Boulder's Energy Future

- Localization Portfolio Standard -

Electricity and Natural Gas

Local Power.

13 JULY 2011

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Please use the following citation for this report:

Fenn, Paul, et al. (Local Power, Inc.). 2011. Boulder's Energy Future: Localization Portfolio Standard – Electricity and Natural Gas.

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EXECUTIVE SUMMARY

The Localization Portfolio Standard created to support Boulder's Energy Future is encompassed in the separate two reports contained in this document. The electricity report was issued first, to meet deadlines set by Boulder's City Council meeting schedule and to ensure adequate time for public review. Consequently, there is some overlap and repetition between the documents.

The City of Boulder is responding to core issues affecting the city's energy supply – chiefly diminishing fossil fuel supplies, increasing prices, the environmental effects of fossil fuel based energy, and the opportunity to nurture an innovative energy industry – and leading a community effort to define Boulder's Energy Future. Central to this discussion is estimating the available local energy resources, how far and how fast Boulder could localize its power and heat supply by deploying these resources, and the general cost of this effort in relation to utility rates and customer bills.

This report outlines pathways for the City of Bolder to transform its energy supply along three overall themes, while maintaining competitive costs of service and grid reliability:

1. Democratizing energy decision making, so customers and the local community have more direct control and involvement in decisions about their energy.
2. Decentralizing energy generation and management, reducing reliance on external energy sources.
3. Decarbonizing the energy supply, by using local renewable and clean fuel sources as much as possible.

Substantial energy localization opportunities exist within Boulder, and within the Denver Boulder Metro Region. The local standard is defined by technologies that either provide renewable fuels, heat, and energy efficiency within these geographic boundaries.

Energy Resources Framework

Boulder's two Localization Portfolio Standards ave been designed to meet or beat the incumbent energy economics. The City of Boulder can re-localize a substantial portion of its energy supply and facilitate greater levels of local ownership, while customers receive bills that are the same or lower than what they are currently. By itself, this methodology is insufficient to account for Boulder's ability to localize its energy supply. The citizens of Boulder are environmentally-conscious and civically-minded, as evidenced by such examples as the far above-average solar photovoltaic installation rates in the city compared to the rest of Xcel Energy's territory. As such, the portfolios presented are the minimum level of achievable energy localization.

The cost of electricity and natural gas in Boulder is currently relatively inexpensive. This posed challenges in developing cost-effective localized energy portfolios. Demand-side resources comprised of efficiency, conservation, and demand-response technologies and practices that cost less than procuring energy comprise a majority of both portfolios. The demand-side analysis included modeling a 'strawman' program design which:

1. Makes every building in Boulder into a 'Smart Building' with smart meters, end-use monitoring equipment, and analytical software paid for annually as SaaS (software-as-a-service);

2. Finances all efficiency measures using capital borrowed at 8% and repaid over 12 years;
3. Recoups investments using on-bill financing so that the customer does not incur any upfront cost;
4. Provides every home with an energy audit and every commercial or industrial business with a retrocommissioning audit.

This is an inherently conservative approach, since in practice not all buildings will warrant or need this level of investment, and not all measures will require the long-term financing and associated debt-service costs. The core idea behind the approach taken was to prove that, using conservative assumptions, the efficiency portfolio would still be cost-effective even given this level of investment and innovative design.

It is well-known that energy efficiency is an often untapped energy resource offering solid returns on investment, but that deploying efficient technologies has historically been difficult due to a variety of market and nonmarket barriers. As explained in detail in the 'Demand Side Management' sections of both reports, this approach fundamentally enhances the market for local energy resources and lays the groundwork for continuous efficiency improvements beyond those anticipated in typical utility programs. Instead of relying on marketing and word-of-mouth, 'Smart Building' energy monitoring and analytics would be essentially sales channels for the placement of efficient technologies and practices where they are most cost-effective.

The programs for energy efficiency and distributed renewable technologies described in these reports are designed to remove many of the barriers which typically constrain public participation in the construction of energy supplies. These programs 'level the playing field' between community-owned distributed energy resources and central power plants by:

1. Providing long-term financing via municipal revenue bonds;
2. Investing heavily in 'Smart Buildings' and efficiency;
3. Lowering transaction costs by aggregating customers for renewable resources;
4. Streamlining city permitting procedures for local resources;
5. Facilitating customer ownership directly and through community sharing programs;
6. Identifying and mitigating various market and non-market barriers.

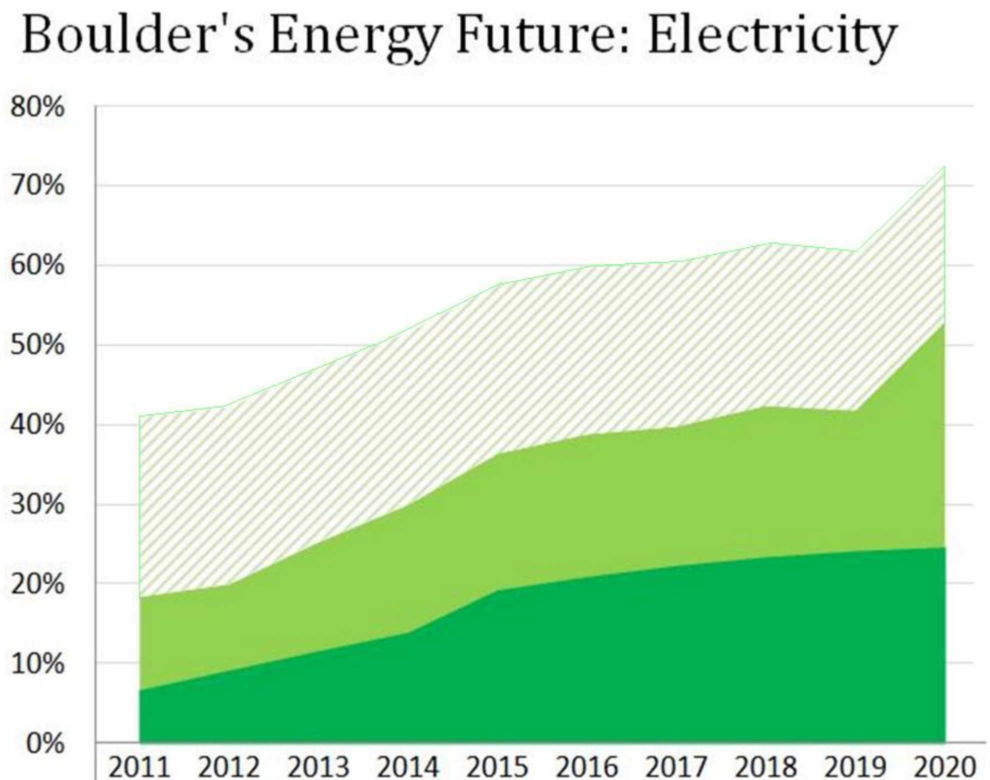
As such, this summary provides graphs which incorporate a higher level of public participation in Boulder's Energy Future than the lower-bound level presented for the Localization Portfolio Standards.

The Localization Portfolio Standard

The Localization Portfolio Standard (LPS) is an idea Local Power is developing for Boulder for the first time, and is conceptually similar to Colorado's Renewable Portfolio Standard (RPS). Qualifying projects for electricity are geographically concentrated within the City of Boulder, and limited to within the County of Boulder; for natural gas, resources are also mainly within the city and county, but biogas sourced from waste streams in the Denver-Boulder Metro Region is also included.

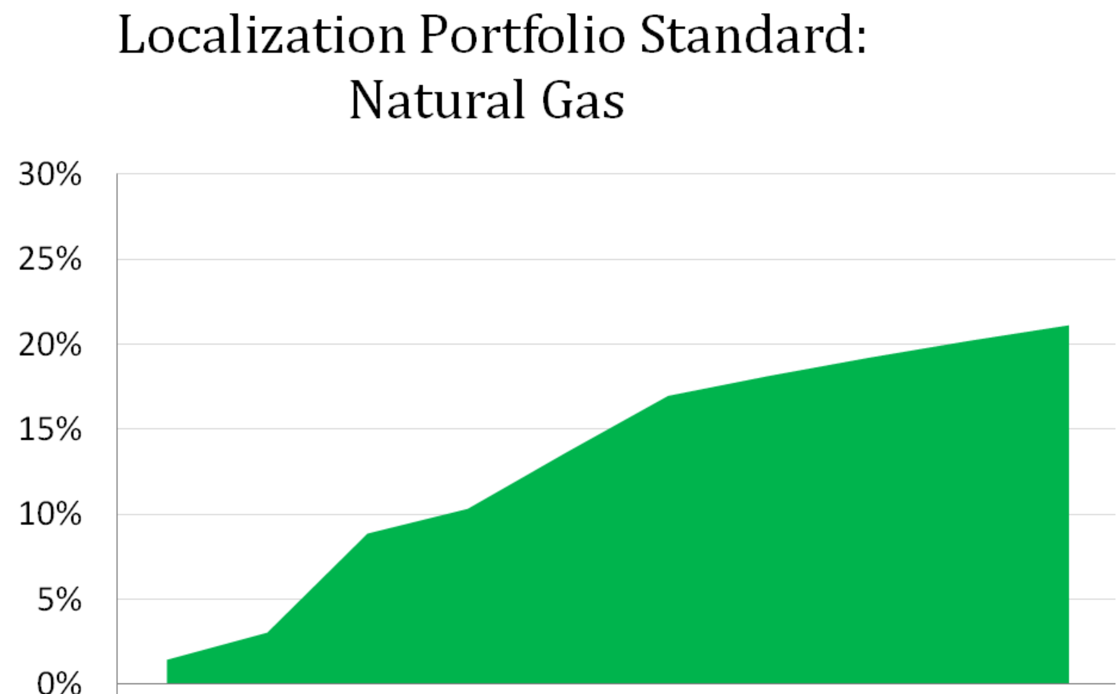
The percentage generated and load eliminated per year in the both portfolios is put forward as a general schedule for development. The proposed LPS could be adopted as a matter of broad energy policy prior to and independent of any renegotiation with Xcel or voter initiative to authorize full municipalization.

The local portfolio for electricity exists within the framework of a larger resource portfolio that includes nearly all of the renewable energy shown in the Boulder Cost Model spreadsheets created by the consulting team from Robertson-Bryan in collaboration with the City of Boulder, as well as other energy products the City may wish to purchase.



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
RECs	23%	22%	22%	22%	21%	21%	21%	20%	20%	20%
Remote Renewables	12%	11%	14%	16%	17%	18%	18%	19%	18%	28%
Local Portfolio	7%	9%	12%	14%	19%	21%	22%	23%	24%	25%
Total	41%	42%	47%	52%	58%	60%	60%	63%	62%	73%

The portfolio for local resources displacing natural gas depend in part upon securing lower cost fuel supplies by aggregating customers and sourcing fuel from competitive suppliers. This is described in detail under the “Natural Gas” section of the LPS report for natural gas.



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas LPS	1%	3%	9%	10%	14%	17%	18%	19%	20%	21%

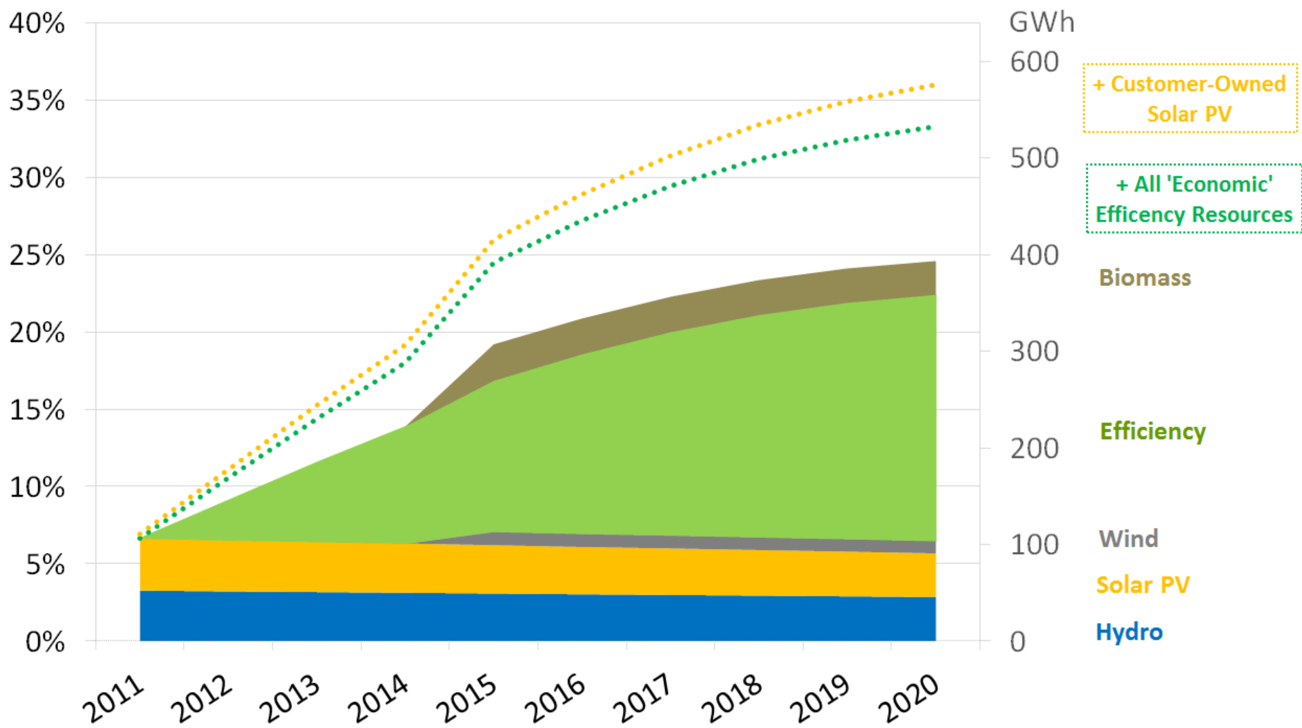
Localization Portfolio Standard & Additional Resources

