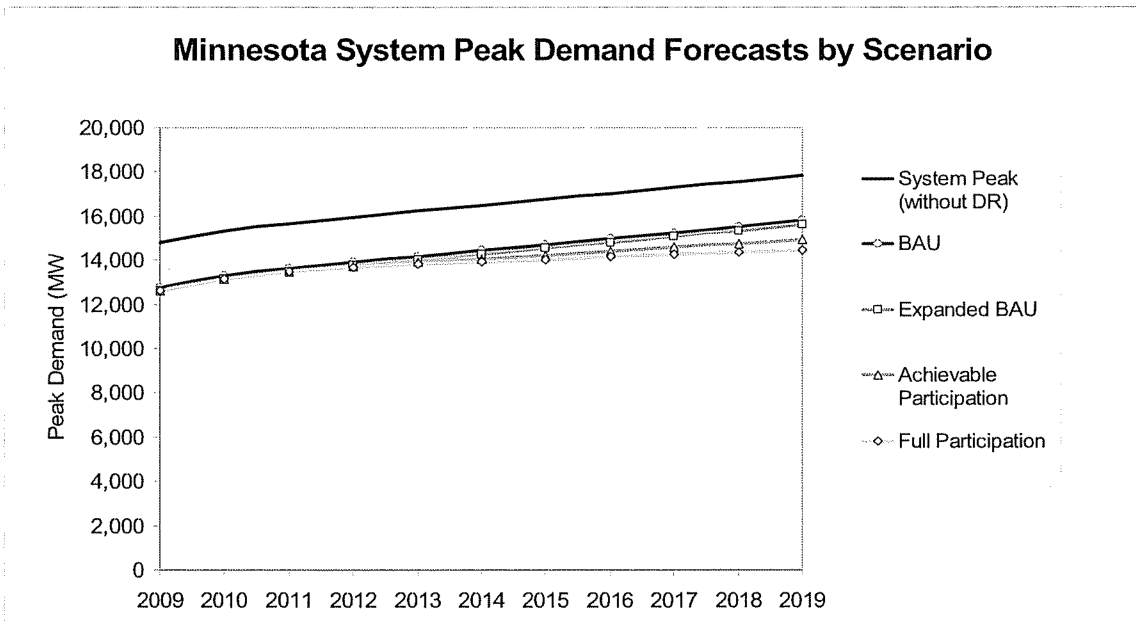
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing without enabling impacts. Dynamic pricing with enabling technology which is cost effective for the Medium C&I class contributes additional savings.

Full Participation: Similar to Achievable Participation, the incremental impacts come from dynamic pricing.



Total Potential Peak Reduction from Demand Response in Minnesota, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	1	0.0%	1	0.0%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	38	0.2%	1,290	7.2%	1,329	7.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	304	1.7%	170	1.0%	49	0.3%	1,533	8.6%	2,056	11.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	15	0.1%	0	0.0%	7	0.0%	5	0.0%	27	0.2%
Automated/Direct Load Control	428	2.4%	170	1.0%	27	0.2%	0	0.0%	626	3.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	443	2.5%	170	1.0%	96	0.5%	1,537	8.6%	2,247	12.6%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	127	0.7%	0	0.0%	127	0.7%
Pricing without Technology	492	2.8%	3	0.0%	102	0.6%	121	0.7%	718	4.0%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	796	4.5%	173	1.0%	302	1.7%	1,653	9.3%	2,924	16.4%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	372	2.1%	0	0.0%	372	2.1%
Pricing without Technology	656	3.7%	4	0.0%	69	0.4%	202	1.1%	931	5.2%
Automated/Direct Load Control	304	1.7%	170	1.0%	11	0.1%	0	0.0%	485	2.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	61	0.3%	1,290	7.2%	1,352	7.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	242	1.4%	242	1.4%
Total	959	5.4%	174	1.0%	514	2.9%	1,734	9.7%	3,381	19.0%



Mississippi State Profile

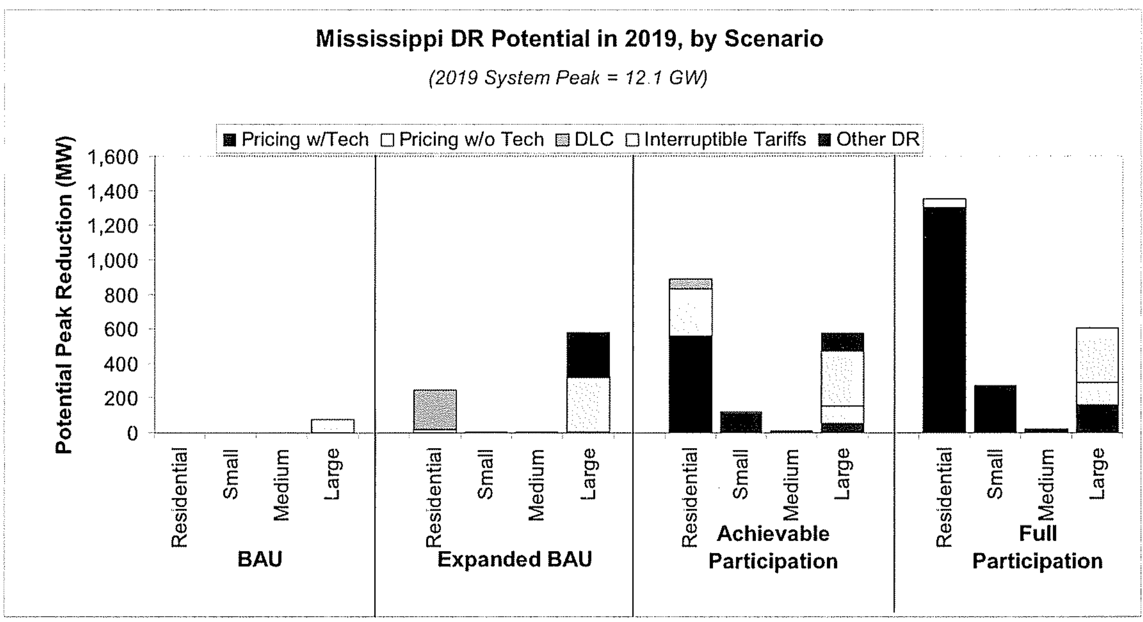
Key drivers of Mississippi's demand response potential estimate include: above average residential CAC saturation of 75% and a customer mix that has an above average share of peak demand in the residential and Large C&I classes (47% and 30%, respectively). Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Mississippi's existing demand response comes solely from interruptible tariffs for the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs for the Large C&I class and DLC for the residential class. Growth in the existing interruptible tariffs accounts for the remaining portion.

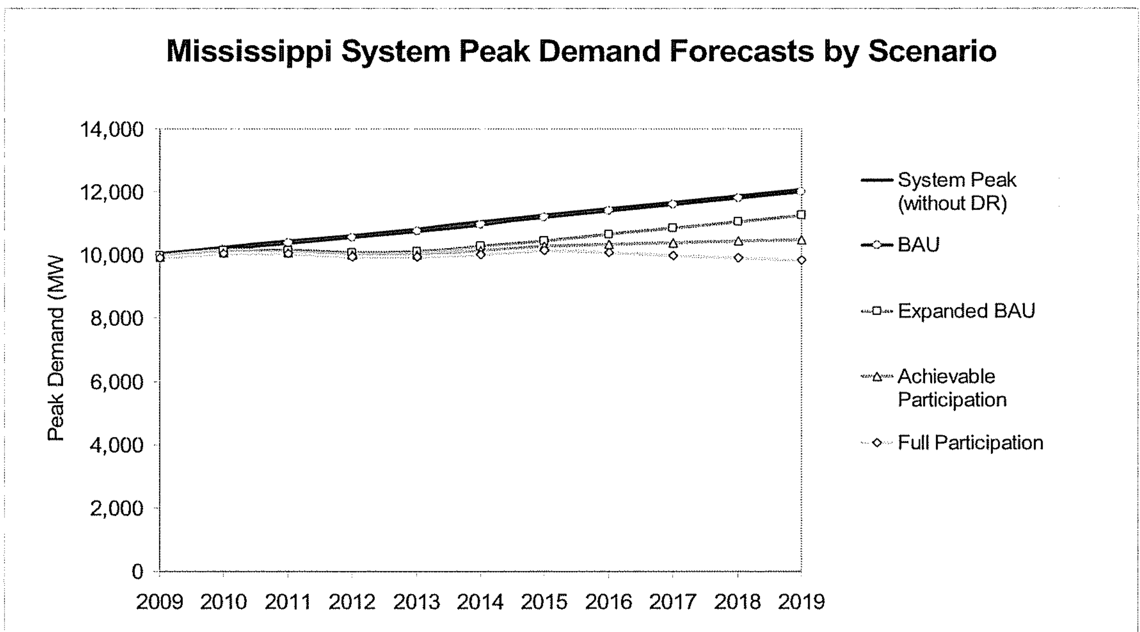
Achievable Participation: Dynamic pricing with enabling impacts accounts for almost 50% of the increase in potential. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing options for all customer classes. Dynamic pricing with enabling represents over 75% of the potential under this scenario. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Mississippi, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	75	0.6%	75	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	75	0.6%	75	0.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	17	0.1%	0	0.0%	0	0.0%	5	0.0%	22	0.2%
Automated/Direct Load Control	230	1.9%	5	0.0%	1	0.0%	0	0.0%	236	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	262	2.2%	262	2.2%
Total	247	2.0%	5	0.0%	3	0.0%	581	4.8%	836	6.9%
Achievable Participation										
Pricing with Technology	557	4.6%	114	0.9%	6	0.0%	55	0.5%	732	6.1%
Pricing without Technology	277	2.3%	6	0.1%	4	0.0%	100	0.8%	387	3.2%
Automated/Direct Load Control	59	0.5%	1	0.0%	0	0.0%	0	0.0%	60	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	107	0.9%	107	0.9%
Total	892	7.4%	122	1.0%	11	0.1%	577	4.8%	1,602	13.3%
Full Participation										
Pricing with Technology	1,303	10.8%	268	2.2%	17	0.1%	161	1.3%	1,748	14.5%
Pricing without Technology	49	0.4%	3	0.0%	2	0.0%	130	1.1%	183	1.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.0%	315	2.6%	316	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,351	11.2%	271	2.2%	20	0.2%	605	5.0%	2,247	18.6%



Missouri State Profile

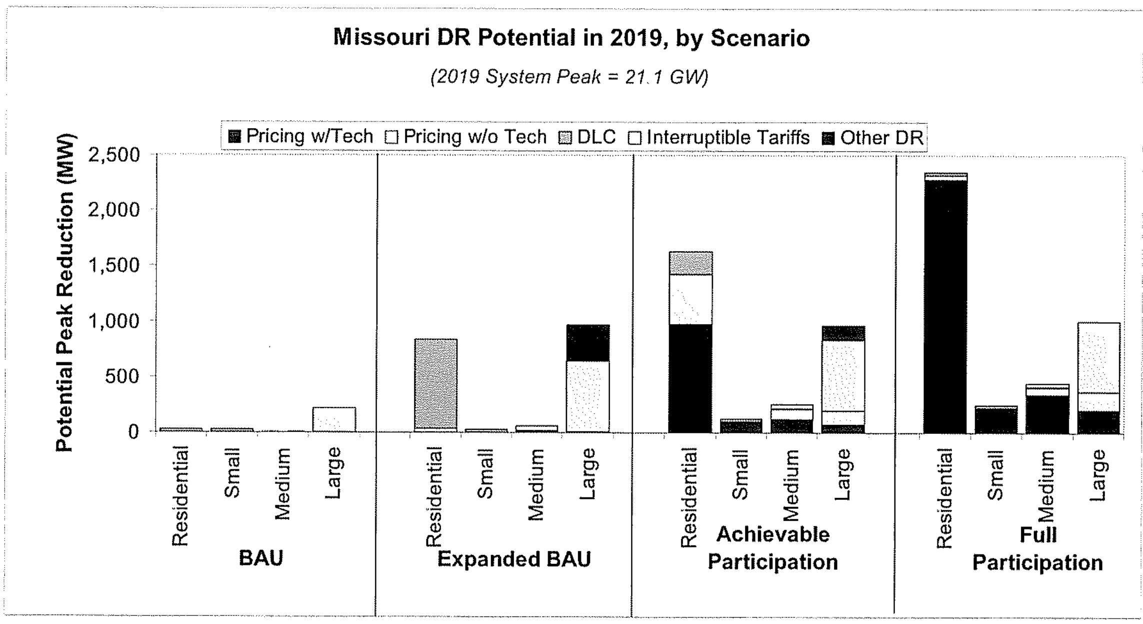
Key drivers of Missouri's demand response potential estimate include: above average residential CAC saturation of 87%, above average share of peak demand (51%) in the residential class, and a moderate amount of existing demand response. Pricing with enabling technologies and DLC are cost effective for all customer classes.

BAU: Missouri's existing demand response comes predominantly from interruptible tariffs for the Large C&I class. Direct load control programs for the other classes account for the remainder.

Expanded BAU: Significant growth in DLC impacts is due to Missouri's above average share of residential load. Growth for the Large C&I class in Other DR and interruptible tariffs account for the remaining portion.

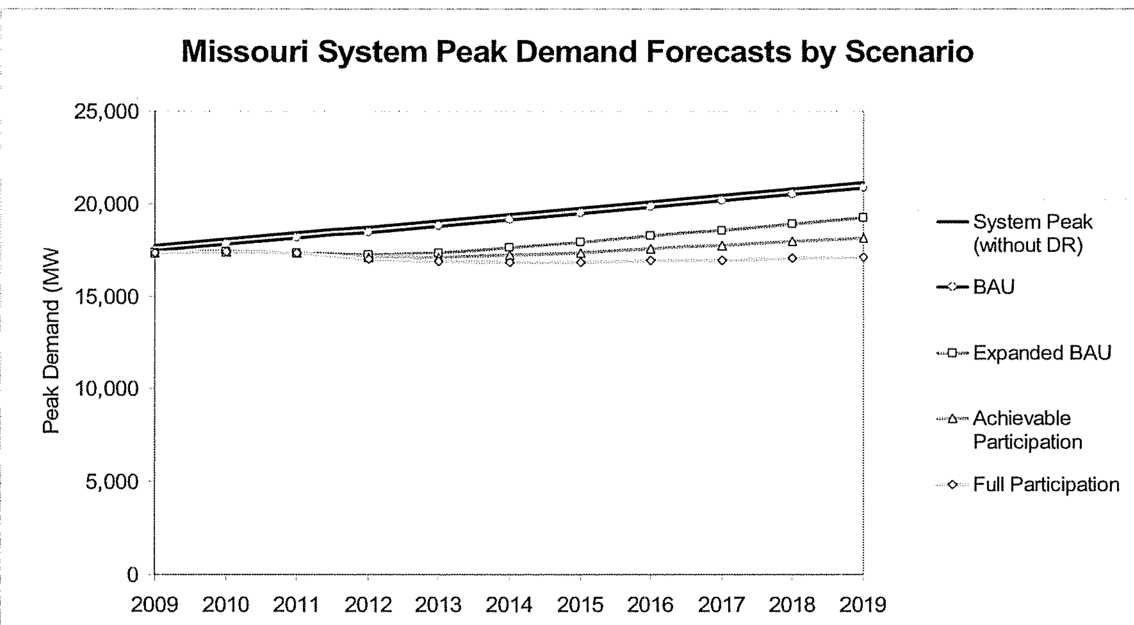
Achievable Participation: The increase in demand response potential comes primarily from dynamic pricing with enabling impacts which is cost effective for all classes. Dynamic pricing without enabling technology contributes additional potential for all customers. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing with enabling option for all customer classes. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Missouri, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	29	0.1%	29	0.1%	5	0.0%	0	0.0%	63	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	219	1.0%	219	1.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	29	0.1%	29	0.1%	5	0.0%	219	1.0%	282	1.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	30	0.1%	0	0.0%	6	0.0%	6	0.0%	43	0.2%
Automated/Direct Load Control	809	3.8%	29	0.1%	13	0.1%	0	0.0%	851	4.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	328	1.6%	328	1.6%
Total	840	4.0%	29	0.1%	58	0.3%	972	4.6%	1,899	9.0%
Achievable Participation										
Pricing with Technology	977	4.6%	93	0.4%	117	0.6%	69	0.3%	1,255	5.9%
Pricing without Technology	450	2.1%	6	0.0%	93	0.4%	126	0.6%	674	3.2%
Automated/Direct Load Control	207	1.0%	29	0.1%	5	0.0%	0	0.0%	241	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	134	0.6%	134	0.6%
Total	1,634	7.7%	127	0.6%	254	1.2%	966	4.6%	2,982	14.1%
Full Participation										
Pricing with Technology	2,285	10.8%	217	1.0%	341	1.6%	202	1.0%	3,045	14.4%
Pricing without Technology	38	0.2%	3	0.0%	64	0.3%	163	0.8%	268	1.3%
Automated/Direct Load Control	29	0.1%	29	0.1%	5	0.0%	0	0.0%	63	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.2%	638	3.0%	677	3.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,352	11.1%	249	1.2%	449	2.1%	1,002	4.7%	4,052	19.2%



Montana State Profile

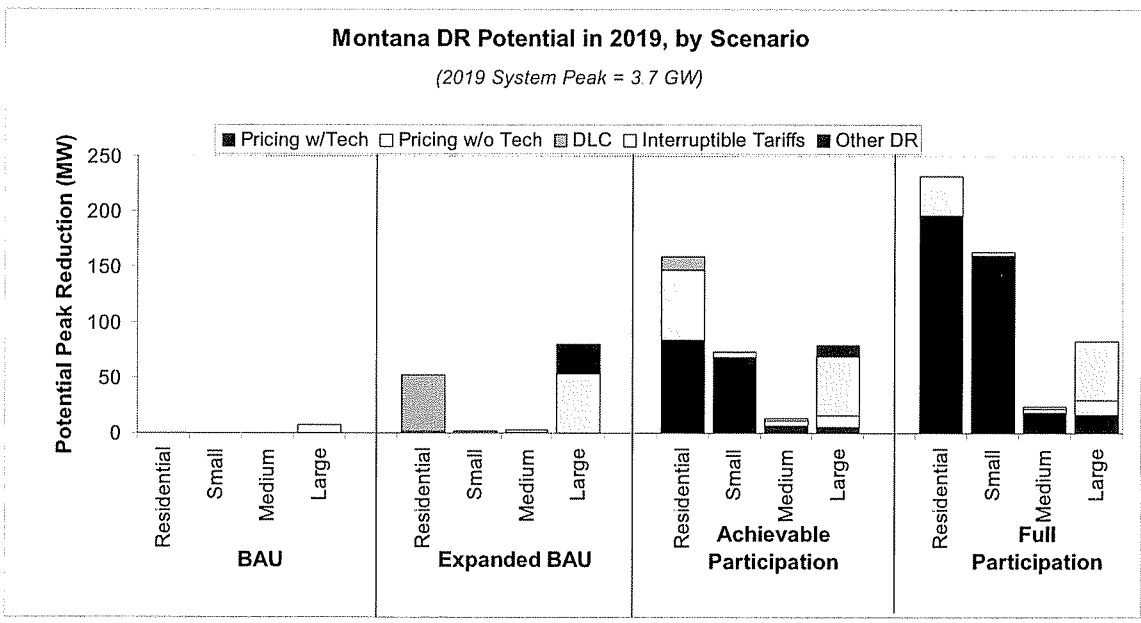
Key drivers of Montana's demand response potential estimate include: a higher than average share of peak demand (53%) in the Small C&I class and a moderate CAC saturation of 42%. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: Montana's existing demand response comes solely from interruptible tariffs for the Large C&I class.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs for the Large C&I class and DLC for the residential and Small C&I classes. Growth in the interruptible tariffs accounts for the remaining portion.

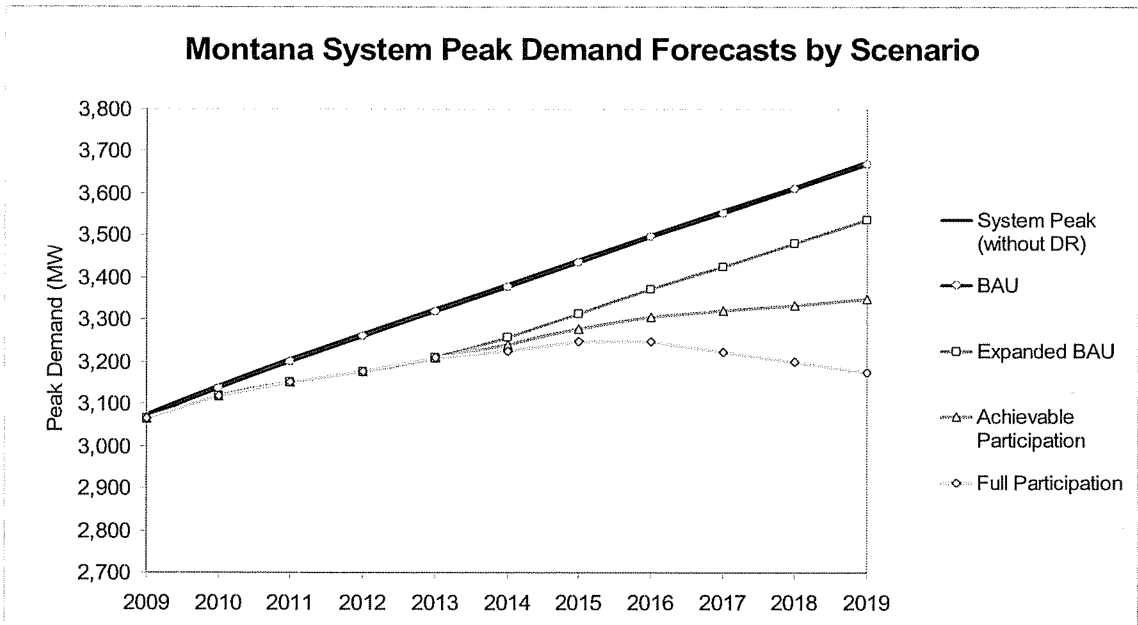
Achievable Participation: Dynamic pricing with enabling impacts accounts for over 50% of the increase in potential, with 20% of this increase due to the potential from Small C&I. Dynamic pricing without enabling technology contributes additional savings.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by the dynamic pricing options for all customer classes. Dynamic pricing with enabling represents almost 80% of the potential under this scenario. This has the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Montana, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	7	0.2%	7	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	7	0.2%	7	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.1%
Automated/Direct Load Control	51	1.4%	2	0.1%	0	0.0%	0	0.0%	53	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	27	0.7%	27	0.7%
Total	52	1.4%	2	0.1%	3	0.1%	80	2.2%	137	3.7%
Achievable Participation										
Pricing with Technology	84	2.3%	69	1.9%	6	0.2%	6	0.2%	164	4.5%
Pricing without Technology	63	1.7%	5	0.1%	5	0.1%	10	0.3%	82	2.2%
Automated/Direct Load Control	13	0.3%	1	0.0%	0	0.0%	0	0.0%	14	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	11	0.3%	11	0.3%
Total	160	4.3%	74	2.0%	13	0.4%	80	2.2%	326	8.9%
Full Participation										
Pricing with Technology	196	5.3%	160	4.4%	18	0.5%	16	0.4%	391	10.7%
Pricing without Technology	35	1.0%	3	0.1%	3	0.1%	13	0.4%	55	1.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.1%	53	1.4%	55	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	232	6.3%	163	4.4%	24	0.6%	83	2.2%	501	13.6%



Nebraska State Profile

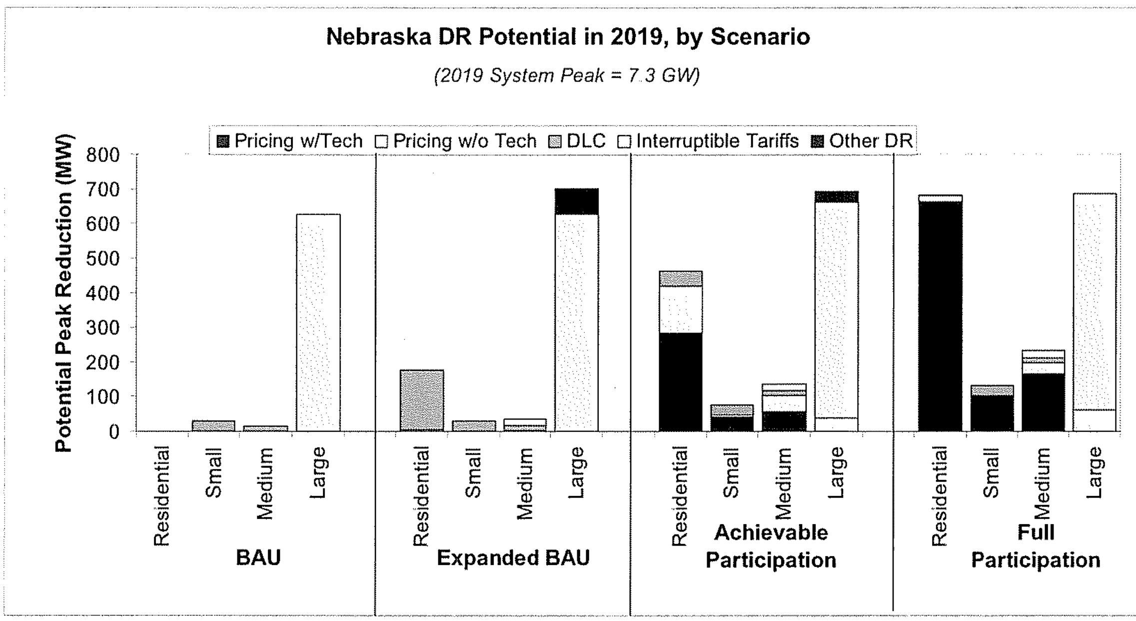
Key drivers of Nebraska's demand response potential estimate include: higher-than-average residential CAC saturation of 83%, a customer mix that has a moderate share of peak demand in the residential and Medium C&I classes (40% and 27%, respectively) and a substantial amount of existing demand response. Pricing with enabling technologies are cost effective for all customer classes, except for the Large C&I class. DLC is cost effective for all customer classes.

BAU: Nebraska's existing demand response comes predominantly from interruptible tariffs for Large C&I customers. The impacts from this option represent at least 30% of the total impacts under all scenarios. DLC for Small & Medium C&I accounts for the remaining portion of existing demand response.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of Other DR for the Large C&I class and DLC for the residential class.

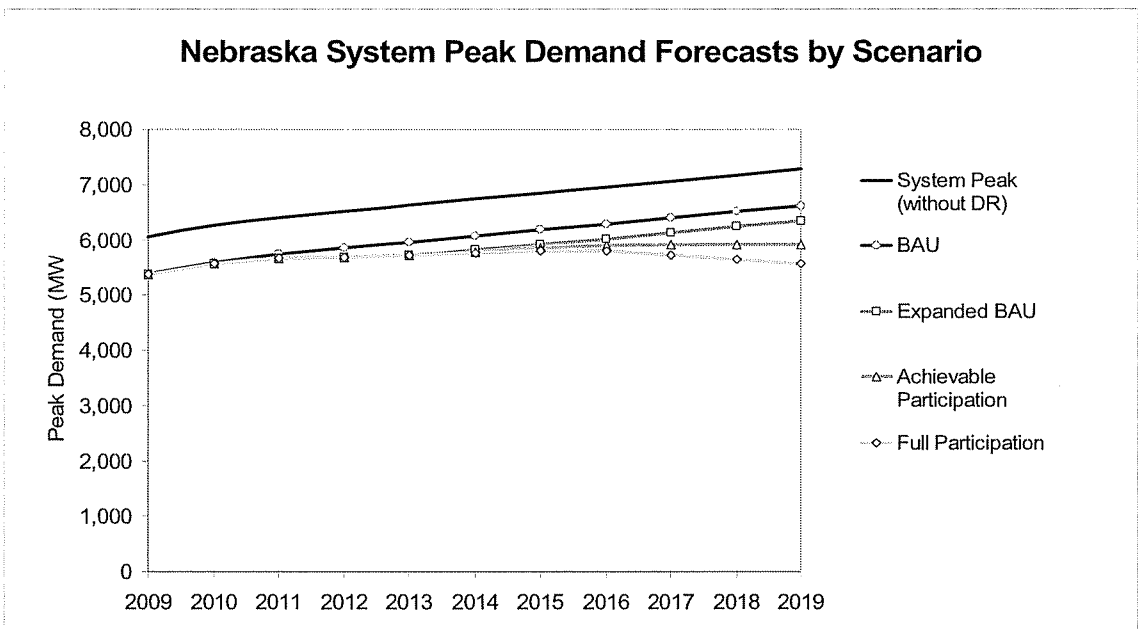
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through dynamic pricing with enabling technologies. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a moderate share of load in the residential sector drives the increase in impacts. The impacts are dominated by pricing with enabling technologies for all customer classes except for the Large C&I customers. The pricing options have the effect of reducing or eliminating the potential from all of the other demand response options, in particular, DLC and Other DR.



Total Potential Peak Reduction from Demand Response in Nebraska, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	1	0.0%	30	0.4%	15	0.2%	0	0.0%	46	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	625	8.6%	625	8.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1	0.0%	30	0.4%	15	0.2%	625	8.6%	671	9.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	1	0.0%	1	0.0%	6	0.1%
Automated/Direct Load Control	172	2.4%	30	0.4%	15	0.2%	0	0.0%	217	3.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	75	1.0%	75	1.0%
Total	176	2.4%	30	0.4%	35	0.5%	701	9.6%	943	12.9%
Achievable Participation										
Pricing with Technology	284	3.9%	43	0.6%	57	0.8%	0	0.0%	384	5.3%
Pricing without Technology	135	1.9%	3	0.0%	46	0.6%	37	0.5%	220	3.0%
Automated/Direct Load Control	44	0.6%	30	0.4%	15	0.2%	0	0.0%	89	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	30	0.4%	30	0.4%
Total	462	6.3%	76	1.0%	137	1.9%	693	9.5%	1,367	18.8%
Full Participation										
Pricing with Technology	664	9.1%	100	1.4%	167	2.3%	0	0.0%	931	12.8%
Pricing without Technology	17	0.2%	2	0.0%	31	0.4%	61	0.8%	111	1.5%
Automated/Direct Load Control	1	0.0%	30	0.4%	15	0.2%	0	0.0%	46	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	19	0.3%	625	8.6%	645	8.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	681	9.3%	132	1.8%	232	3.2%	687	9.4%	1,732	23.8%



Nevada State Profile

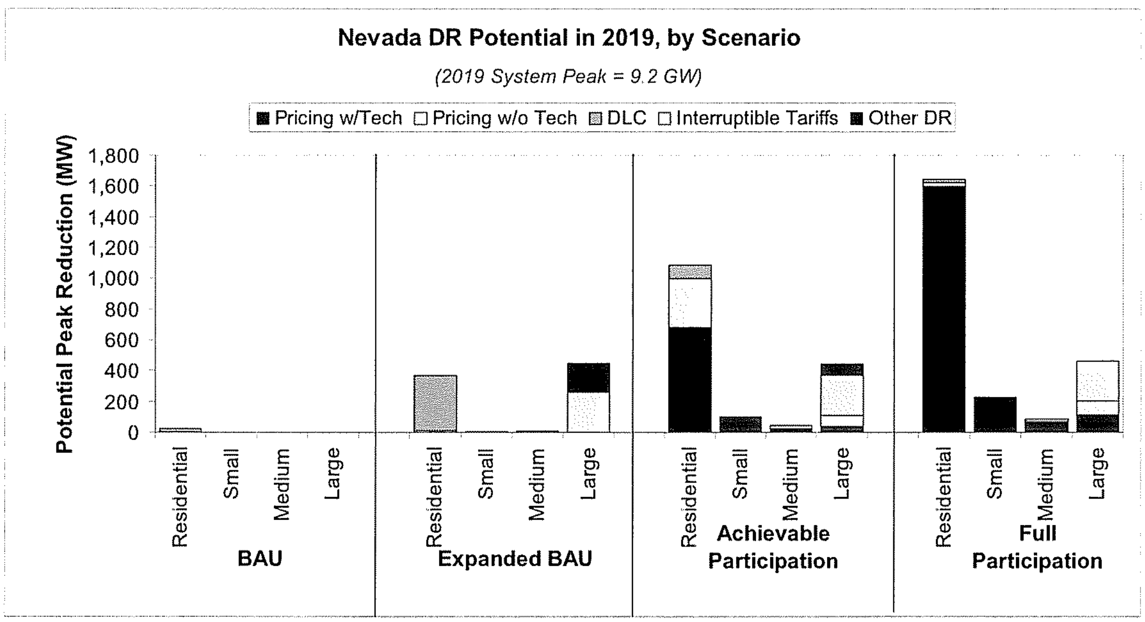
Key drivers of Nevada's demand response potential estimate include: a very high residential CAC saturation of 87%, and a customer mix that has an above average share of peak demand in the residential sector. The rate of AMI deployment is likely to be at a lower-than-average rate. Dynamic pricing with enabling technology and DLC are cost effective for all customer classes in the state. Control of residential air-conditioning load is the key driver of demand response potential in Nevada.

BAU: Nevada's existing demand response comes primarily from residential DLC programs. However, current participation levels are low and there exists scope for significant growth in potential.

Expanded BAU: Growth in demand response impacts is driven primarily through substantial expansion in residential DLC programs due to very high levels of CAC saturation in the state. Impacts also grow due to large C&I participation in 'Interruptible' and 'Other DR' programs.

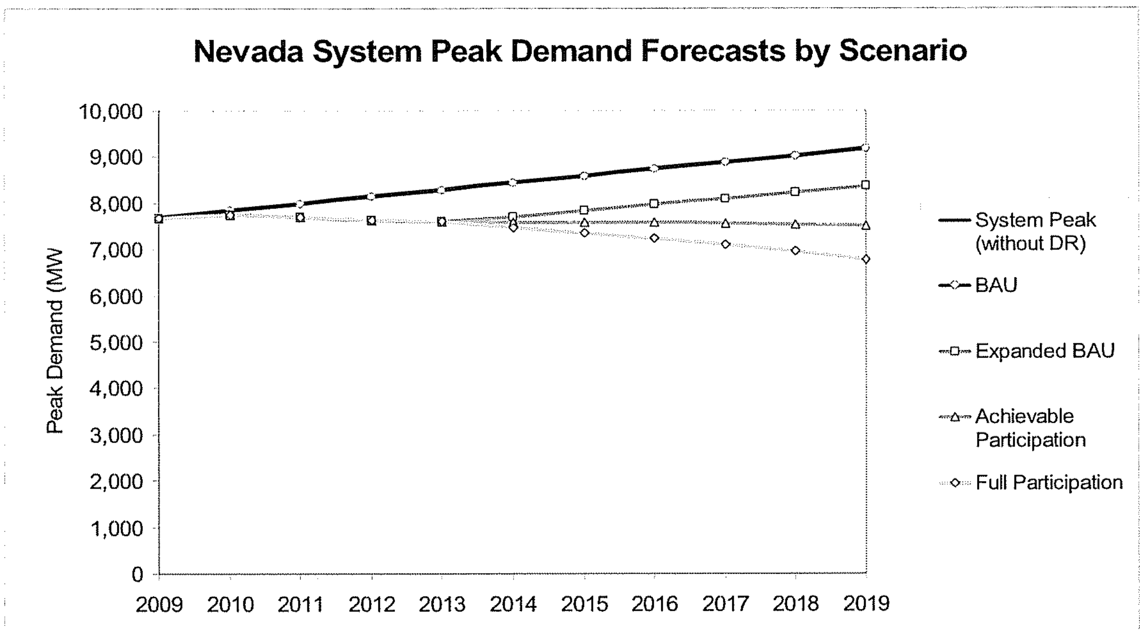
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through pricing programs. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of residential load leads to substantial increase in impacts. The impacts are dominated by pricing with enabling technologies. Small and medium C&I potential from pricing programs increase. Large C&I potential is lower than in the Achievable scenario. This is because customers choose dynamic pricing over 'Other DR' programs, leading to a lower level of impacts caused by smaller per-customer impacts from pricing programs relative to 'Other DR'.



Total Potential Peak Reduction from Demand Response in Nevada, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	12	0.1%	0	0.0%	1	0.0%	2	0.0%	14	0.2%
Automated/Direct Load Control	356	3.9%	4	0.0%	2	0.0%	0	0.0%	363	3.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	186	2.0%	186	2.0%
Total	368	4.0%	4	0.0%	10	0.1%	447	4.9%	830	9.0%
Achievable Participation										
Pricing with Technology	682	7.4%	94	1.0%	23	0.2%	39	0.4%	838	9.1%
Pricing without Technology	313	3.4%	6	0.1%	17	0.2%	71	0.8%	407	4.4%
Automated/Direct Load Control	90	1.0%	1	0.0%	1	0.0%	0	0.0%	92	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	75	0.8%	75	0.8%
Total	1,085	11.8%	102	1.1%	49	0.5%	444	4.8%	1,679	18.3%
Full Participation										
Pricing with Technology	1,596	17.4%	221	2.4%	67	0.7%	113	1.2%	1,996	21.7%
Pricing without Technology	25	0.3%	4	0.0%	11	0.1%	91	1.0%	131	1.4%
Automated/Direct Load Control	22	0.2%	0	0.0%	0	0.0%	0	0.0%	22	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	7	0.1%	259	2.8%	267	2.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,642	17.9%	225	2.4%	85	0.9%	464	5.1%	2,416	26.3%



New Hampshire State Profile

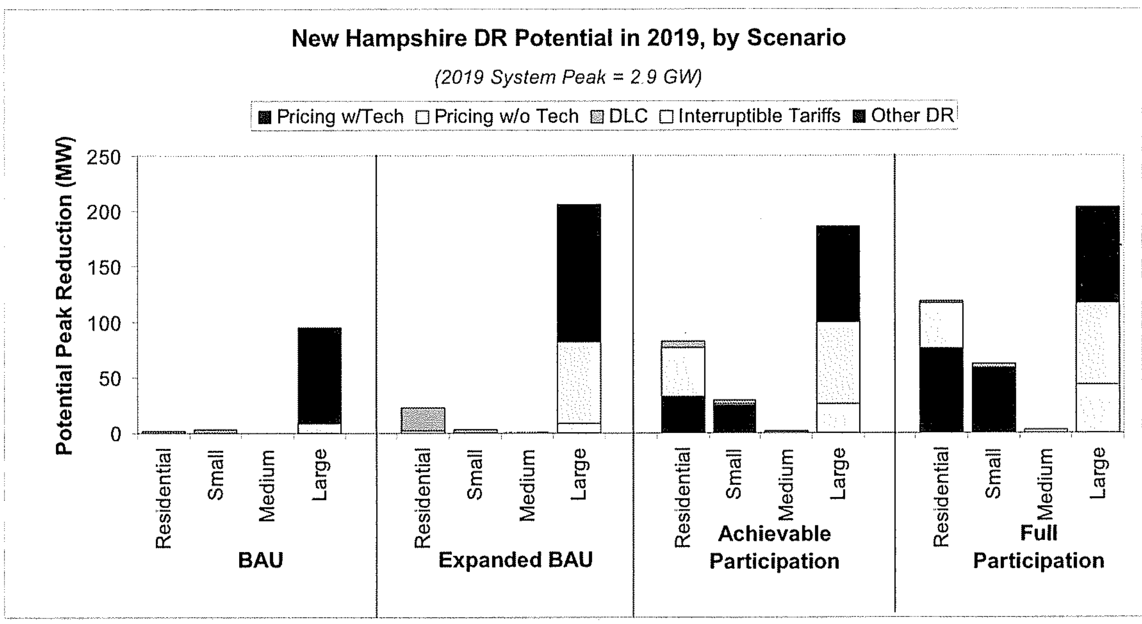
Key drivers of New Hampshire's demand response potential estimate include: a higher than average share of large C&I peak load (33%) and large base of existing load participation in the ISO-NE market. It has a lower than national average residential CAC saturation at 13%, thereby limiting load reduction potential from DLC programs. Dynamic pricing with enabling technology is cost-effective only for residential and small C&I customers. DLC is cost-effective for all customer classes.

BAU: New Hampshire's existing demand response is primarily derived from 'Other DR' programs, due to large C&I load participation in the ISO-NE market.

Expanded BAU: Growth in demand response impacts is driven primarily through the growth of Interruptible programs for large C&I customers. This is due to Rhode Island's high share of large C&I load, which allow for growth in Interruptible programs. Potential for growth in 'Other DR' programs is limited due to current high participation levels. Load reductions from residential DLC programs also grow in this scenario.

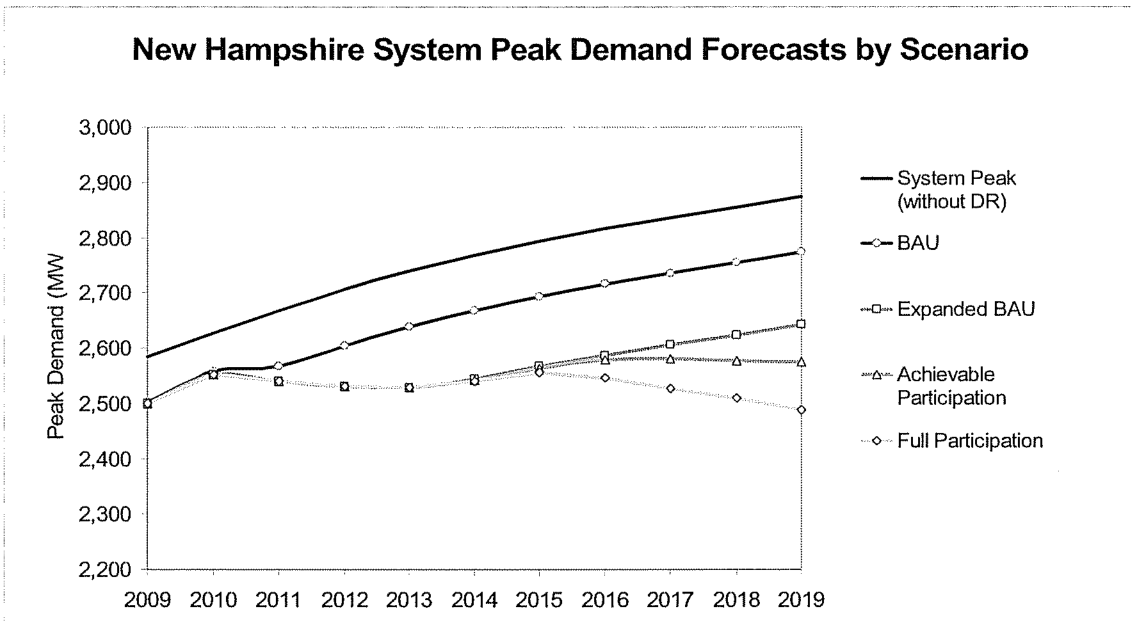
Achievable Participation: Growth in impacts in this scenario is driven by the potential derived through 'pricing without technology' option, primarily from residential and large C&I customers. Growth in impacts from 'pricing with technology' comes from both residential and small C&I customers. 'Other DR' program potential remains at current high levels.

Full Participation: Similar to the Achievable Participation scenario, increase in residential and small C&I customer participation in pricing options drive increase in impacts. Contribution from 'Other DR' and Interruptible programs continues to dominate for large C&I customers.



Total Potential Peak Reduction from Demand Response in New Hampshire, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	9	0.3%	9	0.3%
Automated/Direct Load Control	2	0.1%	3	0.1%	0	0.0%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	2	0.1%	3	0.1%	0	0.0%	95	3.3%	101	3.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	9	0.3%	11	0.4%
Automated/Direct Load Control	21	0.7%	3	0.1%	0	0.0%	0	0.0%	24	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	124	4.3%	124	4.3%
Total	23	0.8%	3	0.1%	1	0.0%	206	7.2%	233	8.1%
Achievable Participation										
Pricing with Technology	32	1.1%	25	0.9%	0	0.0%	0	0.0%	57	2.0%
Pricing without Technology	45	1.6%	2	0.1%	2	0.1%	26	0.9%	74	2.6%
Automated/Direct Load Control	5	0.2%	3	0.1%	0	0.0%	0	0.0%	9	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	82	2.9%	30	1.0%	2	0.1%	186	6.5%	300	10.4%
Full Participation										
Pricing with Technology	76	2.6%	58	2.0%	0	0.0%	0	0.0%	134	4.7%
Pricing without Technology	41	1.4%	1	0.0%	3	0.1%	43	1.5%	88	3.0%
Automated/Direct Load Control	2	0.1%	3	0.1%	0	0.0%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	74	2.6%	74	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	87	3.0%	87	3.0%
Total	119	4.1%	62	2.2%	3	0.1%	203	7.1%	387	13.5%



New Jersey State Profile

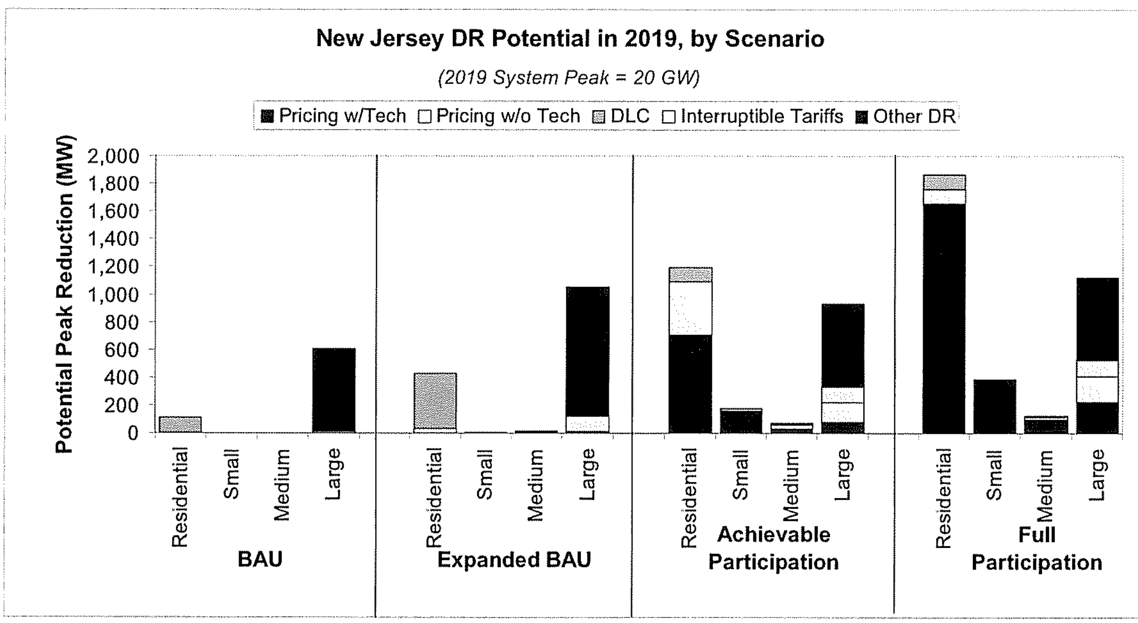
Key drivers of New Jersey's demand response potential estimate include: high levels of large C&I load participation in the PJM market, a customer mix with almost 48% of the load from residential customers and 26% of the load from large C&I customers, and the potential to deploy AMI at a faster-than-average rate. CAC saturation is at a moderate level of 55%. 'Pricing with technology' is cost-effective for all customer classes. DLC is also cost effective for all customer classes in the state.

BAU: New Jersey's existing demand response comes primarily from large C&I load participation in the PJM market. The remaining comes from residential DLC programs.

Expanded BAU: Increase in impacts for this scenario is primarily due to expansion in residential DLC programs and Interruptible programs for large C&I customers, driven by large share in load for these two customer classes. Also, the potential associated with large C&I participation in 'Other DR' programs grows.

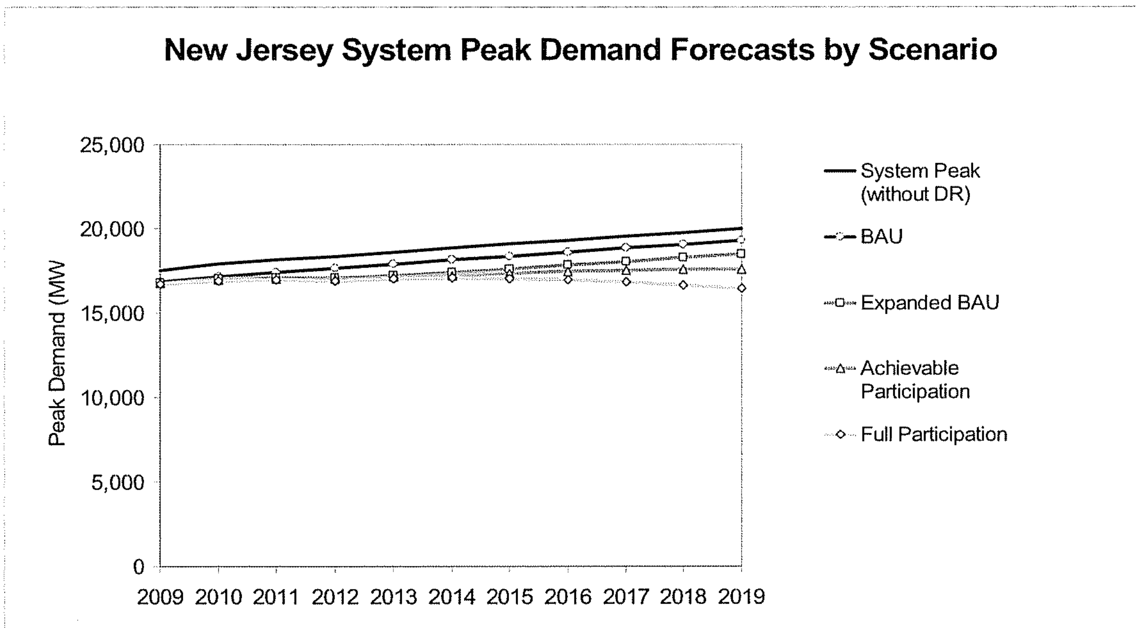
Achievable Participation: A high share of residential load in the total drives a substantial increase in impacts for residential customers through participation in pricing programs. In this scenario, impacts from residential DLC go back to current levels as customers choose pricing over DLC. For C&I customers, additional load reduction is obtained through pricing programs.

Full Participation: Similar to the Achievable Participation scenario, high impacts in this scenario are largely driven by a high level of residential load participating in pricing programs. Also, load reduction from C&I customers participating in pricing programs increases. Large C&I load participation in 'Other DR' programs continues at current high participation levels.



Total Potential Peak Reduction from Demand Response in New Jersey, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	108	0.5%	0	0.0%	0	0.0%	0	0.0%	108	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	108	0.5%	0	0.0%	0	0.0%	609	3.0%	717	3.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	29	0.1%	1	0.0%	2	0.0%	9	0.0%	41	0.2%
Automated/Direct Load Control	401	2.0%	7	0.0%	3	0.0%	0	0.0%	411	2.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	933	4.7%	933	4.7%
Total	430	2.2%	8	0.0%	17	0.1%	1,054	5.3%	1,508	7.5%
Achievable Participation										
Pricing with Technology	709	3.5%	164	0.8%	34	0.2%	78	0.4%	985	4.9%
Pricing without Technology	381	1.9%	10	0.1%	26	0.1%	142	0.7%	559	2.8%
Automated/Direct Load Control	108	0.5%	2	0.0%	1	0.0%	0	0.0%	111	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	1,198	6.0%	176	0.9%	73	0.4%	932	4.7%	2,379	11.9%
Full Participation										
Pricing with Technology	1,659	8.3%	384	1.9%	99	0.5%	227	1.1%	2,369	11.9%
Pricing without Technology	100	0.5%	6	0.0%	17	0.1%	183	0.9%	307	1.5%
Automated/Direct Load Control	108	0.5%	0	0.0%	0	0.0%	0	0.0%	108	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	11	0.1%	112	0.6%	123	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	601	3.0%	601	3.0%
Total	1,867	9.3%	390	2.0%	127	0.6%	1,124	5.6%	3,508	17.5%



New Mexico State Profile

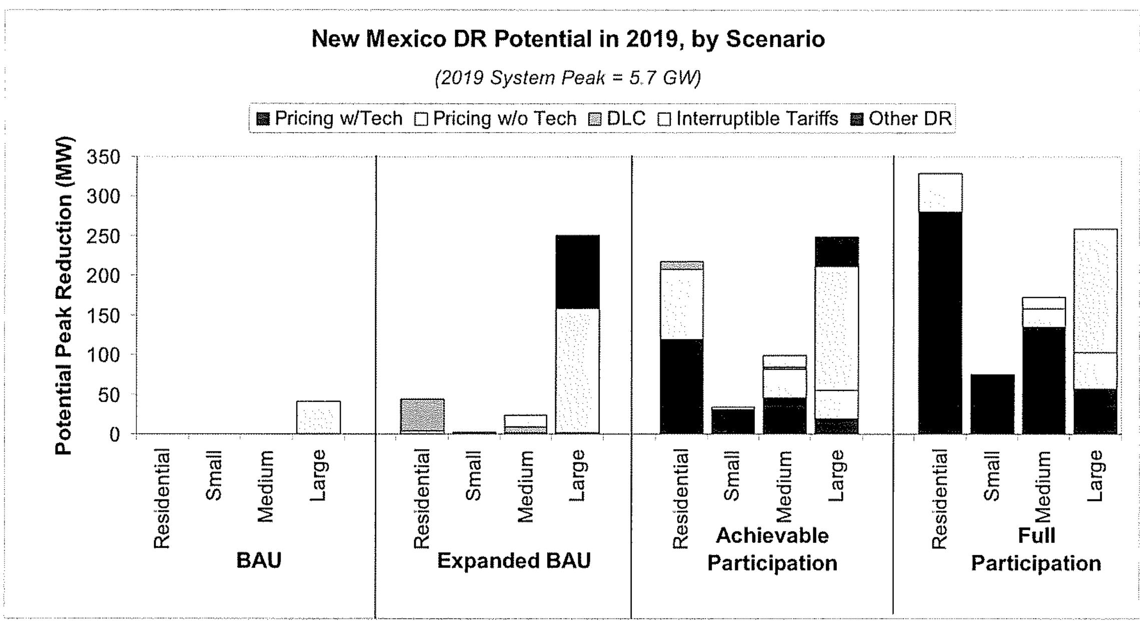
Key drivers of New Mexico's demand response potential estimate include: a customer mix that has an above average share of peak demand for medium C&I customers (50%), and a large share of residential (86%) in the total number of customer accounts. New Mexico has a low level of existing demand response with significant potential for growth across all rate classes. Dynamic pricing with enabling technology is cost-effective for all customer classes. Also, DLC is cost effective for all customer classes.

BAU: The state's existing demand response comes primarily from large C&I participation in Interruptible programs.

Expanded BAU: Growth in demand response potential under this scenario is derived through residential participation in DLC programs, and large C&I load participation in Interruptible and 'Other DR' programs. The potential for expansion is significant, given the low level of existing demand response.

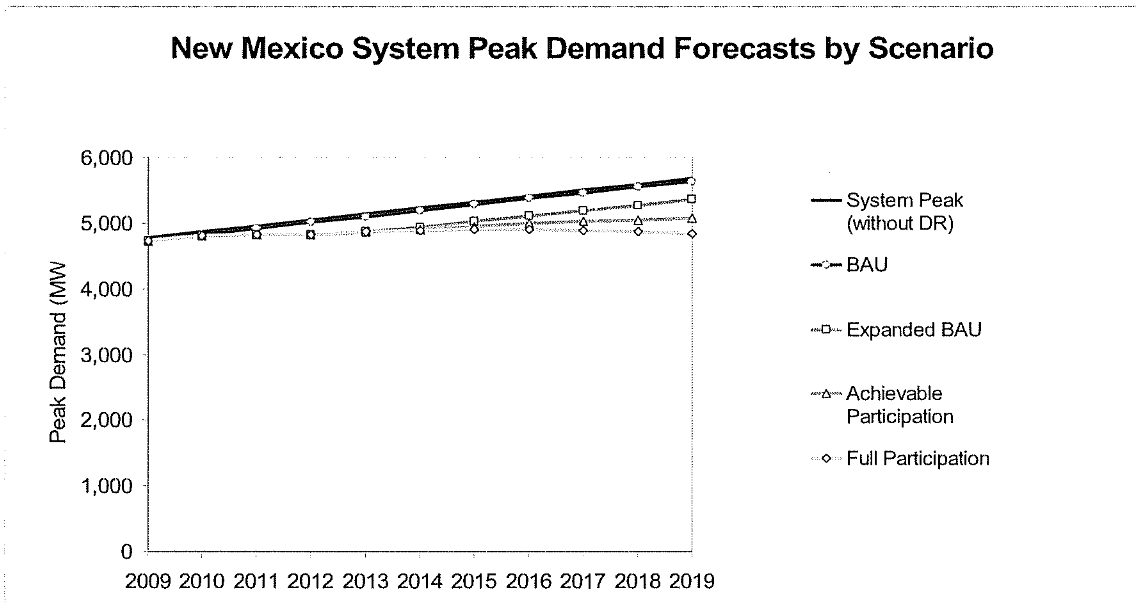
Achievable Participation: The potential increase in this scenario is primarily realized through residential pricing programs. The increase in impacts from the residential class is significant, given its high share in the total account population. Load reduction potential from C&I customers grow due to increased participation in pricing programs. Some of the large C&I customers participating in 'Other DR' programs choose to participate in the pricing programs.

Full Participation: Similar to the Achievable Participation scenario, a very high share of residential accounts in the total number of customer accounts drive increase in impacts from residential pricing programs. For the small and medium C&I classes, impacts are dominated by pricing with enabling technology. However, for the large C&I customers, impacts are dominated by participation in Interruptible programs.



Total Potential Peak Reduction from Demand Response in New Mexico, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	41	0.7%	41	0.7%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	41	0.7%	41	0.7%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	2	0.0%	1	0.0%	7	0.1%
Automated/Direct Load Control	40	0.7%	2	0.0%	7	0.1%	0	0.0%	50	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	1.6%	93	1.6%
Total	44	0.8%	3	0.0%	24	0.4%	251	4.4%	322	5.7%
Achievable Participation										
Pricing with Technology	120	2.1%	32	0.6%	46	0.8%	19	0.3%	217	3.8%
Pricing without Technology	88	1.6%	2	0.0%	35	0.6%	35	0.6%	161	2.8%
Automated/Direct Load Control	10	0.2%	1	0.0%	3	0.0%	0	0.0%	14	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	38	0.7%	38	0.7%
Total	218	3.8%	34	0.6%	100	1.8%	249	4.4%	601	10.6%
Full Participation										
Pricing with Technology	280	4.9%	74	1.3%	135	2.4%	57	1.0%	546	9.6%
Pricing without Technology	49	0.9%	1	0.0%	23	0.4%	46	0.8%	119	2.1%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	15	0.3%	157	2.8%	172	3.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	329	5.8%	76	1.3%	173	3.0%	259	4.6%	837	14.7%



New York State Profile

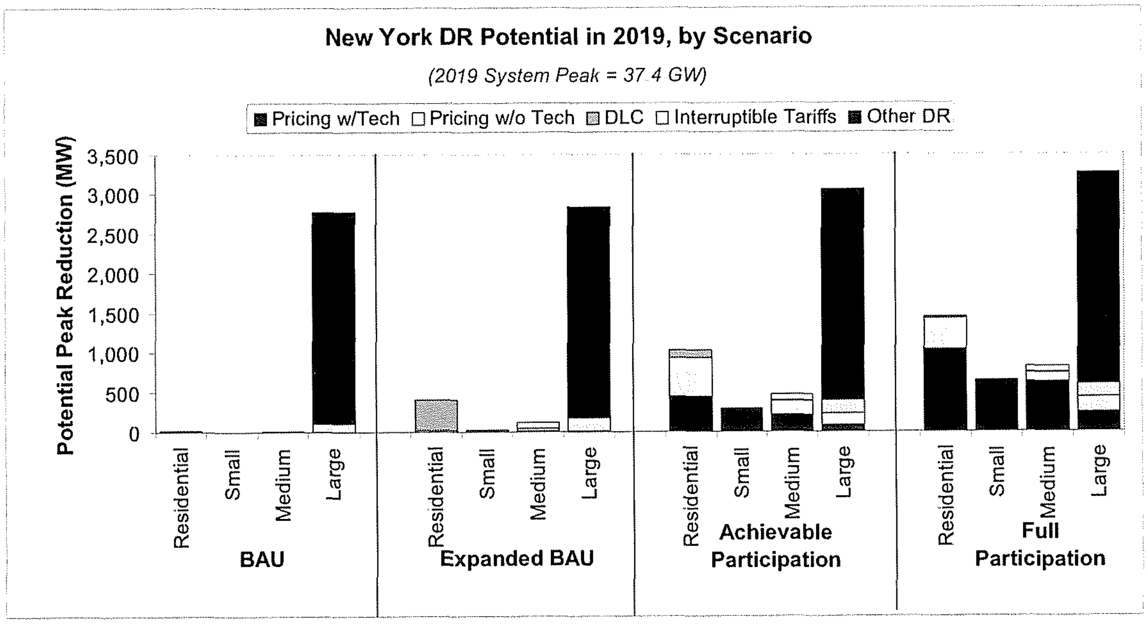
Key drivers of New York's demand response potential estimate include: a very high level of load participating in NYISO demand response Programs, a customer mix with almost 40% of the load from residential customers, and the potential to deploy AMI at a faster-than-average rate. New York has a lower than average residential CAC saturation at 16.7%. 'Pricing with technology' and DLC are cost effective for all customer classes in the state.

BAU: New York's existing demand response comes primarily from large C&I load participation in the NYISO market. This dominates the potential estimated across all scenarios.

Expanded BAU: Since current participation levels in NYISO demand response programs are substantially high, there is not much scope for growth in this program. Increase in impacts for this scenario is primarily derived from an expansion in residential DLC programs and Interruptible programs for large C&I customers.

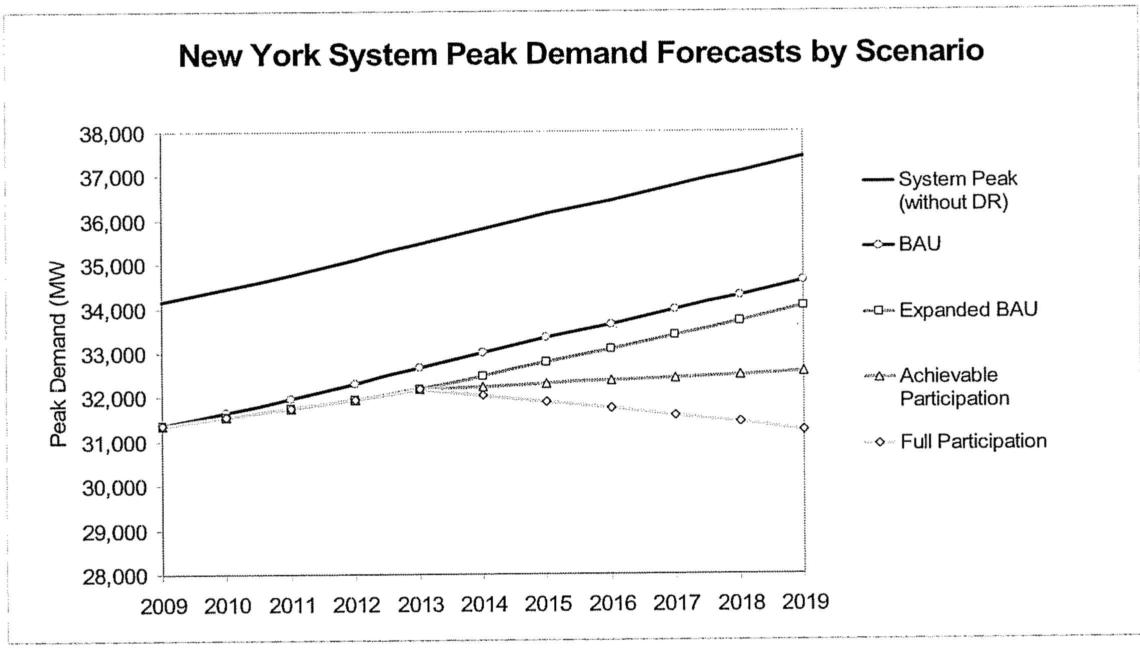
Achievable Participation: A moderately high share of residential load in the total drives a significant increase in demand response potential through pricing programs. For the C&I sector too, additional load reduction is derived through participation in pricing programs. However, impacts from 'Other DR' programs continue to dominate due to persistently high large C&I participation levels in NYISO market.

Full Participation: Higher participation of residential and C&I load (primarily small and medium C&I) in pricing programs drive potential increase in this scenario, as compared to the 'Achievable Participation' scenario. However, the impacts are dominated by high level of large C&I participation in NYISO programs.



Total Potential Peak Reduction from Demand Response in New York, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	21	0.1%	0	0.0%	10	0.0%	0	0.0%	31	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	104	0.3%	104	0.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	21	0.1%	0	0.0%	10	0.0%	2,772	7.4%	2,803	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	1	0.0%	11	0.0%	7	0.0%	39	0.1%
Automated/Direct Load Control	387	1.0%	25	0.1%	35	0.1%	0	0.0%	447	1.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	408	1.1%	25	0.1%	117	0.3%	2,839	7.6%	3,389	9.1%
Achievable Participation										
Pricing with Technology	443	1.2%	272	0.7%	215	0.6%	82	0.2%	1,011	2.7%
Pricing without Technology	485	1.3%	17	0.0%	168	0.4%	149	0.4%	818	2.2%
Automated/Direct Load Control	99	0.3%	6	0.0%	14	0.0%	0	0.0%	120	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	1,026	2.7%	295	0.8%	467	1.2%	3,063	8.2%	4,852	13.0%
Full Participation										
Pricing with Technology	1,035	2.8%	636	1.7%	627	1.7%	240	0.6%	2,538	6.8%
Pricing without Technology	392	1.0%	10	0.0%	111	0.3%	193	0.5%	706	1.9%
Automated/Direct Load Control	21	0.1%	0	0.0%	10	0.0%	0	0.0%	31	0.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	71	0.2%	164	0.4%	235	0.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	2,668	7.1%	2,668	7.1%
Total	1,448	3.9%	647	1.7%	819	2.2%	3,265	8.7%	6,179	16.5%



North Carolina State Profile

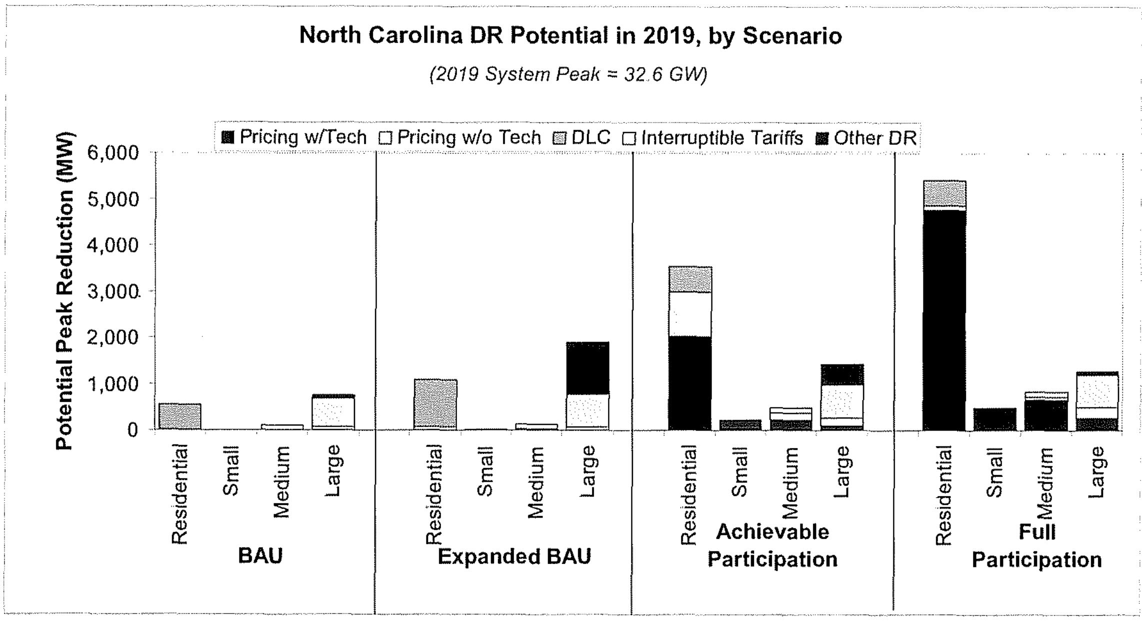
Key drivers of North Carolina's demand response potential estimate include: above average residential CAC saturation of 84%, an above average share of peak demand (51%) in the residential class, and a moderate amount of existing demand response. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: North Carolina's existing demand response comes primarily from residential DLC and interruptible tariffs for the Medium and Large C&I classes. The state is also one of the few states with a significant portion of price induced demand response. Other DR for the Large C&I class accounts for the remaining portion.

Expanded BAU: Growth in demand response impacts is driven through the growth of Other DR programs for the Large C&I class and DLC for the residential class. Growth in dynamic pricing and existing interruptible tariffs account for the remaining portion.

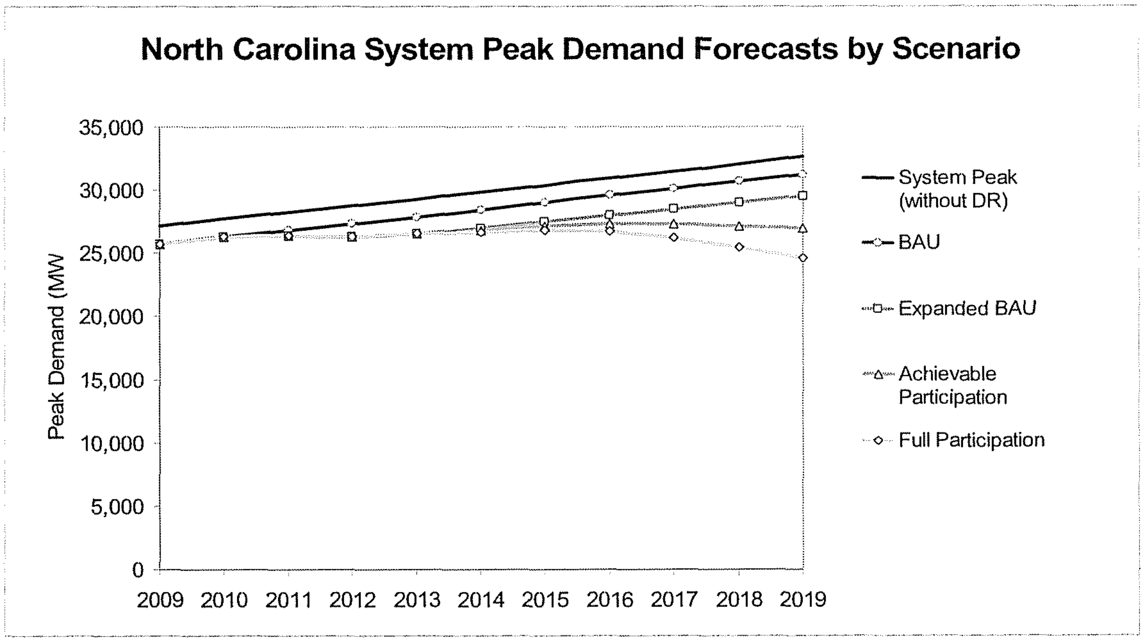
Achievable Participation: Dynamic pricing with enabling impacts accounts for almost 50% of the increase in potential. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing with enabling technologies for all customer classes. This option represents over 75% of the potential in this scenario. The lower potential for Large C&I than in the other scenarios is due to participation changes within the different demand response options.



Total Potential Peak Reduction from Demand Response in North Carolina, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	62	0.2%	62	0.2%
Automated/Direct Load Control	547	1.7%	0	0.0%	0	0.0%	0	0.0%	547	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	93	0.3%	608	1.9%	701	2.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	79	0.2%	79	0.2%
Total	547	1.7%	0	0.0%	93	0.3%	749	2.3%	1,388	4.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	67	0.2%	1	0.0%	11	0.0%	62	0.2%	140	0.4%
Automated/Direct Load Control	1,022	3.1%	14	0.0%	12	0.0%	0	0.0%	1,048	3.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,134	3.5%	1,134	3.5%
Total	1,089	3.3%	15	0.0%	132	0.4%	1,902	5.8%	3,137	9.6%
Achievable Participation										
Pricing with Technology	2,038	6.2%	203	0.6%	226	0.7%	94	0.3%	2,561	7.9%
Pricing without Technology	952	2.9%	11	0.0%	150	0.5%	171	0.5%	1,285	3.9%
Automated/Direct Load Control	547	1.7%	4	0.0%	5	0.0%	0	0.0%	555	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	464	1.4%	465	1.4%
Total	3,537	10.8%	218	0.7%	488	1.5%	1,436	4.4%	5,680	17.4%
Full Participation										
Pricing with Technology	4,768	14.6%	476	1.5%	659	2.0%	275	0.8%	6,178	18.9%
Pricing without Technology	98	0.3%	6	0.0%	73	0.2%	222	0.7%	399	1.2%
Automated/Direct Load Control	547	1.7%	0	0.0%	0	0.0%	0	0.0%	547	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	108	0.3%	707	2.2%	814	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	79	0.2%	79	0.2%
Total	5,413	16.6%	482	1.5%	840	2.6%	1,283	3.9%	8,017	24.6%



North Dakota State Profile

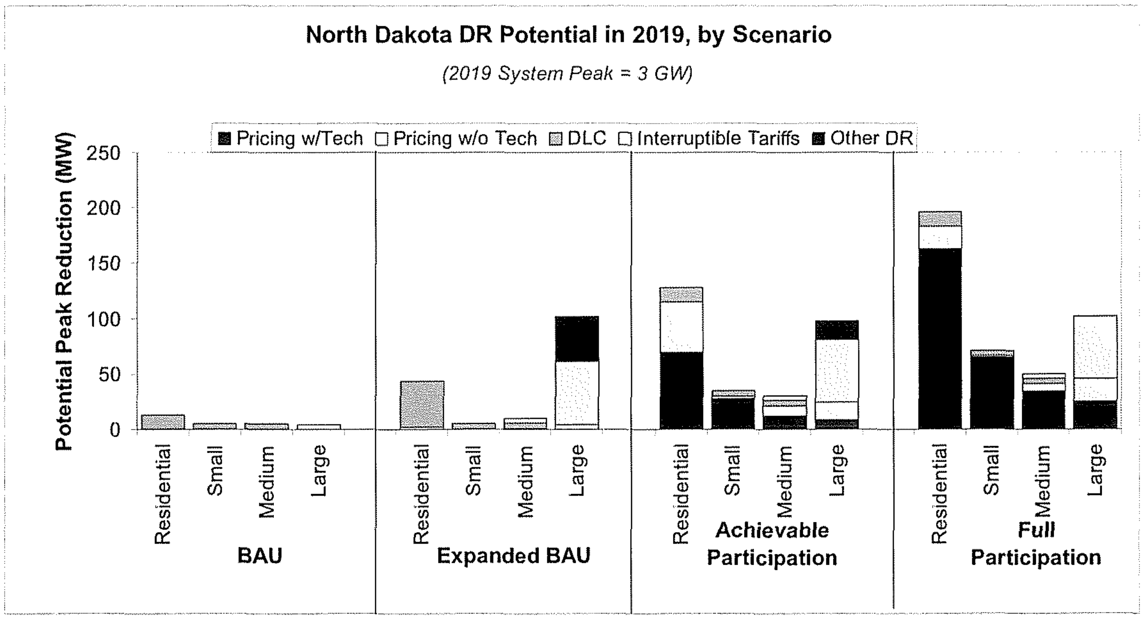
Key drivers of North Dakota's demand response potential estimate include: an above average share of peak demand (27%) in the Small C&I class and a moderate CAC saturation of 51%. Pricing with enabling technologies and DLC are cost effective for all customer classes in the state.

BAU: North Dakota's existing demand response comes primarily from DLC programs for all classes, except for the Large C&I class. Price induced demand response for the Large C&I class accounts for the remaining portion.

Expanded BAU: Growth in demand response impacts is driven through the addition of Other DR programs and interruptible tariffs. Growth in the existing residential DLC programs accounts for the remaining portion.