The graphs below show the range of technologies which have informed the annual LPS targets. These blends are not presented to constrain the City of Boulder as it develops its local energy portfolio, as it is anticipated that the actual resource mix will vary from what is presented here. In addition, the charts depict resources *beyond the LPS*, including:

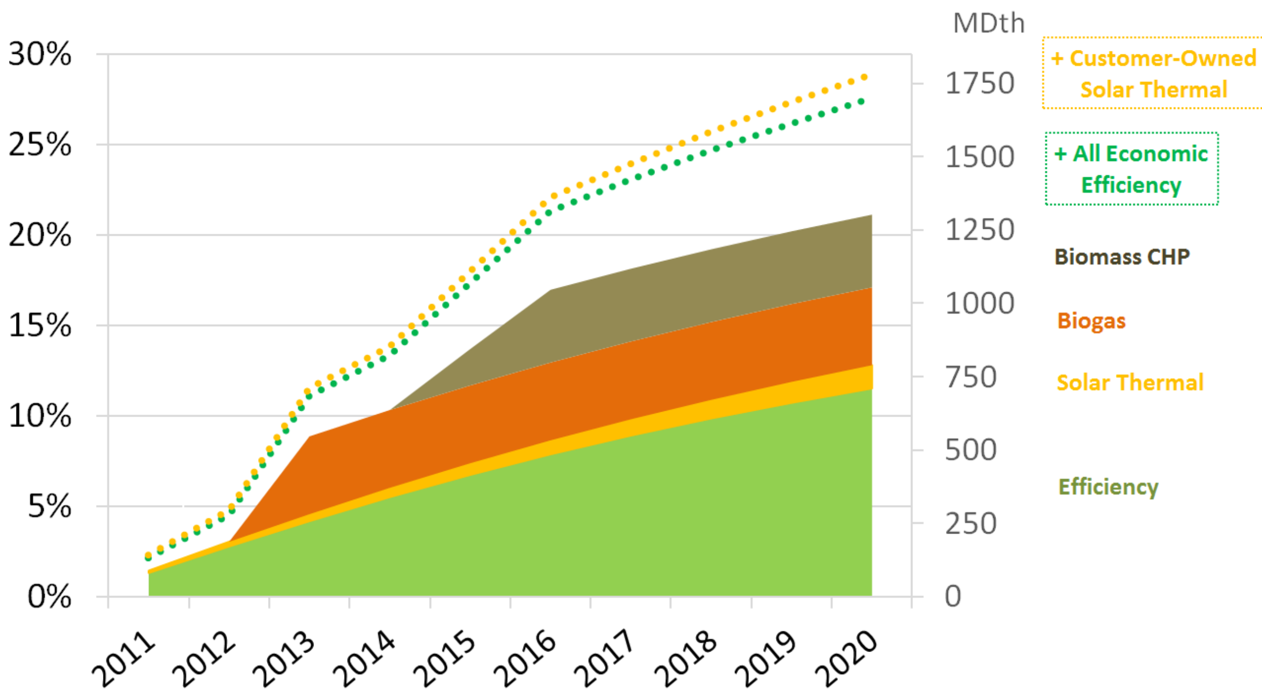
1. The energy efficiency resources which are economically cost-effective to deploy but are not included in the LPS are denoted by the dotted line. The energy efficiency included in the LPS was derived by adapting Xcel’s most recent potential study, and is comparable to current or pending statewide goals in Illinois, Massachusetts, Arizona, and New York. The higher level of savings may well be achievable within the program design advanced in the energy efficiency section, which should structurally overcome several barriers known to hinder the adoption of energy efficiency technologies.

2. The solar photovoltaic resources which would be brought online, if Boulder’s citizens continue to invest their own capital to install privately-owned systems at a rate comparable to recent years. Solar thermal above the LPS target is treated in a similar fashion.

Electricity LPS + Additional Resources



Natural Gas LPS + Additional Resources



Authorities Needed for Boulder's Energy Future

The ability for Boulder to maximize the deployment of local energy resources, and implement the more innovative technologies and practices associated with a well-designed Smart Grid, will vary depending on the degree of control of (1) power procurement at the wholesale level, (2) billing, customer revenue and rate setting at the retail level, (3) metering and utility distribution infrastructure operations, (4) the authority necessary to finance utility investments. Because of the interdependency between all of the technologies considered, and the effect the various authorities have on the scale of the potential implementation, both legally and financially, the sum of the whole portfolio is greater than the individual parts. These synergies are important to the overall outcome, and are described more under the second section of the electricity report, "Building Boulder's Energy Future."

The table below depicts how each of the authorities impacts the technologies in both the electricity and natural gas portfolios. The status-quo of each technology is listed in the second column. In the chart, light green signifies an authority that is beneficial for the technology deployment, whereas dark green connotes the necessity of the authority. Necessity generally implies that an authority is probably required to achieve a significant scale of development. Grey indicates that it is not applicable.

- Democratizing Energy: A Customer-Focused Utility - [1]
Summary of Authorities for the City of Boulder

Technologies & Practices:	Status Quo	Wholesale Control: Electricity Procurement[2]	Wholesale Control: Natural Gas Procurement[2]	Retail Control: Billing, Revenue, & Rate Setting	Operational Control: Metering	Operational Control: Distribution	Operational Control: Other Grid Upgrades	Financial Control: Revenue Bond Authority [3]	Financial Control: New Community & Customer
Heat Islands (Solar Thermal)	Possible								
Waste as a Resource (Biomass CHP)	Not Applicable								
Biomethane Pipeline Injection	Limited								
Combined Heat and Power (CHP) Retrofit	Not Applicable								
Geothermal Heat [8]	Limited								
Valmont Capacity Balancing (Natural Gas) [5]	Not Applicable								
Hydroelectric Power	Ongoing								
Hydroelectic Capacity Balancing [6]	Not Applicable								
Wind Farm on Barker Reservoir	Possible								
Solar PV	Limited								
Demand-Side Management	Limited								
Targeted Efficiency	Not Applicable								
Demand Dispatch	Not Applicable								
Electric Vehicle Technologies	Limited								
Home Area Networks - Upgrade [7]	Limited								
Thermal Gateways - Upgrade	Not Applicable								
LED Streetlights	Possible								
Storage - Distributed and Utility-Scale	Not Applicable								
Virtual Power Plant [9]	Limited								

Color Key: Light green signifies an authority that is beneficial for the technology deployment, whereas dark green connotes the necessity of the authority. Necessity generally implies that an authority is probably requires to achieve significant scale of development. Grey indicates that it is not applicable.

1) These categories are intended as an approximation of the relative roles of different authorities in facilitating local control and development of the various technologies though different market, operational, and financial structures and authorities.

2) New thermal end use technologies can potentially displace either electric or natural gas applications or both; thus wholesale market procurement of these resources may be affected depending on the energy resource displaced.

3) Revenue bonds can be used to fully or partially finance energy resource development, develop enabling infrastructure, or provide flexible options in structuring financing deals.

4) Valmont power is assumed to be procured from the current owner of up to 80 megawatts of natural gas generation capacity located at that site.

5) Capacity balancing implies coordination of Boulder's existing hydropower with other intermittent renewables, and may involve some system improvements.

6) Upgrades means significant expansion of demand side programs into new applications.

7) Geothermal heat means using hot ground water to provide heat to buildings and may have a variety of end uses; it does not refer to generation of electricity.

8) Virtual power plant refers only to the softward platform, not the metering or control hardware.

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EXECUTIVE SUMMARY

This report covers the potential for the localization of electricity resources for Boulder's Energy Future. A separate report will be issued for an energy localization displacing onsite natural gas combustion, although there is some overlap in both reports.

The City of Boulder is responding to core issues affecting the city's energy supply – chiefly diminishing fossil fuel supplies, increasing prices, the environmental effects of fossil fuel based energy, and the opportunity to nurture an innovative energy industry – and leading a community effort to define Boulder's Energy Future. Central to this discussion is estimating the available local energy resources, how far and how fast Boulder could localize its power and heat supply by deploying these resources, and the general cost of this effort in relation to utility rates and customer bills.

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The ability for Boulder to maximize deployment of local energy resources, and implement the more innovative technologies and practices associated with a well-designed Smart Grid, will vary depending on the degree of control of (1) power procurement at the wholesale level, (2) billing, customer revenue and rate setting at the retail level, (3) metering and utility distribution infrastructure operations, (4) the authority necessary to finance electric utility investments. Because of the interdependency between all of the technologies considered, and the effect the various authorities have on the scale of the potential implementation, both legally and financially, the sum of the whole portfolio is greater than the individual parts. These synergies are important to the overall outcome, and are described more under the second section of the report, "Building Boulder's Energy Future" and in Appendix A.

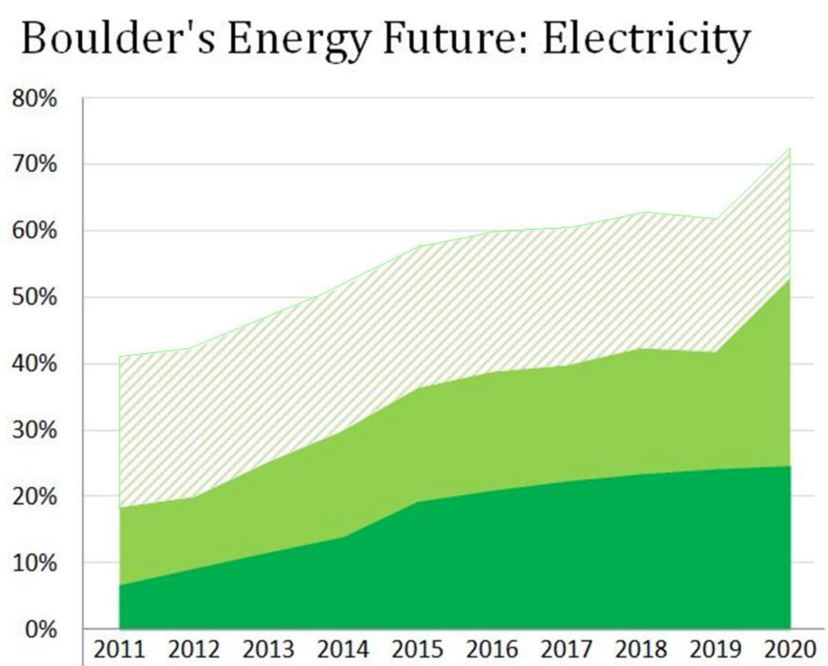
Substantial energy localization opportunities exist within Boulder, and within the Denver Boulder Metro Region. These opportunities are organized by technology and summarized qualitatively in the first section of the report, "Boulder's Local Energy Resources."

Local Power has created a cost model of these localization technologies, to quantify the economic potential for energy localization within the City of Boulder and Boulder County. This effort is described under the final section of the report, "The Localization Portfolio Standard" or "LPS". The local standard is defined by technologies that either provide renewable power generation, energy efficiency, or renewable heat. The standard may also include local energy storage, particularly when used for supporting variable renewable energy output or balancing renewable generation with demand.

Energy Resources Framework

The local portfolio exists within the framework of a larger resource portfolio that includes nearly all of the renewable energy shown in the Boulder Cost Model spreadsheets created by the consulting team from RBI in collaboration with the City of Boulder, as well as other energy products the City may wish to purchase. The largest and most cost-effective local resource is energy efficiency, and the LPS sets an aggressive but we believe achievable target of saving 2 percent of energy demand per year, reaching 20 percent savings by 2020. Local renewable energy starts by claiming use of existing local hydropower, and then expands through development of a few new local renewable energy projects. Over the next 5 years, local renewable generation is projected to produce nearly 10 percent of Boulder's electricity needs.

The Boulder Cost Model builds up to a 39% renewable energy supply by 2020. Due to overlap, and due to progressive efficiency savings, this is not entirely additive to the LPS. However, the net result is that by 2020, renewable energy and local efficiency will meet well over half of forecast energy demand. If Boulder wishes to expand its "green energy" portfolio further, there is the option of doing so with the direct purchase of renewable energy credits from a wide range of renewable energy projects. Ideally, these projects should be new, to insure that the energy is additive to existing power supplies and thus actually reduces greenhouse gas emissions and increases the amount of renewable infrastructure. The following chart is illustrative of how these resources - the Local Portfolio including efficiency and local renewable generation, as well as Remote Renewables, and RECs - can meet up to 75 percent of Boulder's forecast electric power needs by 2020. Note that the percentage of generation is higher than what is shown on the chart, because energy efficiency is included and this removes demand.



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In general, the percentage of renewables in the Boulder Cost Model tracks fairly closely to Xcel, which helps to keep the cost of total energy supply from exceeding that of Xcel. Another major factor controlling cost is that 30% of the total energy supply—or $3/4^{ths}$ of the renewable energy—comes from wind. Wind is by far the lowest cost renewable energy source in Colorado. Recent decreases in the cost of construction of wind farms, combined with improved performance, and generous federal tax credits, allow wind to be competitive with conventional power sources. The parallel construction of the two renewable portfolios allows the proposed Boulder energy supply to be reasonably competitive with Xcel, and is successful enough to generate a consistent surplus for Boulder relative to Xcel's rates for the full next decade.

Boulder can "cash in" this surplus in several interesting ways. One option would be simply to enjoy lower utility rates; however, this is not necessarily the least cost or most advantageous option. One important design feature of the Boulder Cost Model is that bonds are issued in the first year of the program, and payment on the bond is delayed for 1.5 years. This generates a surplus relative to Xcel's rates of over $65 million in the first two years, and $125 million over the decade. This surplus can be realized by charging similar rates to Xcel and then part of this can be used to pay down the 8 percent coupon bonds and save about $5 million per year in interest payments for many years into the future.

Another strategic option for taking advantage of the relative surplus is to invest in energy efficiency improvements that can provide returns to customers in the form of lower future bills. Also, the local generation portion of the LPS is certainly more expensive than conventional power supplies, particularly during the near term. This premium will tend to close over time as Xcel's rates increase. However, over the next decade the premium will need to be covered by the revenue for the utility. A recommended design feature of the program is that the local renewables should be built up within the framework of the available budget, defined as the gap between the cost of energy had customers stayed with Xcel, and the cost of energy for a Boulder electric power supplier. This is a principle key to making the local generation affordable.

Research Methodology

The research methodology included numerous expert interviews, a review of literature, and the analysis of Geographic Information System (GIS) data from the City and County of Boulder. Specifically, Local Power:

- With permission from Boulder staff, several firms retained by the city to provide technical support for the City Council's decision relative to Boulder's Energy Future were interviewed, and further made available related data. First, Local Power interviewed Ted Weaver for data from Boulder's "Baseline Energy Analysis" report by Nexant, to provide Local Power with refined demand curve models and related data to prepare a mock-up for modeling a portfolio of distributed resources. Second, Local Power conducted two interviews with Nils Tellier of Robertson-Bryan, who was preparing a Boulder Municipalization Business Plan to forecast utility operating costs in the current Colorado electricity market. Third, Local Power conducted two interviews with Kelly Crandall of Boulder's Local Environmental Action Division so that Local Power could estimate the technical and economic potential to implement Smart Grid-augmented technologies;
- Interviewed over two dozen independent consultants, energy services vendors, integrators, customers, and other parties with Boulder-specific knowledge deemed

germane to the technical and economic feasibility of diverse renewable power and heat generation, management and storage technologies;i

- Reviewed documentation regarding the City of Boulder's energy programs as well as those offered by the Public Service Company of Colorado (Xcel Energy, referred to hereafter as Xcel), pursuant to Colorado state law and regulation as it relates to energy localization, including a gathering of economic data on pricing assumptions for evaluated technologies;
- Reviewed available energy infrastructure and customer data, which involved importing Geographic Information System (GIS) data from the City and County of Boulder into Local Power's database, analyzing energy use in Boulder, and focusing interviewees on Boulder-specific factors impacting technical or economic feasibility.

Key Energy Resource Opportunities

Key findings of the electricity localization report include opportunities for:

- Energy efficiency and demand-side management, the largest and most cost-effective local resource, with the potential to save up to 20 percent of forecast electricity demand by 2020 (measured against baseline year 2011); energy efficiency programs are currently offered through Xcel, but local programs could likely achieve much more energy savings and reductions in customers' bills. The innovative program design proposed and modeled in this report leverages funds from the City of Boulder to retrofit *every* building with advanced energy monitoring equipment, communications, and energy management software, and, combined with on-bill financing, unlocks the potential for continuous energy management through Smart Buildings. The debt burden is largely shouldered by private investors, and the value of the portfolio savings and demand response outweigh the debt service in year seven, pay it off in year twelve, and net a benefit of approximately $280 million in year twenty.
- Waste-to-energy and waste-to-heat generation, using both non-recyclable municipal solid waste and regional biomass resources.
- Utilizing the city's existing (or enhanced) hydropower facilities.
- Customer- and community-owned distributed solar photovoltaics, including solar gardens, on local commercial rooftops.
- Implementing a well-designed Smart Grid in the city to support targeted efficiency and a variety of demand dispatch options (which turn appliances on or off in response to price or grid stability signals, and can support the integration of intermittent renewable generation).
- A small-footprint wind turbine facility in the vicinity of the Barker Reservoir (adjacent to a high wind area), utilizing the transmission and capacity-balancing resources available in Boulder's existing hydroelectric infrastructure.
- Local natural gas generation from Valmont could provide some "capacity balancing" for the intermittency inherent in local wind and solar generation; there is sufficient biomethane potential to supply the entire Valmont plant, although this is not likely to be economic until either a) the price of natural gas rises to $8 per million BTU, or b) carbon costs are imposed on fossil fuel that are sufficiently large to create an equivalent price to $8 per million BTU.

- Smart-meter retrofit-enabled plug-in electric vehicle technologies such as vehicle-to-building (V2B) strategies, in which the vehicle battery also serves as a storage/ back-up system for the building, and managed charging, in which the charging schedules of electric vehicles are aggregated and controlled in response to grid stability and power price signals for both customer and utility benefit.
- Partnering with large commercial and industrial facilities to develop onsite renewable or combined heat and power generation that could serve to enhance their system reliability and create a potential revenue source for these key customers and partners; however, this will require a careful balance between costs and the realizing the value of the energy streams to customers.

Not all of the available opportunities should necessarily be developed at the same time. Some are more expensive than others, and this will affect the timing that is optimal for deployment. As prices for conventional sources of power grow more expensive, more sources of renewable energy become cost effective. In addition, further investigation will be needed to discover in finer resolution the availability, cost and technical feasibility of the various local resource options. Overall, Local Power proposes a Localization Portfolio Standard of 30 percent of electric power demand, with 2/ 3rds of this being provided by energy efficiency improvements and 1/ 3rd from local renewable power generation.

There is considerable additional development potential; much depends upon future price trends in energy markets. If forecast trends are realized, then it should be possible to reach 40% or even higher localization in the 2020s. A factor that could significantly accelerate the date of cost-effectiveness of larger amounts of local green energy would be imposing a cost on carbon. A carbon price of $30 to $50 per ton will certainly make more investments in green energy cost-effective and practical.

As mentioned above, local development and use of these resources also depends in large part on the existence of a local authority that has the ability to implement and take advantage of the opportunities. Many of these projects could in theory be developed in the status quo, however, these projects are often constrained and can languish for years as simply an idea that has no vehicle for implementation. Local government can play the key role of catalyst by bringing together all the right elements that are needed in order for energy projects to develop:

- An organizing entity that has the policy focus and planning capability to develop a wide range of local green energy resources
- A revenue stream and financing authority that provides monetary support
- A workable target market or deal structure that allows specific project to provide energy service in a cost effective manner
- Adequate technical, program, and legal support that can be provided through a local government energy agency

BOULDER'S LOCAL ENERGY RESOURCES

Overview

The potential of each renewable generation or demand technology in this section is characterized first within the "status quo" and then within a "localized energy utility" scenario, in which the utility is focused on maximizing local power and heat resources.

In our research, the technical feasibility of status quo energy localization is defined primarily by the ability, under existing conditions (without municipalization or another change in state laws and regulations), to provide service from a renewable resource or demand technology. Economic feasibility of the localization of energy resources under a status quo scenario is defined by the ability of a technically feasible energy technology to provide service at a competitive rate with equivalent conventional supply. In power, the price-points for this criterion are defined by Xcel's electricity prices, and in heat, by pipeline natural gas or natural gas prices.

Under a localized energy utility, technical feasibility is defined primarily by the ability of the technology to be deployed and provide energy locally, and within the aggregate community demand curve or load profile. Economic feasibility of energy localization under this scenario is defined by the ability of a locally-deployed technology to satisfy two criteria:

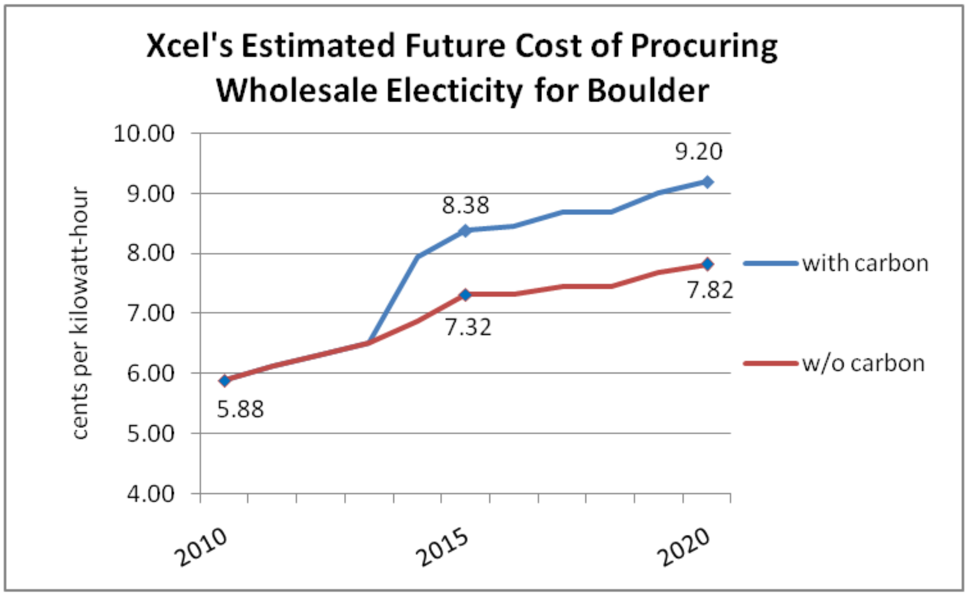
1. Provide energy at a price-point that is competitive with Xcel's retail power or natural gas rate for customers receiving direct energy service from the technology.
2. Support the community's power or natural gas requirements as part of a broader portfolio of technologies deployed at a cost that is price-competitive with non-local energy supplies available. For resources on the electric side, this analysis also takes into account the community's energy demand curve.

The City of Boulder has several primary opportunities for low- or no- carbon resource development under a localized energy utility scenario. These opportunities fall under two major categories, electrical generation and thermal energy (building heating and cooling, and domestic hot water). Using available renewable resources in conjunction with combined heat and power and district heating, can provide low-carbon electricity as well as replace natural gas usage for space and water heating.

There are many available energy sources in the area in and around the City of Boulder:

- Energy efficiency and demand dispatch/ response
- Plug-In Electric Vehicle practices such as Vehicle-to-Building and managed charging
- Solar (thermal and photovoltaic)
- Wind
- Geothermal
- Waste-derived biomass, including beetle-killed trees
- Small-scale hydro, including pumped storage

These resources should be developed as part of the localized energy portfolio according to the degree that opportunities arise and are cost effective. Over time, resources that previously appeared to "cost too much" are likely to require a closer look as energy costs continue to increase over time. Timing of resource deployment is thus a crucial variable that should be used to advantage. The following table shows a forecast for Xcel's future wholesale electricity cost, which are expected to increase by 20 percent to as much as 50 percent over the next decade. As these costs increase, sources of renewable power will become increasingly cost effective.



Demand-Side Management (DSM)

Demand-side management, chiefly comprised of energy efficiency, conservation, demand response and dispatch, and electric vehicle integration with grid operations, represents the greatest cost-effective energy localization potential for the City of Boulder.

Energy Efficiency

Boulder's current energy efficiency programs are run in partnership with Xcel.

Residential program uptake based on 2009 results (shown below) appear promising, with many customers implementing measures based upon the energy audits they received through the program, indicating that the EnergySmart program is well-designed. Boulder's goal is to visit 3,000 homes every year, which would cycle through all existing homes in about 13 years.

In contrast, the commercial program appears to suffer a steep drop-off between energy audits and customer implementation of energy efficiency measures. Local Power has not yet interviewed Boulder staff on existing programs, but problems in the program could be because of non-market barriers (for example, landlord/ tenant split incentives) and the inability of Xcel to offer businesses advanced meters to monitor and manage demand charges, which account for a sizable portion of commercial electric bills. Boulder's goal is to engage 1,000 businesses every year.

Most Popular Xcel Energy Programs Residential Participants - Boulder (2009)	
Energy Audits	400
Insulation Rebates	389
Heating System Rebate	294
Evaporative Cooling Rebate	189
Water Heater Rebates	94
Refrigerator Recycling	60
Low Income Kits	637
Low Income Weatherization	60

Most Popular Xcel Energy Programs Commercial Participants - Boulder (2009)	
Energy Assessment	183
Lighting Efficiency Rebate	87
Variable Frequency Drive Rebate	23
Cooling Efficiency	21
Motor Rebate	20
Custom Efficiency	19
Compressed Air Efficiency	8
Building Recommissioning	5

Boulder has advanced energy-saving building codes, and recently implemented SmartRegs, requiring energy efficiency improvements in residential rental properties (approximately half of Boulder's housing stock) and is researching a similar measure for the commercial sector titled Commercial Energy Conservation Ordinance (CECO). Boulder's SmartRegs could be enhanced by providing performance contract aggregation and additional subsidies to landlords seeking to retrofit their properties.

The city is also funding annual phases of audits of city-owned properties and the implementation of performance contracts for identified measures.