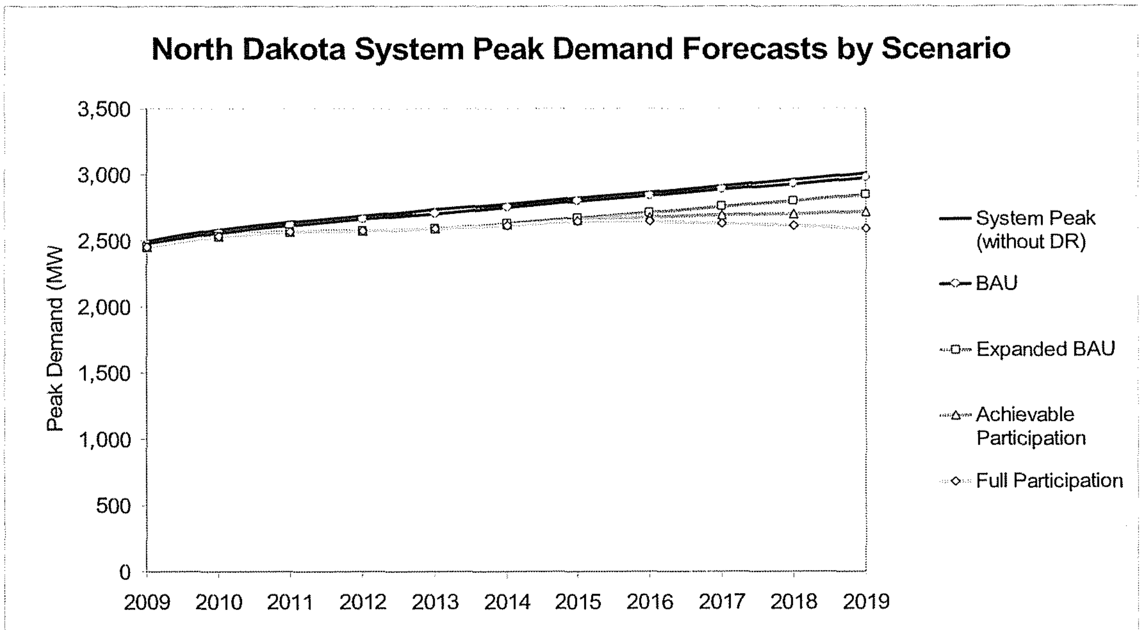
Achievable Participation: Dynamic pricing with enabling impacts accounts for approximately 40% of the increase in potential, with 10% of this increase due to the potential from Small C&I. Dynamic pricing without enabling technology contributes additional savings. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing relative to Other DR. The movement of participants in Other DR to pricing also contributes to this effect.

Full Participation: Similar to the Achievable Participation scenario, the impacts are dominated by dynamic pricing with enabling technologies for all customer classes. This option represents almost 70% of the potential in this scenario. The pricing options have the effect of reducing or eliminating the potential from all of the other demand response options, in particular, Other DR for the Large C&I class.



Total Potential Peak Reduction from Demand Response in North Dakota, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	4	0.1%	4	0.1%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	13	0.4%	5	0.2%	5	0.2%	4	0.1%	28	0.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	4	0.1%	7	0.2%
Automated/Direct Load Control	42	1.4%	5	0.2%	5	0.2%	0	0.0%	52	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	41	1.4%	41	1.4%
Total	43	1.4%	5	0.2%	10	0.3%	102	3.4%	160	5.3%
Achievable Participation										
Pricing with Technology	70	2.3%	28	0.9%	12	0.4%	9	0.3%	118	3.9%
Pricing without Technology	45	1.5%	2	0.1%	9	0.3%	16	0.5%	72	2.4%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	17	0.6%	17	0.6%
Total	128	4.2%	35	1.2%	30	1.0%	97	3.2%	290	9.7%
Full Participation										
Pricing with Technology	163	5.4%	65	2.2%	34	1.1%	25	0.8%	287	9.6%
Pricing without Technology	20	0.7%	1	0.0%	6	0.2%	20	0.7%	48	1.6%
Automated/Direct Load Control	13	0.4%	5	0.2%	5	0.2%	0	0.0%	23	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.1%	57	1.9%	61	2.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	196	6.5%	71	2.4%	50	1.7%	102	3.4%	419	13.9%



Ohio State Profile

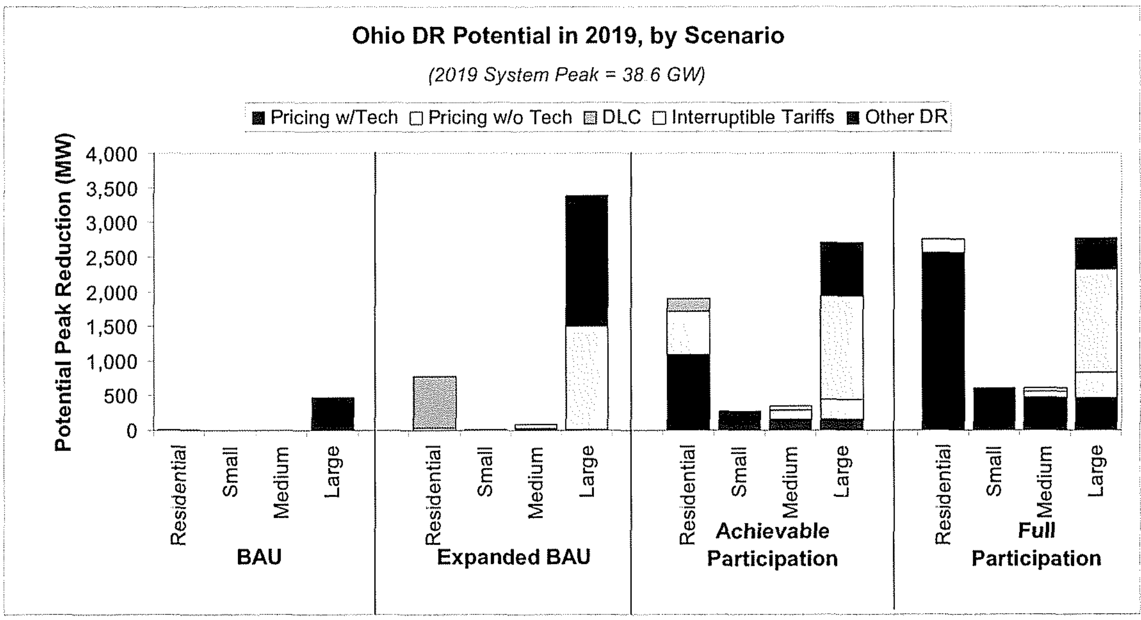
Key drivers of Ohio's demand response potential estimate include: a relatively high number of residential accounts at 5 million, higher-than-average residential CAC saturation of 63%, and a customer mix that has an above average share of peak demand in the large C&I class at 30%. AMI deployment is likely to take place at a lower-than-average rate for the state. 'Pricing with technology' is cost-effective for all customer classes. DLC is cost-effective for all customer classes.

BAU: Ohio's existing demand response comes primarily from large C&I load participation in 'Other DR' programs. Current demand response from DLC and 'Interruptible' programs is low.

Expanded BAU: Growth in demand response impacts is driven primarily through participation in 'Interruptible' and 'Other DR' programs for large C&I customers. Also, there is a significant growth in impacts coming from residential DLC programs. This is due to Ohio's high level of residential accounts with a higher than average CAC saturation.

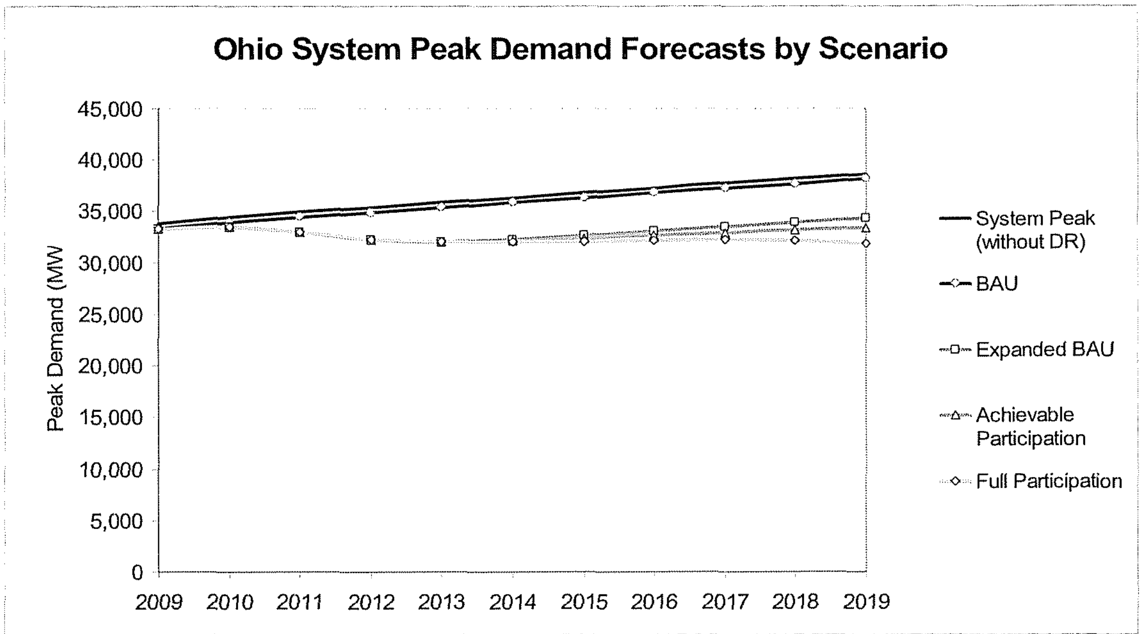
Achievable Participation: High residential customer participation in dynamic pricing options drives the increase in demand response potential for this scenario. C&I customers participate in 'pricing with technology' that also leads to an increase in impacts. Large C&I demand response potential is lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing programs relative to 'Other DR' program impacts.

Full Participation: Similar to the Achievable Participation scenario, increase in potential is driven by a high level of residential and C&I customer participation in 'pricing with technology' option.



Total Potential Peak Reduction from Demand Response in Ohio, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	13	0.0%	13	0.0%
Automated/Direct Load Control	10	0.0%	0	0.0%	2	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	8	0.0%	8	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	450	1.2%	451	1.2%
Total	10	0.0%	0	0.0%	2	0.0%	471	1.2%	483	1.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.1%	1	0.0%	7	0.0%	13	0.0%	54	0.1%
Automated/Direct Load Control	747	1.9%	11	0.0%	21	0.1%	0	0.0%	779	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,891	4.9%	1,891	4.9%
Total	779	2.0%	12	0.0%	83	0.2%	3,396	8.8%	4,270	11.1%
Achievable Participation										
Pricing with Technology	1,095	2.8%	258	0.7%	160	0.4%	156	0.4%	1,670	4.3%
Pricing without Technology	615	1.6%	16	0.0%	128	0.3%	284	0.7%	1,043	2.7%
Automated/Direct Load Control	190	0.5%	3	0.0%	9	0.0%	0	0.0%	202	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	772	2.0%	772	2.0%
Total	1,900	4.9%	277	0.7%	350	0.9%	2,704	7.0%	5,231	13.5%
Full Participation										
Pricing with Technology	2,562	6.6%	605	1.6%	468	1.2%	457	1.2%	4,091	10.6%
Pricing without Technology	190	0.5%	9	0.0%	87	0.2%	369	1.0%	655	1.7%
Automated/Direct Load Control	10	0.0%	0	0.0%	2	0.0%	0	0.0%	11	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	53	0.1%	1,492	3.9%	1,546	4.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	450	1.2%	451	1.2%
Total	2,761	7.1%	614	1.6%	610	1.6%	2,768	7.2%	6,753	17.5%



Oklahoma State Profile

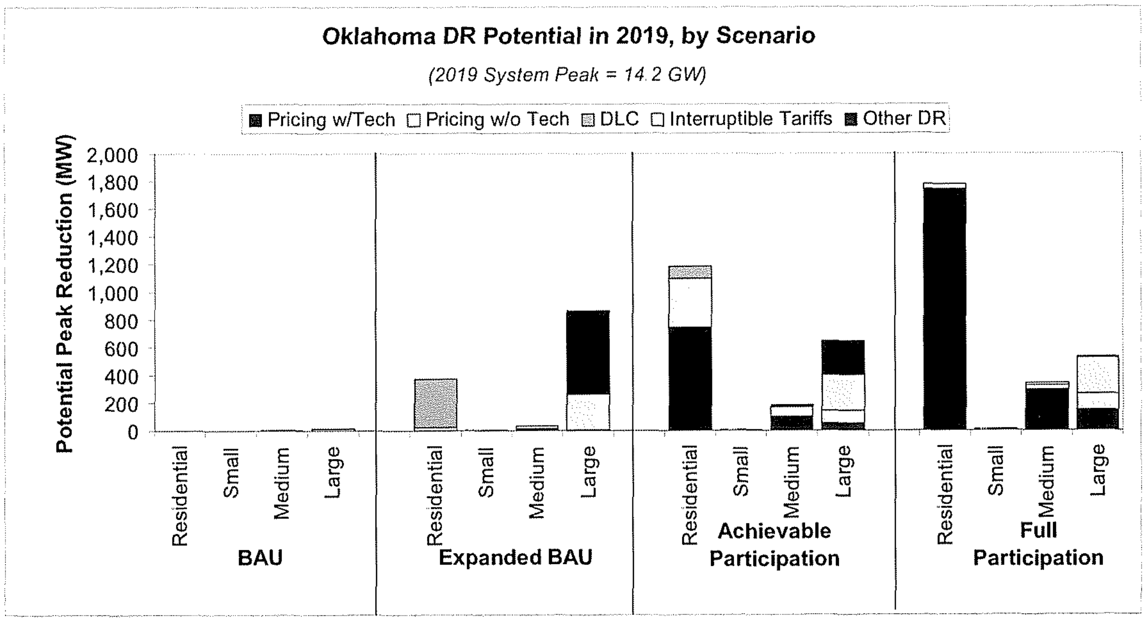
Key drivers of Oklahoma's demand response potential estimate include: higher-than-average residential CAC saturation of 84%, and a customer mix that has an above average share of peak demand in the residential class (50%). The level of existing demand response is low. 'Pricing with technology' is cost-effective for all customers, except for the small C&I class. DLC is cost effective for all customer classes in the state.

BAU: Oklahoma's existing demand response comes primarily from load enrolled in 'Interruptible' and 'Other DR' programs for C&I customers.

Expanded BAU: The residential sector has a high potential for growth due to high CAC saturation level, coupled with a low base of existing programs. In this scenario, growth in demand response impacts is driven primarily through the addition of residential DLC programs and through increase in large C&I load participation in 'Interruptible' and 'Other DR' programs.

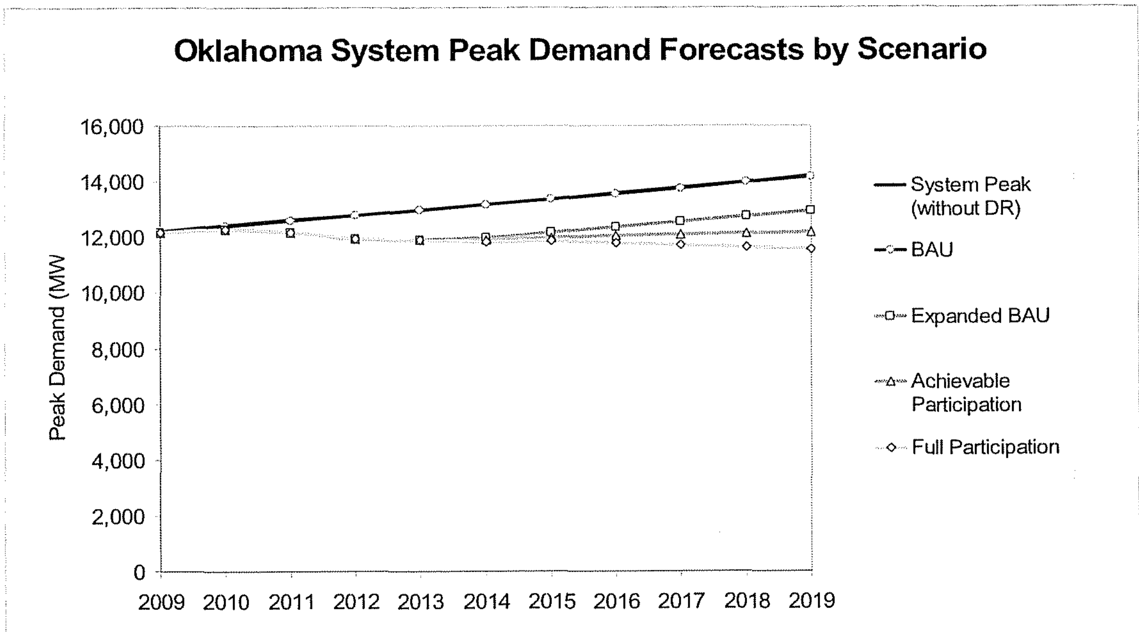
Achievable Participation: High CAC saturation in the residential sector drives a significant increase in demand response potential through 'pricing with technology' option. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing programs relative to Other DR.

Full Participation: Similar to the Achievable Participation scenario, high CAC saturation combined with a large share of load in the residential sector drives increase in impacts. Increase in impacts is dominated by 'pricing with technology', which is cost-effective for all customer classes. Large C&I potential decreases, due to smaller per-customer impacts from pricing programs relative to Other DR.



Total Potential Peak Reduction from Demand Response in Oklahoma, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.0%	8	0.1%	11	0.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	10	0.1%	10	0.1%
Total	0	0.0%	1	0.0%	3	0.0%	18	0.1%	22	0.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	4	0.0%	4	0.0%	30	0.2%
Automated/Direct Load Control	351	2.5%	5	0.0%	13	0.1%	0	0.0%	369	2.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	605	4.3%	605	4.3%
Total	372	2.6%	6	0.0%	29	0.2%	867	6.1%	1,273	9.0%
Achievable Participation										
Pricing with Technology	746	5.3%	0	0.0%	101	0.7%	50	0.4%	896	6.3%
Pricing without Technology	350	2.5%	5	0.0%	67	0.5%	91	0.6%	514	3.6%
Automated/Direct Load Control	90	0.6%	1	0.0%	5	0.0%	0	0.0%	96	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	247	1.7%	247	1.7%
Total	1,185	8.3%	7	0.0%	185	1.3%	646	4.5%	2,023	14.2%
Full Participation										
Pricing with Technology	1,744	12.3%	0	0.0%	295	2.1%	146	1.0%	2,185	15.4%
Pricing without Technology	38	0.3%	7	0.1%	33	0.2%	118	0.8%	196	1.4%
Automated/Direct Load Control	0	0.0%	1	0.0%	0	0.0%	0	0.0%	1	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	12	0.1%	258	1.8%	270	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	10	0.1%	10	0.1%
Total	1,782	12.6%	8	0.1%	339	2.4%	532	3.7%	2,662	18.7%



Oregon State Profile

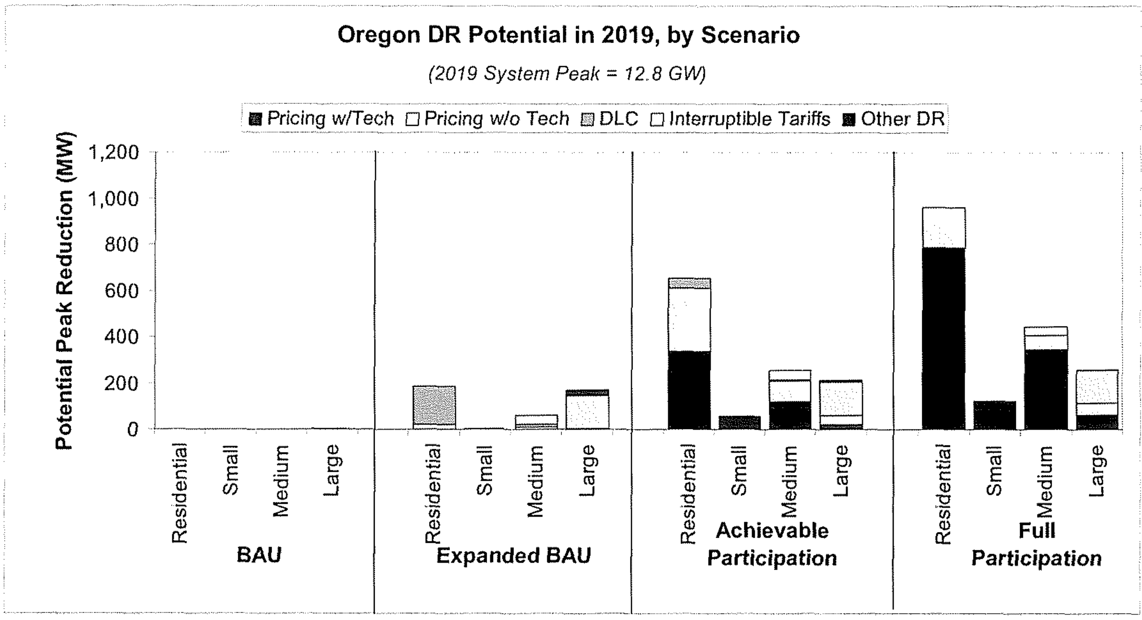
Key drivers of Oregon's demand response potential estimate include: a moderate residential base with 1.6 million accounts, a customer mix that has an above average share of peak demand in the medium C&I class (35%), and the potential to deploy AMI at a faster-than-average rate. Dynamic pricing with enabling technology and DLC are cost effective for all customer classes in the state. Oregon has a moderate residential CAC saturation value of 38%.

BAU: Oregon has a low level of existing demand response, primarily associated with large C&I participation in 'Other DR' programs for one of the IOUs in the region. Dominance on hydro power for generation in the Pacific Northwest region has historically led to low levels of demand response resources.

Expanded BAU: Growth in demand response impacts is driven primarily through the addition of DLC programs for residential customers, and through C&I load participation in 'Interruptible' and 'Other DR' programs. The potential for growth is significant, since existing demand response is at a very low level.

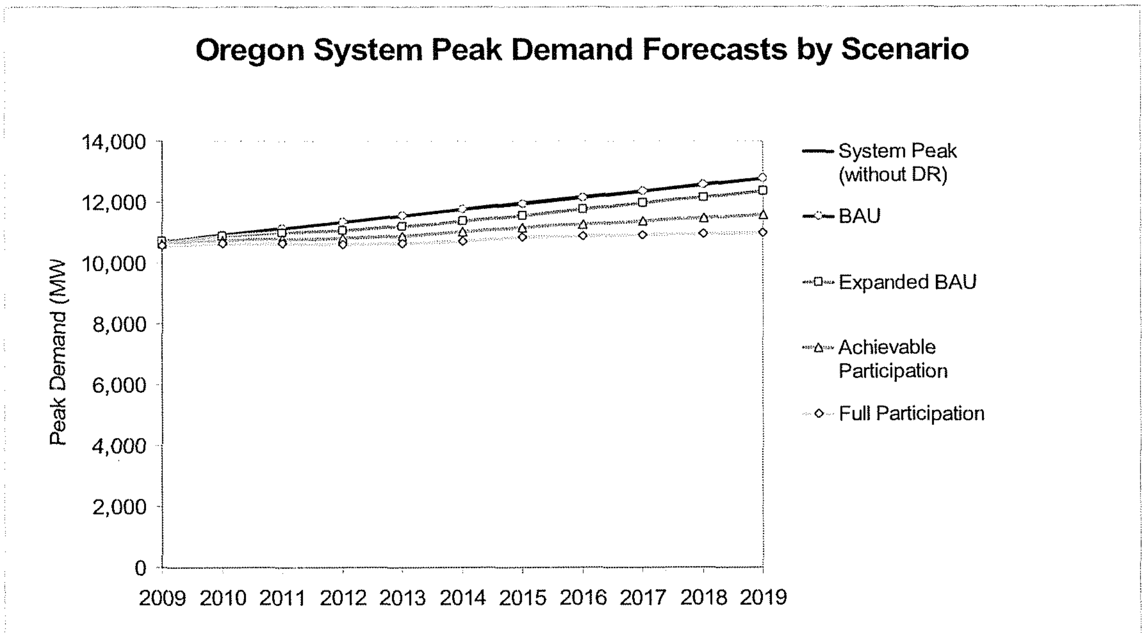
Achievable Participation: The increase in impacts is primarily associated with pricing programs. Participation of residential customers in 'Pricing with technology' option drives a significant increase in demand response potential. Also, impacts from 'pricing without technology' increase across all customer classes.

Full Participation: Similar to the Achievable Participation scenario, impacts are dominated by 'pricing with enabling technology'. Residential impacts grow substantially due to significantly higher participation in pricing programs. Among the three C&I rate classes, medium C&I impacts dominate due to its high share in the overall peak load.



Total Potential Peak Reduction from Demand Response in Oregon, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	3	0.0%	3	0.0%
Total	2	0.0%	0	0.0%	0	0.0%	3	0.0%	5	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	18	0.1%	0	0.0%	8	0.1%	2	0.0%	29	0.2%
Automated/Direct Load Control	168	1.3%	4	0.0%	14	0.1%	0	0.0%	187	1.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	26	0.2%	26	0.2%
Total	187	1.5%	5	0.0%	61	0.5%	171	1.3%	424	3.3%
Achievable Participation										
Pricing with Technology	336	2.6%	52	0.4%	119	0.9%	21	0.2%	528	4.1%
Pricing without Technology	275	2.2%	3	0.0%	91	0.7%	39	0.3%	408	3.2%
Automated/Direct Load Control	43	0.3%	1	0.0%	6	0.0%	0	0.0%	50	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	11	0.1%	11	0.1%
Total	654	5.1%	57	0.4%	254	2.0%	214	1.7%	1,179	9.2%
Full Participation										
Pricing with Technology	786	6.2%	122	1.0%	347	2.7%	63	0.5%	1,318	10.3%
Pricing without Technology	173	1.4%	2	0.0%	58	0.5%	51	0.4%	284	2.2%
Automated/Direct Load Control	2	0.0%	0	0.0%	0	0.0%	0	0.0%	2	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	39	0.3%	143	1.1%	182	1.4%
Other DR Programs	*0*	0.0%	*0*	0.0%	*0*	0.0%	3	0.0%	3	0.0%
Total	961	7.5%	124	1.0%	444	3.5%	259	2.0%	1,788	14.0%



Pennsylvania State Profile

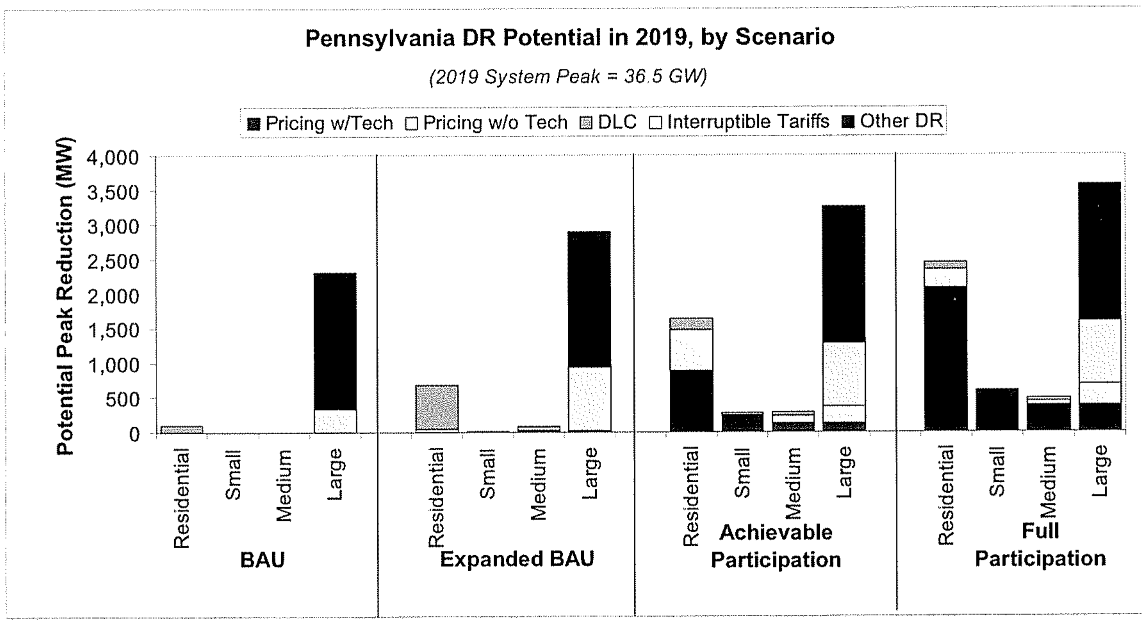
Key drivers of Pennsylvania's demand response potential estimate include: a relatively high level of load participation in the PJM market, a high residential population base with 50% CAC saturation, customer mix that has an above average share of peak demand for large C&I customers, and the potential to deploy AMI at a faster-than-average rate. Pricing with enabling technology and DLC are cost-effective for all customer classes.

BAU: Pennsylvania's existing demand response comes primarily from large C&I load participation in the PJM market. A portion of the existing demand response potential also comes from legacy interruptible programs in the state, along with residential DLC program.

Expanded BAU: Growth in demand response impacts is driven primarily through the increase of 'Other DR' programs for the large C&I class (due to higher load participation in the PJM market), and the expansion of DLC programs for residential customers. Load reduction potential associated with interruptible programs also grows, due to Pennsylvania's high share of large C&I load.

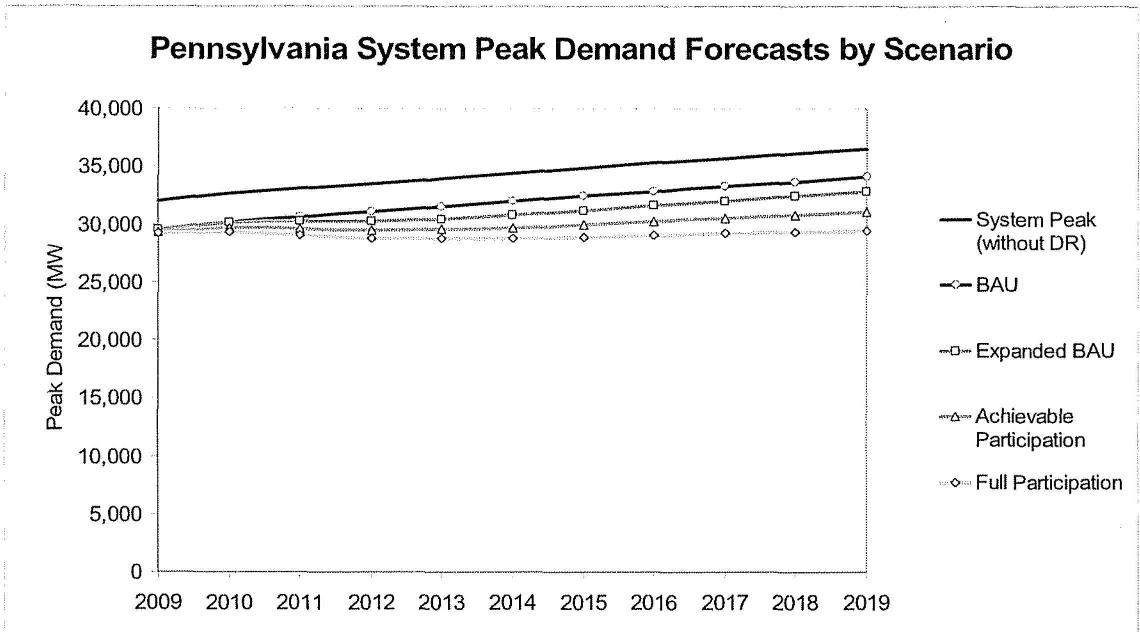
Achievable Participation: For this scenario, growth in residential impacts is associated with the pricing options. C&I customer participation in 'pricing with technology' cause a growth in potential. 'Other DR' programs continue to dominate the load reduction potential for large C&I customers.

Full Participation: Similar to the Achievable Participation scenario, high residential and C&I customer participation in the pricing options (primarily 'pricing with technology') drives the increase in impacts. 'Other DR' programs for large C&I customers maintain their large share in the total potential.



Total Potential Peak Reduction from Demand Response in Pennsylvania, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	108	0.3%	0	0.0%	0	0.0%	0	0.0%	108	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	338	0.9%	338	0.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	108	0.3%	0	0.0%	0	0.0%	2,307	6.3%	2,415	6.6%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	46	0.1%	1	0.0%	10	0.0%	16	0.0%	73	0.2%
Automated/Direct Load Control	641	1.8%	12	0.0%	27	0.1%	0	0.0%	679	1.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	687	1.9%	13	0.0%	79	0.2%	2,901	7.9%	3,680	10.1%
Achievable Participation										
Pricing with Technology	887	2.4%	253	0.7%	129	0.4%	129	0.4%	1,398	3.8%
Pricing without Technology	582	1.6%	16	0.0%	101	0.3%	235	0.6%	934	2.6%
Automated/Direct Load Control	166	0.5%	3	0.0%	11	0.0%	0	0.0%	180	0.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	1,635	4.5%	272	0.7%	283	0.8%	3,250	8.9%	5,439	14.9%
Full Participation										
Pricing with Technology	2,075	5.7%	592	1.6%	377	1.0%	378	1.0%	3,422	9.4%
Pricing without Technology	266	0.7%	10	0.0%	66	0.2%	305	0.8%	647	1.8%
Automated/Direct Load Control	108	0.3%	0	0.0%	0	0.0%	0	0.0%	108	0.3%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	43	0.1%	916	2.5%	958	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	1,969	5.4%	1,969	5.4%
Total	2,450	6.7%	602	1.6%	486	1.3%	3,568	9.8%	7,105	19.5%



Rhode Island State Profile

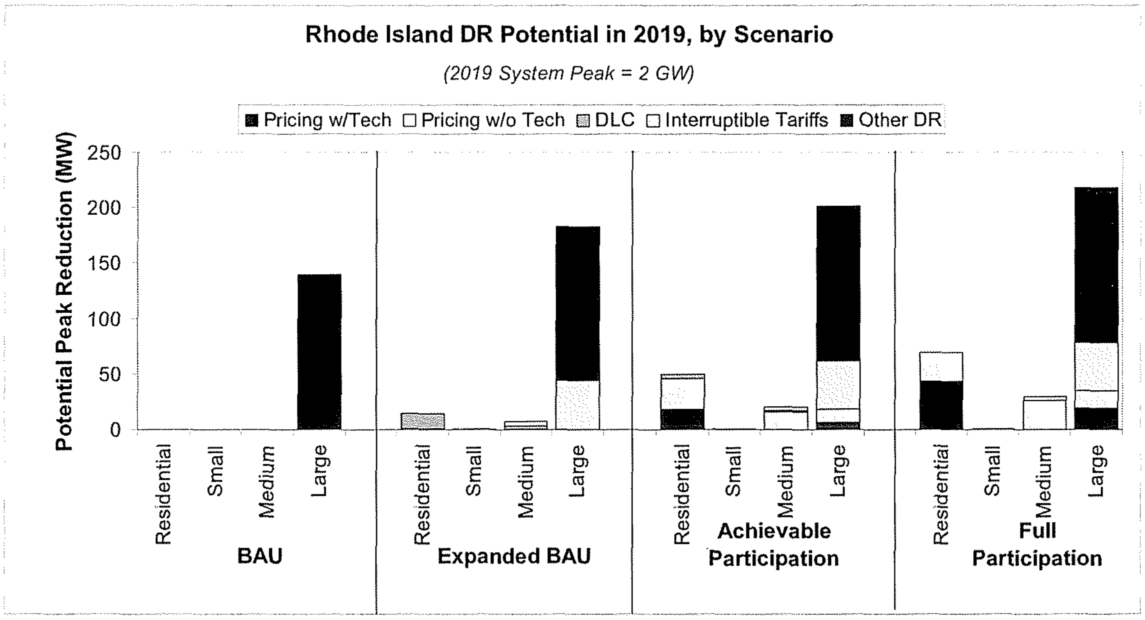
Rhode Island has a higher than average share of large C&I peak load (29%). The state's demand response potential is driven by large C&I load participation in the ISO-NE market. Rhode Island has a lower than average residential CAC saturation at 12%. Dynamic pricing with enabling technology is cost-effective only for residential and large C&I customers, thereby restricting the potential that can be derived from this option. DLC is cost-effective for all customer classes. It has a lower than average AMI deployment rate.

BAU: Rhode Island's existing demand response is derived from 'Other DR' programs, due to large C&I load participation in the ISO-NE market.

Expanded BAU: Growth in demand response impacts is driven primarily through the growth of Interruptible programs for large C&I customers. This is due to Rhode Island's high share of large C&I load, which allow for growth in Interruptible programs. Also, there is a potential for growth in residential DLC programs.

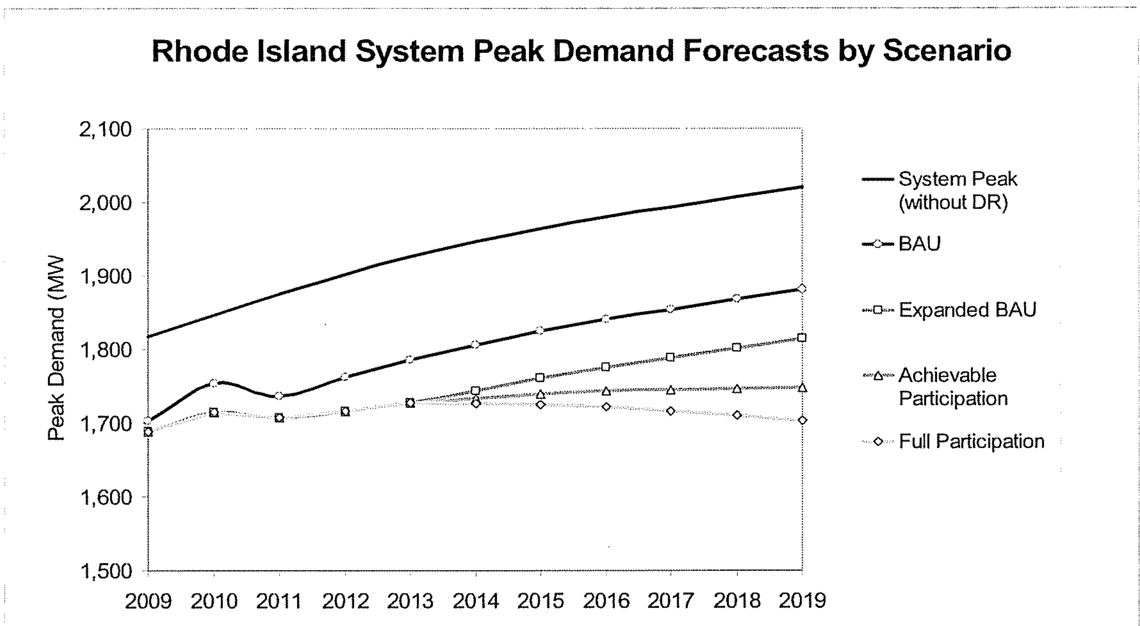
Achievable Participation: Growth in impacts in this scenario is driven by the potential derived from pricing options, primarily from residential customers and to a smaller extent from medium C&I customers. Since 'pricing with technology' is cost-effective only for residential and large C&I customers, there is a low growth in potential associated with this option. Potential through large C&I load participation in the ISO-NE market dominates overall other types of demand response programs.