Energy Efficiency – Boulder's Smart Building Renovation

It is well-known that energy efficiency is an untapped energy resource offering solid returns on investment, but that deploying energy efficiency has historically been difficult due to a variety of market and nonmarket barriers. Boulder's LPS includes an innovative program design which would allow a localized energy utility to mitigate many of these barriers, while minimizing debt and saving 20% of the city's electricity usage over the next ten years (against a baseline year of 2011). Boulder would not be alone in this goal: Illinois, Massachusett, Arizona, and New York all have similar or stronger annual savings goals currently or in the next few years.[ii] However, with the program design proposed below, Boulder could quickly lay a far stronger foundation for continuous efficiency savings.

To answer the City of Boulder's core question – *How fast, how far?* – Local Power modeled a demand-side program that would make every building in the city a 'Smart Building'. Smart Buildings allow for the continuous monitoring, analysis, and optimization of energy usage, and unlock the potential for energy efficiency, demand response or dispatch, and time-of-use (TOU) pricing when combined with appliance automation to save even further on customer bills without sacrificing comfort. Local Power interviewed several leading industry pioneers in Smart Buildings for residential, small, medium, and large commercial and industrial applications to inform the modeling assumptions.

The Smart Building retrofits include installing smart meters, advanced electricity monitoring equipment at the premise and six end-use levels (lighting, refrigeration, etc.), subscribing every main building customer to software as a service (SaaS) energy analytic software, and paying for all energy efficiency measures using on-bill financing so that the customer would not have any initial capital outlays. The loans to cover this program are financed at 8% over a 12 year term, and are paid for – along with the SaaS annual subscriptions - out of the energy efficiency and demand response savings. Even without the substantial savings from demand response, the Total Resource Cost test (TRC) of the program is 1.60 – so Boulder's citizens would see their bills decrease as the loans are paid off.

The debt which accrues to the utility is only for the cost of the infrastructure – not the energy efficiency measures or the energy analytic software. The majority of the cost would accrue to private businesses that use the Smart Buildings' monitoring and communications infrastructure to drill down on the value propositions of demand-side measure. Innovative energy companies and investors will be able to push the envelope of investment-grade energy efficiency deployments in Smart Buildings. In this way, Boulder could leverage funds of approximately $8 million a year to unlock far more efficiency than if rebates and audits were offered for free – by changing the market in a structural and meaningful fashion. The value of the portfolio savings and demand response outweigh the service of both utility and private debt in year seven, pay off the debt in year twelve, and net a benefit of approximately $280 million by year twenty.

The Smart Building infrastructure is assumed to be installed over a ten year period, allowing Boulder to target installations to the most energy intense customers in the early years. Access to customer billing data, when combined with other datasets from the City of Boulder, will permit these targeted efficiency retrofits – for example, all small grocery stores could be analyzed for electricity consumption per square foot, and the top 20% of stores selected for the initial program years, and for investment-grade energy efficiency audits. Those customers could be aggregated into a single performance contract awarded under a competitive bidding process. This could allow for a more cost-effective deployment, fine-tuning of the approach, and early successes to drive customer awareness. It is worth noting that interviews with efficiency program staff revealed that energy audits are currently constrained by significant delays in accessing customer usage data after the customer has signed a release form; it typically takes Xcel 3 to 6 months to make available billing records to use for the purposes of enhancing the audit results. A customer-focused utility would mitigate these barriers, and it would not be an issue for a Smart Building tenant.

In a typical utility-funded energy efficiency program, funds are collected from all ratepayers and used to implement efficiency measures, which increase rates for all customers regardless if they had implemented the measures or not. In the proposed program design, the majority of savings are captured using on-bill financing, which directly tie the efficiency savings to the cost incurred for each customer. While aggressive energy efficiency investments will invariably raise the average cost of electricity, this approach minimizes the effect and clarifies the value proposition for many customers.

The two key barriers that are overcome by this design are 1) access to capital and 2) the lack of certainty surrounding many energy efficiency savings. The ability to continuously monitor, verify, and enhance building and appliance performance also overcomes the split-incentive barrier – for example, a tenant will be more amenable to paying for 'negawatts' if usage and performance is continuously monitored, and the savings are proven in a transparent fashion, allowing the landlord and tenant to negotiate sharing the savings.

In addition to efficiency, the flexibility to monetize and offer customer peak demand charge monitoring and management, demand dispatch, and vehicle electrification rates would enhance customer value-propositions in bundled performance contracts. As building systems become automated in response to customer preferences and price signals, TOU pricing should be implemented where beneficial.

Appendix G contains detailed program tables, by residential, commercial, and industrial sectors as well as the overall portfolio. The next section explains more of the methodology and reasoning behind the analytical approach.

This innovative approach was also selected as a modeling exercise to demonstrate just how cost-effective an energy efficiency portfolio can be. If Boulder chose to run a more traditional utility program, with funds collected on a surcharge mechanism to be deployed in rebates, the portfolio might be more "cost-effective" from a traditional planning perspective, but would fail to address core barriers to the widespread adoption of continuous efficiency improvements. The approach modeled lays a strong foundation to make Boulder a leader in demand-side management, by investing directly in customers' buildings and clarifying the value-proposition of energy efficiency in a comprehensive fashion. Many conservative assumptions were adopted in Local Power's modeling, as documented in the next section. A key takeaway is that Boulder has ample efficiency resources to achieve an average of 2% savings per year for the next decade, and that deploying this resource will lower customers' bills.

Demand-Side Management Estimation Methodology

Local Power has adjusted Xcel's 2010 "Colorado DSM Market Potential Assessment"[iii] to Boulder's territory, using baseline data provided by Nexant and Opinion Dynamics. Xcel's energy efficiency potential study covers several hundred technologies and reveals ample savings that can be achieved in the residential, commercial, and industrial sectors.[iv] Local Power has chosen the most aggressive achievable energy efficiency scenario to include under the LPS, which includes limited emerging technologies (LED building and street lighting, induction street lighting, fiber-optic refrigeration display lighting, and indirect evaporative cooling). The inclusion of these five emerging technologies in Xcel's study added 20% to the *achievable* energy efficiency potential over an 11 year period. It is critical to note that energy efficiency is an innovative and rapidly evolving industry, and that dozens of already-commercialized but not widely known emerging energy efficiency technologies are being tracked by multiple utilities and organizations.[v]

Using this data, Local Power examined efficiency potential at the following levels:

1. Sector (example: offices).
2. End-use (example: Heating, Ventilation and Air Conditioning (HVAC) within offices).
3. Measure (example: demand-controlled ventilation within offices), where available.

In addition, the analysis captured:

1. The City of Boulder's more efficient building stock.
2. Relevant findings from the "emerging technologies" sections of Xcel's potential study.
3. The costs of installing smart meters as well as premise and end-use level metering equipment in all commercial and industrial buildings.[vi] The largest 50 buildings were assumed to have existing energy management systems; costs for these buildings were instead from the activation of two kinds of energy management software sold as a service.

4. The costs of installing smart thermostats and home area network gateway devices in every home, and advanced smart meters in homes which do not yet have them.
5. The annual subscription costs of advanced Software as a Service (SaaS)
6. The costs of energy audits using advanced auditing software sold as a service for every home.
7. On-bill financing capital cost assumptions covering the up-front cost of all installed measures and monitoring equipment, financed at a conservative 8% interest over 12 years.
8. Demand response potential from the Smart Building retrofits, by adapting the "Achievable" scenario results from FERC's National Assessment of Demand Response" model to Boulder's baseline and peak load by customer segment (residential, commercial, and industrial). This analysis assumes building automation and time-of-use pricing.

It should be noted that the Smart Building technologies were modeled as an added cost only to the efficiency calculations. The 'energy as a service' business model which will be deployed in the Smart Buildings will undoubtedly enhance the economics of efficiency measures captured in Xcel's study, should deploy more conservation, and will facilitate the integration of emerging technologies. For example, in Xcel's study, boiler tune-ups are modeled with a two year measure life, after which the savings degrade. In a Smart Building, energy analytic software would recognize the patterns associated with a needed boiler tune-up, and notify maintenance personnel promptly. In fact, many firms have additional revenue streams by selling their services through HVAC firms with maintenance contracts, because only dispatching personnel when necessary is a large cost-cutting measure.

Local Power's analysis built in a decline in measure savings over time to the cumulative energy savings, to take account of measures which reach the end of their useful life and must be replaced. The annual rate was assumed at the average measure life of 12 years, or an 8% annual decay in savings achieved the prior year. In Xcel's potential study, these measures are added back into the pool of available efficiency resources that are considered for market adoption. However, customer relationships are not captured by the methodology used in Xcel's study. In other words, the customers are treated in the same way by the model, regardless of whether or not they were program participants in the past. Our approach assumes that these customers will have been satisfied with the program, will choose to participate again when new efficiency measures are required, and will face low barriers because of Smart Building software monitoring analytics. Efficiency savings have been added into the calculations to mitigate the decline rate, with a corresponding increase in program and measure costs. Marketing costs were also added in, to conservatively account for the need to maintain customer awareness of the program.

It also should be noted that Xcel's study did not capture funding sources such as the tax credits available to commercial and residential customers for installing energy efficiency measures.

The program design assumptions behind Xcel's study and Boulder's Energy Future are divergent; hence, this adaptation is at best an approximation, in anticipation of more rigorous program designs which capture the cross-cutting programmatic integration assumptions of

Local Power's approach which would lead to notable reductions in overall costs and customer bill impacts. Furthermore, unique opportunities exist within the localized energy utility scenario which will drive costs below those experienced by larger statewide programs that rely on marketing and outreach. For example, Boulder's current SmartRegs and proposed CECO (Commercial Energy Conservation Ordinance) allow a majority of the building stock to be enrolled in efficiency programs with relatively little program marketing effort compared to more market-based approaches to customer enrollment.

Demand Dispatch

Demand dispatch is the practice of turning appliances on or off to mitigate grid instability (for example, from renewable energy intermittency) instead of relying on combustion turbines burning natural gas. Demand dispatch is an expanded form of demand response, which typically only targets demand reductions during peak summer periods, and requires the full automation of appliances. Key targets would include server farms, refrigerated warehouses, agricultural pumping, and commercial facilities with energy management systems used to dispatch lighting and HVAC end uses, in addition to residential customers not served by natural gas. Demand dispatch also includes managed charging of electric vehicles, which is detailed in the section below.

Lawrence Berkeley National Laboratory's (LBNL) Demand Response Research Center has pioneered the automation of demand response for commercial and industrial facilities in a program called Open Automated Demand Response (OpenADR). It is operational in approximately 300 facilities in California, and has been adopted by over 60 commercial vendors. The second iteration of OpenADR will also encompass the residential sector, and is being incorporated into Smart Grid standards later this year.[vii]

OpenADR has primarily been used for demand response, but is being explored for demand-dispatch.[viii] It has a fast enough response time to deliver ancillary services such as regulation up, regulation down, and non-spinning reserve, and may be able to serve as spinning reserve in certain applications. In other words, aggregated OpenADR has similar grid-balancing characteristics to those of grid-scale battery systems, and at a fraction of the cost and environmental impact. In addition, it is a highly distributed resource and may be used to relieve temporary system constraints across the grid topology, or to smooth out pockets of load or generation.

Demand charges in Xcel's territory are substantial.[ix] The ability to monitor and shape monthly customer peak demand would be a significant value-added for any building owner, and the technology required to do this would also enable the dispatching of demand (up or down) to balance renewable intermittency. Monitoring and dispatch of customer demand could be monetized, and used for both the customer's benefit and the energy resource portfolio as a whole. Smart Buildings will also provide early adoption of demand dispatch standards. Research in this field, as in other cutting-edge Smart Grid applications, is still evolving rapidly.[x]

The ability of Boulder's citizens and businesses to implement demand response or dispatch is dependent upon Xcel's willingness to contract for these resources. Under a localized energy utility, demand dispatch could be implemented to its full potential.

Plug-In Electric Vehicles

Plug-In Electrified Vehicles (PEVs) may interact with the electric power grid in three beneficial ways:

1. **Managed charging** or smart charging is the coordination of when plug-in electric vehicles draw power from the grid to recharge. This is performed by the grid operator or an aggregator, and in accordance with the PEV owner's specified preferences. For example, a PEV owner may commute to work and plug-in their vehicle at 8:30 AM, and specify that it must have a 10 mile charge by noon (for a lunch trip) and must be fully charged by 4:30 PM; the aggregator managing the charging of the vehicle could then turn the charger on and off, in observance of grid conditions and price signals, providing the PEV owner's conditions are met at the end of the charging duration. Alternatively, the PEV owner's preferences might be to charge the vehicle as quickly as possible; in that case, since no value could be derived from using the PEV as a grid resource, the owner would be assessed a higher billing rate compared to the managed charging rate. Managed charging is not yet commercially offered, but is a near-term possibility.

2. **Vehicle-to-grid (V2G)** is when the grid draws power from the vehicle battery, when called upon by the utility or grid operator. V2G is still being researched, as cycling the PEV battery too often may degrade the performance of vehicle range over time, and is a medium-term goal.

3. **Vehicle-to-building (V2B)** is when a PEV owner's home or business draws a portion of power for the building from the vehicle battery, at the customer's discretion and in observance of grid conditions and price signals. This offering must be targeted to PEV owners who have a short enough commute so that the battery does not cycle more than would be expected if they had an average commute. V2B is offered by one commercial vendor in the United States.

Google has worked with the regional transmission operator (RTO) PJM Interconnect to model how the managed charging of 3.2 million electric vehicles could provide all necessary regulation services within the control area, which would give each vehicle a 3.5cent/ kWh discount for charging.[xi] In Boulder, this figure equates to 6,400 electric vehicles. Since service territories are different, the use of electric vehicles for grid-level benefits in Boulder should be explored further, and is outside the scope of this report.

President Obama has issued a policy goal of having one million electric vehicles on the road by 2015, and has taken steps to remove barriers to this transition.[xii] Using a distribution sales model predicated upon consumer preferences revealed in Prius sales data, the projected volume of PEVs sold in the Denver-Boulder metropolitan area for the first 1 million vehicles will be 11,230 PEVs, of which 9,000 are owned by consumers and 2,230 by fleets. This method of apportioning sales captures consumer demographics and preferences well but does not address non-market barriers, some of which may be critical to PEV sales. This could represent as much as 62 MW of additional load. However, if charging is managed using automated demand dispatch, this load could be reduced to 7 MW over 8 hours or 5 MW over 12 hours and used as a grid resource.[xiii]

The City of Boulder appears well prepared to analyze and remove barriers to vehicle electrification, as a member of Rocky Mountain Institute's 'Project Get RSeady,' and host to a DOE-funded PHEV conversion and V2G demonstration pilot as part of SmartGridCity. However, Xcel does not currently offer an electric vehicle rate schedule, or managed charging. A localized energy utility would be free to set attractive rate schedules to incentivize electric vehicle ownership, and to implement innovative value propositions such as managed charging and V2B in the near-term, for both fleet and privately owned electric vehicles.

Smart Thermostats

Using a programmable controllable thermostat, customer heating load, supplied by natural gas or electricity, could be conserved through thermostat setbacks and scheduling; ensuring savings equivalent to if the customer had a programmable thermostat and used it correctly. Additionally, several innovative companies offer Smart Grid analytics and automation to optimize home heating loads to weather forecasts. This is a significant value-add from the customer's perspective, in addition to being an efficiency measure and potentially further enabling demand-dispatch on electric heating systems. This approach requires control of the utility metering infrastructure to be implemented. It is worth noting that the price has dropped dramatically for smart thermostats, and that the forthcoming ENERGY STAR specification for thermostats is a smart thermostat.

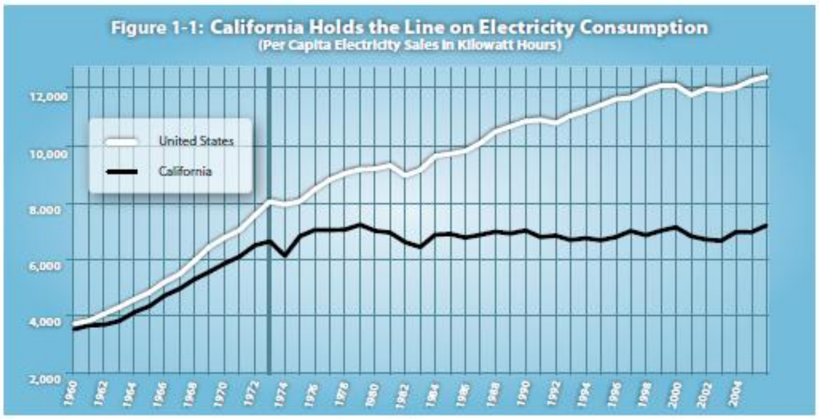
LED Streetlights

LED streetlights have evolved rapidly over the last few years. In addition to offering significant gains in efficiency and decreased maintenance costs, some LED streetlights may be used for demand dispatch grid service. In California, the City of San Jose has installed LED streetlights in an ARRA pilot, to test the ability to increase efficiency through dimmable lighting, and has adopted ordinances which allow, for example, for the lights to be dimmed late at night when foot traffic is low. The US Department of Energy has a knowledge sharing group specifically for cities interested in developing this resource, the Municipal Solid-State Lighting Consortium. Both Fort Collins and Colorado Springs are members of the Consortium. Boulder should join this consortium and monitor the development of this technology.

Electric Rate and Electric Bills

Many people are very concerned about their "electric rate", which is the price of every kilowatt-hour a customer consumes. However, *the amount of money customers actually pay depends both on the rate and on the amount of energy consumed.* This highlights the importance of energy efficiency and conservation programs to reduce energy expenditures and bills. It is important for utilities to plan efficiency programs along with spending on infrastructure to avoid the need to raise future rates to cover fixed costs on the sunk investments. This is an often overlooked part of Integrated Resource Planning—treating efficiency and conservation as a real grid resource, rather than as a vague reduction in demand. To properly scale up the investment in energy efficiency necessary to Boulder's Energy Future, this distinction must be understood by Boulder's citizens.

Efficiency and conservation can turn ordinary thinking about electric rates on its head. For example, in 2009 California residential customers paid 14.7 cents/ kWh, making their *residential electricity rates* 28 percent higher than the national average. However, average *residential electricity bills* were 10% below the national average—superior to 3/ 4ths of the states. Prior to conservation programs begun in the 1970s, California used nearly the amount of electricity per capita as the US average; by the 2000s the US as a whole consumed 70 percent more electricity per capita than California—an effect of 4 decades of effective policies in California and comparative neglect in the US as a whole. By 2020 annual efficiency and conservation savings are forecast to reach 80 Terawatt-hours, valued at $16 billion per year. (For scale, Colorado consumed 50 Terawatt-hours in 2009.)



Source: California Energy Commission.

Efficiency and conservation savings benefits are real, and should be prioritized, well-funded and well administered to ensure the most benefit to ratepayers.

The Smart Grid

The Smart Grid is a variety of strategic investments designed to transition today's centralized 'silo' grid architecture into a network-based grid architecture. This must be done in order to support the deployment, in place of traditional centralized generation, of high levels of distributed generation, storage, and demand response or dispatch (to provide capacity balancing and other ancillary services), renewables, and electric vehicles. This transition must be accomplished while maintaining grid reliability, and ensuring privacy, cyber-security, and interoperability between grid components and customer appliances.

Energy is most efficiently used or stored, and energy supply and demand most efficiently balanced, nearest to where the generation and consumption are occurring. As such, a properly designed and executed Smart Grid implementation will:

- Enhance the performance of the distribution system;
- Increase the cost-effectiveness of interconnected devices - a synergistic effect making the whole greater than the sum of the individual parts in isolation - by assuring interoperability and even aggregating generation, storage, and demand assets into "Virtual Power Plants" optimized and dispatched in response to price and grid stability signals;
- Facilitate the evolution of smaller autonomous grids, termed 'microgrids' or 'islands';

- Enhance the economics of the localization effort at the portfolio level, as it lessens the dependence overall on non-local grid assets: central generation plants providing energy, capacity, and ancillary services, with the associated fuel-based marginal price, fuel-price volatility risk cost, and transmission financial amortization costs and physical electrical line losses. Even renewable generation assets such as centralized wind farms and photovoltaic arrays are still constrained by the physical nature of the traditional 'silo' grid architecture, in comparison to distributed generation operated under a well-designed Smart Grid network architecture.

The integration of all these technologies and practices depends upon the ability to monitor, communicate, store, analyze, and broadcast data throughout the Smart Grid – it is a revolution in communication infrastructure as much as traditional grid components and operations. These investments must be based on widely adopted, open standards or else risk becoming obsolete as technologies and practices rapidly evolve.

Business Cases: Where Xcel and Boulder Meet or Diverge

As grid investments are quite capital intensive, utilities must plan their systems over decades, and as such must anticipate technological trends as well as customer and political expectations regarding price, reliability, and environmental considerations. Vertically integrated investor-owned utilities, which own assets in and control energy generation, transmission, and distribution in order to maximize shareholder returns, have a complex and conflicted relationship with the Smart Grid. Certain components enhance their value as a company, such as distribution automation upgrades, which invest in the distribution sector without necessarily compromising their returns on transmission and generation assets. Other components, such as distributed generation owned by their customers, may necessitate the need for upgrading their distribution assets, but come at the expense of the other sectors, as distributed generation lessens the need for transmission or central generation assets. The balance of these competing and complex business cases, and how they interact over a planning horizon of decades, determines the way in which a vertically-integrated IOU must legally pursue Smart Grid investments to maximize their investors' returns on capital.

Xcel has invested heavily in creating the City of Boulder's Smart Grid infrastructure, in their distribution system, customer smart meters, communications 'backbone', and 'back office' data management systems. Local Power is exploring the ways in which these investments were made and how they diverge from, support, or can be made to support, Boulder's energy localization.[xiv] Exploring this 'grey area' and determining what is necessary to deploy a well-designed Smart Grid would provide important information to Boulder's energy localization efforts. Our initial findings indicate that there are significant technology obsolescence risks in certain aspects of Xcel's Smart Grid infrastructure deployment.

Local Power interviewed the Austin, Texas 'Pecan Street Project', a non-profit collaboration between the municipal utility in Austin, the local Chamber of Commerce, the Environmental Defense Fund, and the University of Texas. The project is a 'deep dive' smart grid pilot on 1,000 homes and 75 commercial premises in a new development with diverse loads and generation (micro CHP, PV, adsorption chiller, EV, storage and/ or fuel cells). The project is funding the development of open-source smart grid protocols, and is focused on creating a vendor-neutral space to allow for a customer-focused approach to the delivery of smart grid services. A number of innovative firms have participated intensely in the project. Staff suggested continued knowledge-sharing and potentially a collaboration between the Pecan Street Project and the City of Boulder.

Hydroelectric Power

There are eight hydroelectric generation facilities located on the city's water supply system that provide annual generation of about 45 million kilowatt-hours per year. This represents an average production of about 10 megawatts; however, production of electricity can vary greatly at different times of the year and in different years.

Currently, the City sells the generated power to Xcel which provides revenue to the City. The hydroelectricity is then blended with Xcel's power mix, diluting the value to 15 hundredths of one percent of the utility's retail sales in Colorado. Contracts for production from each of the locations expire in different years, ranging from 2010 to 2018. At that time the City can either renew the contracts with Xcel or sell the power to one of the numerous retailers of electricity in Colorado, most of which are small municipal utilities. One option might be to have shorter contract terms, with the right to terminate in a year upon advance notice, in order to provide the City with flexibility if it wishes to form a local energy authority in the future. Xcel currently owns the power lines to the hydro facilities.

A local energy authority would allow the City to provide this clean, renewable energy from these hydro plants exclusively to local electric power customers. The locally-owned hydropower could supply about 3 percent of the electricity needs within the jurisdiction of Boulder, with a reported potential to increase this to over 4 percent with certain improvements. Therefore, a local municipal utility could make the electric supply, environmental and financial benefits of this local energy resource 20 times more significant to Boulder utility customers than in the current arrangement with Xcel. Xcel's entire share of hydropower in its electricity mix is expected to range from 1 to 2 percent over the next decade, which gives Boulder a significant advantage over Xcel in this low cost resource.

Local hydropower provides the single most feasible option for developing renewable energy as part of a Local Portfolio Standard. The generation infrastructure already exists and is owned by the City of Boulder. If the City wishes the hydropower resource to benefit the local customers specifically, then it should be determined wheter there is a way to get out of the contract with Xcel at an earlier date.

Boulder Hydropower								
	Maxwell	Kohler	Orodell	Sunshine	Betasso/ Lakewood	Silver Lake	Boulder Canyon	Total
Notes					*	*	*	
Initial Capacity (kW)	70	136	180	800	2,900	3,200	20,000	27,286
Present Capacity (kW)	70	136	180	800	6,100	3,200	10,000	20,486
Annual Energy (kWh) *	610,000	820,000	700,000	3,400,000	17,400,000	9,710,000	9,680,000	42,320,000
Capacity Factor	99%	69%	44%	49%	33%	35%	11%	24%
Inservice Date	1985	1985	1987	1987	1987; 2003	2000	1910	
Xcel Contract Date	2016	2017	2018	2017	2018	2018	2010	

*** Notes:**
Lakewood: 2005 was a full production year and future production should be similar
Betasso: altering piping configuration at Water Treatment Plant should result in higher head and more power; operational in 2008
Silver Lake: went into service in May 2000, but operational difficulties with the control systems prevented it from operating fully until 2004.
Boulder Canyon: has 2 x 10 MW turbines, but only one operational; 2005 report recommended replacing with one 4.9 MW unit.
Generation: estimates rely heavily on 2005,an average water year for supply and demand at lower post-drought levels.

An important advantage of hydropower is its relatively fixed cost compared to purchasing conventional power on the wholesale market and the fact that it does not rely on potentially volatile fuel costs. On the other hand, variability in hydropower means that the energy must be made up from other sources when production is low. This creates an exposure to market risk. Utilities can mitigate this risk either through pooling the output from different hydro facilities, and/ or through paying to reserve natural gas power generation capacity in case there is a need to make up for lost power. On the other hand, this risk would be quite small to Boulder since the hydropower would be supplying 3 percent of local electricity.