Full Participation: Similar to the Achievable Participation scenario, increase in customer participation in pricing options, primarily for residential and medium C&I customers, drives the increase in impacts. Similar to the other scenarios, large C&I load maintains high participation levels in the ISO-NE market.



Total Potential Peak Reduction from Demand Response in Rhode Island, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	0	0.0%	1	0.1%
Automated/Direct Load Control	14	0.7%	1	0.0%	3	0.2%	0	0.0%	18	0.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	15	0.7%	1	0.0%	7	0.4%	183	9.1%	206	10.2%
Achievable Participation										
Pricing with Technology	19	0.9%	0	0.0%	0	0.0%	7	0.3%	25	1.2%
Pricing without Technology	28	1.4%	1	0.0%	16	0.8%	12	0.6%	56	2.8%
Automated/Direct Load Control	4	0.2%	0	0.0%	1	0.1%	0	0.0%	5	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	50	2.5%	1	0.0%	20	1.0%	201	10.0%	273	13.5%
Full Participation										
Pricing with Technology	44	2.2%	0	0.0%	0	0.0%	19	0.9%	63	3.1%
Pricing without Technology	26	1.3%	1	0.0%	26	1.3%	15	0.8%	68	3.4%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	4	0.2%	44	2.2%	47	2.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	140	6.9%	140	6.9%
Total	70	3.4%	1	0.0%	30	1.5%	218	10.8%	318	15.7%



South Carolina State Profile

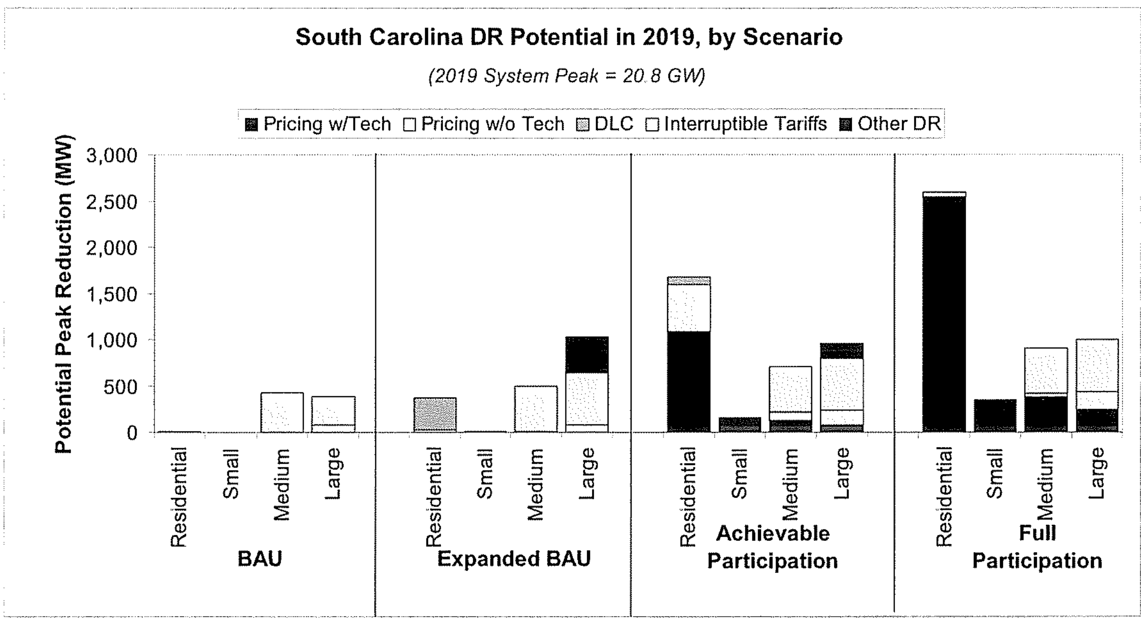
Key drivers of South Carolina's demand response potential estimate include: higher-than-average residential CAC saturation of 84 percent and a moderate amount of existing demand response. An expectation for AMI deployment that slightly lags the national average could lead to less potential demand response. Enabling technologies and DLC are cost-effective for all customer classes in the state.

BAU: South Carolina's existing demand response comes primarily from an interruptible tariff program for both Medium and Large C&I classes. A small amount comes from pricing without technology for the Large C&I class.

Expanded BAU: Growth in demand response impacts are driven through the addition of Other DR programs for the Large C&I class, which currently do not exist in the state. Significant growth also results from residential participation in DLC programs and large C&I customer participation in Interruptible tariffs.

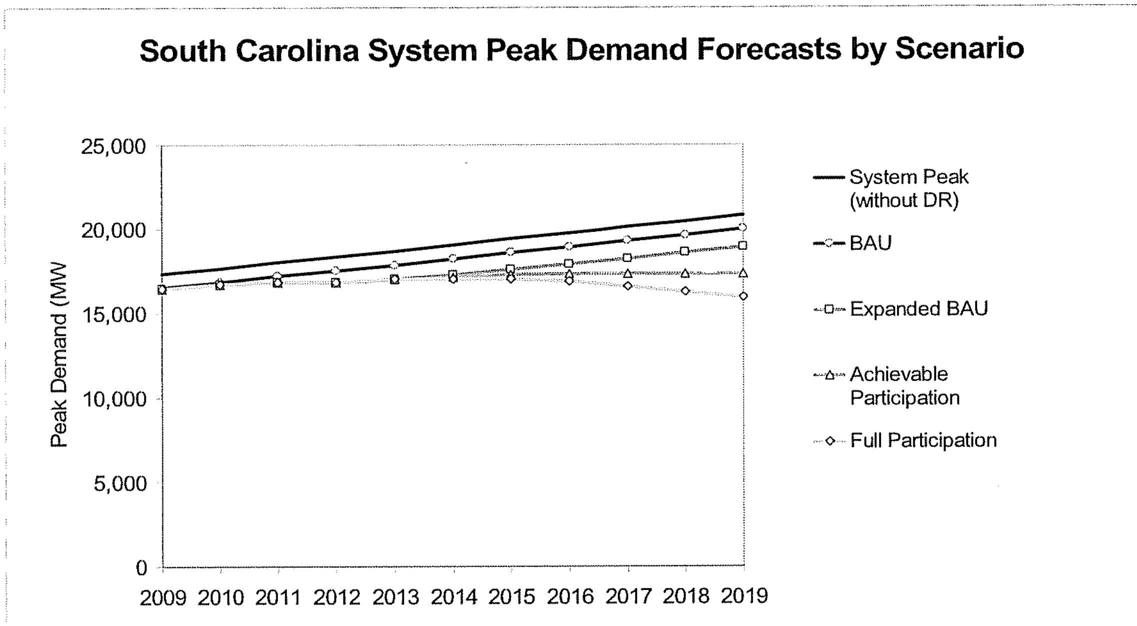
Achievable Participation: High CAC saturation in the Residential sector drives a significant increase in demand response potential through dynamic pricing, with the majority of customers increasing impacts through the use of enabling technologies. Medium C&I demand response potential is slightly increased through the addition of dynamic pricing. Large C&I demand response potential is slightly lower than in the Expanded BAU scenario due to smaller per-customer impacts from pricing with technology relative to Other DR.

Full Participation: Residential potential demand response increases dramatically due to dynamic pricing with technology reaching more customers. Again, high CAC saturation leads to large demand response potential for the residential sector. Dynamic pricing with technology modestly increases the demand response potential for the remaining sectors.



Total Potential Peak Reduction from Demand Response in South Carolina, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	76	0.4%	76	0.4%
Automated/Direct Load Control	5	0.0%	0	0.0%	0	0.0%	0	0.0%	5	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	423	2.0%	307	1.5%	730	3.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	5	0.0%	0	0.0%	423	2.0%	383	1.8%	811	3.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	27	0.1%	0	0.0%	5	0.0%	76	0.4%	109	0.5%
Automated/Direct Load Control	343	1.6%	5	0.0%	5	0.0%	0	0.0%	353	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	394	1.9%	395	1.9%
Total	370	1.8%	6	0.0%	499	2.4%	1,034	5.0%	1,909	9.2%
Achievable Participation										
Pricing with Technology	1,086	5.2%	147	0.7%	129	0.6%	83	0.4%	1,445	6.9%
Pricing without Technology	506	2.4%	8	0.0%	86	0.4%	150	0.7%	750	3.6%
Automated/Direct Load Control	87	0.4%	1	0.0%	2	0.0%	0	0.0%	91	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	161	0.8%	161	0.8%
Total	1,679	8.1%	156	0.8%	706	3.4%	957	4.6%	3,498	16.8%
Full Participation										
Pricing with Technology	2,541	12.2%	344	1.7%	377	1.8%	242	1.2%	3,503	16.8%
Pricing without Technology	50	0.2%	4	0.0%	42	0.2%	195	0.9%	291	1.4%
Automated/Direct Load Control	5	0.0%	0	0.0%	0	0.0%	0	0.0%	5	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	489	2.3%	563	2.7%	1,052	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	2,596	12.5%	348	1.7%	907	4.4%	1,000	4.8%	4,851	23.3%



South Dakota State Profile

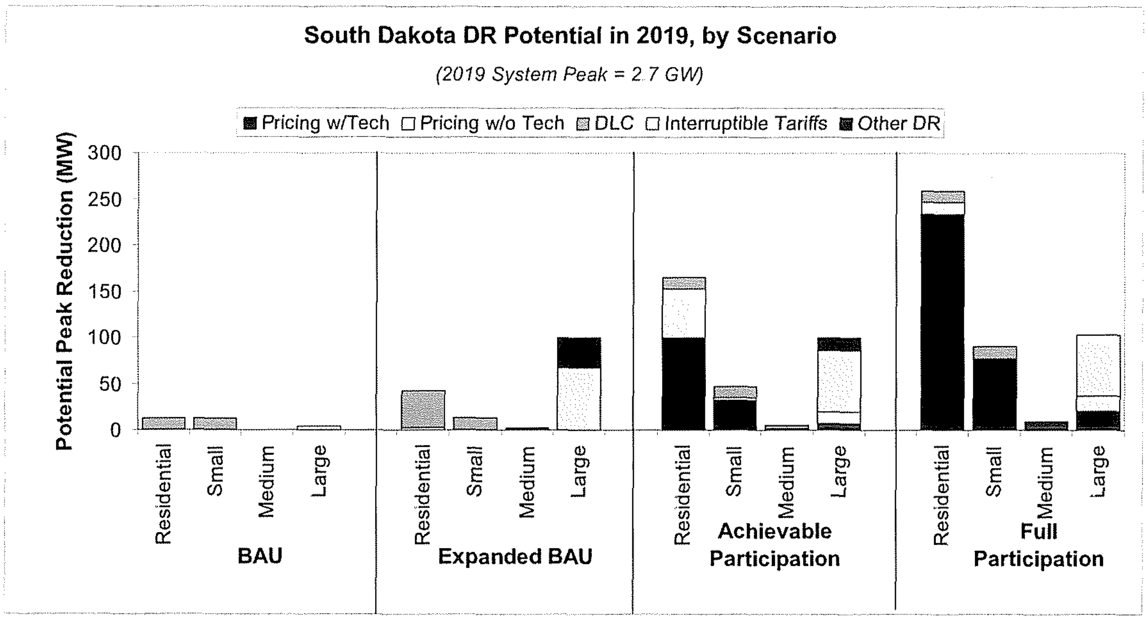
Key drivers of South Dakota's demand response potential estimate include: higher-than-average residential CAC saturation of 71 percent and a small amount of existing demand response. Enabling technologies are cost-effective for all C&I classes and Residential customers. Also, AMI deployment that potentially lags the national average could lead to slower realized demand response potential.

BAU: South Dakota's existing demand response comes primarily from direct load control for both the Residential and Small C&I classes. A small amount of demand response comes from the Large C&I class, in the form of interruptible tariffs.

Expanded BAU: Growth in demand response is driven equally through an interruptible tariff program and other demand response programs for the Large C&I class. The other category of demand response programs does not currently exist in the state. Residential DLC contributes to increased demand response potential, as well.

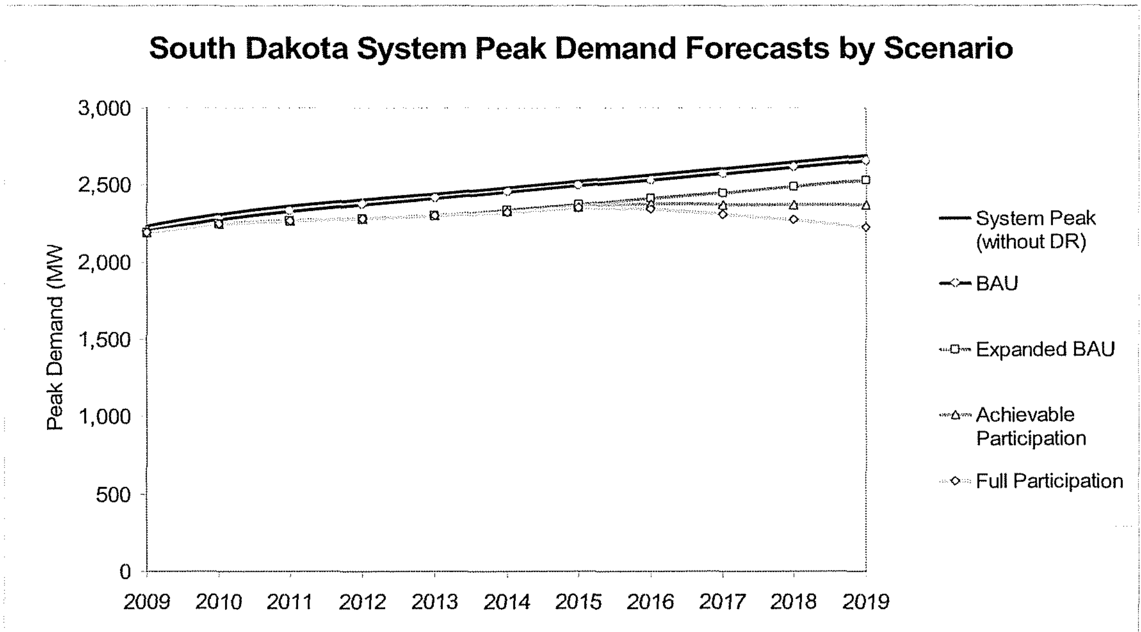
Achievable Participation: Increases in this scenario result from dynamic pricing programs, both with and without enabling technology, primarily through participation of residential and small C&I customers in these pricing programs.

Full Participation: Demand response potential is further realized through increases in both dynamic pricing programs. Large C&I customers that were in other demand response programs have shifted in to both dynamic pricing programs, with the majority enrolling in the with technology option. Again, higher-than-average CAC saturation results in the Residential class having the largest amount of potential demand response, with a very large fraction coming in the form of dynamic pricing with enabling technologies.



Total Potential Peak Reduction from Demand Response in South Dakota, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	13	0.5%	13	0.5%	0	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	4	0.2%	4	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	13	0.5%	13	0.5%	0	0.0%	4	0.2%	30	1.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	2	0.1%	0	0.0%	0	0.0%	0	0.0%	3	0.1%
Automated/Direct Load Control	41	1.5%	13	0.5%	1	0.0%	0	0.0%	55	2.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	33	1.2%	33	1.2%
Total	43	1.6%	13	0.5%	2	0.1%	100	3.7%	158	5.9%
Achievable Participation										
Pricing with Technology	100	3.7%	33	1.2%	2	0.1%	7	0.3%	142	5.3%
Pricing without Technology	53	2.0%	2	0.1%	2	0.1%	13	0.5%	69	2.6%
Automated/Direct Load Control	13	0.5%	13	0.5%	1	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	14	0.5%	14	0.5%
Total	165	6.2%	48	1.8%	6	0.2%	100	3.7%	318	11.8%
Full Participation										
Pricing with Technology	234	8.7%	76	2.8%	7	0.3%	20	0.8%	337	12.6%
Pricing without Technology	13	0.5%	1	0.0%	1	0.0%	16	0.6%	31	1.2%
Automated/Direct Load Control	13	0.5%	13	0.5%	0	0.0%	0	0.0%	26	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	67	2.5%	67	2.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	259	9.6%	90	3.4%	9	0.3%	103	3.8%	462	17.2%



Tennessee State Profile

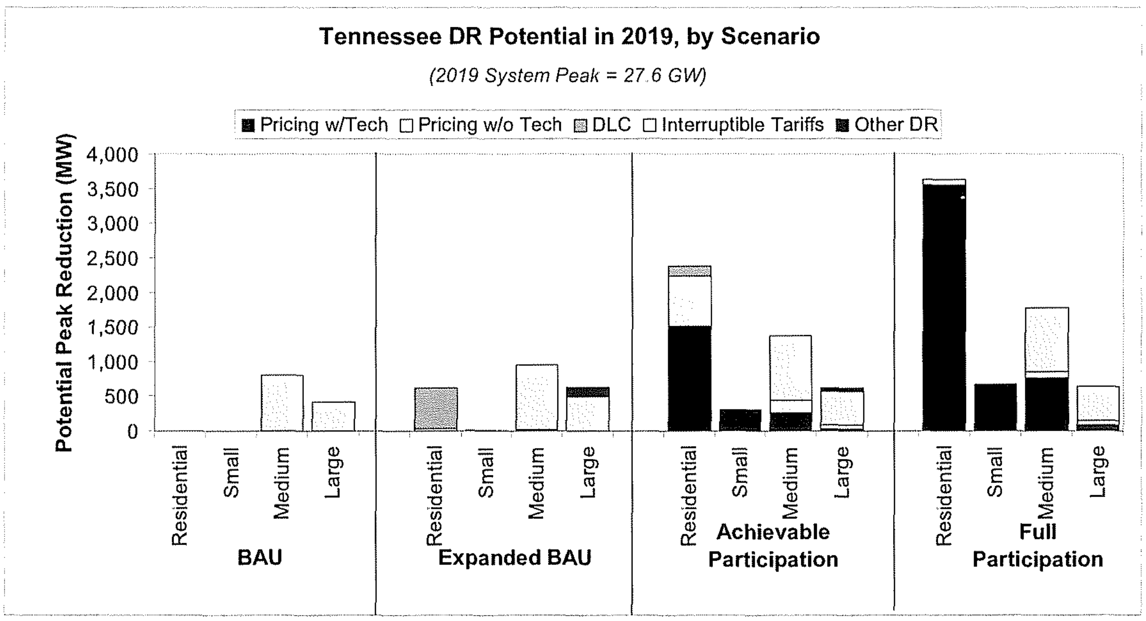
Key drivers of Tennessee's demand response potential estimate include: higher-than-average residential CAC saturation of 81 percent and a moderate amount of existing demand response. Dynamic pricing with enabling technologies are cost-effective for all customer classes. AMI deployment that potentially lags the national average could lead to slower realized demand response potential. Large C&I represents a significantly smaller-than-average share of peak (6%), resulting in a smaller state-wide impact for this class.

BAU: Tennessee has existing demand response for Medium and Large C&I classes, through participation in Interruptible tariffs. A smaller impact comes from Large C&I due to this class representing a smaller portion of overall peak.

Expanded BAU: Demand response potential increase is driven by DLC for Residential customers. Smaller increases result Interruptible and 'Other DR' programs, for the remaining classes.

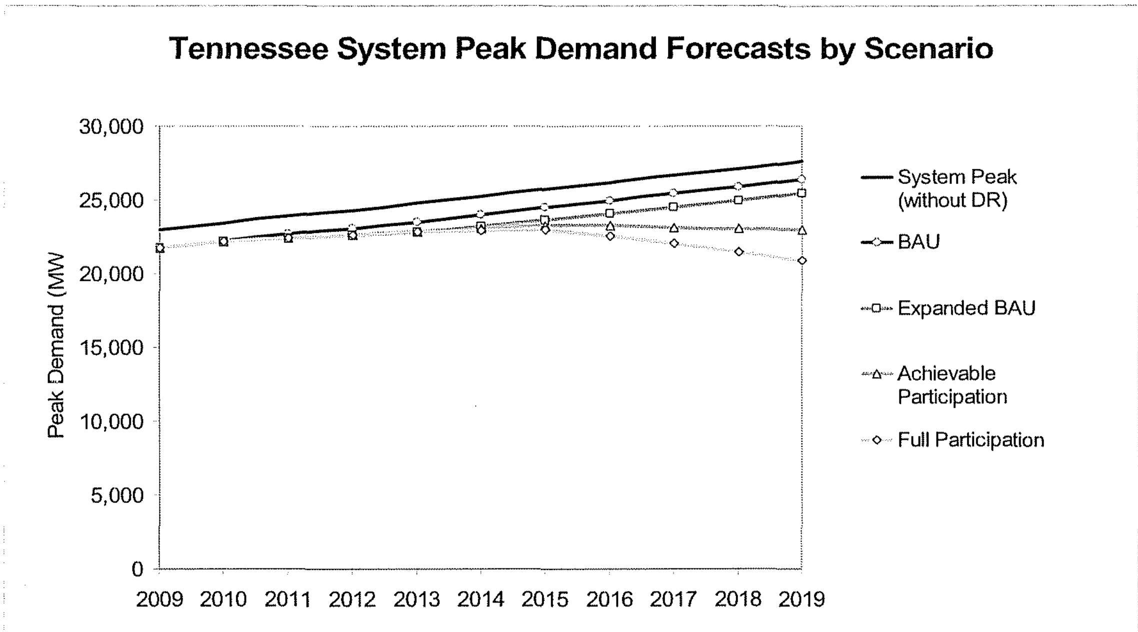
Achievable Participation: Significant potential comes from the two pricing programs, mostly for the residential class of customers. Residential potential demand response is driven by high CAC saturation, leading to this class representing a large share of system peak.

Full Participation: Demand response potential increases are driven mostly by pricing with enabling technology, for all customer classes. This is most pronounced for the residential customers who switch from DLC programs in to pricing with technologies. Again, high CAC saturation drives most of the potential impact for this class of customers.



Total Potential Peak Reduction from Demand Response in Tennessee, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	*0*	*0.0%*	*0*	*0.0%*	*809*	2.9%	425	1.5%	1,234	4.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	809	2.9%	425	1.5%	1,234	4.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	30	0.1%	1	0.0%	8	0.0%	2	0.0%	41	0.1%
Automated/Direct Load Control	586	2.1%	9	0.0%	13	0.0%	0	0.0%	608	2.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	137	0.5%	137	0.5%
Total	617	2.2%	10	0.0%	951	3.4%	627	2.3%	2,204	8.0%
Achievable Participation										
Pricing with Technology	1,515	5.5%	282	1.0%	262	0.9%	29	0.1%	2,087	7.6%
Pricing without Technology	717	2.6%	16	0.1%	174	0.6%	52	0.2%	959	3.5%
Automated/Direct Load Control	149	0.5%	2	0.0%	5	0.0%	0	0.0%	156	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	55	0.2%	56	0.2%
Total	2,381	8.6%	300	1.1%	1,370	5.0%	624	2.3%	4,676	16.9%
Full Participation										
Pricing with Technology	3,544	12.8%	660	2.4%	765	2.8%	83	0.3%	5,053	18.3%
Pricing without Technology	85	0.3%	8	0.0%	84	0.3%	67	0.2%	245	0.9%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	930	3.4%	488	1.8%	1,418	5.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	3,629	13.1%	668	2.4%	1,779	6.4%	639	2.3%	6,715	24.3%



Texas State Profile

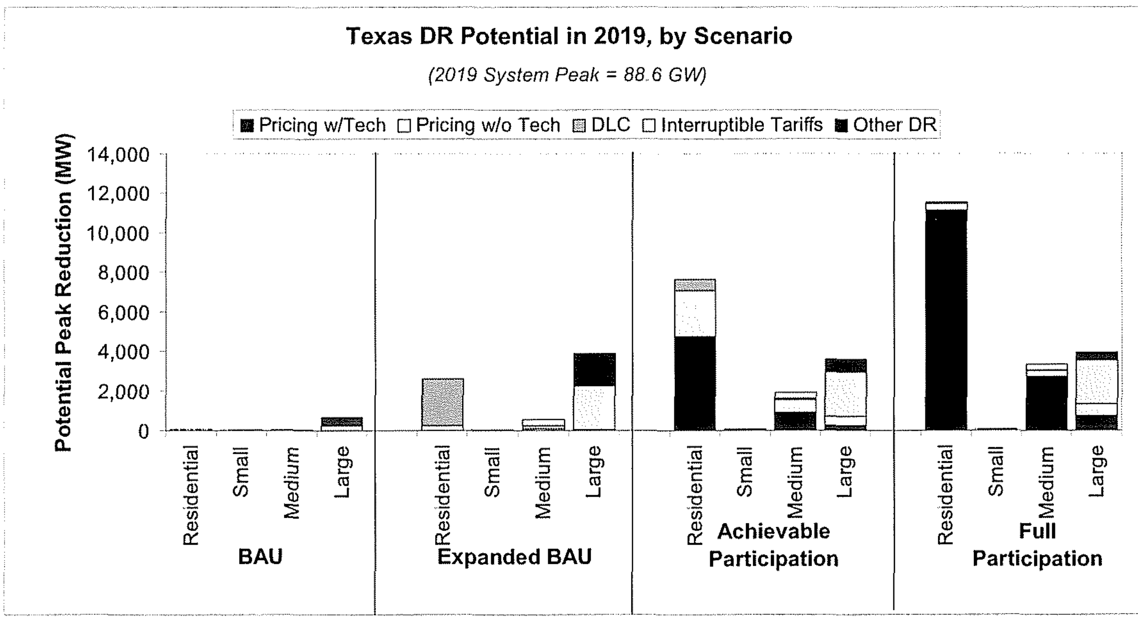
Key drivers of demand response potential in Texas include: higher-than-average residential CAC saturation of 80 percent and very little existing demand response. Enabling technologies are cost-effective for all customer classes, except for small C&I customers. Also, potential AMI deployment significantly leads the national average and could lead to faster realization of potential demand response.

BAU: The majority of Texas's current demand response comes from the Large C&I class, through participation in Interruptible tariffs and 'Other DR' programs in the ERCOT market. The state has a small amount of direct load control for the other customer classes.

Expanded BAU: High CAC saturation leads to growth in residential demand response potential through direct load control. Most of the remaining growth in potential comes from the Large C&I class, through participation in Interruptible and 'Other DR' programs.

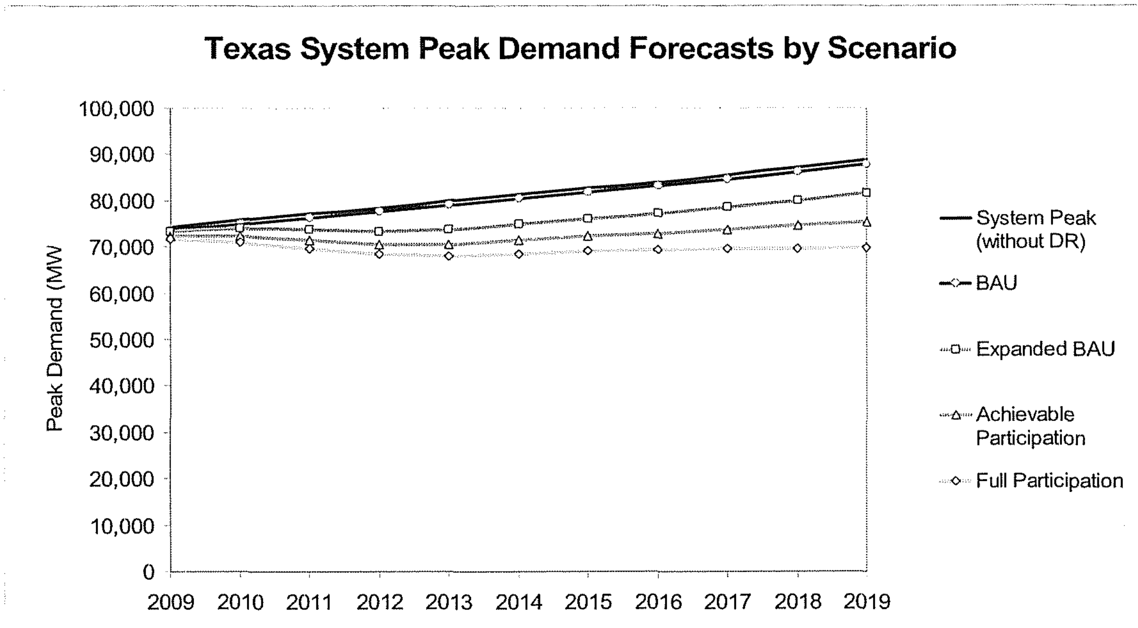
Achievable Participation: High CAC saturation coupled with faster-than-average AMI deployment lead to significant potential acceptance of dynamic pricing for the Residential class. Some residential growth results from customers shifting from DLC programs in to the two dynamic pricing programs. Small increases in demand response potential result from medium and large C&I customers enrolling in both dynamic pricing programs.

Full Participation: Significant demand response potential comes from the Residential class, driven primarily by high CAC saturation and a faster-than-average AMI penetration rate. Both Medium and Large C&I classes show growth in demand response through increased enrollment in dynamic pricing with enabling technology.



Total Potential Peak Reduction from Demand Response in Texas, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	79	0.1%	39	0.0%	48	0.1%	0	0.0%	166	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	232	0.3%	232	0.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	413	0.5%	413	0.5%
Total	79	0.1%	39	0.0%	48	0.1%	645	0.7%	810	0.9%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	236	0.3%	1	0.0%	70	0.1%	35	0.0%	343	0.4%
Automated/Direct Load Control	2,371	2.7%	39	0.0%	190	0.2%	0	0.0%	2,599	2.9%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	3	0.0%	1,640	1.9%	1,643	1.9%
Total	2,607	2.9%	40	0.0%	543	0.6%	3,894	4.4%	7,083	8.0%
Achievable Participation										
Pricing with Technology	4,758	5.4%	0	0.0%	925	1.0%	250	0.3%	5,932	6.7%
Pricing without Technology	2,289	2.6%	27	0.0%	615	0.7%	454	0.5%	3,386	3.8%
Automated/Direct Load Control	614	0.7%	39	0.0%	79	0.1%	0	0.0%	732	0.8%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	1	0.0%	680	0.8%	681	0.8%
Total	7,661	8.6%	66	0.1%	1,900	2.1%	3,602	4.1%	13,230	14.9%
Full Participation										
Pricing with Technology	11,129	12.6%	0	0.0%	2,703	3.1%	730	0.8%	14,562	16.4%
Pricing without Technology	318	0.4%	37	0.0%	298	0.3%	588	0.7%	1,241	1.4%
Automated/Direct Load Control	79	0.1%	39	0.0%	48	0.1%	0	0.0%	166	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	280	0.3%	2,218	2.5%	2,498	2.8%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	413	0.5%	413	0.5%
Total	11,525	13.0%	75	0.1%	3,330	3.8%	3,949	4.5%	18,880	21.3%



Utah State Profile

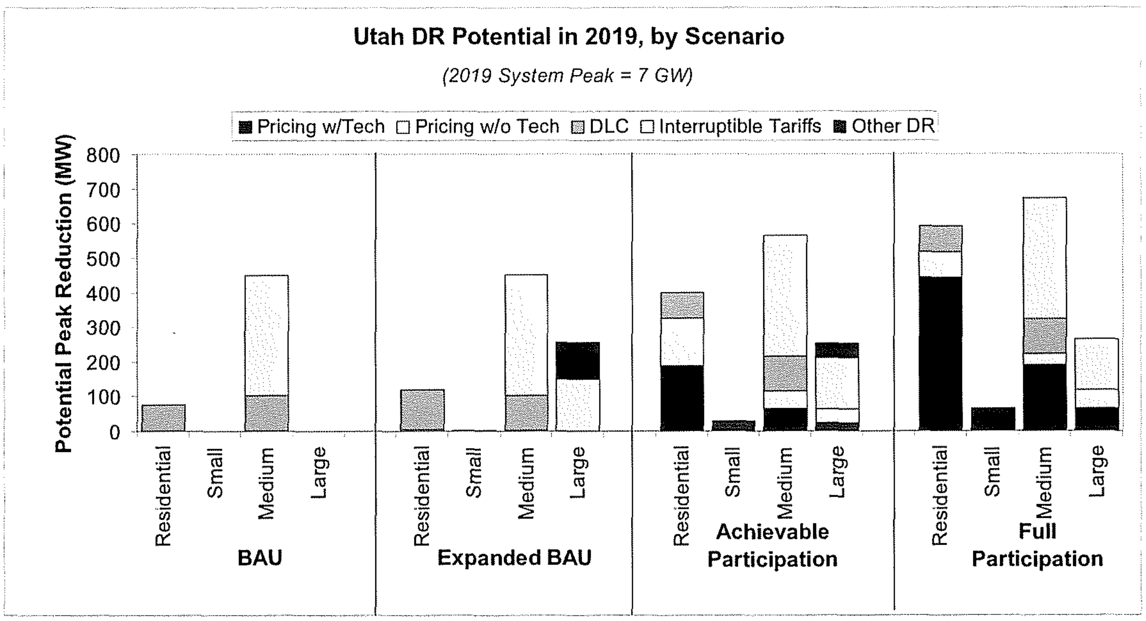
Key drivers of Utah's demand response potential estimate include: lower-than-average residential CAC saturation of 42 percent and a fair amount of existing demand response. Enabling technologies are cost-effective for all customer classes. The state has a smaller-than-average Residential class and AMI deployment that potentially lags the national average, potentially leading to slower realized demand response potential. The state is characterized by a larger-than-average Medium C&I class that has significant amounts of existing demand response.

BAU: Utah's existing demand response is characterized by a large interruptible tariff program for the Medium C&I class. The rest of the existing demand response is through direct load control programs for the Residential and Medium C&I classes.

Expanded BAU: The majority of the growth in demand response potential is driven by interruptible tariffs and other demand response for the Large C&I class.

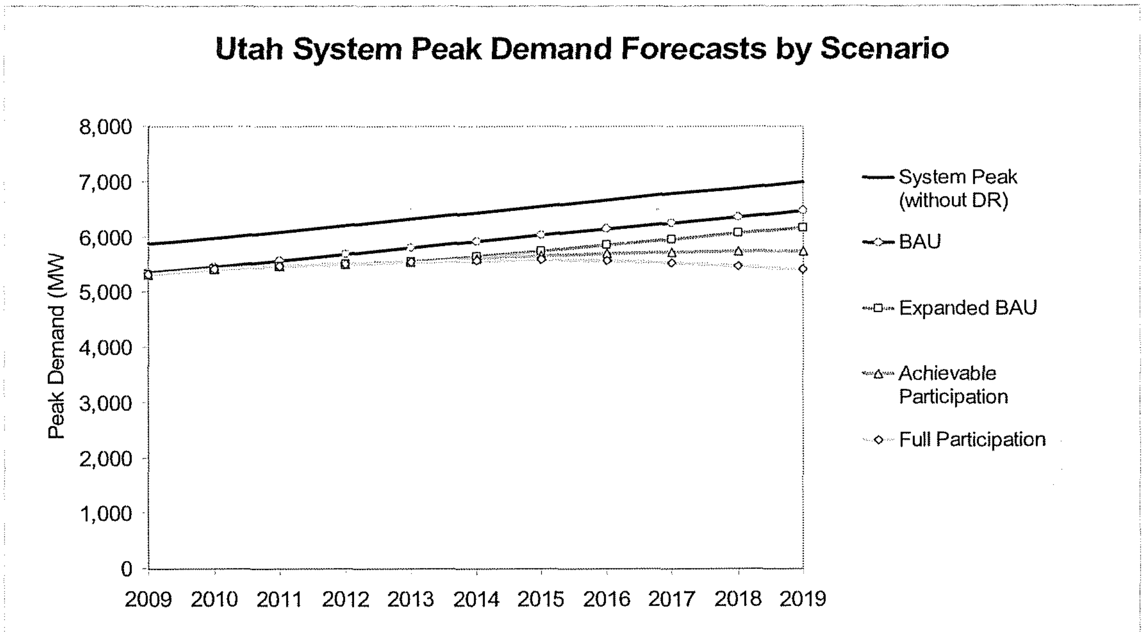
Achievable Participation: Demand response potential for this scenario comes mostly through the two dynamic pricing programs, with the majority utilizing enabling technologies. Enabling technologies are cost-effective for all customer classes.

Full Participation: Under this scenario, dynamic pricing with enabling technology continues to grow for all customer classes. Demand response potential for the Large C&I class decreases slightly, as customers switch from other demand response programs to the dynamic pricing programs, which have smaller per-customer impacts.