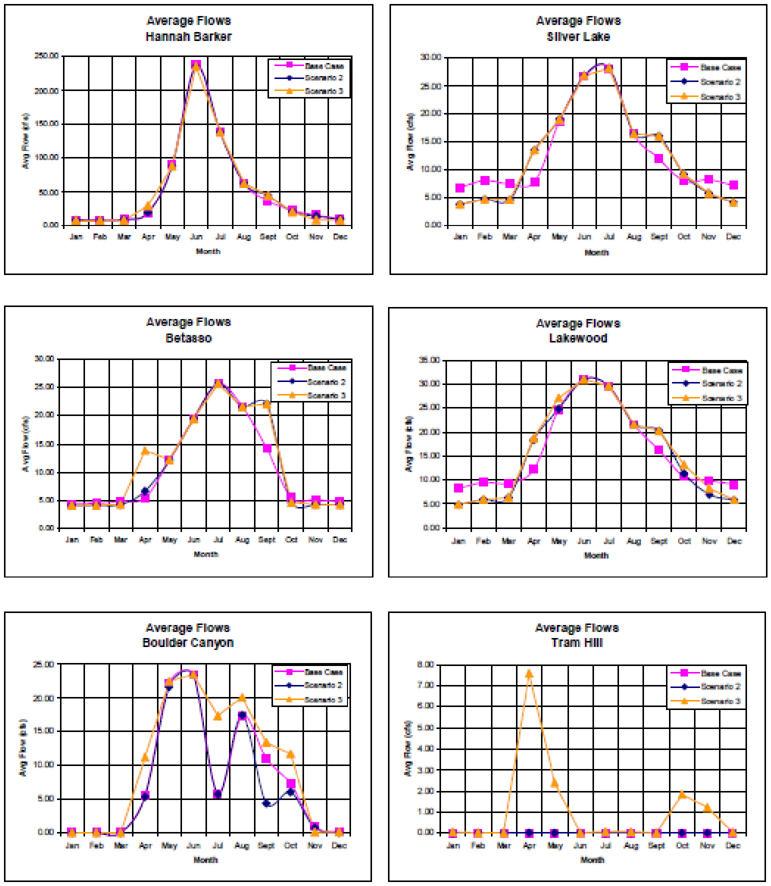
Furthermore, only a fraction of hydropower is lost in a given year, which is usually made up in other years when hydropower generation increases. The risk of variability is further limited by the fact that Boulder already owns multiple generators on multiple sites.

The City might want to explore the option of purchasing the power lines to the hydro resources from Xcel as well as the potential for further enhancements of the generating potential of its hydropower system, including adding wind and energy storage as discussed in another section of this report. Nameplate capacity is much larger than the average generation, but actual generation only reaches that high a level during the peak of the summer. This suggests significant extra capacity may exist on the wires for other power generation through most of the year.

Local Hydropower & Municipal Load

The following charts show the monthly flow rates at six locations in the Boulder water system. These flows illustrate the available energy for use in hydropower generation over the course of the year. Very limited energy is available during the winter months, December through March, while most the most generation would be available from May until September.

Average Flow per Month
Existing Flow Vs Proposed Flow at Each Plant



The Baseline Report load charts show Boulder electric power demand is lowest in the spring and fall, and has a modest increase during the winter. The largest increase is during the summer, when demand peaks at about 260 Megawatts. The peak local demand is far in excess of the generation from the Boulder hydropower system; however, the annual energy potential from the water system broadly follows the need for electric power over the course of the year as shown in the following charts:[xv, xvi]

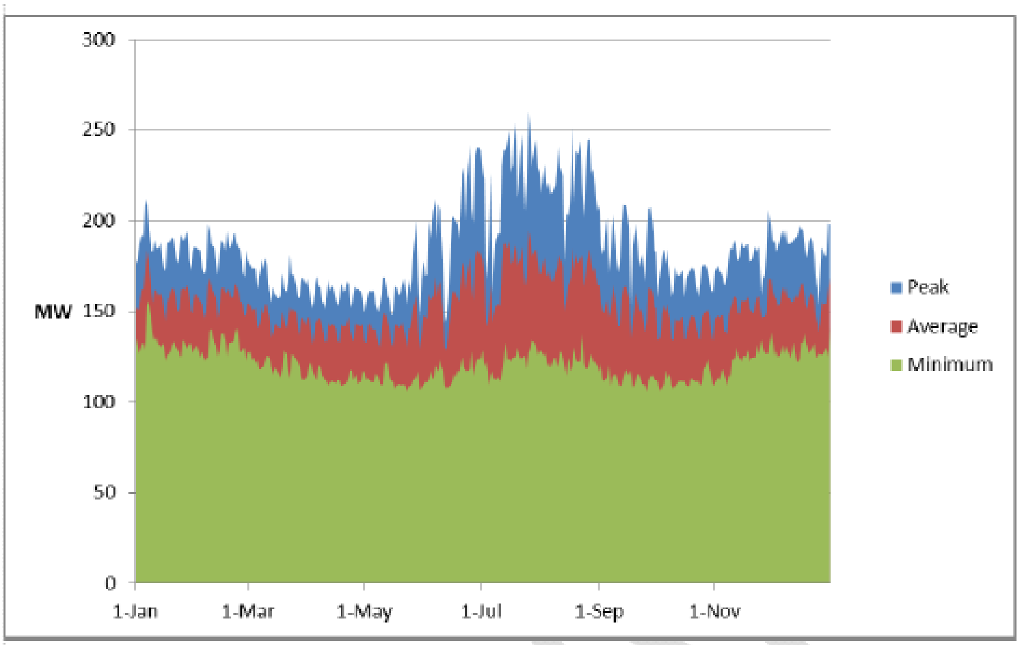


Figure 4-9: Daily Load – Peak, Average, and Minimum Loads (MW)

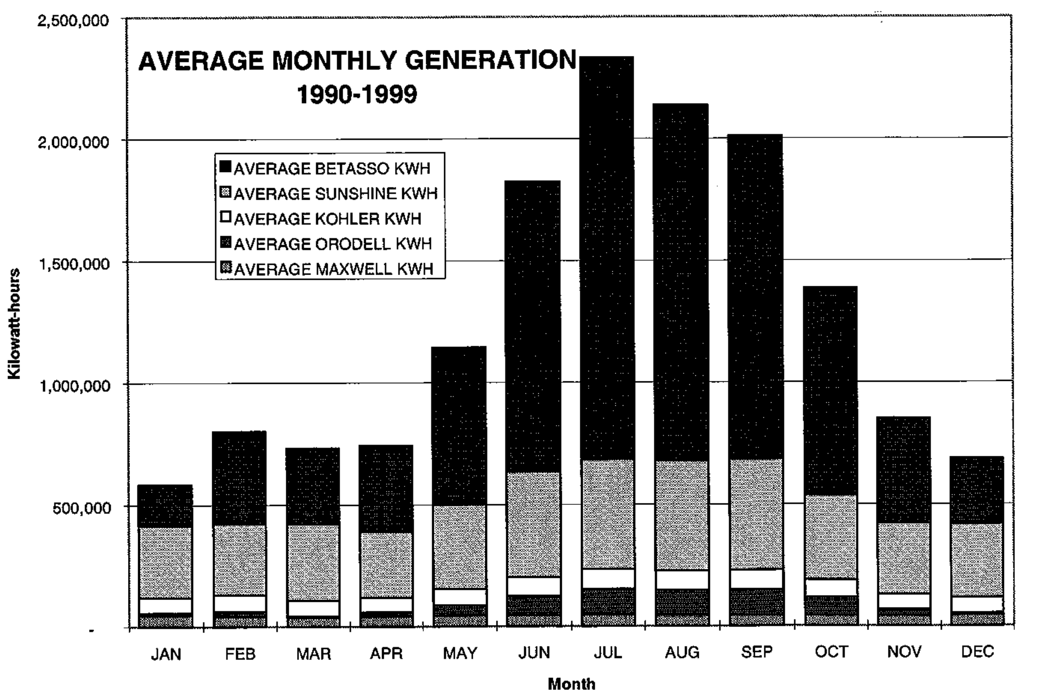


FIGURE 5—HYDRO GENERATION BY MONTH SHOWING EXTRA SUMMER GENERATION DUE TO HIGH WATER DEMAND.

A simple visual comparison of the two charts shows that there is a good match between the local hydropower generation and local demand patterns, for both base load and peak loads that increase during the summer.

Development of Hydropower

Local Power interviewed city staff and relevant literature to assess potential upgrades to the hydroelectric system. TCB-AECOM report in 2005 had several findings about development of Boulder's hydropower, summarized below: [xvii]

1. The Barker site has between 70 and 132 feet of gross head, but no power generation is located there; a Hannah Barker Hydroelectric Plant is proposed. City staff indicate that this upgrade was found not to be cost effective, but may become so in the future.
2. The Betasso Hydro plant is rated at 3.2 megawatts, but only produces at a peak of 2.7 megawatts due to head loss in the pipe; an upgrade could increase the hydro to its full potential. Staff indicates that this upgrade has been performed.
3. One of the original two 10 megawatt units at Boulder Canyon was out of service, and both generators are near the end of their service life. The generator that is out of service is reported to have been removed.
4. Reductions in flow due to Boulder's water usage indicate that existing generators at Boulder Canyon should be retired and replaced with a single 4.9 megawatt unit. This upgrade is expected to occur in 2012.
5. Some additional hydro generation is possible at the Silver Lake and Lakewood sites, primarily for water that is not used by the municipal water supply; very high operating head of 1406 and 1554 feet suggests that even modest water flow could produce a significant amount of power.
6. A hydro generator could be placed at Tram Hill, parallel to the pressure reducing valve (PRV); this assumes a new 30 inch pipeline is built between Boulder Canyon Hydro and Betasso Hydro, allowing the existing 20 inch pipeline to be run in the opposite direction; With the proposed flow scenario, power could be generated four months out of the year. This upgrade is reported by staff to have been accomplished, and some new operational changes have been made to increase power generation starting in fall, 2010.

The proposed modifications would reduce the operating capacity of Boulder Canyon by just over 5 megawatts, but actually increase the amount of electricity generated by adding new equipment that would be more efficient in relation to the stream flow. Other than the Boulder Canyon plant, generating capacity would increase by over 2 megawatts. The combined upgrades would, according to the report, add approximately 13.8 million kilowatt-hours of annual generation compared to the current hydropower output. The potential result of these upgrades is summarized in the proceeding table. In addition, the smallest generation unit at Maxwell site, at only 70 kilowatts, seems to be operating at very high capacity and might benefit from a significantly larger generator.[xviii]

TCB-AECOM	Scenario 3		
Proposed Modifications	Annual Energy (kWh)	Capacity (kW)	Capacity Factor
New 30 inch Line (BH)	8,906,000	3,200	0.32
New 30 inch Line (SL)	11,787,000	3,200	0.42
New 30 inch Line (LW)	16,846,000	3,600	0.53
Boulder Canyon	11,660,000	4,900	0.27
Hannah Barker (HBH 1&2)	1,477,000	1,500	0.11
Total Combined Annual Generation *	50,676,000	16,400	0.35
Current Operations *	Annual Energy (kWh)	Capacity (kW)	Capacity Factor
Silver Lake	9,710,000	3,200	0.35
Betasso-Lakewoood	17,400,000	6,100	0.33
Boulder Canyon	9,680,000	10,000	0.11
Hannah Barker (HBH 1&2)	-	-	-
Total Combined Annual Generation *	36,790,000	19,300	0.22
Incremental Change	13,886,000	(2,900)	
New Capacity (Hannah Barker + Pipeline)		2,200	
* Excludes Maxwell, Kohler, Orodell and Sunshine, which equal 1.2 megawatts capacity & 5.5 million kWh/year			

The ability to develop additional hydropower projects could be significantly affected by the presence of a locally controlled power system that would have a direct interest in electric generation. The Boulder power authority could help plan and finance improvements, as well as secure a direct market for the electricity. The local focus of the utility would provide a much stronger incentive for such development than if all the electric power were sold to Xcel, since there is a significant need for low cost hydropower to offset some of the higher cost sources of energy.

Cost of Hydropower

The 2001 report on Boulder's hydro system showed 51.7 million kilowatt-hours providing annual revenue of $2.1 million, reflecting an energy cost of 4.0 cents per kilowatt-hour. However, the 2005 hydropower report states: [xix]

> The City's hydropower sales agreement with Xcel Energy has provided an average rate of $0.02 per kW-hr for the existing units at Betasso, Silver Lake and Lakewood. The agreement also includes payments to the City for monthly capacity tests.

Capacity payments are made by Xcel to the City according to the rated capacity of the plants, and are adjusted according to whether the hydropower generates at less than half or more than half of its rated capacity. The capacity payments are in addition to the 2 cents per kilowatt-hour rate for electricity generated, and are somewhat larger than the total amount of cash paid on the contract. Thus, the effective rate appears to be closer to 4.5 cents per kilowatt-hour once the capacity payments are factored in. While market purchases of electricity are currently quite low, the average cost of Xcel's wholesale power is forecast to be significantly higher than 4.5 cents per kilowatt-hour over the next ten to twenty years. This will make local hydropower one of the lowest cost sources of electric power.

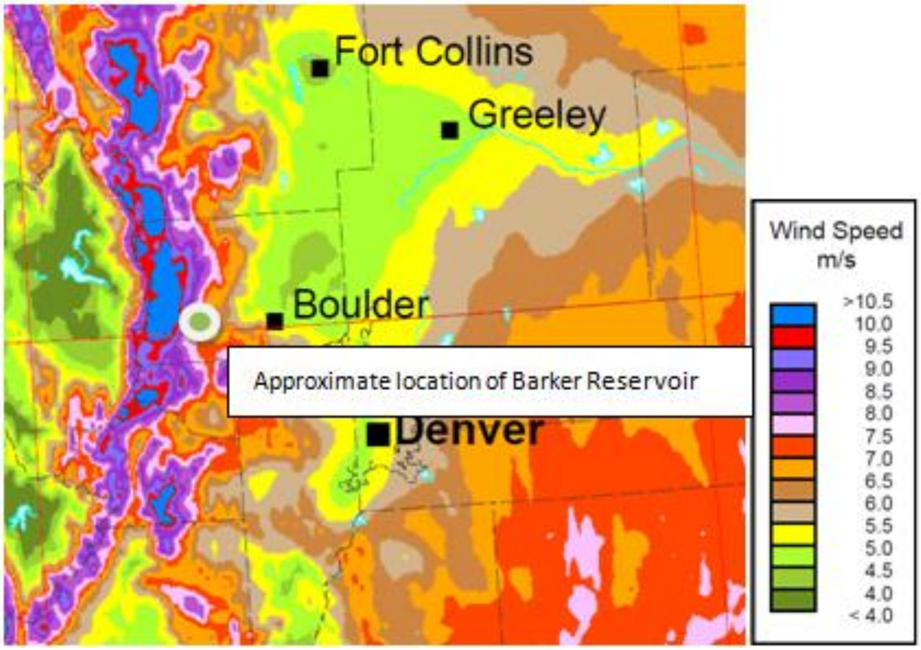
On the other hand, newer contracts for hydropower generally reflect the higher cost of energy in current markets. The City would have to evaluate the relative merits of reducing overall cost of electric power for a municipal utility, versus the value of energy selling into the current market that could provide increased revenue. In general, if the City's principle aim includes increasing the volume of more expensive forms of renewable energy, such as local solar photovoltaics, then the low cost hydropower can serve to balance out these higher cost sources of energy in a full supply portfolio. The balancing potential would become increasingly important over time, as conventional wholesale electricity procurement becomes ever more expensive.

Hydroelectric Capacity Balancing and Nearby Wind Resources

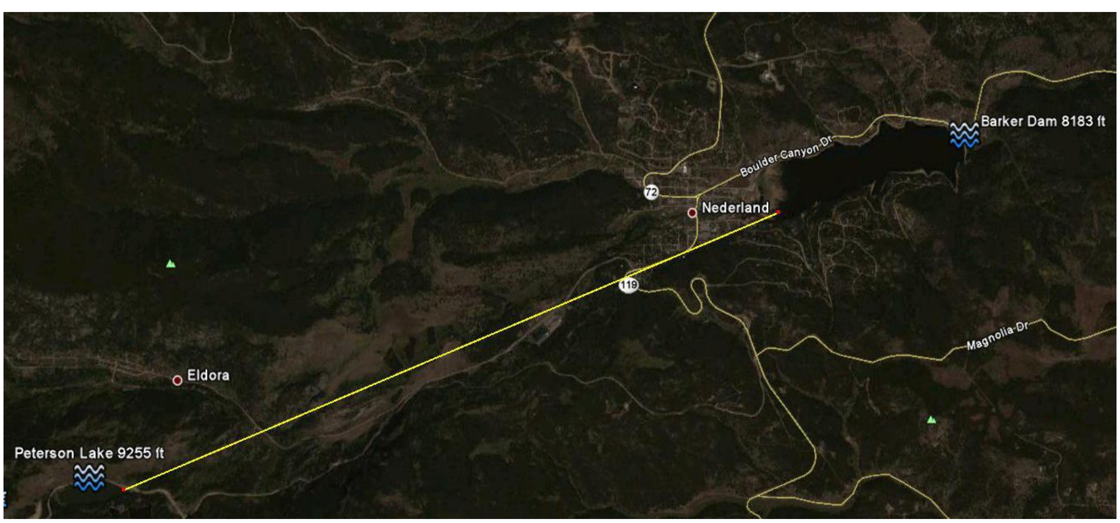
A key challenge to electricity localization is the need to provide backup or capacity balancing for intermittent local renewable generation. In this case, in order to increase the role of local renewables like wind power in Boulder's power mix, power storage and local generation or demand resources that can be modulated are needed. Boulder is fortunate in having some key resources such as Barker Reservoir to provide capacity balancing for new local renewables.

Coupling Wind and Hydroelectric Capacity Balancing

There is an excellent opportunity to locate wind turbines in the high wind area west of Barker Reservoir. As shown in the figure below, Barker Reservoir borders on an area that has average wind speeds of 8.5 meters per second or greater, making it one of the finest wind regions in the state. Wind turbines could be located near the reservoir to take advantage of this resource. A modest development of approximately 5 megawatts of generation capacity could be tapped with only a few modern wind turbines. Typically, one of the major challenges of wind power is intermittency of generation. The transmission capability used for the hydro system associated with the reservoir could be leveraged to include the wind generation capacity. The nameplate capacity of the hydroelectric generators is much larger than the average generation, and actual generation rarely if ever reaches that high a level. This suggests significant extra capacity may exist on the wires for other power generation.



Another challenge of wind power is its variability and its tendency to produce power at night when demand and power prices are low. The value of wind generation can be significantly increased when coupled with energy storage. Pumped hydro storage can be a lower cost storage alternative if it leverages existing water bodies and infrastructure. The hydroelectric power system owned by the City of Boulder has many of the attributes required to cost-effectively implement pumped hydro storage in conjunction with wind. The Boulder hydroelectric system could be enhanced to provide pumped storage capability. This would involve running a newpipe with additional generation beyond the existing hydroelectric capacity. One possible route would be from Peterson Lake near the Eldora Mountain Ski resort to the Barker Reservoir. Another possible route, suggested by Ned Williams, would run between Kossler Reservoir and the Boulder Canyon generation facility. In the latter route, a water storage facility or small reservoir would have to be sited at or near the Boulder Canyon plant. In either case, the water would be pumped from the lower altitude reservoir to the higher altitude reservoir during higher wind hours, and released as necessary during low wind hours. This approach would firm the wind resource, while limiting effects on the primary water supply system.



Pumped storage capacity is based on head (height difference between storage pond and water outlet) and water quantity. With 100 meters of head, each megawatt-hour of storage requires approximately four acre-feet of storage capacity. For example, a 5 MW generator can be driven for eight hours, producing 40 MWh of electricity, on the energy stored in 160 acre-feet of water with 100 meters of head.

Barker Reservoir is at elevation 8187 ft. The elevation of Peterson Lake is 9255 ft. This is approximately 320 m of head. 40 MWh of energy could be stored in 55 acre-feet of water if a pipe was run between the two reservoirs. Barker reservoir is approximately 115 acres in area, so the water level would be changed approximately 6 inches by this transfer of water.

Installing a pipe between Peterson Lake and Barker Reservoir involves less than a distance of 4 miles. There may be a relatively low permitting standard. Water transmission lines are a permitted use in the Forestry zone

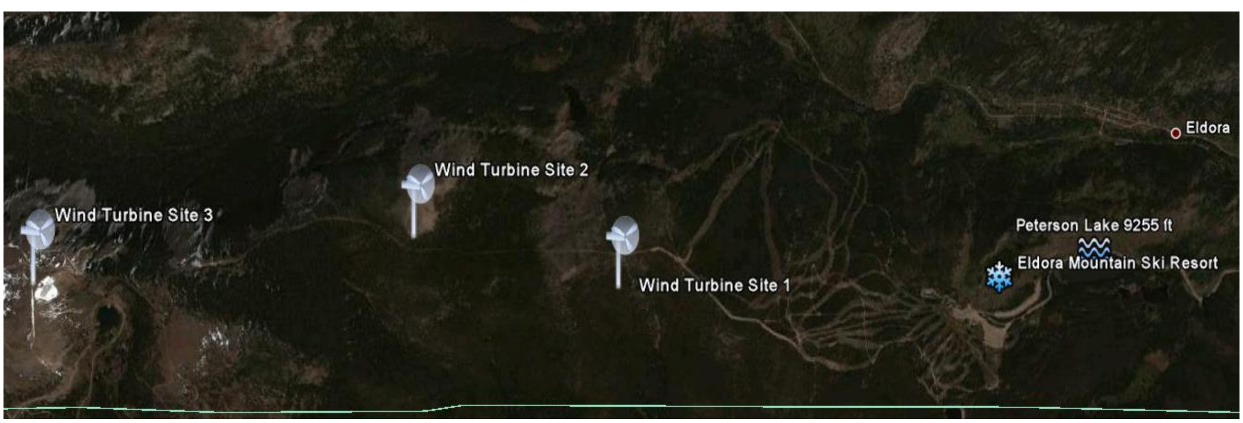
There are other possible pumped storage locations in the county that should be investigated for cost, capacity and political feasibility. The above described system is only used for illustrative purposes. Larger scale systems may be more cost effective, but may face greater challenges. These challenges can be addressed by finding an optimal scale and project design that meets political, environmental, water use, energy system, and cost criteria.

Proposed Wind and Existing Hydro System Map

The following map is a schematic representation of where wind turbines might be sited in mountains around the Boulder water and hydropower system. Actual siting may vary from what is shown, and would depend on local measurements of wind resource and further determination of feasibility of the sites for development of wind power generation. The area poses several potential benefits for Boulder:

- Superior wind resource compared to lower elevations
- Proximity to existing hydro generation
- Potential to interconnect with hydro transmission system
- Potential for balancing wind with local hydro generation

The best resources are even further into the mountains, but would be more remote from existing hydropower generation, transmission wires, and possibly roads as well.

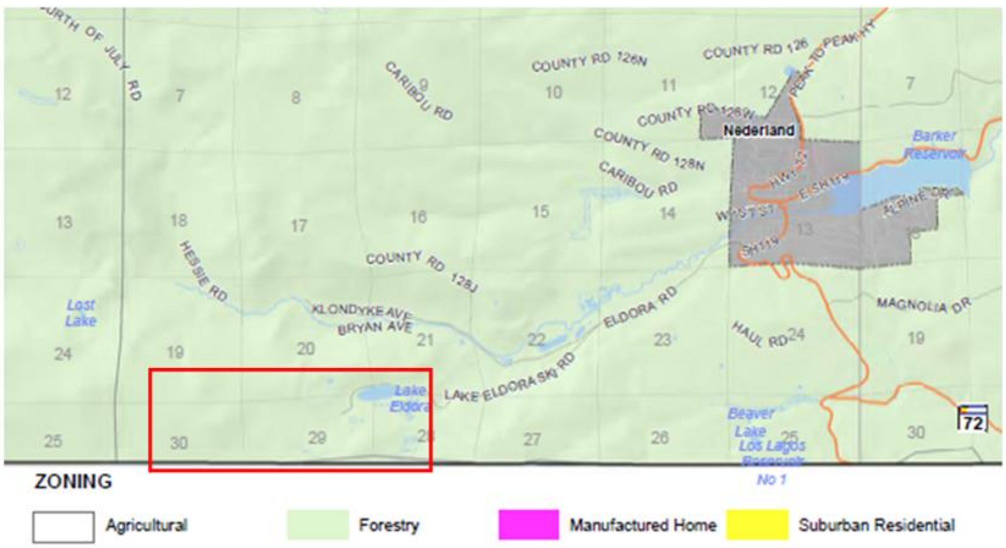


An example of the wind turbines required to give 4.5 MW of faceplate capacity are three 1.5 MW GE 1.5s turbines, shown to the right:

This type of turbine is commonly used, but no particular endorsement of this manufacturer or type is implied. This turbine has a hub height of 64.7m (212 ft). The rotor diameter is 70.5m (230 ft).

Zoning and Permitting

Nearly all of the high wind areas near Boulder are in the mountains, to the west and north. In Boulder County, these areas, for the most part, are zoned “Forestry.” The example are is shown below.



The Forestry zone has specific regulations regarding the construction of wind generation equipment. The following is from the Boulder County Forestry zoning code:

1. *Definition: A wind energy conversion system which may include a wind turbine and blades, a tower, and associated control or conversion electronics.*

2. *Districts Permitted: By site plan review waiver in all districts if the height does not exceed the maximum height of the zone district. By site plan review in all districts if the height is greater than the maximum height of the zone district and does not exceed 80 feet.*

b. *This use may be considered accessory, that is, customary and incidental to a principal use when its primary purpose is to reduce consumption of utility power on the parcel on which it is located.*

d. *The maximum height of a wind energy system shall not exceed 80 feet in height, and no variance may be granted to exceed this maximum height limit.*

A system that exceeds the applicable height limit of the zone district in which it is located will not be approved, unless the applicant demonstrates through competent information, such as anemometer data or National Renewable Energy Laboratory mapping, that the proposed site provides sufficient wind potential to justify a taller system, and that the other requirements for this use and review criteria can be met.

e. *Applications shall be reviewed according to the required review criteria based on the height of the structure with special consideration to:*

(i) *Comprehensive Plan designations. This use shall not have a significant adverse visual impact on the natural features or neighborhood character of the surrounding area. Particular consideration to view protection shall be given to proposals that would be visible from areas designated Peak-to-Peak Scenic Corridor, Open Corridor – Roadside, and areas within the Natural Landmarks and Natural Areas and buffers as designated in the Boulder County Comprehensive Plan.*

(ii) *Visual impacts. Colors and surface treatment of the installation shall be as neutral and non-reflective as possible with muted colors on all surfaces. Graphics, signs and other decoration are prohibited.*[xx]

The 212 ft height of the GE 1.5s clearly violates the stated regulatory limit of 80 ft. A case can be made that the wind resource in the area justifies the height of the turbine. Another regulatory barrier is in the regulation regarding Comprehensive Plan designations. The example wind turbine site borders Natural Landmarks and Natural Areas designated lands. There would likely be some debate about whether the presence of the wind turbine represents an "adverse visual impact" to these areas.