Total Potential Peak Reduction from Demand Response in Utah, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	*0*	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	75	1.1%	0	0.0%	102	1.5%	0	0.0%	177	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	0	0.0%	347	5.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	75	1.1%	0	0.0%	449	6.4%	0	0.0%	524	7.5%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	4	0.1%	0	0.0%	2	0.0%	1	0.0%	7	0.1%
Automated/Direct Load Control	115	1.6%	2	0.0%	102	1.5%	0	0.0%	219	3.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	107	1.5%	107	1.5%
Total	119	1.7%	2	0.0%	451	6.4%	256	3.7%	828	11.8%
Achievable Participation										
Pricing with Technology	190	2.7%	27	0.4%	65	0.9%	22	0.3%	304	4.4%
Pricing without Technology	136	1.9%	2	0.0%	50	0.7%	40	0.6%	228	3.3%
Automated/Direct Load Control	75	1.1%	1	0.0%	102	1.5%	0	0.0%	178	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	43	0.6%	43	0.6%
Total	401	5.7%	30	0.4%	564	8.1%	254	3.6%	1,249	17.9%
Full Participation										
Pricing with Technology	444	6.3%	64	0.9%	191	2.7%	65	0.9%	763	10.9%
Pricing without Technology	72	1.0%	1	0.0%	32	0.5%	52	0.7%	158	2.3%
Automated/Direct Load Control	75	1.1%	0	0.0%	102	1.5%	0	0.0%	177	2.5%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	347	5.0%	148	2.1%	495	7.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	591	8.5%	65	0.9%	671	9.6%	266	3.8%	1,593	22.8%



Vermont State Profile

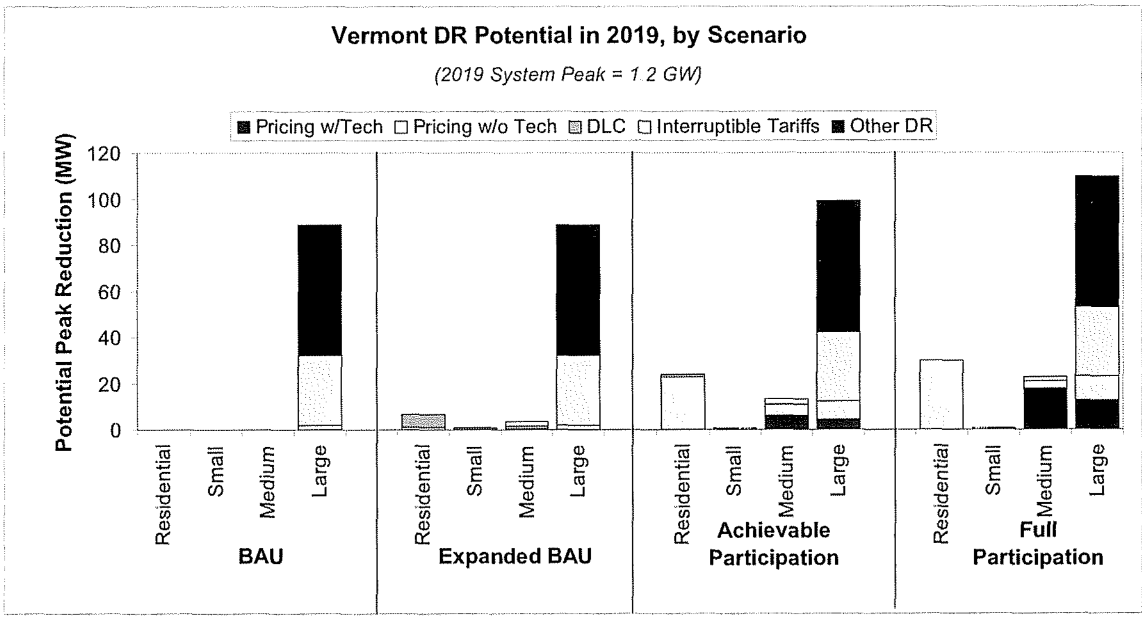
Key drivers of Vermont's demand response potential estimate include: significantly lower-than-average CAC saturation of 7 percent and enabling technologies that are cost-effective for only the Medium and Large C&I classes. Vermont's potential AMI deployment could lead the national average and result in faster realized demand response potential. However, the key driver of this state's demand response potential is very low residential CAC saturation and enabling technologies not being cost-effective for this class, leading to fairly small incremental potential relative to the BAU scenario.

BAU: Vermont has a large amount of existing demand response for the Large C&I class, through interruptible tariffs and other demand response.

Expanded BAU: Small demand response potential increases occur for the Large C&I class, through interruptible tariffs and other demand response. The Residential class shows a small amount of potential demand response through participation in DLC programs.

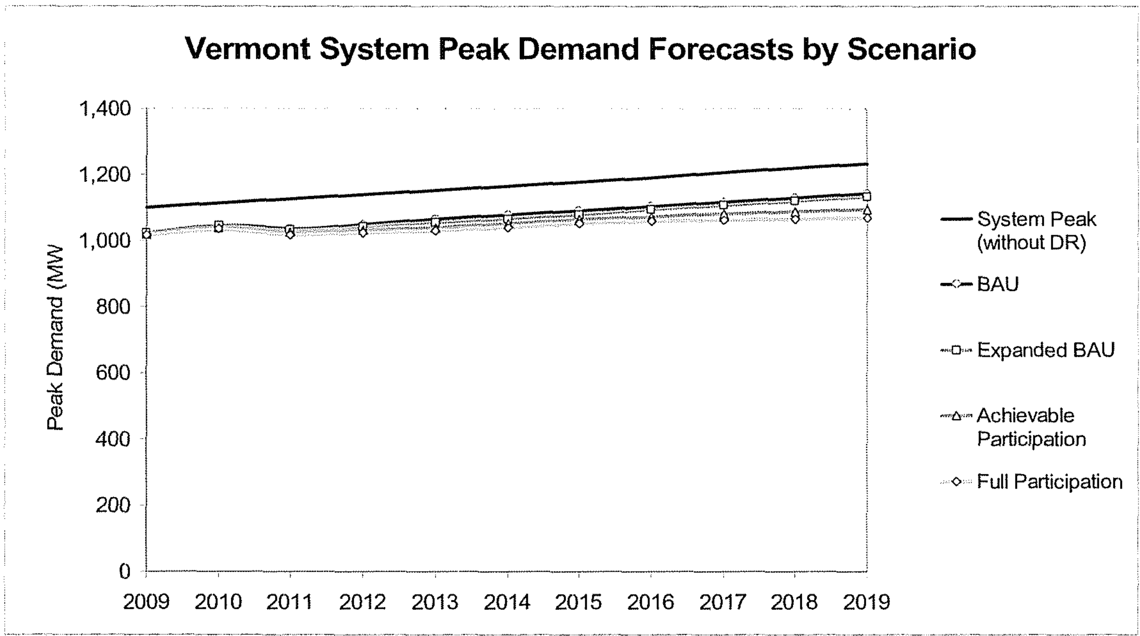
Achievable Participation: Residential and Medium and Large C&I classes show slight increases in dynamic pricing programs. The residential class has a much smaller-than-average demand response potential due to very low CAC saturation and enabling technologies not being cost-effective for this class.

Full Participation: Small increases in potential demand response result for all classes of customers. Overall the state shows a small amount incremental demand response potential driven primarily by low CAC saturation and enabling technologies not being cost-effective for both Residential and Small C&I classes.



Total Potential Peak Reduction from Demand Response in Vermont, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	2	0.2%	2	0.2%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	30	2.4%	30	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	0	0.0%	0	0.0%	0	0.0%	89	7.2%	89	7.2%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.1%	0	0.0%	0	0.0%	2	0.2%	3	0.3%
Automated/Direct Load Control	6	0.5%	1	0.1%	1	0.1%	0	0.0%	8	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	7	0.5%	1	0.1%	4	0.3%	89	7.2%	100	8.1%
Achievable Participation										
Pricing with Technology	0	0.0%	0	0.0%	6	0.5%	4	0.4%	10	0.8%
Pricing without Technology	23	1.8%	1	0.0%	5	0.4%	8	0.6%	36	2.9%
Automated/Direct Load Control	1	0.1%	0	0.0%	0	0.0%	0	0.0%	2	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	24	1.9%	1	0.1%	13	1.1%	99	8.0%	137	11.1%
Full Participation										
Pricing with Technology	0	0.0%	0	0.0%	18	1.4%	13	1.0%	30	2.5%
Pricing without Technology	30	2.4%	1	0.1%	3	0.3%	10	0.8%	44	3.6%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	2	0.2%	30	2.4%	32	2.6%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	57	4.6%	57	4.6%
Total	30	2.4%	1	0.1%	23	1.8%	110	8.9%	163	13.2%



Virginia State Profile

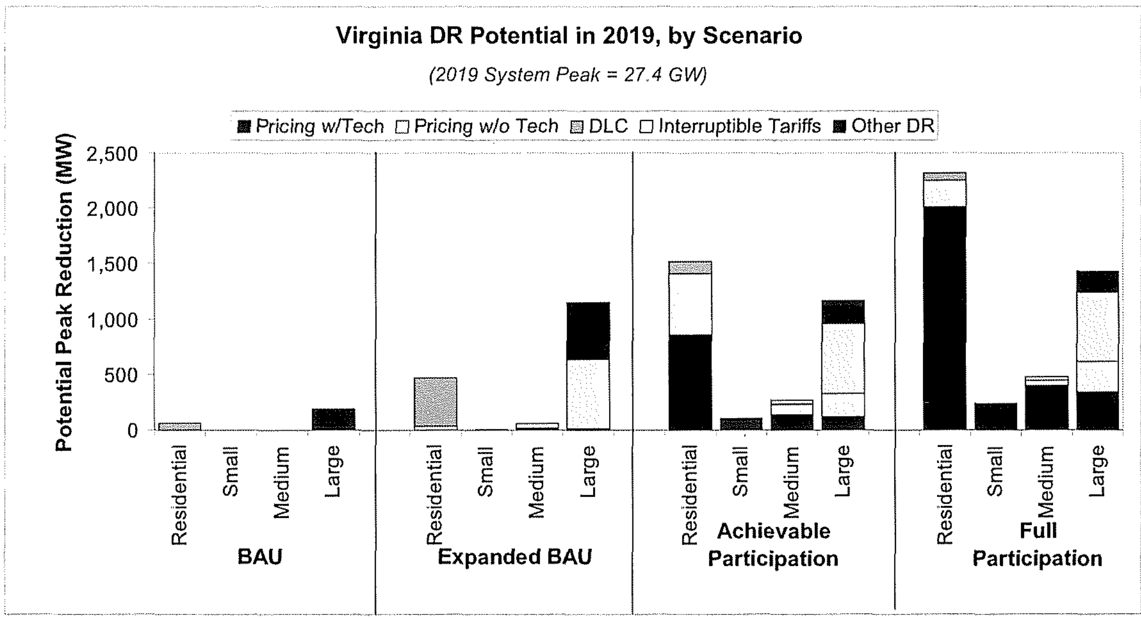
Key drivers of Virginia's demand response potential include lower-than-average residential CAC saturation (50 percent) and a small amount of existing demand response. Enabling technologies are cost-effective for all customer classes. Also, potential AMI deployment slightly leads the national average. A Large C&I class with a higher than average share of the system peak results in the class representing a significant amount of the state's overall demand response potential.

BAU: Virginia's small amount of existing demand response comes from DLC programs for residential customers and large C&I customer participation in 'Other DR' programs.

Expanded BAU: Growth in potential demand response is the result of higher than average peak demand in the large C&I class, resulting in large impacts from both interruptible tariffs and other demand response. The Residential class has a significant growth in load reduction coming from DLC programs.

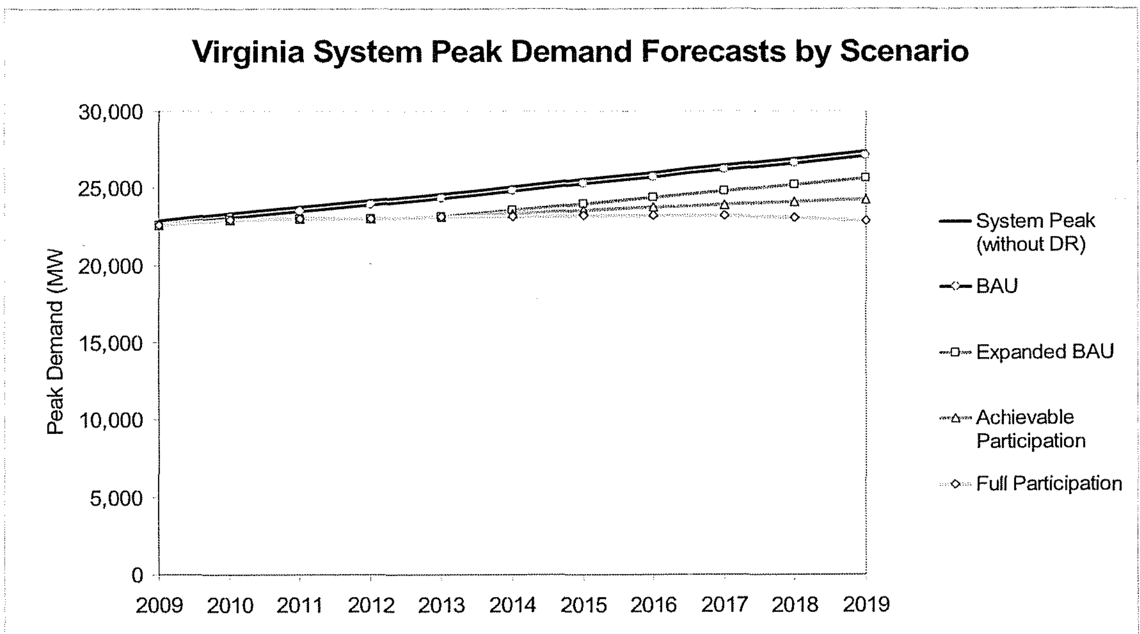
Achievable Participation: Enabling technologies are cost-effective for all customer classes, resulting in large dynamic pricing potential growth from these technologies. The Residential and Small C&I classes show customers enrolling in to the two dynamic pricing programs rather than in DLC programs.

Full Participation: The cost-effectiveness of enabling technology leads to significant growth in dynamic pricing for all classes, especially residential customers. The Residential and Large C&I classes account for most of the peak load, resulting in the majority of the demand response potential coming from these two classes.



Total Potential Peak Reduction from Demand Response in Virginia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	68	0.2%	0	0.0%	0	0.0%	0	0.0%	68	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	1	0.0%	2	0.0%	3	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	189	0.7%	189	0.7%
Total	68	0.2%	0	0.0%	1	0.0%	191	0.7%	260	1.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	32	0.1%	0	0.0%	7	0.0%	11	0.0%	50	0.2%
Automated/Direct Load Control	439	1.6%	8	0.0%	14	0.1%	0	0.0%	461	1.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	519	1.9%	519	1.9%
Total	471	1.7%	8	0.0%	57	0.2%	1,154	4.2%	1,691	6.2%
Achievable Participation										
Pricing with Technology	861	3.1%	100	0.4%	137	0.5%	117	0.4%	1,215	4.4%
Pricing without Technology	550	2.0%	5	0.0%	91	0.3%	213	0.8%	859	3.1%
Automated/Direct Load Control	112	0.4%	2	0.0%	6	0.0%	0	0.0%	120	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	212	0.8%	212	0.8%
Total	1,523	5.6%	107	0.4%	270	1.0%	1,167	4.3%	3,068	11.2%
Full Participation										
Pricing with Technology	2,015	7.4%	233	0.9%	400	1.5%	342	1.2%	2,990	10.9%
Pricing without Technology	238	0.9%	3	0.0%	44	0.2%	276	1.0%	560	2.0%
Automated/Direct Load Control	68	0.2%	0	0.0%	0	0.0%	0	0.0%	68	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.1%	625	2.3%	662	2.4%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	189	0.7%	189	0.7%
Total	2,321	8.5%	236	0.9%	480	1.8%	1,431	5.2%	4,468	16.3%



Washington State Profile

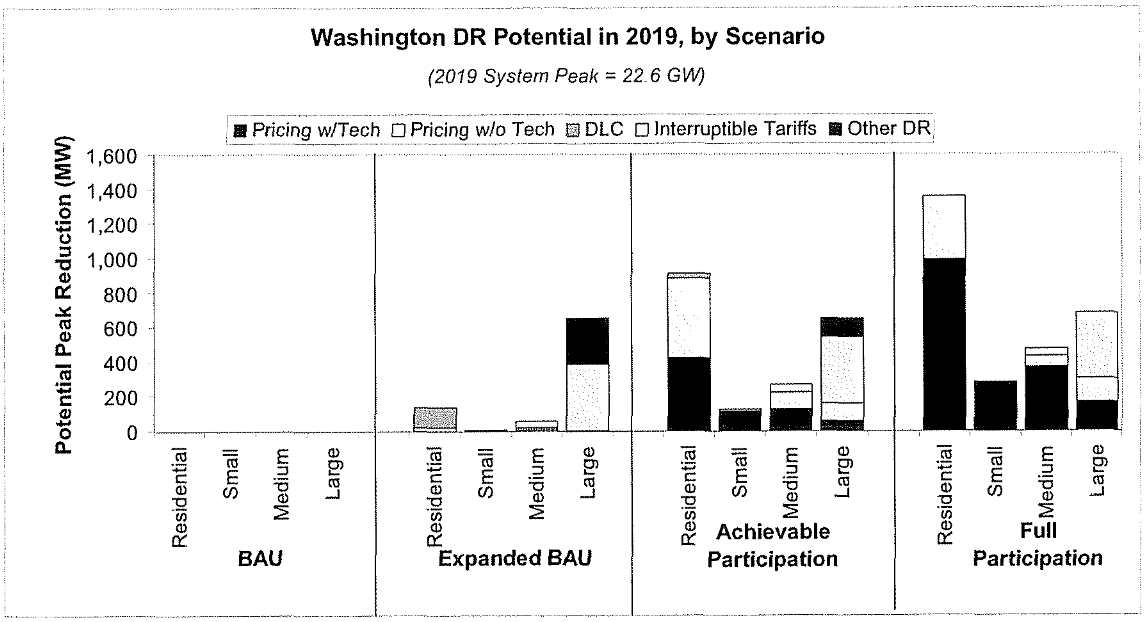
Key drivers of Washington's demand response potential estimate include: lower-than-average residential CAC saturation of 29 percent and no existing demand response. Enabling technologies are cost-effective for all classes. Also, the state's potential AMI deployment slightly leads the national average. Low CAC saturation and non-existent demand response are the key drivers for the state.

BAU: Currently, the state has no demand response. Historically, low energy prices and a surplus of hydro capacity have made demand response seemingly less attractive in this region.

Expanded BAU: The majority of the potential demand response is from Large C&I, through interruptible tariffs and other demand response. Some Residential demand response potential comes from DLC and dynamic pricing.

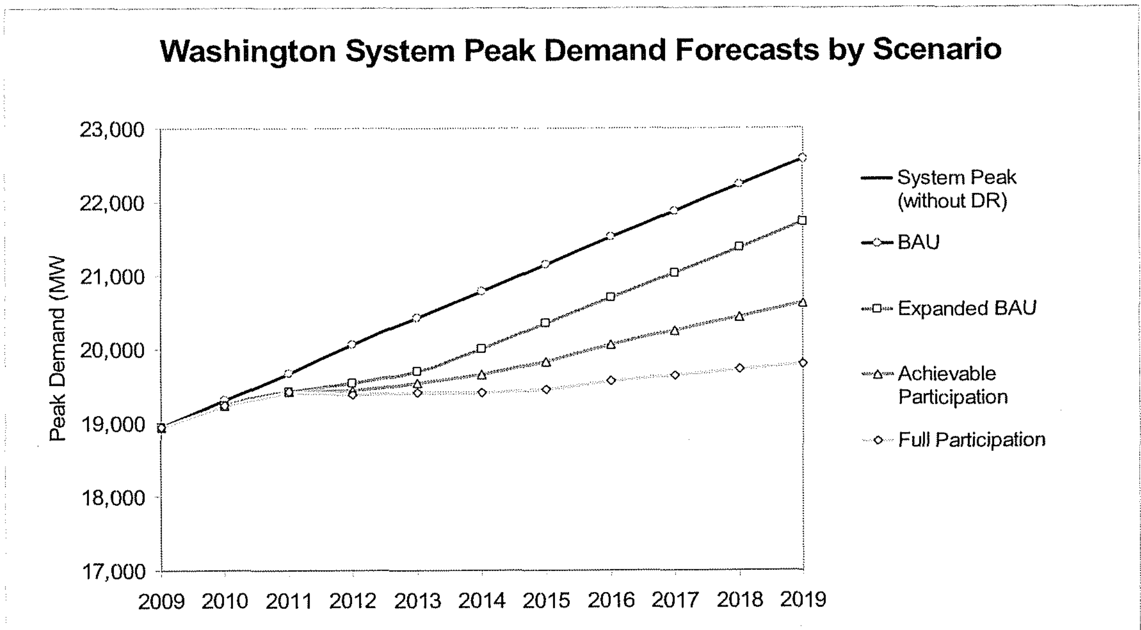
Achievable Participation: Demand response potential is driven by dynamic pricing with and without enabling technology. Many of the residential customers enrolled in DLC programs under the EBAU scenario would instead be expected to enroll in dynamic pricing with enabling technology under this scenario. Relative to the EBAU scenario, Large C&I customers would be enrolled more heavily in dynamic pricing than in interruptible tariff and other demand response programs.

Full Participation: Dynamic pricing programs dominate the demand response potential for this scenario, primarily those utilizing enabling technologies. The largest amount of load reduction can be potentially derived from residential customers. Enabling technologies are cost-effective for all customer classes. Some interruptible tariff demand response remains for both Medium and Large C&I.



Total Potential Peak Reduction from Demand Response in Washington, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	7	0.0%	5	0.0%	33	0.1%
Automated/Direct Load Control	118	0.5%	8	0.0%	12	0.1%	0	0.0%	138	0.6%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	271	1.2%	271	1.2%
Total	139	0.6%	9	0.0%	60	0.3%	657	2.9%	864	3.8%
Achievable Participation										
Pricing with Technology	424	1.9%	118	0.5%	127	0.6%	57	0.3%	725	3.2%
Pricing without Technology	457	2.0%	8	0.0%	97	0.4%	104	0.5%	665	2.9%
Automated/Direct Load Control	30	0.1%	2	0.0%	5	0.0%	0	0.0%	37	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	111	0.5%	111	0.5%
Total	911	4.0%	128	0.6%	270	1.2%	652	2.9%	1,960	8.7%
Full Participation										
Pricing with Technology	991	4.4%	275	1.2%	370	1.6%	167	0.7%	1,803	8.0%
Pricing without Technology	365	1.6%	5	0.0%	62	0.3%	134	0.6%	567	2.5%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	41	0.2%	381	1.7%	422	1.9%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	1,357	6.0%	280	1.2%	473	2.1%	682	3.0%	2,792	12.4%



West Virginia State Profile

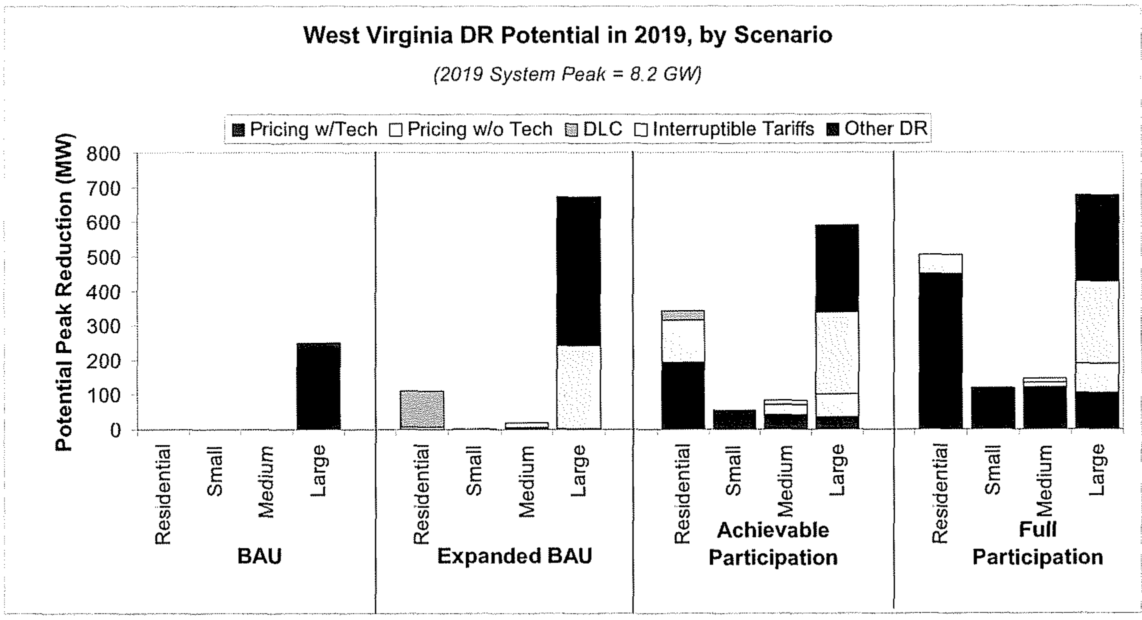
Key drivers of West Virginia's demand response potential estimate include: a CAC saturation of 50 percent and a moderate amount of existing demand response, and a larger-than-average Large C&I class (32%). Enabling technologies are cost-effective for all classes of customers. Also, potential AMI deployment slightly leads the national average. The larger-than-average Large C&I class, with significant existing demand response, is the primary driver for the state.

BAU: West Virginia has a significant amount of existing demand response for the Large C&I class, but none for the remaining classes.

Expanded BAU: Demand response potential comes primarily from the Residential and Large C&I classes. Residential demand response potential is in DLC programs, while the incremental increase in Large C&I potential is in interruptible tariff and 'Other DR' programs.

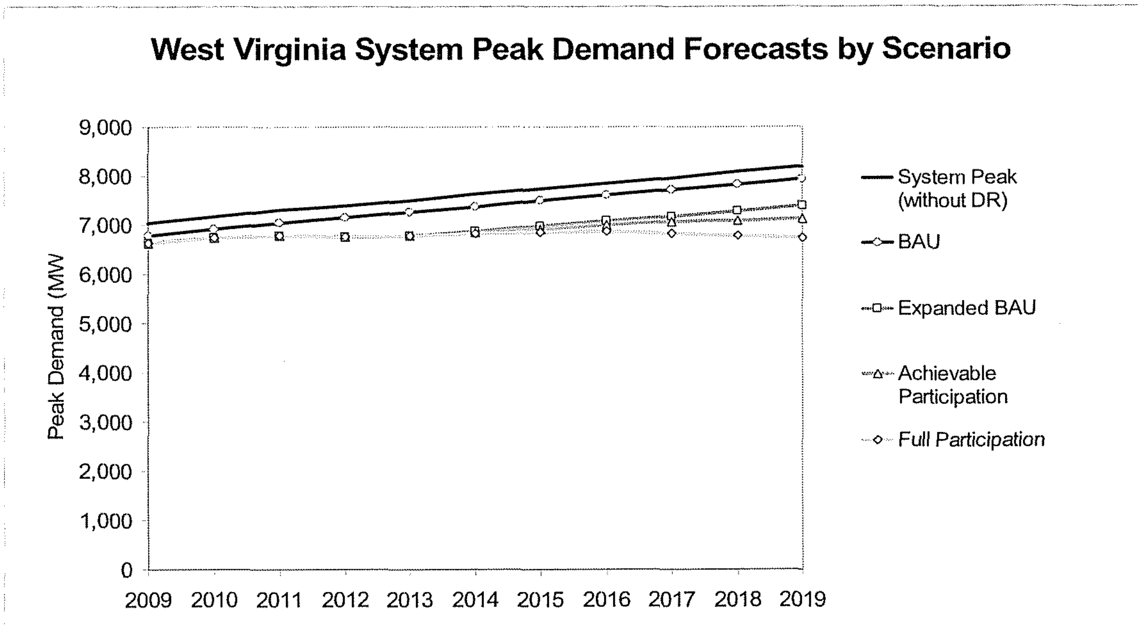
Achievable Participation: The main driver of demand response potential in this scenario is through dynamic pricing, with a significant amount of impact coming from the use of enabling technologies. Enabling technologies are cost-effective for all customer classes. The Large C&I class continues to dominate demand response potential because of its larger-than-average share of system peak load.

Full Participation: Demand response potential from dynamic pricing with enabling technology is largest under this scenario, with all customer classes exhibiting incremental increases in demand response potential relative to the other scenarios. For large C&I customers, potential from Interruptible tariffs and 'Other DR' programs continue to dominate.



Total Potential Peak Reduction from Demand Response in West Virginia, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	7	0.1%	0	0.0%	2	0.0%	3	0.0%	12	0.1%
Automated/Direct Load Control	104	1.3%	3	0.0%	5	0.1%	0	0.0%	112	1.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	431	5.3%	431	5.3%
Total	111	1.4%	3	0.0%	19	0.2%	672	8.2%	806	9.8%
Achievable Participation										
Pricing with Technology	192	2.3%	50	0.6%	42	0.5%	36	0.4%	320	3.9%
Pricing without Technology	123	1.5%	3	0.0%	28	0.3%	65	0.8%	219	2.7%
Automated/Direct Load Control	27	0.3%	1	0.0%	2	0.0%	0	0.0%	29	0.4%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	342	4.2%	54	0.7%	84	1.0%	589	7.2%	1,069	13.1%
Full Participation										
Pricing with Technology	450	5.5%	118	1.4%	121	1.5%	104	1.3%	794	9.7%
Pricing without Technology	54	0.7%	1	0.0%	13	0.2%	84	1.0%	153	1.9%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	13	0.2%	238	2.9%	251	3.1%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	250	3.1%	250	3.1%
Total	504	6.2%	119	1.5%	147	1.8%	677	8.3%	1,448	17.7%



Wisconsin State Profile

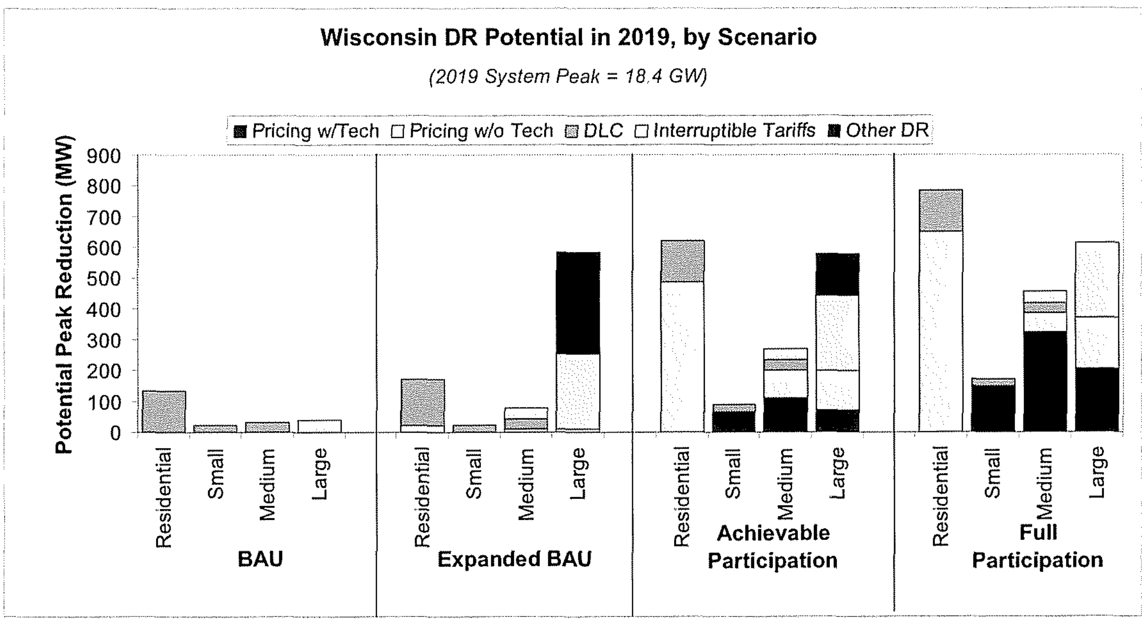
Key drivers of Wisconsin's demand response potential estimate include: a significant level of CAC saturation at 62 percent and a small amount of existing demand response. Enabling technologies are cost-effective for all C&I classes, but not for the Residential class. Also, a potential AMI deployment schedule that leads the national average could lead to faster realized demand response potential.

BAU: Wisconsin has existing demand response for Large C&I through an interruptible tariff program. DLC programs are in place for the remaining customer classes, with the Residential class exhibiting the largest impacts.

Expanded BAU: The Large C&I class exhibits significant demand response potential, which is driven by enrollment in new interruptible tariff and other demand response programs. Dynamic pricing plays a very small role relative to DLC impacts for Residential customers in this scenario

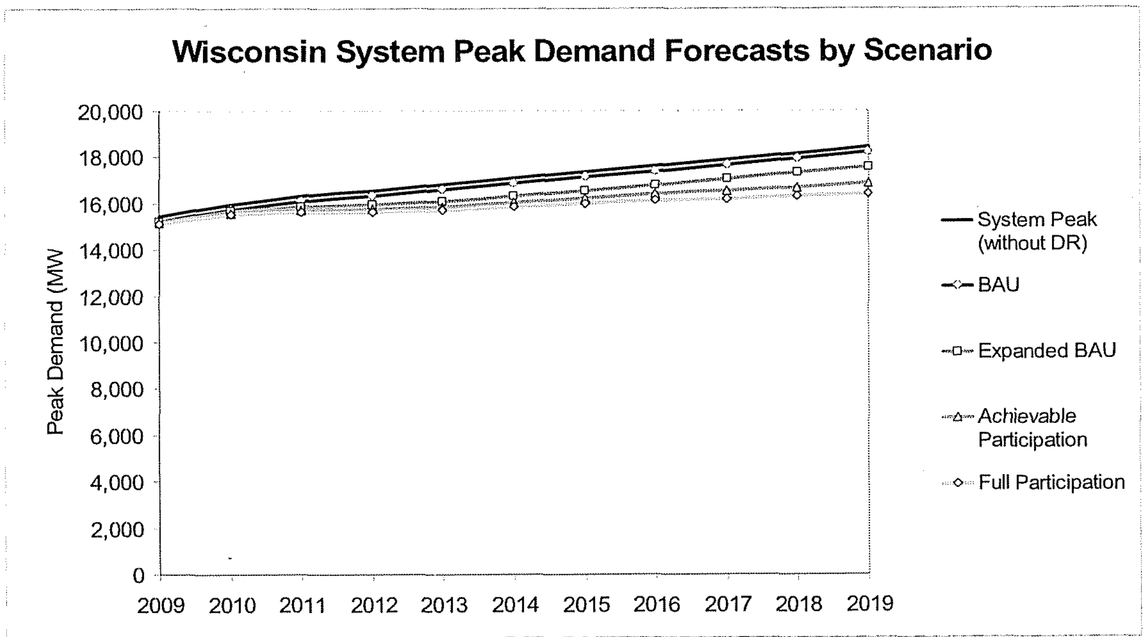
Achievable Participation: The majority of the incremental increase in demand response potential is due to dynamic pricing. Pricing with enabling technologies appears for all classes, except for the Residential class for which it is not cost effective. Still, the Residential class exhibits significant potential through participation in dynamic pricing programs without enabling technology. Total potential demand response decreases for the Large C&I class as a result of customers shifting to dynamic pricing programs, which produce smaller per-customer impacts.

Full Participation: Potential demand response continues to grow through increased enrollment in dynamic pricing programs. Large C&I customers are more heavily enrolled in dynamic pricing programs, slightly decreasing potential impacts from this class.



Total Potential Peak Reduction from Demand Response in Wisconsin, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	40	0.2%	40	0.2%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	135	0.7%	24	0.1%	33	0.2%	40	0.2%	231	1.3%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	21	0.1%	0	0.0%	9	0.0%	9	0.0%	39	0.2%
Automated/Direct Load Control	151	0.8%	24	0.1%	33	0.2%	0	0.0%	207	1.1%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	331	1.8%	331	1.8%
Total	172	0.9%	24	0.1%	79	0.4%	583	3.2%	858	4.7%
Achievable Participation										
Pricing with Technology	0	0.0%	63	0.3%	111	0.6%	70	0.4%	244	1.3%
Pricing without Technology	487	2.6%	4	0.0%	89	0.5%	128	0.7%	707	3.8%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	137	0.7%	137	0.7%
Total	621	3.4%	90	0.5%	270	1.5%	579	3.1%	1,560	8.5%
Full Participation										
Pricing with Technology	0	0.0%	147	0.8%	324	1.8%	205	1.1%	677	3.7%
Pricing without Technology	649	3.5%	2	0.0%	61	0.3%	166	0.9%	878	4.8%
Automated/Direct Load Control	135	0.7%	24	0.1%	33	0.2%	0	0.0%	191	1.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	37	0.2%	244	1.3%	281	1.5%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	784	4.3%	173	0.9%	455	2.5%	615	3.3%	2,027	11.0%



Wyoming State Profile

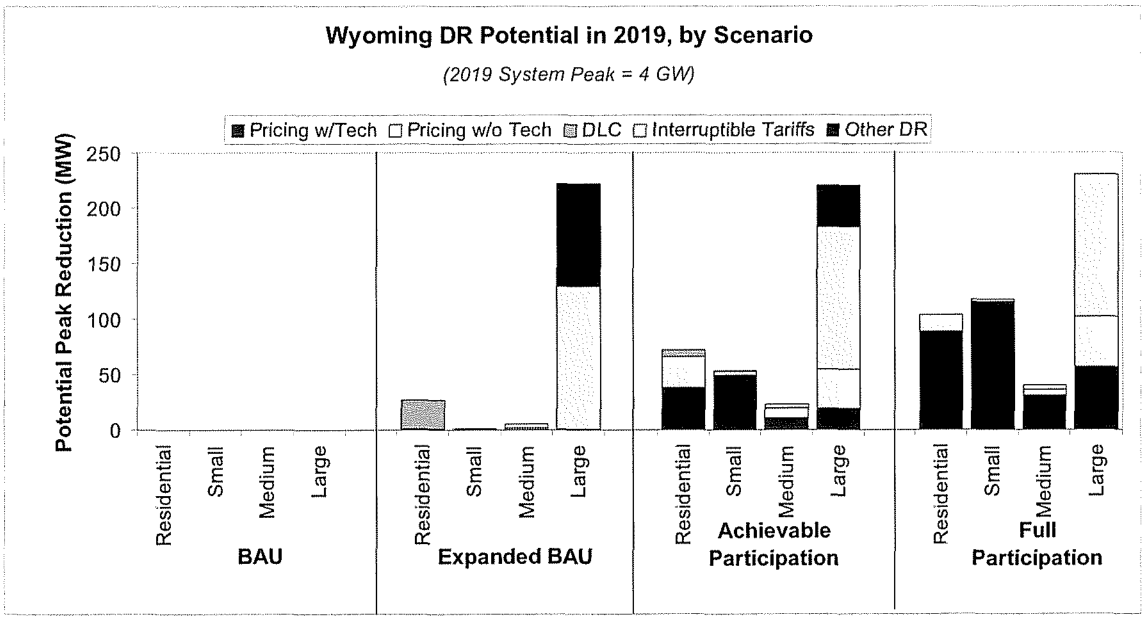
Key drivers of Wyoming's demand response potential estimate include: lower-than-average residential CAC saturation of 42 percent and no existing demand response. Enabling technologies are cost-effective for all C&I classes and for residential customers. Also, potential AMI deployment that lags the national average could lead to slower realized demand response potential. The larger-than-average Large C&I class (36%) is the main driver of demand response in the state.

BAU: Currently, Wyoming has no existing demand response.

Expanded BAU: The Large C&I class represents the vast majority of demand response potential in the state, through enrollment in both interruptible tariff and other demand response programs. A moderate amount of demand response potential exists in residential DLC programs.

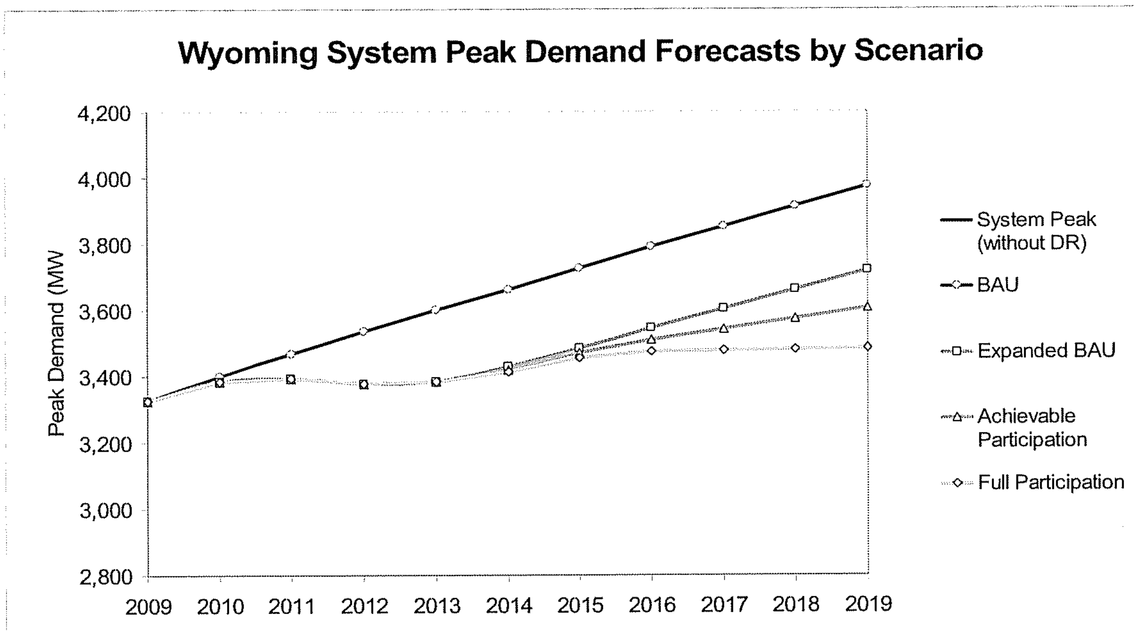
Achievable Participation: Impacts from dynamic pricing are relatively small compared to demand response potential in Other DR and Interruptible tariffs. All classes adopt enabling technologies. Total demand response potential decreases slightly for the Large C&I class due to customers shifting from other demand response programs in to pricing programs, which have smaller per- customer peak impacts.

Full Participation: Incremental demand response potential is highest for the residential, small, and medium C&I classes under this scenario. The Large C&I class drives total potential demand response in the state.



Total Potential Peak Reduction from Demand Response in Wyoming, 2019

	Residential (MW)	Residential (% of system)	Small C&I (MW)	Small C&I (% of system)	Med. C&I (MW)	Med C&I (% of system)	Large C&I (MW)	Large C&I (% of system)	Total (MW)	Total (% of system)
BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Expanded BAU										
Pricing with Technology	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Pricing without Technology	1	0.0%	0	0.0%	0	0.0%	1	0.0%	2	0.0%
Automated/Direct Load Control	26	0.7%	1	0.0%	1	0.0%	0	0.0%	29	0.7%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	93	2.3%	93	2.3%
Total	27	0.7%	1	0.0%	5	0.1%	222	5.6%	256	6.4%
Achievable Participation										
Pricing with Technology	38	0.9%	49	1.2%	11	0.3%	19	0.5%	117	2.9%
Pricing without Technology	28	0.7%	3	0.1%	8	0.2%	35	0.9%	74	1.9%
Automated/Direct Load Control	7	0.2%	0	0.0%	1	0.0%	0	0.0%	8	0.2%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	37	0.9%	37	0.9%
Total	72	1.8%	53	1.3%	23	0.6%	220	5.5%	368	9.3%
Full Participation										
Pricing with Technology	88	2.2%	115	2.9%	31	0.8%	56	1.4%	291	7.3%
Pricing without Technology	15	0.4%	2	0.1%	5	0.1%	45	1.1%	68	1.7%
Automated/Direct Load Control	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Interruptible/Curtailable Tariffs	0	0.0%	0	0.0%	3	0.1%	129	3.2%	132	3.3%
Other DR Programs	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total	104	2.6%	117	3.0%	40	1.0%	230	5.8%	491	12.4%



ATTACHMENTS

SC Responses to

KPC-22(a)

Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, MA 02139
Tel 617 661 3248 F 617 661 0599
www.synapse-energy.com

Synapse Mini-Paper

To: Interested energy advocates and analysts
From: Bruce Biewald and Sarah Jackson
Re: Exelon's Maryland coal plant sale, a window on the market value of coal in the US
Date: August 29, 2012

On August 9, 2012, Exelon Power announced that it would sell the three Maryland coal-fired power plants it had acquired in its $7.9 billion merger with Constellation Energy Group. This asset sale provides a rare market test for the value of coal-fired generating capacity in US electricity markets. It also offers an important cautionary tale about emission control investments and planning risk. The owner of this capacity recently invested roughly one billion in environmental retrofits, only to find that the market value of the assets is only $400 million.[1] This suggests that the "assets" without the retrofit investment would have a significant negative market value of more than one half of a billion dollars. Owners of existing coal units facing environmental retrofit requirements should consider retiring the plants rather than sinking hundreds of millions of dollars into an uneconomic stranded investment. Merchant generation owners such as Constellation/Exelon who make investments in uneconomic plants will be looking at write-offs. Regulated utility generation owners who make such imprudent investments will be facing rate disallowances for imprudent planning.

Between 2008 and 2010, in order to meet the Maryland Healthy Air Act and in anticipation of federal environmental regulations, Constellation spent approximately $1 billion retrofitting the coal units at the Brandon Shores, C.P. Crane, and H.A. Wagner power plants. These plants have the following characteristics:

Plant	Unit	Capacity (MW)*	Capacity Factor**	Vintage	Fuel Type
Brandon Shores	1	635	49%	1984	Coal
	2	638	57%	1991	Coal
CP Crane	1	190	30%	1961	Coal
	2	195	29%	1963	Coal
HA Wagner	1	126	3%	1956	NG (oil backup)
	2	135	33%	1959	Coal
	3	305	42%	1966	Coal
	4	397	1%	1972	Oil
Coal Subtotal		2,098			
Oil & Gas Subtotal		523			
Total Capacity		**2,621**			

Source: * EIA Form 860 (2010) **EIA Form 923 (2011)

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[1] The sale of the three plants was a condition of FERC approval of the merger. Exelon has complained in the press that the final sale price was depressed for a number of reasons, including: low natural gas prices, uncertainty regarding future environmental regulations, restrictions on who could buy the plants, and a tight (180 day) deadline for the sale. The purchaser, Raven Power Holdings, LLC, may have gotten a good deal in this transaction. Nonetheless, if the true current market value is a bit higher than the actual sale price, that does not change the basic point of this paper.

Constellation spent $885 million on retrofitting the 1,273MW Brandon Shores plant with wet scrubbers to remove SO2, new baghouses to control particulates, activated carbon injection for mercury and sulfuric mist control, and an effluent treatment system to remove nitrogen from wastewater being discharged into the Chesapeake Bay watershed. These retrofits also allow the Brandon Shores plant to burn higher-sulfur coal. The 50+/- year old coal units at Constellation's CP Crane and HA Wagner plants were also retrofitted with overfire air NOx controls and activated carbon injection to reduce mercury emissions at a cost of approximately $115 million.

Yet just two years after these $1 billion upgrades went into service, the three power plants (which are, collectively, 80% coal-fired) fetched only $400 million at market, or just $151/kW of capacity. This is a far cry from the $1,000/kW typically garnered by large coal plants just a few years ago. Exelon will write off $275 million in a pre-tax loss on the sale, which is said to reflect the difference between the sale price and the carrying value of the plants.

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SC Responses to

KPC-23(c)

FOR IMMEDIATE RELEASE – August 10, 2012

Contact: Kim Teplitzky, 412-802-6161, kim.teplitzky@sierraclub.org
Chris Hill, 301-277-7111, chris.hill@mdsierra.org

Communities concerned about new owner of Baltimore Coal Plants

Riverstone Holdings experience with coal plants unclear, record of violations in coal mining

Baltimore, MD – Last night Exelon announced the sale of three coal plants in the Baltimore area to Riverstone Holdings LLC, a private-equity firm who's subsidiary Penn Virginia Resource Partner (NYSE: PVR) was recently sued for violations of the Clean Water Act at 14 locations on 7 former surface mining sites in Southwestern Virginia. Now the company will run another subsidiary operating the Crane, Wagner and Brandon Shores coal plants in Baltimore.

"Aside from their apparent mismanagement of land used for surfacing mining operations in Virginia, it is unclear what experience Riverstone Holdings has that qualifies them to come to Baltimore and operate these toxic facilities in people's backyard," said Mark Kresowick, Deputy Director of the Sierra Club's Beyond Coal Campaign in the East.

In an effort to blend in Riverstone created a new subsidiary called Raven Power to operate the plants, although it's not apparent that this subsidiary has any other purpose than attempting to make this out-of-state company appear to have local resonance.

"It will take more than a clever new name for a subsidiary company to demonstrate that Riverstone cares about Baltimore. Our kids are sick. Our hospitals see more patients suffering from breathing and heart conditions from poor air quality than they should, and pollution from the Crane and Wagner coal plants is responsible," said Christine Hill, Conservation Representative for the Maryland Sierra Club.

"The only way to truly be a good new neighbor in Baltimore is to retire these dirty, outdated plants, ensure a responsible transition for the workers over the next several years and invest instead in clean, renewable energy like wind and solar power that will mean cleaner air and good-paying jobs in the Baltimore area."

The Sierra Club is renewing efforts to retire both the Crane and Wagner plants and clean up Baltimore's air by transitioning Maryland beyond coal to clean energy sources like wind, solar and energy efficiency that have the potential to create thousands of new jobs and mean cleaner, healthier air for the region.

Both Baltimore and Anne Arrundel counties, where the plants are located, have failing air quality with dangerous levels of both soot and smog which can lead to respiratory illness, heart disease, strokes, diminished lung function and even premature death.

Both the Crane and Wagner plants lack modern pollution safeguards making them a hazard for local communities. Upgrading the plants would be costly and is one of the main reasons why they were sold for less than half of what they were initially valued at.

"We hope Riverstone will prove to be a good neighbor here in Baltimore by caring for the health and safety of our families. It's time to retire these aging, dirty coal plants and begin the work of cleaning up our air and transitioning Baltimore to a clean, healthy and prosperous energy economy that's built to last," said Hill.

###

FAMILIES AT RISK

Toxic Pollution Threatens Baltimore's Kids at their Schools, Parks, and Homes

BEYOND COAL

SIERRA CLUB

FOUNDED 1892

Families at Risk: Toxic Pollution Threatens Baltimore's Kids at their Schools, Parks, and Homes

The Charles P. Crane and Herbert A. Wagner coal plants in Baltimore and Anne Arundel counties have threatened public health in the area for decades. The state of Maryland currently allows these plants to emit toxic sulfur dioxide pollution at levels that would cause four times the concentration of pollution our federal Environmental Protection Agency (EPA) has deemed safe. This pollution puts kids at risk where they play outside, including public parks, recreation areas and over 100 schools in the region, as well as residential areas and parts of Baltimore's downtown business district. These maps show how far the plants' toxic pollution travels and who is at risk.

Sulfur dioxide or SO_2 is classified as a harmful pollutant. The EPA sets limits on how much can accumulate in our air. Sulfur dioxide triggers asthma attacks, airway constriction, and other respiratory problems.[1] Exposure to sulfur dioxide pollution for even five minutes can make it hard for a person to breathe and high levels of SO_2 can send people to the emergency room. This is especially dangerous for the nearly 10 percent of all people in Baltimore and Anne Arundel counties who suffer from asthma, especially the 35,000 kids who have pediatric asthma.[2]

Coal burning plants like Charles P. Crane and Herbert A. Wagner are the largest sources of dangerous sulfur dioxide pollution in the nation. In fact, Crane and Wagner are the last two large coal burning plants in the Mid-Atlantic[3] still without a plan to either install modern pollution safeguards, commonly known as "scrubbers", or a commitment to retire their coal units. Scrubbers help cut a plant's dangerous air pollutants including sulfur dioxide, mercury and particulate matter, but don't reduce pollution entirely.

The EPA recently strengthened limits on sulfur dioxide through the National Ambient Air Quality Standard in order to protect people's health and reflect the latest scientific knowledge. States like Maryland are required to develop plans to ensure that pollution does not reach the levels EPA has designated to be unsafe.

The Crane and Wagner coal plants' current permits were issued before this critical update and therefore allow them to emit such high amounts of sulfur dioxide that the new National Ambient Air Quality Standard, the standard for what is deemed safe, would be violated. As a result, the Crane and Wagner coal plants threaten Baltimore area residents with sulfur dioxide pollution nearly four times the limit determined to protect public health.

Sulfur dioxide is measured in either parts per billion ("ppb") or micrograms per cubic meter ("$\mu g/m^3$"). Right now, the EPA's National Ambient Air Quality Standard for SO_2 is 196 $\mu g/m^3$, but the Crane plant alone is permitted to emit SO_2 at rates that result in air pollution concentrations of 736 $\mu g/m^3$.

In order to meet the EPA's safe standards for short-term one-hour SO_2 emissions, the Crane plant would need to cut its current maximum emissions by over 70 percent and the Wagner plant would need to cut its current allowable emissions by over 30 percent.

Because sulfur dioxide travels through the air, it threatens people throughout the region, especially families whose homes, schools, or parks fall within the toxic plumes.

Sulfur dioxide is very dangerous for children, the elderly, and those suffering from respiratory diseases like asthma.

Populations At Risk From Sulfur Dioxide Pollution

	65 & OVER	PEDIATRIC ASTHMA	ADULT ASTHMA	CHRONIC BRONCHITIS	EMPHYSEMA	CARDIO VASCULAR DISEASE
Anne Arundel County	63,664	14,812	34,592	17,788	7,591	134,216
Baltimore County	117,476	20,933	52,259	27,501	12,505	212,641

source: American Lung Associate, State of the Air Report 2012

More than 86,000 adults and 35,000 children in Baltimore and Anne Arundel counties suffer from asthma which can be exacerbated by sulfur dioxide pollution. Baltimore has the highest asthma mortality rate in the state at more than twice the statewide average, as well as the highest pediatric asthma hospitalization rate in the state that is also one of the highest in the nation.[4]

Studies show that air pollution from coal plants can have an even greater impact on communities of color.[5] In Maryland, African Americans are 4.5 times more likely to have to visit an emergency room because of asthma and more than twice as likely to die from asthma.[6] The rate of asthma for African American children is more 60 percent higher than among White children.[7]

Riverstone Holdings

In August 2012, Exelon announced that Riverstone Holdings LLC, a private equity firm with offices in New York, Houston and London, won a bidding process to buy three coal plants in the Baltimore region, including Crane and Wagner. Once the sale is finalized near the end of 2012, Riverstone Holdings will be responsible for the plants - and their toxic pollution - through a subsidiary it recently created named Raven Power. Prior to the sale announcement, Exelon's own experts suggested that both plants would likely need upgrades to limit sulfur dioxide pollution,[8] providing a clear warning to Riverstone Holdings. Riverstone Holdings now has a choice to make. It can decide to retire these outdated and dirty coal plants and clean up the region's air or continue to emit dangerous pollution that threatens the health of Baltimore families.

Maryland Department of the Environment

As part of the sale process, the Maryland Department of the Environment (MDE) has an opportunity to review the air pollution permits for the plants. MDE can decide to ratchet down the pollution these plants are allowed to emit and force them to meet the latest scientifically determined standards by the EPA. If MDE decides to review the permits before Riverstone Holdings is allowed to take them over, it could help reduce the threat of dangerous sulfur dioxide pollution and protect families.

Tell the Maryland Department of the Environment to ratchet down the pollution limits for the Crane and Wagner coal plants and protect Maryland's families immediately, before the new owners take over the plants.

Call Maryland Secretary of the Environment Robert Summers at: 410-537-3084

Or write to: Secretary Robert Summers
Maryland Department of the Environment
1800 Washington Blvd.
Baltimore, MD 21230

Join the Maryland Sierra Club in calling on Riverstone Holdings to retire the Crane and Wagner coal plants and instead invest in local clean-energy solutions that will mean cleaner air, new jobs, and a stronger economy that's built to last.

Send a message to Riverstone Holdings at: http://action.sierraclub.org/MDRetireCoal

ENDNOTES

1 Environmental Protection Agency: http://www.epa.gov/air/sulfurdioxide/health.html

2 American Lung Association State of the Air Report 2012: http://www.stateoftheair.org/2012/states/maryland/

3 Mid-Atlantic states include: New Jersey, Delaware, Pennsylvania, Virginia, West Virginia, District of Columbia, Maryland, North Carolina

4 Baltimore City Health Department: http://www.baltimorehealth.org/asthma.html#fha

5 NAACP Coal Blooded Report: http://naacp.3cdn.net/400b26db2c10378833_jrm6bknse.pdf

6 Maryland Department of Health and Mental Hygiene, Asthma in Maryland 2011: http://fha.dhmh.maryland.gov/mch/Documents/Asthma_in_Maryland-2011.pdf

7 Maryland Department of Health and Mental Hygiene, Asthma Report 2008: http://fha.maryland.gov/pdf/mch/asthma_control/AsthmaReport2008.pdf

8 Public Service Commission Proceedings: Merger of Exelon Corporation and Constellation Energy Group, Inc., Case No. 9271, Market Power Rebuttal Testimony of Michael M. Schnitzer

Sulfur Dioxide Plume Maps

These maps show that the Baltimore area is threatened with concentrations of sulfur dioxide pollution that exceed the level the Environmental Protection Agency has determined safe All of the colored portions are areas directly threatened by dangerous levels of pollution coming from the Crane and Wagner coal plants Darker colors on the maps represent areas with higher potential concentrations of SO_2 The plumes cover portions of Baltimore's downtown business district, public parks and recreation areas and over 100 schools They also cover residential areas, meaning that many in the Baltimore area are exposed to this risk at their own homes

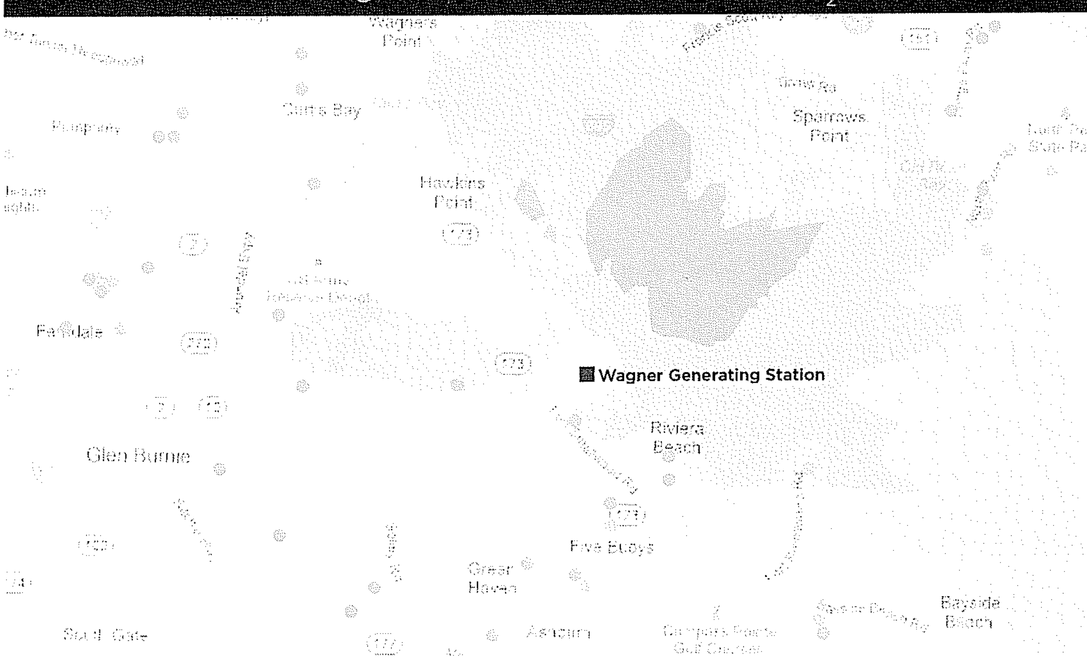
The Charles P. Crane Coal Plant's Toxic SO_2 Plume

All shaded areas are in violation of the EPA's one-hour SO_2 limits.

141
196
250
392
490
588
686

School
Health Facility
Park
Government Facility

The Herbert A. Wagner Coal Plant's Toxic SO_2 Plume



All shaded areas are in violation of the EPA's one-hour SO_2 limits.

141
196
250

School
Park

These maps were created by an independent company, Gray Sky Solutions, Inc., that works for industry, government, and nonprofits using an air dispersion model called AERMOD in accordance with the EPA's protocols for modeling the impacts of SO_2 Maps were made using publicly available information including emissions information, plant characteristics, topographical information, and meteorological data to demonstrate how air pollution disperses from a source, and in what concentrations.

1 Baltimore City Community College
2 Baltimore City Hall
3 Baltimore Lutheran High School
4 Battle Monument
5 Bengies-Chase Recreation Center
6 Berkshire Elementary School
7 Boys Latin School of MD
8 Bryn Mawr
9 Calvert Hall College High School
10 Carver Center for Arts & Tech
11 Cath of Mary Our Queen
12 CCBC - Dundalk
13 Chase Elementary School
14 Clifton Park
15 Colgate Elementary School
16 Collington Square Elementary School
17 Community College of Baltimore City
18 Coppin State University
19 Country Club of Maryland
20 Cylburn Arboretum
21 Dallas F Nicholas Sr Elementary School
22 Deep Creek Elementary School
23 Deep Creek Middle School
24 Deerfield Elementary School
25 Digital Harbor High School
26 Dr Bernard Harris Sr Elementary School
27 Dr Samuel L Banks High School
28 Dumbarton Middle School
29 Dundalk High School
30 Dundalk Middle School
31 Dundee Natural Environment Area
32 Eastern Regional Park
33 Eastern Technical High
34 Eastwood Elementary School
35 Edgecombe Circle Elementary School
36 Edgewood Elementary School
37 Essex Elementary School
38 Excel Academy
39 F S K Elementary School/Middle School
40 Federal Hill Prep
41 Fort McHenry
42 Franklin Square Elementary School
43 Franklin Square Medical Center
44 Frederick Douglass High School
45 Friends School-Baltimore
46 Fullerton Reservoir
47 Gilman School
48 Gilmor Elementary School
49 Glenmar Elementary School
50 Glenmount Elementary School/Middle School
51 Goddard
52 Golden Ring Middle School
53 Goucher College
54 Govans Elementary School
55 Grange Elementary School
56 Gunpowder Falls State Park
57 Gwynns Falls Elementary School
58 Harford Heights Institute
59 Hart-Miller Island State Park
60 Hawthorne Elementary School
61 Hazelwood Elementary School/Middle School
62 Herring Run Park
63 Hopkins Creek Elementary School
64 Hyde Park Elementary School
65 Immaculate Conception
66 Inner Harbor
67 Institute of Notre Dame
68 James McHenry Elementary School
69 John Eager Howard Elementary School
70 Johns Hopkins Bayview Medical Center
71 Johns Hopkins University
72 Johnston Square Elementary School
73 Joppa View Elementary School
74 Joppatowne High School
75 Kennedy Krieger High School
76 Kenwood High
77 Lake Montebello
78 Lakewood Elementary School
79 Leith Walk Elementary School
80 Loch Raven High
81 Loch Raven Tech
82 Logan Elementary School
83 Loyola Blakefield
84 Loyola University - MD
85 M&T Bank Stadium - Home of the Baltimore Ravens
86 Magnolia Elementary School
87 Magnolia Middle School
88 Maritime Industries Academy
89 Mars Estates Elementary School
90 Martin Blvd Elementary School
91 Maryland General Hospital
92 Matthew A Henson Elementary School
93 MedStar Harbor Hospital
94 Mercy High School
95 Mercy Medical Center
96 Mergenthaler Vo-Tech
97 Miami Beach Park
98 Middle River Middle School
99 Middleborough Elementary School
100 Middlesex Elementary School
101 MLK Jr Elementary School
102 Morgan State University
103 Mount Pleasant Park
104 Mt Royal Elementary School/Middle School
105 Mt Zion Baptist Christian
106 Northwood Elementary School
107 Notre Dame of MD University
108 Oakleigh Elementary School
109 Oliver Beach Elementary School
110 Orems Elementary School
111 Oriole Park at Camden Yards
112 Our Lady of Mt Carmel
113 Parkville Evening High School
114 Patapsco High School
115 Patterson Park
116 Perry Hall Middle School
117 Pimlico Elementary School
118 Pine Grove Elementary School
119 Pine Grove Middle School
120 Reginald F Lewis High School
121 Ridge Ruxton
122 Riverside Elementary School
123 Robert E Lee Park
124 Robert W Coleman Elementary School
125 Rocky Point Park
126 Rodgers Forge Elementary School
127 Roland Park Country
128 Saint Clare's
129 Sandalwood Elementary School
130 Seneca Elementary School
131 Sharp-Leadenhall Elementary School
132 St Ambrose Catholic
133 St Clements
134 St Elizabeth
135 St Elizabeth of Hungary
136 St Frances Academy
137 St Mary's University
138 Stemmers Run Middle School
139 Stoneleigh Elementary School
140 Sussex Elementary School
141 Tench Tilghman Elementary School/Middle School
142 The Maryland Zoo
143 Thomas Johnson Elementary School
144 Towson High School
145 Towson University
146 Tunbridge Public Charter
147 Turkey Point Middle School
148 UMD-Baltimore
149 University of Baltimore
150 Upton School
151 Villa Cresta Elementary School
152 Vincent Farm Elementary School
153 W E B DuBois High School
154 Waldorf School of Baltimore
155 Waverly Elementary School
156 Westside Elementary School
157 White Oak
158 Yorkwood Elementary School

SCHOOLS AND PARKS IN THE HERBERT A. WAGNER COAL PLANT SULFUR DIOXIDE PLUME

1 Bay Brook Elementary School
2 Bello Machre Special School
3 Benjamin Franklin High School
4 Brooklyn Park Elementary School
5 Brooklyn Park High School
6 Brooklyn Park Middle School
7 Chesapeake Terrace Elementary School
8 Creative Garden Learning Center
9 Ferndale Elementary School
10 Fort Howard Park
11 Fort Smallwood Elementary School
12 Fort Smallwood Park
13 Freetown Elementary School
14 Ft Howard Elementary School
15 George Fox Middle School
16 Glendale Elementary School
17 Hancocks Resolution Park
18 High Point Elementary School
19 Hilltop Elementary School
20 Marley Middle School
21 Monarch Academy
22 North County High School
23 North Glen Elementary School
24 North Glen Park
25 North Point State Park
26 Northeast Senior High School
27 Pleasantville Park
28 Point Pleasant Elementary School
29 Poplar Ridge Park
30 Riviera Beach Elementary School
31 Saint Lukes School
32 Shallow Creek Park
33 Solley Elementary School
34 Sparrows Point High/Middle School
35 St Jane Frances School
36 Sunset Elementary School
37 Sunset Park
38 Tick Neck Park
39 YWCA North County Daycare

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Sierra Club Kicks Off Campaign Targeting New Owners of Dirty Coal Plants in Baltimore Region
Campaign launched with kayak trip to the dirty, outdated CP Crane coal plant in Curtis Bay

Baltimore, MD - On Saturday morning the Maryland Sierra Club kicked off a renewed effort to move Maryland beyond coal by calling for retirement of the Charles P. Crane and Herbert Wagner coal plants in Baltimore and Anne Arundel counties.

"We're here to show people the dirty, outdated CP Crane coal plant that has been contributing to bad air quality in Baltimore for decades. Pollution from this plant is making our kids sick, causing asthma attacks and contributing to heart disease, cancer and premature death," said Chris Hill, Conservation Representative for the Maryland Sierra Club.

The event, on the heels of Thursday night's announcement that the plants were sold to private equity firm Riverstone Holdings LLC, marked the beginning of renewed efforts by the Sierra Club to improve air quality in the Baltimore region. They're advocating for Riverstone to retire the dirty Crane and Wagner coal plants and help transition Maryland to clean energy sources like wind and solar.

Both Baltimore and Anne Arrundel counties suffer from failing air quality with dangerously high levels of both soot and smog pollution which cause respiratory illness, heart disease and premature death. The Clean Air Task Force estimates that pollution from the plants contributes to more than 1,300 asthma attacks every year.

Activists kayaked out to the Crane coal plant, a four-mile round trip, in order to get a good look at the aging, polluting behemoth on Curtis Bay. Once out there, they made a human, floating billboard by holding up signs from each kayak to spell out the word "RETIRE" in front of the plant.

"These plants are operating with equipment that's more than 50-years-old. It's time to retire these dirty, outdated plants that are polluting our air and threatening our health. We need to transition Maryland to clean energy sources like wind and solar that will mean healthier communities and thousands of new jobs," Steve Satzberg, Anne Arundel County resident.

The sale of the plants to Riverstone was part of the merger deal between Exelon and Constellation. The final sale price of $400 million was well under their anticipated value, due in part to the fact that the Crane and Wagner plants are in need of expensive upgrades to limit dangerous sulfur dioxide pollution.

"We don't know much about Riverstone Holdings, but we do know it's time to retire both the Crane and Wagner coal plants and ensure a responsible transition for the workers. Baltimore communities deserve better than toxic air and we're going to make sure the new owners understand that," said Hill.

ATTACHMENTS

SC Responses to

KPC-6(a)

An Overview of Kentucky's Energy Consumption and Energy Efficiency Potential

Kentucky Pollution Prevention Center
University of Louisville

American Council for an Energy-Efficient Economy

Prepared for:

Governor's Office of Energy Policy

August 2007

AN OVERVIEW OF KENTUCKY'S ENERGY CONSUMPTION AND ENERGY EFFICIENCY POTENTIAL

AUGUST 2007

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EXECUTIVE SUMMARY

The Kentucky Governor's Office of Energy Policy commissioned the Kentucky Pollution Prevention Center at the University of Louisville to conduct a preliminary study of the potential for energy efficiency in Kentucky. A growing demand for electricity, increasing strains on electric transmission infrastructure, spiking natural gas and crude oil prices, concerns about global climate change and the need to achieve energy independence have prompted a renewed focus on energy efficiency. Energy efficiency has emerged as a viable resource and the least-cost alternative to reduce these energy vulnerabilities.

Kentucky's 2005 Comprehensive Energy Strategy Report[1] identified energy efficiency as a key resource to maintain low energy costs and help address environmental concerns. Recent studies conducted by other states also conclude that energy efficiency can play a significant role in meeting future energy needs without adversely affecting the economy.[2,3,4] Given Kentucky's relatively high per capita energy consumption, similar opportunities for energy efficiency are likely to exist, but a formal evaluation of the potential offered by energy efficiency has not been made until now.

This report analyzes energy consumption in Kentucky's residential, commercial and industrial sectors and estimates the impact that energy efficiency could play in reducing future energy demand. It is intended as a starting point for discussion; additional efforts will need to address specific actions or incentives necessary to improve energy efficiency in the Commonwealth. While the methodologies differ among the sectors, the objectives are similar:

- Quantify current energy consumption and energy expenditures;
- Forecast energy consumption under a base case scenario for the 10-year period 2008 – 2017; and
- Estimate the potential for energy savings under a minimally aggressive and moderately aggressive scenario, and compare against this base case.

There is significant opportunity and value for energy efficiency in Kentucky. **Improved energy efficiency could meet all of the growth in energy demand predicted by 2017**. Under the moderately aggressive scenario, energy consumption in 2017 would be less than in 2008 by 30 trillion British thermal units (tBtu). The annual energy savings would represent more energy than 300,000[5] households use <u>each year</u>. Over the 10-year period, the cumulative potential from improved energy efficiency would save Kentucky 449 tBtu and $6.8 billion. This amount of energy is equivalent to the power that three 500-megawatt power plants would generate over a 10-year period.

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[1] Commonwealth Energy Policy Task Force, *Kentucky's Energy Opportunities for our Future – A Comprehensive Energy Strategy*, February 2005

[2] American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency and Renewable Energy to Meet Florida's Growing Energy Demands*, February 2007

[3] American Council for an Energy-Efficient Economy, *Potential for Energy Efficiency, Demand Response, and Onsite Renewable Energy to Meet Texas's Growing Electricity Needs*, March 2007

[4] ICF Consulting, *Assessment of Energy Efficiency Potential in Georgia*, May 2005

[5] Annual energy use for 10,000 homes is equivalent to 1 tBtu

Residential Sector

The residential sector consumed nearly 354 tBtu of energy in 2003 at a cost of $2.2 billion (2003 dollars). Electricity and natural gas comprised the majority of delivered energy at 51% and 38%, respectively (excluding electricity related losses). The primary end use for energy was space heating (42%), followed by lighting and miscellaneous equipment (32%).

From 2008 to 2017, residential consumption is expected to increase 7.8% to 458 tBtu. Under the minimally aggressive scenario, delivered energy consumption would decline by 5 tBtu in 2017 and save 23 tBtu, which represents $459 million in savings over the 10-year period. Under the moderately aggressive scenario, delivered energy consumption would decline by 15 tBtu in 2017 and save 81 tBtu, which represents a savings of $1.6 billion over the 10-year period.

Commercial Sector

The commercial sector consumed nearly 249 tBtu of energy in 2003, while total expenditures were approximately $1.4 billion. Electricity (54%) and natural gas (35%) were the dominant forms of delivered energy. Energy use for space heating (17%) and lighting (12%) was significant, however half of the energy was attributed to the "all other" category.

Energy consumption in Kentucky's commercial sector is expected to grow 22% between 2008 and 2017 – three times the increase predicted for the residential sector. Without changes, consumption is predicted to reach 382 tBtu in 2017 due, in part, to an increase in the use of electrical equipment.

Under the minimally aggressive scenario, energy consumption would decline by 2 tBtu in 2017 and save 14 tBtu representing $211 million in savings over the 10-year period. Under the moderately aggressive scenario, energy consumption would decline by 10 tBtu in 2017 and save 62 tBtu representing a savings of $950 million over the 10-year period.

Industrial Sector

Kentucky's industrial sector consumed nearly 830 tBtu of energy in 2003 at a cost of approximately $3.2 billion. Petroleum (36%), electricity (30%) and natural gas (21%) were the main forms of delivered energy consumed by the industrial sector. One-half of all electricity was used by motors; 17% was used for process heating applications. The vast majority of natural gas is used in process heating (54%) and boilers (36%).

Energy consumption in the industrial sector is expected to reach 989 tBtu in 2017, a 6.5% increase over the forecast for 2008. Under the minimally aggressive scenario, delivered energy consumption would decrease by 39 tBtu in 2017 and save 208 tBtu, which represents $3 billion in savings over the 10-year period. For the moderately aggressive scenario, delivered energy consumption would decline by 57 tBtu and save 306 tBu which represents $4.2 billion over the 10-year period. A summary of energy efficiency potential for Kentucky is provided in **Table 1**.

Table 1: Summary of Energy Efficiency Potential in Kentucky

	Annual Energy Consumption and Cost				Cumulative Delivered Energy and Cost Savings 2008 – 2017	
	*Source		Delivered		Minimally Aggressive	Moderately Aggressive
	2003	2017	2003	2017		
Residential	354 tBtu	458 tBtu	167 tBtu $2.2 billion	185 tBtu $3.9 billion	23 tBtu $459 million	81 tBtu $1.6 billion
Commercial	249 tBtu	382 tBtu	113 tBtu $1.4 billion	148 tBtu $2.4 billion	14 tBtu $211 million	62 tBtu $950 million
Industrial	830 tBtu	989 tBtu	507 tBtu $3.2 billion	580 tBtu $8.8 billion	208 tBtu $3 billion	306 tBtu $4.2 billion
Total	**1,433 tBtu**	**1,829 tBtu**	**787 tBtu $6.8 billion**	**913 tBtu $15.1 billion**	**245 tBtu $3.7 billion**	**449 tBtu $6.8 billion**

*Source is defined as total energy consumption including electricity generation and transmission losses

Conclusions

Overall, the savings potential from energy efficiency in Kentucky is large, achievable and significant – it has the promise of "supplying" the energy needs that will fuel Kentucky's growth and prosperity over the next decade.

The benefits offered from energy efficiency have a positive impact on the economy and the environment which reflect us as individuals and as a society. These benefits include:

- Reduced energy expenditures keep money in Kentucky's communities, towns and homes; money not spent for imported energy can be used to meet Kentucky's needs.
- Reduced emissions of greenhouse gasses improve the global environment while reductions in regulated pollutants, such as particulates, sulfur oxides (SO_x) and nitrous oxides (NO_x), improve local air quality.
- Creation of new markets for jobs and economic development, while helping existing Kentucky businesses and manufacturers remain profitable through improved efficiency.
- Reduced impact of higher energy prices and costs on families throughout the Commonwealth.
- Reduced energy demand slows the need for additional power generation facilities, transmission lines and pipelines.
- Reduced dependence on imported energy – much of which comes from nations that occasionally have strained relations with the United States. This decreased dependence on foreign sources of energy will increase our national security.

Energy efficiency is the fastest, cheapest and cleanest source of "new" energy. It can help reduce the strain on existing energy infrastructure and offer new solutions to slowing energy demand growth.

Seizing the opportunity that energy efficiency provides will require dedicated efforts from multiple stakeholders that must be sustained over many years. The challenge presented to the Commonwealth is how best to develop the right policies, procedures and incentives that will afford all Kentuckians the benefits of energy efficiency.

1.0 INTRODUCTION AND SCOPE

The rising cost of energy affects all facets of American society, and there are no indications that prices will decrease in the near future. In 2003, Kentuckians enjoyed one of the lowest combined utility rates throughout the nation, and the lowest retail electricity rates nationwide.[6,7] However, these low rates do not necessarily mean lower utility costs. According to the Kentucky Comprehensive Energy Strategy Report[8], released in 2005:

- Kentucky residents actually paid 1% more on their electric bills than West Virginia residents (even though our electricity rates are 9% lower).
- Although our electricity rates are 18% lower than Indiana's, our residents paid only 6% less on their electric bills.
- On an average monthly electric bill, Kentucky's schools spend 7% more per student than the national average.
- The average Kentucky industrial bill is 123% higher than the national average.
- Kentucky's average residential electric rate is 33% less than the national average but the average residential bill is only 17% below the national average.

As concluded in the Kentucky Comprehensive Energy Strategy Report, "... Kentucky's low electricity rates have encouraged energy-intensive practices, processes and procedures. This historic energy intensity provides a great opportunity for energy efficiency to help lower consumption, reduce energy bills, and improve the environment."

The purpose of this report is to provide a general indication of the energy consumption and forecasting as well as energy efficiency potential that exists within residential, commercial and industrial sectors of Kentucky. It is not designed to represent an exhaustive analysis, but rather to be viewed as a tool to identify opportunities for additional evaluation. The majority of data within this document is based on 2003 data that was available at the time this report was prepared. In some cases, older data was used, but still represents the most recent and pertinent information available.

2.0 RESIDENTIAL SECTOR

The residential sector consists of occupied housing units, including mobile homes, single-family housing units (attached and detached), and apartments.

2.1 Residential Energy Consumption

In 2003, Kentucky's residential sector consumed 353.9[9] trillion British thermal units (tBtu) of total energy, ranking the state 23rd nationwide in energy consumption.[10] The residential per

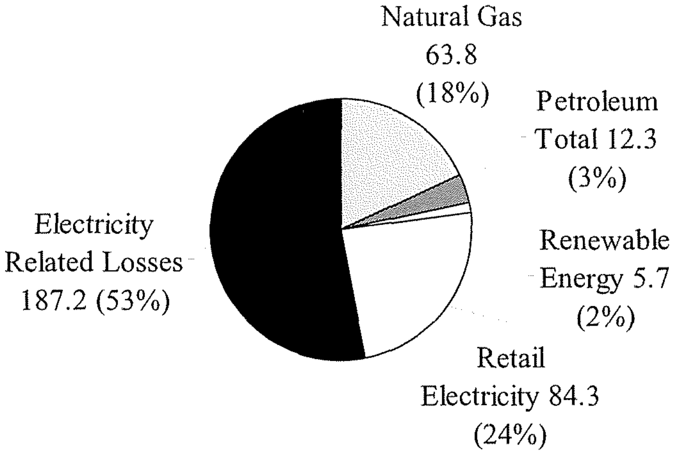
[6] Energy Information Administration (EIA), *Table R1. Energy Prices and Expenditures Ranked by State, 2003*
[7] EIA, *Table R4. Coal and Retail Electricity Prices and Expenditures Ranked by State, 2003*
[8] Commonwealth Energy Policy Task Force, *Kentucky's Energy Opportunities for our Future – A Comprehensive Energy Strategy*, February 2005
[9] EIA, *Table 8. Residential Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

capita energy consumption was estimated at 86 million Btu (MMBtu) in 2003, ranking the state 9th in the nation; this is approximately 18% above the nation's per capita use of 73 MMBtu. The total energy expenditures were $2.186 billion (2003 dollars).[11]

In 2003, per capita income for Kentuckians was $25,840[12], while per capita residential energy expenditure was estimated to be $531 or 2% of their income. For the same year, the nationwide per capita income was $31,466[13], and the energy expenditure was $615 or approximately 2% of their income. Despite Kentucky's low energy prices, Kentuckians spend the same portion of their salary on energy compared to the national average.

Kentucky's 2003 total energy consumption by energy components is provided in **Figure 1**. Over three-fourths of the energy consumed is attributed to purchased electricity and electricity-related losses. Excluding electricity losses, the majority of energy used in Kentucky homes is electricity and natural gas at 51% and 38%, respectively.

Figure 1: 2003 Kentucky Residential Sector Total Energy Consumption
353.3 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.
Coal consumption of 0.6 tBtu is not shown resulting in a total of 353.3 tBtu.
Electricity Related Losses – the amount of energy lost during generation, transmission and distribution of electricity.

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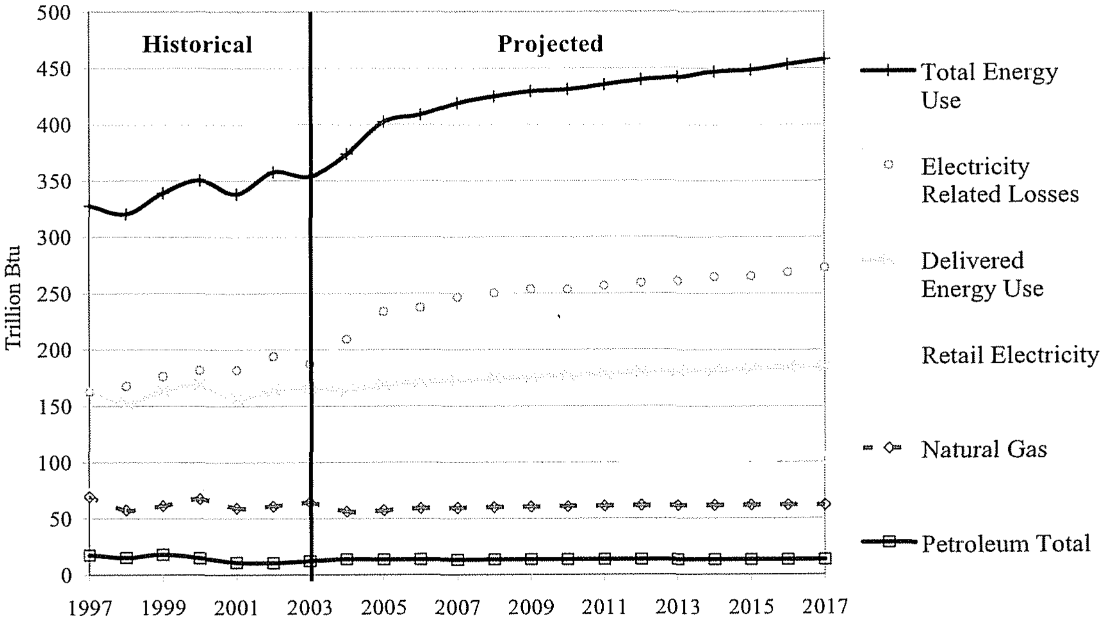
[10] EIA, *Table R1. Energy Consumption by Sector, Ranked by State, 2003*
[11] EIA, *Table S2b. Residential Sector Energy Expenditure Estimates by Source, 2003*
[12] U.S. Bureau of Economic Analysis, Regional Economic Accounts, *Bearfacts 1993-2003, Kentucky*
[13] U.S. Bureau of Economic Analysis, Regional Economic Accounts, *Personal Income and Per Capita Personal Income by BEA Economic Area, 2003-2005*

2.2 Residential Energy Forecast

Kentucky's historical and projected residential sector energy consumption trends for major energy sources are shown in **Figure 2**. Total energy consumption is expected to increase 7.8% from 425 tBtu in 2008 to 458 tBtu in 2017. This represents an annual average increase of 0.9%.

The energy profile from 1997 through 2003 is historical data for Kentucky[14] gathered from the U.S. Department of Energy, Energy Information Administration (EIA). Projected energy consumption for the residential sector is estimated by adjusting the forecasted energy consumption in the Annual Energy Outlook (AEO) 2006 using the National Energy Modeling System[15] (NEMS) for the East South Central region for Kentucky's household population[16] and climatic conditions (based on degree days).[17]

Figure 2: Kentucky Residential Sector Projected Energy Consumption



Note: "Total Energy Use" also includes coal and renewable energy.

2.3 Residential End Use Analysis

The majority of energy use (42%) is consumed for space heating. Lighting and other miscellaneous equipment, such as televisions and home appliances, are the second largest, consuming 32% of the total energy. A summary of end use energy consumption is provided in **Figure 3**.

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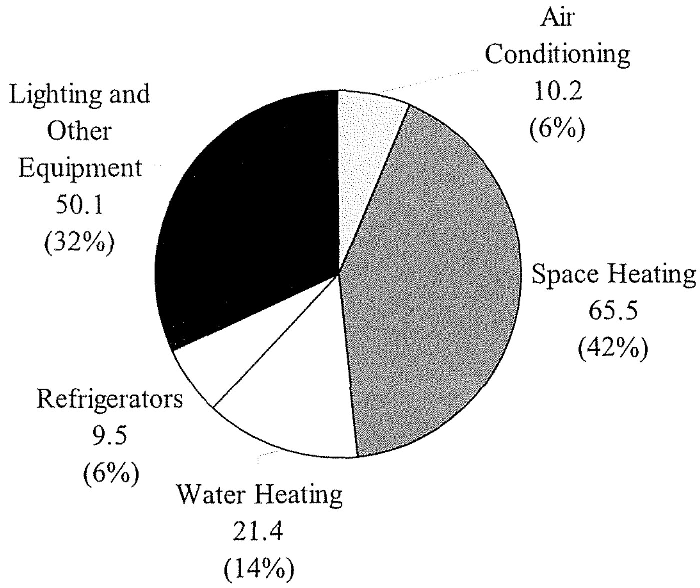
[14] EIA, *Table 8. Residential Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[15] EIA, *Table 6. Energy Consumption by Sector and Source – East South Central, February 2006*
[16] U.S. Census Bureau, *American Community Survey – Household Population*
[17] National Oceanic & Atmospheric Administration, *Population-Weighted Monthly Normals, 1971-2000*

Data from the 2001 Residential Energy Consumption Survey (RECS) for the East South Central region was adjusted for Kentucky's household population and climate to estimate end use energy consumption.[18] This 2001 survey is the most recent year for which information is available for this sector.

Figure 3: 2001 Kentucky Residential Sector Delivered Energy by End Use
156.7 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

2.4 Potential for Residential Energy Savings

The residential sector was analyzed using a minimally aggressive scenario and a moderately aggressive scenario from 2008 to 2017. Assuming a minimally aggressive scenario, a 2.7% decrease in energy usage would be achieved in 2017. For the moderately aggressive scenario, an 8.2% savings would be achieved for this same period.

For the moderately aggressive scenario, the energy savings that could be achieved by 2017 are approximately 15 tBtu annually; cumulative energy savings over the same period would be approximately 81 tBtu. This is equivalent to a cumulative cost savings of $1.6 billion. A summary of the projected energy efficiency potential for the residential sector is provided in **Table 2**.

[18] EIA, *Residential Energy Consumption Survey 2001 Consumption and Expenditure Data Tables*

Table 2: Summary of Kentucky's Energy Efficiency Potential – Residential Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Energy Usage – Delivered Energy	173 tBtu
2017 Base Case Energy Usage – Delivered Energy	183 tBtu
Percent Increase in Delivered Energy Consumption from 2008 to 2017	5.8%
2017 Minimally Aggressive Delivered Energy Savings over 2017 Base Case	5 tBtu
2017 Moderately Aggressive Delivered Energy Savings over 2017 Base Case	15 tBtu
2017 Minimally Aggressive Cumulative Delivered Energy Savings	23 tBtu
2017 Moderately Aggressive Cumulative Delivered Energy Savings	81 tBtu
2017 Minimally Aggressive Cumulative Energy Cost Savings	$459 million
2017 Moderately Aggressive Cumulative Energy Cost Savings	$1.6 billion

In AEO 2006, "Reference Case" average national residential energy intensities are forecasted until 2030. These national trends in energy intensities from 2003 to 2017 are applied to Kentucky's 2003 energy intensity estimated from EIA and U.S. Census Bureau data to forecast Kentucky's energy intensity through 2017. Kentucky's Base Case energy use is estimated from the forecasted energy intensities and projected trends in the number of households in Kentucky obtained from the University of Louisville's Kentucky State Data Center (KSDC).[19]

Energy savings for the Minimally Aggressive and Moderately Aggressive scenarios are estimated by applying, respectively, AEO 2006 "High Technology" and "Best Available Technology" energy intensity data to Base Case energy consumption. Consistent with AEO 2006 definitions, the Minimally Aggressive scenario assumes earlier availability of the most energy efficient technologies with lower costs and higher efficiencies, but does not constrain consumer choices. The Moderately Aggressive scenario assumes that the most energy efficient technology is always chosen, regardless of cost. Future energy prices are estimated by applying an average rate of increase in prices for each fuel type during the period from 1997-2003 to 2003 respective energy prices.

3.0 COMMERCIAL SECTOR

The commercial sector includes non-manufacturing businesses, such as office buildings, warehouses, retail outlets, schools and other similar types of facilities.

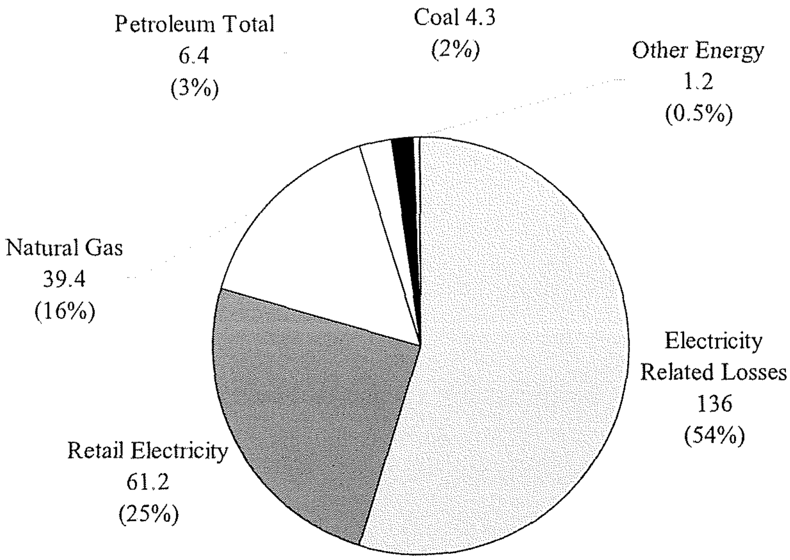
3.1 Commercial Energy Consumption

In 2003, Kentucky's commercial sector consumed 248.6[20] tBtu of total energy ranking the state 25th nationwide in energy consumption.[21] The total energy expenditures were $1.356 million (2003 dollars).[22]

[19] KSDC, *Historical and Projected Household Populations, Number of Households, and Average Household Size, State of Kentucky, Area Development Districts, and Counties*
[20] EIA, *Table 9. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

Kentucky's total energy consumption by energy components for 2003 is provided in **Figure 4**. Over three-fourths of energy is from purchased electricity and electricity related losses. Approximately 54% of total energy was lost in electricity related losses. Excluding electricity losses, the energy used in commercial buildings is predominantly electricity (54%) and natural gas (35%).

Figure 4: 2003 Kentucky Commercial Sector Total Energy Consumption
248.5 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.
"Other Energy" includes biomass and geothermal.

3.2 Commercial Energy Forecast

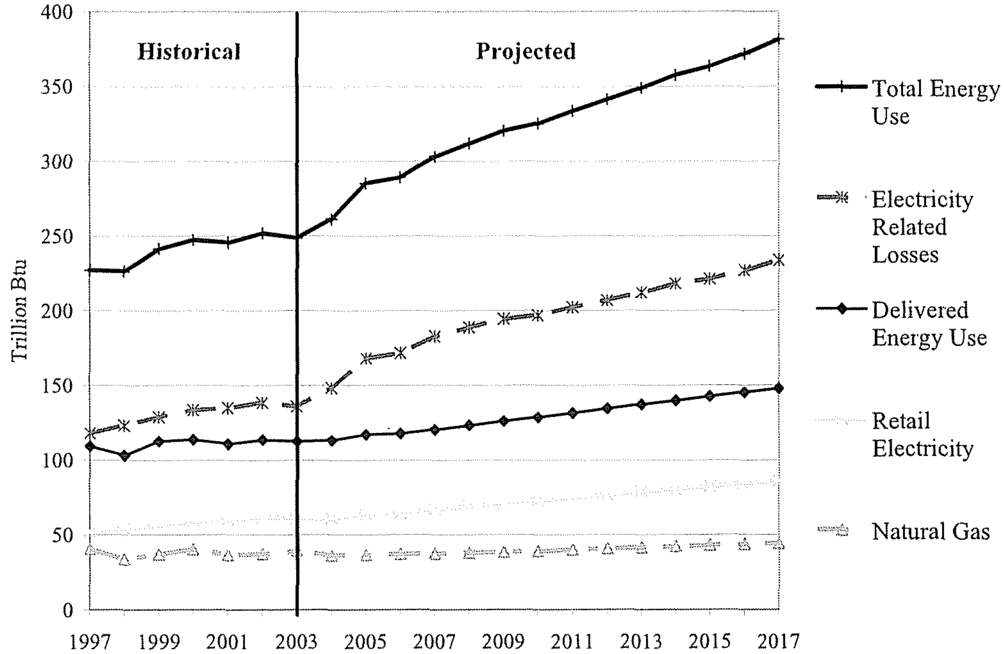
Figure 5 illustrates Kentucky historical and projected commercial sector trends for major energy sources. From 2008 to 2017, total energy consumption is expected to increase 22.4% from 312 tBtu to 382 tBtu. This represents a 2.5% annual average increase and is approximately three times greater than the rate of increase for the residential sector.

[21] EIA, *Table R1. Energy Consumption by Sector, Ranked by State, 2003*
[22] EIA, *Table S3b. Commercial Sector Energy Expenditure Estimates by Source, 2003*

The profile from 1997 through 2003 is based on historical data for Kentucky gathered from EIA.[23] The trends from 2004 through 2017 are forecasts derived from the NEMS model.[24] Applying the NEMS model, Kentucky's delivered energy intensity (kBtu/ft^2/yr) for the commercial sector is expected to increase from 135 kBtu/ft^2/yr in 2008 to 151.3 kBtu/ft^2/yr by 2017 due to increased use of electronic equipment (despite anticipated improved efficiencies in modern equipment).

The methodology to forecast commercial sector energy consumption is based first on applying Kentucky's historic (1997-2003) energy components (as a percentage) to the forecasted energy consumption in the AEO 2006 for the East South Central region. Then, the 2003 EIA Commercial Buildings Energy Consumption Survey (CBECS) data[25] for the East South Central region was adjusted for Kentucky's 2003 population. Finally, the growth in commercial space was assumed to increase at the same rate as the state's population as estimated by KSDC.[19] Forecasted energy usages and square footages are used to estimate energy intensities.

Figure 5: Kentucky Commercial Sector Projected Energy Consumption



Note: "Total Energy Use" also includes petroleum, coal, biomass and geothermal.

3.3 Commercial Energy Consumption: Sub-Sector and End Use Analysis

In 2003, Kentucky had approximately 85,300 commercial structures, which accounted for an estimated 881 million square feet.[26] **Table 3** provides the 2003 energy intensity for various commercial buildings on a national basis. Food Service is the most energy intensive sub-sector

[23] EIA, *Table 9. Commercial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

[24] EIA, *Table 6. Energy Consumption by Sector and Source – East South Central, February 2006*

[25] CBECS, *Table A3. Census Region and Division, Number of Buildings for All Buildings (Including Malls), 2003, East South Central*

using approximately 227 $kBtu/ft^2/yr$, followed by the Health Care and Food Sales sectors. The variation in energy intensity observed among the sub-sectors is likely attributed to several factors, particularly the number of hours of daily activity and the type and prevalence of specialized equipment.

Figure 6 shows 2003 commercial sector delivered energy by end use. The majority of energy use (50%) is consumed by the category "All Other," which may include specialized equipment for hospitals, laboratories, and other similar facilities that have not been specified in AEO 2006. Space heating is the second largest, consuming 17% of the total energy.

National energy intensities for buildings with various principal building activities are estimated from AEO 2006 and presented in **Table 3**. National energy intensity percentages for specific end uses were estimated from AEO 2006 and applied to Kentucky's 2003 delivered energy consumption to estimate energy consumption by end uses.

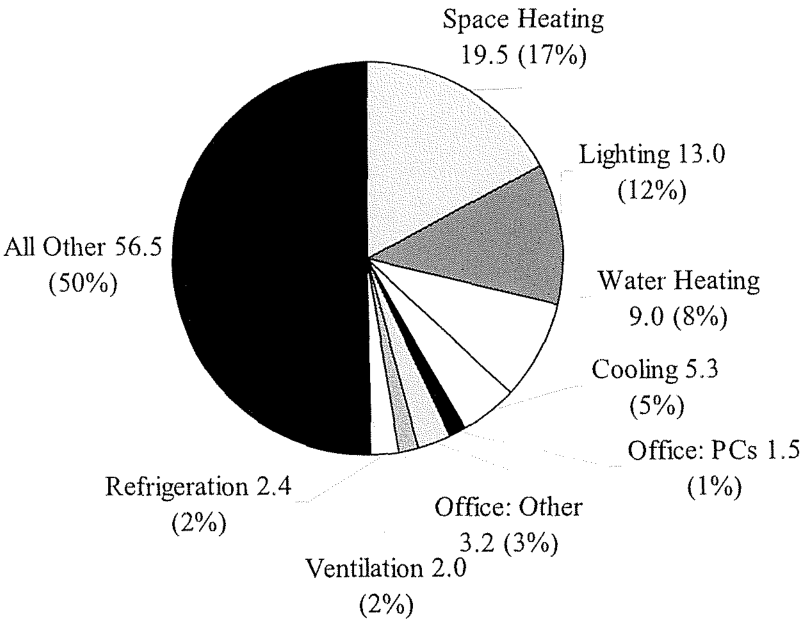
Table 3: 2003 National Commercial Building Energy Intensity (delivered energy)

Commercial Building Types	Energy Intensity ($kBtu/ft^2/yr$)
Food Service	226.5
Health Care	209.1
Food Sales	195.0
Office – Large	91.7
Lodging	90.6
Mercantile/Service	81.4
Education	74.1
Office – Small	66.5
Public Assembly	59.4
Warehouse	42.9
Other	78.8

Source: AEO 2006, *Table 22. Commercial Sector Energy Consumption, Floorspace, and Equipment Efficiency*

[26] CBECS, *Table A4. Census Region and Division, Floorspace for All Buildings (Including Malls), 2003, East South Central*

Figure 6: 2003 Kentucky Commercial Sector Delivered Energy by End Use
112.4 Total tBtu



Note: *Summary of percentages may not equal 100% due to rounding.*

3.4 Potential for Commercial Energy Savings

The commercial sector was analyzed using the minimally aggressive and moderately aggressive scenarios from 2008 to 2017. Assuming a minimally aggressive scenario, a 1.5% savings in energy usage would be achieved by 2017. For the moderately aggressive scenario, a 6.8% savings would be achievable in the same period. For the moderately aggressive scenario, the annual energy savings that could be achieved by 2017 are approximately 10 tBtu, and the cumulative savings over the same period are approximately 62 tBtu. The results suggest that up to $950 million in cumulative potential savings is achievable under a moderately aggressive scenario. A summary of the projected energy efficiency potential for the commercial sector is provided in **Table 4**.

Table 4: Summary of Kentucky's Energy Efficiency Potential – Commercial Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Energy Usage – Delivered Energy	123 tBtu
2017 Base Case Energy Usage – Delivered Energy	148 tBtu
Percent Increase in Delivered Energy from 2008 to 2017	20.3%
2017 Minimally Aggressive Delivered Energy Savings over 2017 Base Case	2 tBtu
2017 Moderately Aggressive Delivered Energy Savings over 2017 Base Case	10 tBtu
2017 Minimally Aggressive Cumulative Delivered Energy Savings	14 tBtu
2017 Moderately Aggressive Cumulative Delivered Energy Savings	62 tBtu
2017 Minimally Aggressive Cumulative Energy Cost Savings	$211 million
2017 Moderately Aggressive Cumulative Energy Cost Savings	$950 million

Energy savings for the Minimally Aggressive and Moderately Aggressive scenarios are estimated by applying, respectively, AEO 2006 "High Technology" and "Best Available Technology" commercial building energy intensity data to Base Case energy consumption (see **Section 3.2**). Future energy prices are estimated by applying an average rate of increase in prices for each fuel type during the period from 1997-2003 to 2003 respective energy prices.

4.0 INDUSTRIAL SECTOR

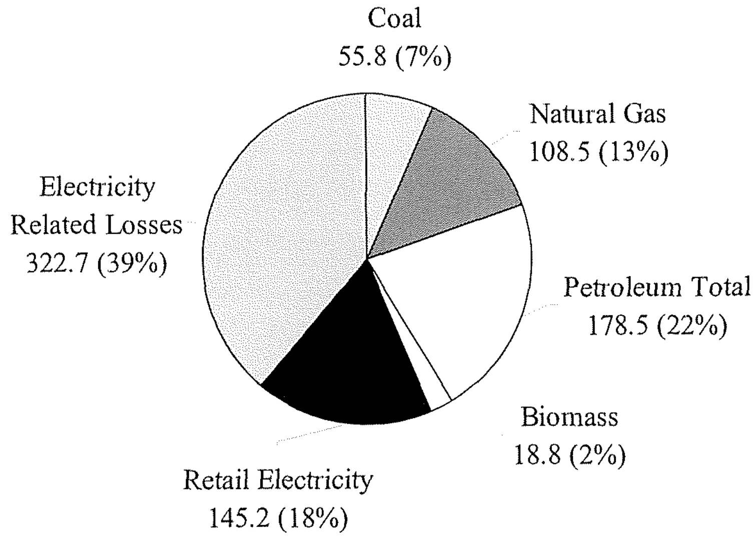
The Kentucky industrial sector is expansive and includes many different sub-sectors. However, not all sub-sectors are as energy intensive as others. Consequently, this report targeted only key industrial sub-sectors that consumed the majority of energy (electricity and natural gas).

4.1 Industrial Energy Consumption

In 2003, Kentucky's industrial sector consumed 829.5[27] tBtu of energy, ranking the state 11th nationwide in industrial consumption.[28] Total energy expenditures were $3.182 billion (2003 dollars).[29] **Figure 7** illustrates Kentucky's total energy consumption for the industrial sector by energy source for 2003 (this includes electrical system losses). Excluding electricity related losses, petroleum (36%), electricity (30%) and natural gas (21%) were the main forms of delivered energy consumed by the industrial sector.

[27] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[28] EIA, *Table R1. Energy Consumption by Sector, Ranked by State, 2003*
[29] EIA, *Table 4. Industrial Sector Energy Price and Expenditure Estimates, Selected Years, 1970-2003, Kentucky*

Figure 7: 2003 Kentucky Industrial Sector Total Energy Consumption
829.5 Total tBtu



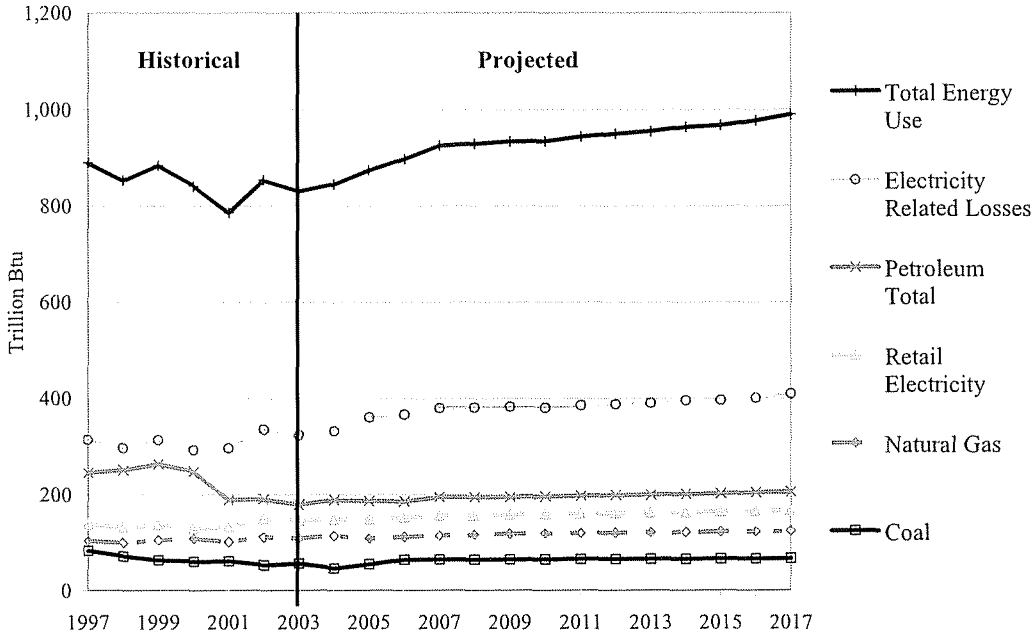
Note: Summary of percentages may not equal 100% due to rounding.

4.2 Industrial Energy Forecast

Kentucky's historical and projected industrial sector energy trends for major energy sources are provided in **Figure 8**. Based on this energy forecast, total energy consumption is expected to increase approximately 6.5%, from 929 tBtu in 2008 to 989 tBtu by 2017. This represents a 0.7% average increase each year. Historical data (from 1997 through 2003) was obtained from EIA.[30] AEO's projected increases are provided for each energy source except biomass, which is assumed to be constant at the 2003 level of 18.8 tBtu.

[30] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

Figure 8: Kentucky Industrial Sector Projected Energy Consumption



Note: "Total Energy Use" also includes biomass.

4.3 Industrial Electricity Consumption: Sub-Sector and End Use Analysis

Primary metal manufacturers purchased the largest portion of electricity consumption, estimated to represent 36% of the industrial total. The chemical sector represented the second greatest electricity consumption at 13%. A summary of electricity consumption for the top seven industrial sub-sectors in Kentucky is provided in **Table 5**.

Approximately one-half of electricity consumption was attributed to motors for all sub-sectors. Process heating, which includes heat treating, melting and casting, represented approximately 17% of end uses for electricity. A summary of weighted average industrial end uses is provided in **Figure 9**. The "Total Motors" category includes pumps, fans and blowers, compressed air, material handling, material processing, refrigeration and other motors. The category "Other" includes miscellaneous equipment, such as office equipment and specialty process equipment. Although lighting and HVAC represent a relatively small percentage of the industrial sector electricity consumption, they are important in some of the key industries found in the region, such as transportation equipment manufacturers.

Data on industrial electricity consumption is not available for individual industrial sub-sectors. To estimate electricity sub-sector usage in Kentucky, the national electric intensity estimates provided in the 2002 EIA Manufacturing Energy Consumption Survey[31] (MECS) and the 2002 U.S. Census Bureau (USCB) national value of shipments[32] were applied to the USCB 2002

[31] EIA, *2002 MECS, Energy Consumption as a Fuel, Table 3.1. By Manufacturing Industry and Region (physical units)*

[32] U.S. Census Bureau, *2002 Economic Census Manufacturing Subject Series; Report Number EC02-31SG-1*

Kentucky value of shipments.[33] These were adjusted for electric intensity (defined as kilowatt-hour consumption per dollar of value of shipments) in the south census region from the 2002 MECS. The results were then calibrated to match the actual consumption for 2003. Only sub-sectors with electricity consumption greater than 4% of the total industrial electricity were included in the analysis.

The end uses of electricity in the industrial sector were estimated by using information collected in a study for the New York State Energy Research and Development Authority (NYSERDA) on industrial end uses.[34] Again, only the top seven industrial sub-sectors were considered when evaluating electricity consumption by end use.

Table 5: 2003 Estimated Electricity Consumption - Top Seven Sub-Sectors in Kentucky

NAICS Code	Industry Name	Estimated Electricity Consumption Million kWh (tBtu)	Percent of Total Industrial Electricity Consumption	Estimated Sub-Sector Costs (Million /yr)
331	Primary Metal Manufacturers	15,395 (53)	36%	$481
325	Chemical	5,414 (18)	13%	$169
336	Transportation Equipment	4,230 (14)	10%	$132
322	Paper	3,431 (12)	8%	$107
326	Plastics & Rubber Products	2,080 (7)	5%	$65
212	Mining (except oil & gas)	1,831 (6)	4%	$57
311	Food Manufacturers	1,731 (6)	4%	$54
Sub-Sector Total		**34,112 (116)**	**80%**	**$1,065**
Industrial Total		**42,570 (145)**[35]	**100%**	**$1,329**[36]

NAICS – North American Industry Classification System

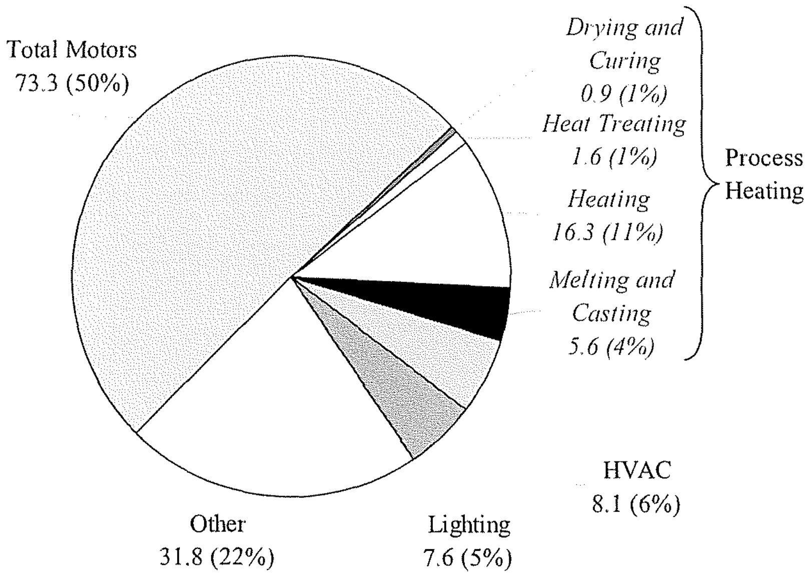
[33] U.S. Census Bureau, *2002 Economic Census Manufacturing Geographic Area Series; Report Number EC02-31A-KY (RV)*

[34] New York State Energy Research and Development Authority, *Energy Efficiency and Renewable Energy Resource Development Potential in New York State, Final Report*, May 2004

[35] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*

[36] EIA, *Table 4. Industrial Sector Energy Price and Expenditure Estimates, Selected Years 1970-2003, Kentucky*

Figure 9: 2003 Kentucky Weighted Average Industrial Electricity by End Use 145.2 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

4.3.1 Potential for Industrial Electricity Savings

An analysis of 19 distinct measures for reducing electricity consumption was conducted for the Kentucky industrial sector. The savings potential for electricity as shown in **Table 6** was calculated based on the study of industrial electricity use for NYSERDA.[34] Future energy prices were estimated by applying an average rate of increase in electricity prices during the period from 1997-2003 to 2003 prices and forecasted to 2017.

The findings of this report reveal that cost-effective (minimally aggressive) investments in energy efficiency can save Kentucky industries an estimated 15.5% of electricity use by 2017, resulting in a cumulative cost savings of up to $1.7 billion. The energy savings that could be achieved with these minimally aggressive energy efficient cost-effective investments are approximately 26 tBtu annually, with a cumulative energy savings of 139 tBtu by 2017. A summary of Kentucky's electricity efficiency potential for the industrial sector is provided in **Table 7**.

The eight cost-intensive (moderately aggressive) measures would also improve efficiency, but existing technology is more expensive relative to the energy saved. These measures may become cost-effective when the cost of energy rises and the cost of the technologies fall. The energy savings that could be achieved through a moderately aggressive scenario are approximately 44 tBtu, with a cumulative energy savings of 237 tBtu by 2017. When considering all measures (cost effective and cost intensive), the total savings potential for electricity savings is over 26% by 2017, resulting in a cumulative cost savings of $2.9 billion.

Table 6: Electricity Savings Measures

Measure	Cost of Saved Energy ($/kWh saved)	Technical Savings Potential (% of Total Industrial Electricity)
Cost-Effective Measures (Minimally Aggressive)		
Pumps	0.010	3.1%
Sensors/controls	0.021	3.0%
Electric supply improvements	0.010	3.0%
Compressed air management	-	2.1%
Lighting	0.030	1.5%
Motor management	0.020	0.7%
Fans	0.030	0.7%
Lubricants	-	0.6%
Motor System Optimization	0.012	0.4%
Compressed air - advanced	-	0.1%
Refrigeration	0.004	0.4%
Subtotal		**15.5%**
Cost-Intensive Measures (Moderately Aggressive)		
Energy Information Systems	0.090	5.0%
Motor design	0.040	2.3%
Pipe insulation	0.090	1.3%
Microwave processing	0.450	1.0%
Energy Management Systems	0.450	0.6%
Transformers	0.188	0.3%
Cooling/storage – food	0.530	0.3%
HVAC	0.650	0.1%
Subtotal		**10.9%**

Source: New York State Energy Research and Development Authority, *Energy Efficiency and Renewable Energy Resource Development Potential in New York State, Final Report*, May 2004

Note: The retail industrial electricity price in 2003 in Kentucky was $0.032 per kWh. Cost-effectiveness is defined as all measures that cost less than $0.032/kWh saved over the life of the measure.
Summary of percentages may not equal subtotal due to rounding.

Table 7: Summary of Kentucky's Electricity Efficiency Potential – Industrial Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Electricity Usage	157 tBtu
2017 Base Case Electricity Usage	167 tBtu
Percent Increase in Electricity Usage from 2008 to 2017	6.4%
2017 Minimally Aggressive Electricity Savings over 2017 Base Case	26 tBtu
2017 Moderately Aggressive Electricity Savings over 2017 Base Case	44 tBtu
2017 Minimally Aggressive Cumulative Electricity Savings	139 tBtu
2017 Moderately Aggressive Cumulative Electricity Savings	237 tBtu
2017 Minimally Aggressive Cumulative Electricity Cost Savings	$1.7 billion
2017 Moderately Aggressive Cumulative Electricity Cost Savings	$2.9 billion

4.4 Industrial Natural Gas Consumption: Sub-Sector and End Use Analysis

Primary metal manufacturing is the largest consumer of natural gas in Kentucky's industrial sector, estimated at 25% of the total natural gas consumption. Chemical manufacturing is the second largest user, estimated at 21% of the total. A summary of natural gas consumption for the top seven industrial sub-sectors is provided in **Table 8**.

Within the industrial sector, direct process heating and boilers consume the greatest natural gas, estimated at 54% and 36%, respectively (**Figure 10**). Boilers in industrial facilities are primarily used to generate steam and hot water used in manufacturing processes; direct process heat refers to usage by other process equipment, such as ovens and driers.

Data on industrial natural gas usage by sub-sector and end use consumption of natural gas is not available for Kentucky. Similar to the electricity analysis, the 2002 national energy intensities of the sub-sectors, estimated from MECS and value of shipments, were applied to the 2002 Kentucky value of shipments to estimate natural gas usage in the sub-sectors. The results were calibrated to match the actual consumption for 2003.[37] Only seven sub-sectors with gas consumption greater than 6% of the total industrial gas (representing 88% of industrial natural gas consumption in Kentucky) were evaluated in the analysis.

National end use data for sub-sectors, available in the 1998 MECS survey[38], was used in conjunction with data in **Table 8** to estimate the weighted average end use energy consumption presented in **Figure 10**.

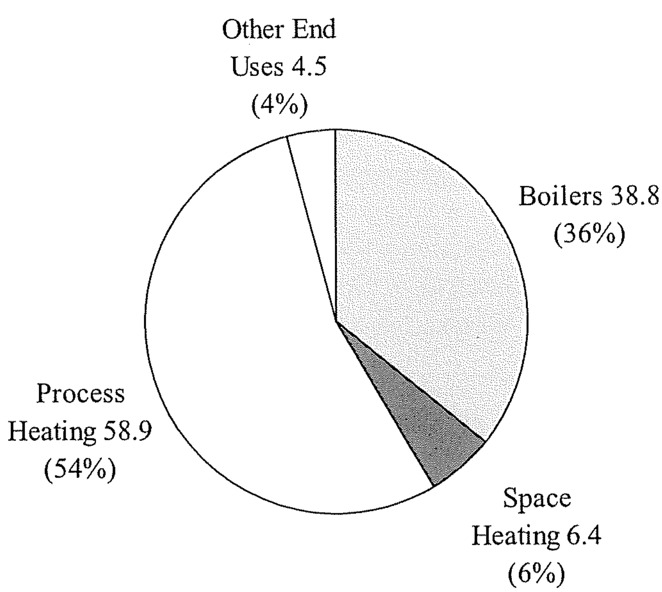
[37] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[38] EIA, MECS, *Table N6.1. End Uses of Fuel Consumption, 1998*

Table 8: 2003 Estimated Natural Gas Consumption - Top Seven Sub-Sectors in Kentucky

NAICS Code	Industry Name	Estimated Natural Gas Consumption (tBtu)	Percent of Total Industrial Consumption	Estimated Sub-Sector Costs (Million /yr)
331	Primary Metal Manufacturers	26.9	25%	$157.0
325	Chemical	22.5	21%	$131.2
322	Paper	12.5	12%	$73.2
324	Petroleum and Coal Products	10.5	10%	$61.3
336	Transportation Equipment	8.8	8%	$51.3
311	Food Manufacturers	7.2	7%	$42.3
327	Nonmetallic Mineral Products	7.1	7%	$41.6
Sub-Sector Total		**95.5**	**88%**	**$558**
Industrial Total		**108.5**[39]	**100%**	**$633.7**[40]

Note: Summary of columns may not equal sub-sector totals due to rounding.
NAICS – North American Industry Classification System

Figure 10: 2003 Kentucky Weighted Average Industrial Natural Gas by End Use 108.6 Total tBtu



Note: Summary of percentages may not equal 100% due to rounding.

[39] EIA, *Table 10. Industrial Sector Energy Consumption Estimates, Selected Years, 1960-2003, Kentucky*
[40] EIA, *Table 4. Industrial Sector Energy Price and Expenditure Estimates, Selected Years 1970-2003, Kentucky*

4.4.1 Potential for Industrial Natural Gas Savings

The savings potential for natural gas was calculated based on a study of industrial gas use in California.[41] The study calculated the 10-year achievable potential for natural gas savings in the California industrial sector. The study found that 12% of boilers, 10% of process heating, and 10% of space heating gas use could be saved in 10 years. These totals do not include estimates of how much natural gas can be saved by fuel switching. When applied to the industrial natural gas consumption in Kentucky, it is estimated that gas savings of approximately 10.3% could be achieved from 2008 to 2017 resulting in a cumulative cost savings of up to $1.3 billion. The annual energy savings that could be achieved by 2017 is approximately 13 tBtu, and the cumulative savings over the same period is approximately 69 tBtu. A summary of the natural gas efficiency potential for the industrial sector is provided in **Table 9**.

Future energy prices are estimated by applying an average rate of increase in gas prices during the period from 1997-2003 to 2003 prices and then projected to 2017.

Table 9: Summary of Kentucky's Natural Gas Efficiency Potential – Industrial Sector

Projected Scenario	Usage/Estimated Savings
2008 Base Case Natural Gas Usage	116 tBtu
2017 Base Case Natural Gas Usage	123 tBtu
Percent Increase in Natural Gas Usage from 2008 to 2017	6%
2017 Natural Gas Savings over 2017 Base Case	13 tBtu
2017 Cumulative Natural Gas Savings	69 tBtu
2017 Cumulative Natural Gas Cost Savings	$1.3 billion

5.0 SUMMARY AND CONCLUSION

Results from this report suggest that the residential, commercial and industrial sectors in Kentucky have the potential to achieve significant cost savings by implementing energy efficiency practices. Conservative estimates for implementing energy efficiency measures indicate that by 2017 Kentucky could save the following:

- Residential Sector - $459 million in savings
- Commercial Sector - $211 million in savings
- Industrial Sector - $3 billion in savings

In 2003, Kentucky was fortunate to have one of the lowest combined utility rate structures and the lowest electricity rates in the nation. According to Kentucky's Comprehensive Energy Strategy Report, these low rates encourage "... energy-intensive practices, policies and

[41] Pacific Gas and Electric Company, *California Industrial Energy Efficiency Market Characterization Study*, December 2001

procedures." Clearly, energy efficiency opportunities exist within the state. Significant improvements in energy efficiency can be achieved by implementing currently available and cost-effective technologies.

Kentucky has many options on how to achieve these potential savings. Many states have implemented or are considering implementing various incentive programs to promote energy efficiency. For example, in July 2007 Florida's Governor signed Executive Orders concerning the state's energy policy. Specifically, future state building construction will be energy efficient and include solar panels whenever possible. Office space leased in the future must be in energy efficient buildings. Additionally, the Governor requested the Public Service Commission to adopt a 20% Renewable Portfolio Standard by 2020, with a strong focus on solar and wind energy.

Overall, the savings potential from energy efficiency in Kentucky is large, achievable and significant – it has the promise of "supplying" the energy needs that will fuel Kentucky's growth and prosperity over the next decade.

The benefits offered from energy efficiency have a positive impact on the economy and the environment which reflect us as individuals and as a society. These benefits include:

- Reduced energy expenditures keep money in Kentucky's communities, towns and homes; money not spent for imported energy can be used to meet Kentucky's needs.
- Reduced emissions of greenhouse gasses improve the global environment while reductions in regulated pollutants, such as particulates, sulfur oxides (SO_x) and nitrous oxides (NO_x), improve local air quality.
- Creation of new markets for jobs and economic development, while helping existing Kentucky businesses and manufacturers remain profitable through improved efficiency.
- Reduced impact of higher energy prices and costs on families throughout the Commonwealth.
- Reduced energy demand slows the need for additional power generation facilities, transmission lines and pipelines.
- Reduced dependence on imported energy – much of which comes from nations that occasionally have strained relations with the United States. This decreased dependence on foreign sources of energy will increase our national security.

Energy efficiency is the fastest, cheapest and cleanest source of "new" energy. It can help reduce the strain on existing energy infrastructure and offer new solutions to slowing energy demand growth.

Seizing the opportunity that energy efficiency provides will require dedicated efforts from multiple stakeholders that must be sustained over many years. The challenge presented to the Commonwealth is how best to develop the right policies, procedures and incentives that will afford all Kentuckians the benefits of energy efficiency.

ATTACHMENTS

SC Responses to

KPC-9

Market Transformation and Resource Acquisition: Challenges and Opportunities in California's Residential Efficiency Lighting Programs

Lara Ettenson and Noah Long, Natural Resources Defense Council

ABSTRACT

California's energy efficiency lighting programs continue to be an integral component strategy to displace dirty conventional energy supply resources while ensuring the ongoing evolution of the lighting market. Although the California lighting efficiency programs have been successful in building the lighting industry and raising customer awareness, the market is not fully transformed. Seventy-five percent of screw-based sockets are still filled with an inefficient alternative. While the federal and state efficiency lighting standards will provide significant savings when fully implemented in 2020, there is significant opportunity to capture savings from residential lighting applications until that time. Programs should continue as long as there are cost-effective energy savings available and must be modified as needed to reach the remaining potential.

To continue to transform the lighting market and fulfill the need to displace the dirtier and more expensive conventional energy source, effective policy should include research and development funding, incentives to promote higher-efficiency products, code and standard development and enforcement, as well as education. With these policies utilities and regulators can achieve the mutual goals of cost effective efficiency resource acquisition and continuous market transformation.

Introduction

This paper addresses how investments in energy efficient lighting programs support the transformation of the lighting market while simultaneously fulfilling resource acquisition goals. These two outcomes of efficiency programs are not at odds with one another; rather, efficiency programs must both transform markets and meet resource acquisition goals if they are to achieve their primary objective of ensuring that customers receive reliable, clean, and affordable energy services at the lowest societal cost.

Recent data shows that California market intervention through lighting efficiency programs has successfully increased the availability, quality, and usage of efficient lighting products. However, the residential lighting market is not fully "transformed," since the majority of available sockets do not contain an efficient lamp. Efficiency programs are therefore still necessary to capture savings with existing technologies as well as to ensure that additional technologies become more affordable and available in the market.

This paper begins with a discussion of market transformation, followed by how past lighting programs established the current status of the residential lighting market. The authors then identify how further intervention is needed to capture the remaining energy savings potential and concludes with recommendations to create the most effective programs that will ensure continual progress towards lighting market transformation.

What Is Market Transformation?

The energy efficiency community has long debated the appropriate degree of regulatory focus on "market transformation," especially with respect to designing and continuing energy efficiency programs. In 2007, the California Public Utilities Commission (CPUC) directed the investor-owned utilities (IOUs) to develop a California Long Term Energy Efficiency Strategic Plan (Strategic Plan) in which they were to indicate "how energy efficiency programs are or will be designed with the goal of transitioning to either the marketplace without ratepayer subsidies, or codes and standards."[1] The Strategic Plan, adopted in September 2008, notes that as early at 1998, the CPUC defined Market Transformation as: "Long-lasting sustainable changes in the structure or functioning of a market achieved by reducing barriers to the adoption of energy efficiency measures to the point where further publicly-funded intervention is no longer appropriate in that specific market."[2] A 1997 CPUC decision is perhaps even more indicative of the prevailing view of the role of market transformation at the time: "The mission of market transformation is to ultimately privatize the provision of cost-effective energy efficiency services so that customers seek and obtain these services in the private competitive market."[3]

The various definitions of "market transformation" raise a number of questions: What is a transformed market and when is a market transformed? How do you measure a transformed market? Can any market ever stay fully transformed if new technologies continually improve the efficiency of the previous version? These questions can best be addressed in two ways. First, the market transformation definition noted above should be modified to acknowledge the dynamic nature of markets. This modification would define market transformation as a continuous process, rather than one defined outcome. Second, a comprehensive set of key metrics and baseline information must be established at the onset of program design to ensure that all stakeholders are operating with the same set of assumptions and that the programs are designed to move the market in a variety of ways.

To address the first point, market transformation should be viewed as a continuous process for technology improvement beginning with research, innovation and demonstration, followed by introduction into the mass market, growing market acceptance, and finally updated efficiency standards and codes to lock in minimum efficiency savings across the market. At each stage of market transformation, different policy tools are useful, and often crucial, to move the market along for a particular technology. Research programs support innovation and demonstration, energy efficiency programs help more efficient products or practices gain market share, and codes and standards ensure that the particular efficiency level of a technology or practice becomes mandatory.[4]

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[1] See Reference CPUC. R.06-04-010; D.07-10-032, p.33.
[2] See Reference CPUC. *"California Long Term Energy Efficiency Strategic Plan."* Section 1, p.4.
[3] See Reference CPUC D. 97-02-014. These definitions (which are consistent with literature of the period), arose during California's efforts to restructure the electricity industry when the Commission was focused on getting the utilities out of the resource procurement business (including energy efficiency) and leaving these key decisions up to the "market." One of the state's first actions to address the electricity crisis of 2000 and 2001 was to restore the utilities' resource planning and procurement responsibilities. Today, the Commission's energy efficiency objectives should be aligned with both the utilities' procurement responsibilities and the state's commitment to reduce greenhouse gas emissions in the near- and long-term.
[4] Code enforcement is also necessary to ensure that savings from mandatory standards are achieved.

From a manufacturer's perspective, the market is transformed only when it is no longer profitable (or legal) to continue manufacturing products with subpar efficiency levels. Manufacturers will continue to produce and retailers will continue to sell inefficient products as long as there is a market for it. Therefore, the cycle of market transformation is critical to retire inefficient technologies (by updating codes or standards), encourage manufacturers to develop and invest in the next generation of more efficient technologies (through research and development programs) and ensure that retailers stock the most efficient products and those are the ones demanded by consumers (through efficiency programs). As manufacturers and retailers are generally part of a national industry, it is increasingly important to develop coordinated approaches to most effectively engage them at a level that alters the types of products they produce for the market. Still, California has shown that it can drive the national market through use of the full range of efficiency-promotion policies discussed above.

This process of market transformation is different from the single outcome, discussed above, of discontinuing efficiency programs based on a narrow definition of what a transformed market looks like. The proposed modification to the traditional definition illustrates a dynamic and continuous process: as one efficiency level becomes mandated, policies and programs focus on pulling the next generation of efficient products to market. Until the theoretical limits for energy efficiency are reached, energy can always be used more efficiently and the market for that particular product or end-use will continue to change.

Thus, a dynamic definition of market transformation means that each of the noted policy tools will continue indefinitely for every energy end use, although the level of efficiency they promote will improve as technology advances and markets change. Ceasing this cycle by considering a market fully "transformed" when a particular technology is accepted as a standard practice or as part of the code will stifle innovation and halt efficiency gains. If pursued continuously, this cycle will ensure innovative developments of the next generation efficient technology and ensure that minimum efficiency levels required for various technologies can cost effectively become increasingly stringent over time..

To address the second point, a comprehensive set of key metrics and baseline information must be agreed upon at the onset of efficiency program development to ensure that the 'end point' (or series of end points) is clearly defined. It is imperative that a common terminology and set of metrics be identified in advance of program development and deployment to (1) best design programs that advance multiple aspects of the market (e.g., sales, awareness, technology deployment, etc.), (2) best answer the question 'when is the market transformed?' for a given product, (3) minimize contention surrounding when it is time to discontinue a particular efficiency program or a program's support for a particular level of efficiency, and (4) determine when it is necessary to modify programs to pull the next generation of a particular product to market. For example, while some might call a market transformed when prices reach a certain level or most consumers know of a product, others might conclude that a market is not transformed unless a technology is widely adopted. There are a number of metrics used to determine various levels of market transformation. However, one critical metric that must be considered is the amount of remaining cost effective potential that can be reached by continuation or modification of a particular program. Section V, below, includes further discussion on metrics that measure movement towards market transformation.

Market Transformation and Resource Acquisition

The CPUC definition of market transformation as an outcome "where further publicly-funded intervention is no longer appropriate in that specific market" [5] has led to the assertion that market transformation activities are an alternative to energy efficiency "resource acquisition."[6] For example, a recent white paper asserted that the focus of efficiency programs shifted from being designed for resource acquisition needs to being designed for market transformation purposes.[7]

This distinction fails to recognize that these goals are interconnected. A utility's role in promoting and investing in energy efficiency results from the obligation of regulators and utilities to provide customers with affordable and reliable energy services at minimum societal costs. If a utility can incentivize customers to use energy more efficiently, and do so at a lower societal cost than procuring conventional sources of electricity, they should always do so. It also saves customers money in avoided energy costs, either directly from less usage or system-wide through lower costs to procure less energy, improves reliability, and reduces the environmental impacts of energy services. The dynamic description of market transformation implies a synergy between this use of energy efficiency as a resource and the policy goals of market transformation. Specifically, the main goal of policies to transform markets toward technologies that reduce energy consumption is in fact to reduce the societal costs of energy consumption. This is the very same principle that drives California and other states to require utilities to invest in efficiency to supplant supply side resource acquisition.

Thus, utility efficiency programs have a natural role in the continuing process of market transformation as they pull more efficient products to market and thereby speed up the process of market acceptance. For this to work, efficiency programs must be regularly modified to address the ever changing market conditions and focus new program offerings on pulling the next generation of efficiency products to the market. It is also essential to align efficiency programs with research and development funding priorities and updates to codes and standards, which often requires coordinating with other state and federal regulators and stakeholders.[8]

To achieve significant energy savings and to ensure that market transformation efforts complement the goal of using efficiency as a resource, it is imperative to align the interests of the utilities with the interests of society. The CPUC implemented numerous policies to ensure that the goals of the utilities are properly aligned with the state's objective of ensuring that customers received reliable, clean, and affordable energy services. In particular, the CPUC:

- Removed utility disincentives for investments in energy efficiency by decoupling the utilities' recovery of fixed-costs from sales,
- Set stretch energy saving goals for the utilities,
- Required utilities to invest in efficiency when cheaper than conventional power,
- Adopted an administrative structure that integrates efficiency into utility procurement,

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[5] *Supra footnote 2*
[6] This same debate was common in the late 1990s when restructuring was a popular theme.
[7] See Reference Roberts, Thomas, p.1
[8] In California, utilities play an important role in advancing codes, standards and research, but the California Energy Commission (CEC), not the CPUC, has primary responsibility for these policies. In addition, CEC policy on research, codes and standards is often heavily influenced by national policy. For example, California is frequently preempted by federal appliance efficiency standards, including on lighting efficiency standards.

- Delineated clear rules for the efficiency programs,
- Developed a shared savings risk/reward performance-based incentive mechanism
- Adopted the first ever California Long-term Energy Efficiency Strategic Plan, and
- Encouraged all stakeholders to work together to develop the next generation programs.

As a result, California utilities administer significant energy efficiency programs as a means of displacing the need for additional generation and transforming the markets for efficient products and practices. These offerings include, but are not limited to, the following:

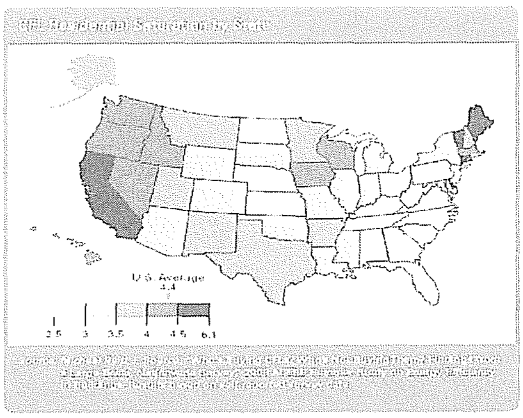
- Early stage and emerging technology programs;
- Incentive/rebate programs that target multiple points in product distribution chains (e.g. end-consumer, contractor, manufacturer, etc);
- Funding to provide the technical basis for efficiency code and standard updates;
- Innovative pilot programs
- Third party programs
- Assistance for local governments (e.g., code compliance);
- Contractor incentives and design assistance for efficient construction

The policy structure in California enables the utilities to carry out extensive programs and encourages them to support and advocate for more stringent codes and standards. Setting up the right policies and pushing towards advancing codes and standards will further advance market transformation while minimizing the tendency to revert to previous manufacturing and purchasing habits, which would undermine efforts towards sustained market transformation. While there can be healthy debate about the prioritization, planning, and implementation of these programs, there is little doubt that they reduce energy use and move new and more efficient technologies to market.

California's Residential Lighting Market

Over the past few decades, lighting programs have been an important part of California's efficiency programs. These programs significantly improved the availability of efficient lighting technologies on the market and by doing so, saved a great deal of energy. California utilities not only played a substantial role in developing the CFL industry through their program efforts, but also actively supported the Federal Energy Independence and Security Act of 2007, which mandates minimum efficiency levels for screw-based lighting products beginning in 2012 (see Section VI below for more details).

Figure 1: CFL Residential Saturation by State



Recent California lighting market effects studies (market studies) indicate that the market in California for CFLs has significantly expanded in recent years. In particular, California investor-owned utility customer awareness of CFLs reached 96% in

2008 and the percentage of households that purchased CFLs exceeded 75% in the same year.[9] Furthermore, as indicated by Figure 1, California households average 6.1 CFLs per home while the rest of the nation averages 4.4 lamps. While this indicates significant progress, there's still significant saving opportunities since CFLs still are not the preferred screw-based bulb for most consumers. Fewer than 11% of the sockets in U.S. homes contain a CFL today.[10] On average, American homes leave nearly 30-40 sockets filled with inefficient bulbs.[11] Although performance is better in California, recent analyses found that the majority of lamps installed in homes are still incandescent bulbs, with only one fifth of sockets filled by the more efficient CFLs.[12] There is clearly room for more savings in residential lighting.

Although efficiency programs increased market penetration of efficient lighting and enabled state and federal lighting standards, the residential lighting market continues to yield significant unfilled potential. Approximately 62% of medium screw-base sockets and 93% of small screw-base sockets are still filled by inefficient lamps.[13] Even in the areas where CFLs are most commonly installed, (e.g., bedrooms and bathrooms) or have moderate or high use sockets (e.g., kitchens, bedrooms, and living rooms), socket penetration is still quite low.[14] The potential to deploy more efficient lighting (and therefore save significant energy) is even greater in three-way and dimmer sockets, where inefficient lighting fills 71% and 63% of the sockets respectively.[15] These results indicate that there is substantial opportunity for significant savings by installing more efficient lighting options in these sockets.

While some of these sockets could be filled by basic CFLs, others (especially dimmers) have unique characteristics that require specialty lamps. These market studies reports illustrate an ongoing need to promote efficient lighting for the sockets that still contain the more inefficient option. Education, promotion of basic specialty lamps, and support for research into alternative efficient lighting options all provide opportunities for ongoing intervention to improve the lighting market.

Despite the data on penetration of efficient lamps, stakeholders and regulators continue to debate about whether or not there is a need to continue lighting programs. Disagreements about attribution of savings, program design, costs of the programs, and upcoming state and federal lighting standards threatened the continuation of residential lighting programs for this program cycle and beyond.[16] Regardless of these disagreements, the CPUC found that there was still significant cost-effective lighting savings to be captured during the current cycle and approved a modified version of the investor owned utilities' lighting programs. The CPUC directed the utilities to reassess their lighting subsidies for basic CFLs and increase investment in the advanced lighting programs to promote technologies that address the harder to reach sockets. In

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[9] See Reference CADMUS p.vi-vii.
[10] See Reference U.S. Department of Energy, p.5.
[11] See Reference NRDC.
[12] See Reference KEMA, Appendix E, Table 1, p.1.
[13] *Ibid.* Appendix E, Table 7. p.4.
[14] *Ibid.* Appendix E, Table 22. p.17 (e.g., CFL socket penetration in bathrooms = 24%, bedrooms = 27%) & Appendix E, Table 22. p.17 (e.g., CFL socket penetration in kitchens = 19%, bedrooms = 27%, living rooms = 27% and Bathrooms, = 24%).
[15] *Ibid.* Appendix E, Table 9. p.5.
[16] CA IOU program cycles operate on a 3-year program cycle. Current cycle is 2010-2012, next cycle is 2013-2015

addition, the CPUC authorized the utilities "to explore the incorporation of next generation halogen and incandescent bulbs in their programs" using authorized funding for subsidies.[17]

The Role of Efficiency Programs in Moving the Lighting Market

As noted above, energy efficiency programs are crucial to capturing dependable and affordable savings, while also pulling new technologies from the design stage to general market acceptance. Whether programs target the end-use customer, retailer, contractor, or manufacturer, consistent program intervention is critical to increase the availability and usage of efficient technologies. However, the ongoing debate about when a market is actually transformed threatens the continuity of beneficial programs that achieve real savings and bring new technologies to market. Prematurely discontinuing programs also ignores the important role that efficiency programs play in the market transformation continuum and threatens the advancement of the market as well as resource acquisition needs. If programs are removed before the technology has been locked into codes and standards, before the efficiency level fully becomes standard market practice, or there is no longer a market for inefficient lighting options, manufacturers and retailers will resume selling and stocking the inefficient options and consumers will tend towards purchasing the less expensive and less efficient lighting options.

For example, some advocates claim that the general lighting market is fully transformed based solely on the fact that the Northwest Energy Efficiency Alliance (NEEA) ceased funding their CFL programs. Claiming that a market is transformed based on this fact misses the big picture of the northwest lighting market. The experience of the Northwestern utilities and NEEA cooperation in the lighting market demonstrates that market intervention can effectively promote widespread availability and acceptance of CFLs. The Northwest experience also shows the importance of defining appropriate metrics to determine success at various stages of market transformation before discontinuing successful programs.

Beginning in 1997, NEEA specifically designed CFL programs to (1) increase sales, (2) reduce product prices, (3) increase availability, (4) increase consumer awareness and (5) encourage quality improvement.[18] Although NEEA removed their incentives once these goals were met according to project theory and metrics, the CFL market was not yet sustainable without continued support.[19] When NEEA's funding was removed, utilities continued to carry out the programs rather than remove these offerings all together.[20]

NEEA's efforts also highlight the importance of designing programs to meet specific goals and metrics to ensure success. However, the metrics used to measure the success of the NEEA programs were limited and did not necessarily indicate a fully "transformed market," but only that the defined objectives had been achieved. Moreover, the NEEA experience should not be used as a benchmark for when other states should cease funding for lighting programs, as each market landscape is different depending on size, demographics, and identified metrics of success.

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[17] See Reference CPUC. A.08-07-021 et al. D.09-09-047, p. 122. The best available now halogen bulbs are only about 30% more efficient than regular incandescent bulbs and far less efficient then CFLs.
[18] See Reference Rasmussen, p. 6-182.
[19] *Ibid.* p.6-190.
[20] See: http://www.pse.com/SOLUTIONS/FORYOURHOME/pages/rebatesOnLighting.aspx?tab=2&chapter=1 and http://www.avistautilities.com/savings/rebates/Pages/CFL.aspx for continuing lighting intervention programs

Furthermore, while the NEEA program metrics of sales, price, and awareness are important measures of program success and can indicate a path towards market transformation, saturation (e.g., the percentage of sockets filled with efficient lighting) is also a critical indicator. As noted above, over 75% of sockets in California are still filled with inefficient lamps. Even though sales and awareness are high in California, success cannot be claimed and programs should not be discontinued when savings potential remains. Price, manufacturing production quantities and sales, retail availability, and consumer awareness can all be used to estimate how consumer behavior is affecting the market for a specific product. However, ultimately the transformation of a product should also be gauged by the energy consumption of the particular product being used. In California, as in the rest of the country, the most recent data available indicates that the majority of sockets are filled with inefficient bulbs that consume significant energy.

While efficiency programs were instrumental in reaching the current level of socket penetration, continuing to deliver carefully designed programs is critical to reach the remaining potential until codes and standards are fully implemented. As discussed in Section VI below, even after the codes are implemented, programs will continue driving even greater levels of efficiency. In most of the country, utilities could save huge amounts of energy at very low cost by running well designed lighting programs that target basic lighting applications as well as more targeted strategies (Section VII discusses program recommendations).

Lighting Efficiency Standards

The 2007 Energy Independence and Security Act (EISA) lighting efficiency standards will provide substantial savings when fully implemented in 2020.[21] When all bulbs in the roughly four billion screw-based sockets in the United States shift to CFL-equivalent levels of efficiency, it will prevent approximately100 million tons of CO_2 per year, save more than $10 billion per year in energy costs and eliminate the need for more than 30 large (500 MW) power plants.[22]

However, various stakeholders and regulatory bodies have misinterpreted what EISA will actually require. For example, passage of the law does not mean that the lighting market will automatically be "transformed" when the standards begin to go into effect in 2012, since the standards are only fully phased in by 2020. Furthermore, EISA does not ban incandescent bulbs or require compact fluorescent bulbs to be used. Rather, between 2012 and 2014, the EISA standard phases in a requirement that bulbs use 25-30% less power. In 2020 the law requires roughly CFL-level efficiency (but not the use of CFLs specifically). Between 2012 and 2020 CFLs (which are 75-80% more efficient than the main stream incandescent bulbs) will continue to provide low-cost and above-code savings.

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[21] In California, the efficient lighting market is also affected by AB 1109 (Huffman), which requires a 50% reduction in energy consumption from 2007 to 2018 for residential lighting and 25% reduction in consumption in commercial and outdoor lighting. The Huffman Bill will require savings in technologies not covered by EISA (for example many commercial and outdoor light bulbs) and also acts on a different timeline. California plans to implement the EISA requirements early and doing so will help meet the Huffman requirement: Tier 1 implementation will begin in 2011 and Tier 2 will begin in 2018.

[22] NRDC Calculations based on conservative estimate of savings at 10 cents/kWh from the change of 60 to 15 watt bulbs in the roughly 3 billion US sockets which do not yet contain CFLs.

TIER 1 – 2012-2014

Tier 1 of EISA removes low cost, inefficient bulbs from the market starting in 2012. Today's 25 cent incandescent will no longer be available for purchase as EISA sets a slightly higher efficiency requirement for these lamps as noted in Table 1 below.

Table 1: Implementation of Tier 1 – EISA (2007)

Today's Bulb	Becomes	Tier I Standard	Lumens	Lumens/Watt	Effective Date
100W	→	≤ 72 W	1490-2600	~20-36	1/1/2012
75W	→	≤ 53W	1050-1489	~20-28	1/1/2013
60W	→	≤ 43 W	750-1049	~14-17	1/1/2014
40W	→	≤ 29 W	310-749	~13-26	1/1/2014

NRDC calculations based on EISA 2007 requirements, Public Law 110-140.

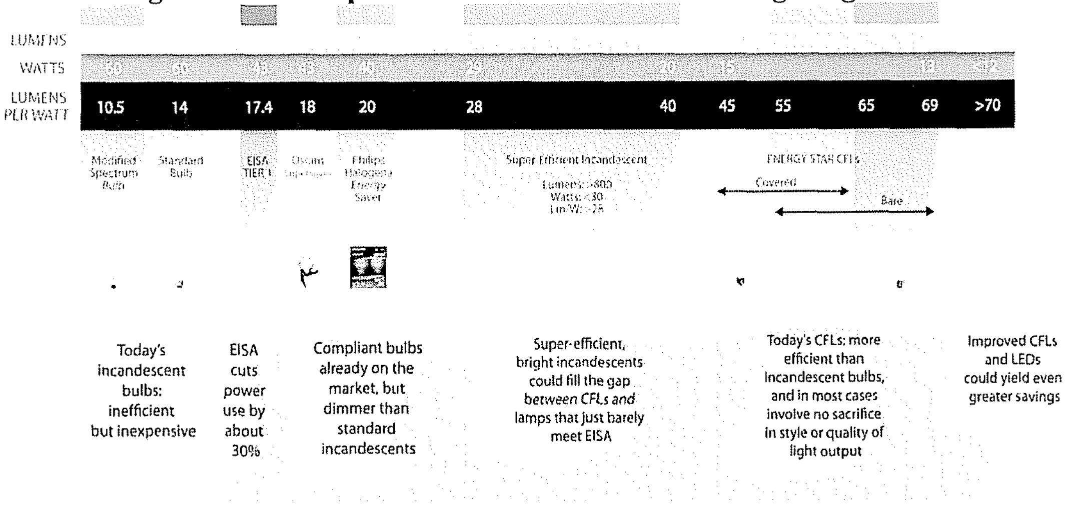
With the most inefficient lamps removed from market due to Tier 1 efficiency levels, more efficient lamps, such as CFLs and new "improved" incandescent lamps, will be expected to increase in sales.[23] However, CFLs will continue to provide significant above-code energy savings and be considerably more efficient than other products on the market. For example, a CFL today can generate as much light as today's 100 W bulb using only 23 W, or less than a fourth as much power.

EISA will require that today's 100W bulb use only 72 W, but CFLs will still be three times as efficient. Similarly, EISA will require today's 60 W incandescent to use only 43 W, but a CFL can provide the same amount of light using only 13 W—this is 80% more efficient than today's incandescent and 70% more efficient than the bulbs that will meet the EISA standard.

After Tier 1 of EISA is fully in place (in early 2014 as noted in Table 1 above), CFLs will still be considerably more efficient than the bulbs that meet the minimum standard. If consumers buy CFLs instead of the new more efficient incandescents, they will save more energy sooner and bring about faster lighting market transformation. In many cases, efficiency programs will remain useful tools to achieve these savings by promoting the most efficient bulb to consumers and filling the remaining sockets (whether basic or hard to reach) with the most efficient option.

[23] The costs of LEDs continue to be prohibitive for many general lighting applications and it is uncertain if they will be commercially competitive or cost effective for wide spread residential applications by 2012.

Figure 2: The Impact of EISA Tier One on the Lighting Market



NRDC Fact Sheet. *"Residential Lighting Efficiency – Where Do We Go From Here?"* 2009.

TIER 2 - 2020

Tier 2 requires DOE to set new standards for screw based bulbs. The new standard has not been established yet, but at a minimum the standard must require bulbs to produce at least 45 lumens per watt. This is almost as efficient as current CFLs. Light Emitting Diodes (LED) and "super efficient incandescent" will hopefully be market ready by that time.

Accessing the Remaining Potential

There is still significant energy savings potential in the residential lighting market. Therefore, the debate should not focus on *if* efficiency programs should continue to access the remaining cost effective savings, but *how* best to design programs to ensure they capture the remaining energy savings. Below are a few suggestions to access the remaining potential in California based on current market conditions and the upcoming lighting standards. While the following recommendations are crafted to address the California market, these suggestions are also applicable to other utilities, states, and regions that design and carry out lighting energy efficiency programs. The lessons learned from the markets and program designs in the Northwest and California (such as which metrics to use and what type of targeted programs to design) can inform the development of comprehensive lighting programs in other areas as well.

- **Target sockets that more likely hold inefficient lighting**: In addition to promoting basic CFLs wherever there is potential, programs should target three-way and dimming sockets, which recent studies indicate are dominated by inefficient lamps. Education programs could address perceived barriers to installing more efficient lamps in these sockets while additional programs promoting various specialty bulbs can overcome the unique challenges presented by different types of sockets (e.g., dimmers).
- **Explore more versatile technologies that offer sizable energy savings** There are currently technologies, such as the next generation incandescent lamp, that could deliver

savings of up to 30% of what is possible with traditional incandescent lamps.[24] This level of efficiency will be required by EISA between 2012 and 2014, as discussed above. Additional incentives could encourage manufacturers to produce incandescent lamps that provide at least 50% savings.[25] While this is still lower than the savings provided by a CFL, these bulbs will provide an energy savings alternative for those consumers who are not willing to purchase or install CFL in particular sockets due to customer preferences (e.g., aesthetics, product components, dimmer socket, etc.).

- **Offer a tiered rebate approach to incentivizing efficient lamps:** Since there are increasingly more options of efficient lamps on the market, energy efficient programs could offer varying levels of incentives to continue promoting the basic efficient technologies while simultaneously bringing the more efficient or specialty bulbs to market. For example, higher rebates could be offered for lamps that would more likely be placed into socket types with low efficient lighting saturation rates (e.g., dimmers) Thus, the efficient options that offer preferred performance and more versatile applications should receive a higher rebate initially as these improved technologies build market acceptance. A tiered system would leave in place basic CFL incentives (at lower rebate levels) as these lamps continue to need additional support, but not to the same degree as more advanced technologies.
- **Target existing advanced technologies or practices to bring down cost while pulling the next generation technologies to market:** LED and similar technologies are currently available but are more expensive than most customers are willing to spend. Addition research and development programs should focus on bringing down the cost of these technologies, while improving efficiency, versatility, and quality.
- **Expand education and improved labeling programs:** Awareness and understanding of the numerous lighting options continues to be a real barrier to the uptake of efficient lighting. Most people do not know how to compare lighting products by light output- and a better understanding would allow easier comparison across all product options. Programs that encourage retailers to display lighting options and their applications would build customer awareness and improve efficient lighting penetration. Similarly, programs that support improved labeling requirements and help customers decipher current labeling terminology would improve consumer understanding of which bulbs to purchase. National coordination of these efforts is crucial, as multiple labeling strategies would lead to confusion.

Conclusion

California efficiency lighting programs continue to provide cost effective energy savings and are an important part of the portfolio of programs helping to ensure customers receive affordable and reliable energy services at the lowest societal cost. These programs can satisfy both the short term need of resource acquisition, by displacing fossil fuel generation, as well as the longer term goal of transforming the lighting market, by integrating more efficient products into standard practice.

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[24] Philips' "Halogena" and Osram Sylvania "Halogen Super Saver" are on the market; General Electric is also working to release more efficient incandescent bulbs.

[25] Existing products already provide roughly 30% savings that meet the Tier One EISA standard. New coating technology may enable these lamps to achieve approximately 50% savings.

To be most effective in permanently moving the lighting market towards more efficient options, the standard definition of market transformation noted in Section II should be modified to acknowledge the dynamic nature of markets. Rather than a single defined outcome leading towards elimination of the efficiency program, market transformation is a continuous process. This process for technology improvement begins with research, innovation and demonstration, followed by introduction into the mass market through efficiency programs and other means to grow market acceptance, and finally updated efficiency standards and codes to lock in minimum efficiency savings across the market; and continues for each generation of technology. In addition, key metrics and baseline information must be established at the onset of efficiency program design and development to ensure that an agreed upon 'end point' (or series of end points) for a specific program design is clearly defined.

Furthermore, lighting programs should continue to ensure that past successes are not undermined by prematurely removing incentives for efficient lighting technologies and practices before they gain full market acceptance or become code. While some advocates argue that now is the time to remove support for CFLs, the evidence indicates that doing so would leave significant highly cost-effective savings opportunities on the table. Instead, to ensure the remaining potential is captured, programs must be modified where necessary to respond to dynamic market conditions.

Finally, well designed policies encourage greater innovation and adoption of efficiency in ever evolving markets. A comprehensive policy approach has played, and will continue to play, a key role in transforming the lighting market in California and beyond. Efficiency programs are only one strategy of the various methods used by utilities and regulators to encourage continued market transformation towards greater efficiency. When and how each policy strategy is deployed should be guided by the most current information on the state of technology, prices, and customer trends. Only then will utilities and regulators best achieve the mutual goals of resource acquisition and market transformation, and succeed in continually improving levels of efficiency and lowering customer energy service costs.

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