This example demonstrates the difficulty of taking advantage of the high quality wind resources in the mountainous areas to the west of Boulder.

Pumped Hydro cost

Total project cost including generator/ pump, 30" pipe, generator house and construction costs is estimated at $15-$20 million, based on survey of similar projects.[xxi]

Solar Photovoltaics

The primary existing support for photovoltaics is a system of subsidies provided through the state's renewable energy policies, net metering, and certain tax benefits. Boulder could increase the market growth of photovoltaics by building constructively upon existing programs, especially by using its ability to reduce barriers, aggregate bulk purchases, and facilitate community-based projects.

Solar power development is limited in part by the relatively higher cost of energy from photovoltaics compared to utility electric rates. Over time utility rates are expected to increase, while the cost of solar is likely to continue to decrease. A closer analysis of cost of energy from solar, especially with regard to existing and potential policy options discussed in the sections below, will be conducted by Local Power in order to assess the viability of local solar power in Boulder. Additionally, further details regarding distributed solar using existing and potential future policy and program design options will be explored.

Colorado Renewable Energy Standard

Colorado law requires Xcel to purchase a certain percentage of its energy from renewable distributed generation according to a schedule, starting at 1 percent in 2011 and increasing to 3 percent by 2020.[xxii] Half of the scheduled amounts are supposed to come from “retail” renewable projects, meaning that they would be owned by customers of the utility. Local solar photovoltaic projects can be supported by the utility in a variety of ways, including a) direct purchase of the electricity generated, b) purchase of renewable energy credits (RECs) from the solar project, c) providing rebates to the project owner. The law allows purchases of solar energy from projects constructed prior to July 1, 2016 to count as triple its value in kilowatt-hours, and community-based projects to count 1.5 times its value, for the purpose of compliance with the renewable energy standard.

While these requirements for the utility are intended to benefit solar energy and distributed generation, there is no assurance that projects from this program will create the expected results or that they will specifically benefit Boulder in a proportionate manner. This is true for several reasons:

- The solar “triple credit” appears to apply to all solar projects, and not just distributed generation—thus smaller local projects must compete with larger remotely located projects on open land that may have better economy of scale while providing the same triple credit benefit.
- There is no legal requirement that any specific amount of distributed generation be located in Boulder—the requirement applies to the full service territory of Xcel in Colorado, and local projects must compete for a limited program allocation of rebates and REC purchases.
- The distributed renewable energy requirements are phased in over a 10 year period such that the early year requirement of 1 percent of Xcel’s retail sales is relatively low, and only half of that amount needs to be placed on customer sites—for Boulder that would represent only about 4 megawatts pro-rata share of customer-owned solar power.
- The state renewable energy law allows the utility commission to reduce or reallocate the distributed generation requirement on Xcel.
- The increasing popularity of solar photovoltaics in Colorado can put a strain on limited program allocations and result in interruptions of the program and significantly lower subsidies, as recently happened with Xcel’s Solar*Rewards program.

State Solar Subsidies

Those who install solar energy projects are eligible for several subsidies. A federal tax credit can offset 30% of the installed cost of a solar PV system, available for both residential and commercial owners. Commercial owners are also eligible for accelerated depreciation for 80% of the cost of the solar equipment. In Boulder, residential customers of Xcel can apply for a rebate of $1.75 per watt combined with a 20-year payment of $0.04 per kilowatt-hour for the renewable energy credits which Xcel purchases from the system owner, for projects smaller than 10 kilowatts. Larger projects, receive a regular payment of $0.15 per kilowatt-hour for the RECs but no upfront rebate.

There are several significant limitations to the existing programs. The rebate and utility REC purchases reflect payments as of March 2011, and will decrease over time as certain cumulative megawatt targets are met, and availability is limited as program funds are used up. The current residential solar rebate level of $1.75 per watt is limited to 4 megawatts total installations in Xcel’s territory, and one-third of the program step allocation already has projects under review within the first month of its availability. Once the 4 megawatts have claimed their rebates, the rebate will decrease to $1.00 per watt. While the decreasing rebate will be partially offset by higher REC payments, the RECs are paid out over 10 or 20 years. Since the primary barrier to solar PV is the high upfront cost, a decreasing upfront rebate has a relatively large effect on market uptake.

Federal and State Tax Benefits

The federal government provides a tax credit of 30 percent of the upfront cost of solar energy installations, and allows accelerated depreciation of the asset. While the existing tax benefits are quite generous, they form a patchwork that does not benefit all potential owners equally. Residential customers cannot use the depreciation, even though the unit cost of photovoltaic systems are higher for residential customers than for commercial customers that get this extra benefit. Non-profit organizations, schools, government agencies and individuals or businesses that do not owe federal taxes cannot take these tax benefits directly. Sometimes this difficulty can be overcome through a third-party owner that can take the tax benefits and then sell the electricity or lease the PV system to the utility customer. This arrangement also overcomes the problem of how to cover the high upfront cost, since investment funds are provided by the third party. On the other hand, the third party typically requires a certain rate of profit which can offset the tax benefits.

In addition to the federal tax subsidies, the state of Colorado provides a 100 percent exemption from property tax on residential solar projects.

Net Energy Metering

Customer-owned solar photovoltaic systems receiving rebates in Colorado are placed on net metering, which allows customers to "spin the meter backwards" to offset their electric power bill at the full retail rate. Any excess energy credit over the course of a month is carried over to the next month for up to a full year. The customer has the option to allow ongoing carryover of this credit indefinitely, or to get paid by the utility at much lower rates for the excess energy—which ranged from 2.8 to 4.8 cents per kilowatt-hour between 2006 and 2010. Projects are not permitted to generate more than 120% of the energy used on-site over the course of a year, which limits the potential size of individual solar PV systems and places constraints on the ability to benefit from economy of scale.

Local Boulder Regulations and Programs

The City of Boulder currently provides several types of support for development of solar photovoltaics in the community.

Those who purchase solar PV systems are eligible for a partial rebate of about 15% of the cost of taxes and fees paid to the City of Boulder. Typically, local taxes and fees represent a relatively small portion of the cost of a photovoltaic system. With the Boulder sales tax rate at 3.41%, a 15% rebate on the tax will offset about ½ percent of the total cost to the buyer. In addition, permit fees for photovoltaic systems are set at very reasonable levels: $69 for residential and $139 for non-residential and multi-family structures.

Local green building regulations provide special green credit for installation of solar PV based on a schedule of project sizes and the portion of onsite electricity usage that is offset. Builders are also incentivized though the green point credit system to make new structures solar friendly by insuring rooftops have sufficient structural strength to carry solar panels and to provide electrical conduit leading to the roof.

Boulder currently subsidizes solar photovoltaic systems for low and moderate income residential customers of Xcel using proceeds from the local sales taxes on solar photovoltaic systems. While the program provides an important social equity benefit, the revenue produced by the sales tax on installed photovoltaic systems can only support a small fraction of photovoltaic capacity in the community.

Boulder voters approved Ballot Issue 1A in 2008, allowing issuance of bonds for PACE financing of energy efficiency and renewable energy improvements to property. However, PACE has been impaired by regulations from federal mortgage lenders.

Boulder Program Options in Status Quo

The city's efforts to promote solar photovoltaics could be expanded in a few key ways.

Boulder could further reduce the sales tax on solar PV and should consider whether there is an opportunity to streamline the permitting process, which can create a market barrier and add to project cost.

A larger opportunity for reducing the cost of solar PV is to aggregate buyers into a bulk purchase agreement. One example is One Block Off the Grid (1BOG), which signs up dozens of homeowners and arranges for a discount that can reduce upfront expense by 30 percent or more. When combined with the federal tax credit, the net cost to the homeowner is reduced by half.

Another opportunity to increase accessibility is to support community solar gardens. The city can help arrange sites, either on public land or on commercial rooftops. If the commercial site owner is interested in a solar photovoltaic project, then the larger project size can reduce the energy unit cost of the entire system. Solar gardens have several benefits, including increasing accessibility to renters and low income residents, reduced cost and economy of scale, optimal siting, and the ability to retain ownership if the shareholder moves to another location.

The City of Boulder is also granted by state law the ability to declare a solar PV system to be a community-based project. This allows the project to sell renewable energy or renewable energy credits to the utility that count 1.5 times the amount of kilowatt-hours generated. While solar projects currently can count for triple their value, this will change to only one time its value after 2016. At that point, the community-based projects will have the greatest value for compliance toward the renewable energy targets.

Solar Photovoltaics in a Localized Energy Utility

At the time of this report, Xcel has not yet offered any alternative arrangement to be evaluated, and so the 'localized energy utility' framework considered in the sections below will be defined as a municipal utility.

The legal framework of a municipal utility in regard to development of local photovoltaic projects is significantly different than for continued service by Xcel. While existing Colorado renewable energy law has much lower requirements for a new municipal utility than for Xcel, the local utility could also go well beyond Xcel in providing specific benefits to the community solar program. In addition to building constructively upon existing programs, by reducing barriers, aggregate bulk purchases, and community based projects, the municipal utility would also have institutional infrastructure and expertise, as well as financial resources, for supporting local solar energy projects.

The local portfolio standard does not fully reflect the development potential for solar photovoltaics. This is because it is expected that much of the solar energy would be customer-owned and placed "behind the meter" in a net metering or other similar arrangement, such as solar gardens or other community solar ventures. These market structures reduce customer demand rather than provide increased electricity that is sold to the utility for meeting power supply needs. The relatively low cost of energy in Colorado suggests strongly that customer ownership is a better model for solar energy from the standpoint of utility costs and customer bills. In the future as electric power costs increase, and solar power decreases, this issue should be revisited.

Colorado Renewable Energy Standard

Colorado has much lower requirements for renewable energy, and does not have any distributed generation requirement, for municipal utilities; further, municipal utilities are free to adopt for themselves similar requirements as Colorado places on Xcel. Additionally, unlike Xcel, municipal utilities have the freedom to try to design better programs. Local solar photovoltaic projects can be supported by a municipal utility in the same way Xcel would, including a) direct purchase of the electricity generated, b) purchase of renewable energy credits (RECs) from the solar project, c) providing rebates to the project owner. The law allows purchases of solar energy from projects constructed prior to July 1, 2016 to count as triple its value in kilowatt-hours, and community-based projects to count 1.5 times its value, for the purpose of compliance with the renewable energy standard.

A major advantage of a local utility solar program is that it can provide assurance that projects from this program will create local results that specifically benefit Boulder.

Solar Subsidies

Customers of a local utility would no longer be eligible for a rebate from Xcel. However, rebates are scheduled to decrease rapidly to the point where local programs could easily compensate for the loss of Xcel rebates, either with a local rebate program or another program that provides equal or greater benefit than a rebate. In addition, certain incentive structures such as upfront rebates may actually increase the cost of solar energy in some cases. In California, rebates have been observed to increase the cost of rooftop solar projects by as much as 60 to 80 percent of the value of the rebate. Supporting the solar industry using performance-based approaches, such as performance-based incentives and turn-key contracts such as design-build-operate-maintain or power-purchase agreements, mitigates this risk.

Federal and State Tax Benefits

The same tax benefits would be available for local owners of photovoltaic projects in a local utility as for customers of Xcel. However, if the municipal utility owns the project it will not be able to take such tax benefits since it is not a tax-paying entity. On the other hand, municipal utilities have access to low-cost financing that can offset part or all of a tax benefit.

Net Energy Metering

The local utility can allow net metering for customers to offset their electric power bill at the full retail rate. It could also offer a better price for excess energy than is currently provided by Xcel, as well as removing the cap of 120% of the energy used on-site over the course of a year. This could increase the potential size of individual solar PV systems and improve economy of scale. The municipal utility could also implement a solar garden program, but allow much more flexibility for ownership, siting, project operation, and participation.

Local Boulder Regulations and Programs

Options such as One Block Off the Grid (1BOG, which signs up dozens of homeowners and arranges for a discount that can reduce upfront expense by 30 percent or more) can be implemented more fully in a municipal utility, since Boulder would have more freedom in defining the program financing, including purchase of renewable energy credits from the local projects.

If the local utility purchases the production or renewable credits from the solar photovoltaic project prior to 2016, the value would be triple toward compliance with Colorado's renewable energy targets. After that date the local government can declare community-based projects in order to allow them to count 1.5 times their energy value toward compliance.

A local utility might be able to provide alternatives to replace the current hole in the PACE financing of energy efficiency and renewable energy improvements to property. One option might be to place a charge on the utility bill for the customer site rather than relying primarily on the property tax assessment.

The Valmont Natural Gas Facility

The Southwest Generation Company owns and operates a simple-cycle natural gas generation facility that is located at the Valmont plant just outside of the City of Boulder. This facility is used to generate up to 80 MW of dispatchable power, which may be ramped up or down as needed. In an interview with Southwest Generation, the possibility of adding cogeneration capacity to the plant was discussed. It was indicated that the plant is used in a variable load firming capacity – so it may be used to balance intermittent renewable generation such as wind - and that the generators, two General Electric LM6000 natural gas turbines, were not outfitted with any type of heat recovery.

Under a status quo scenario, Southwest Generation sells power from the Valmont plant on the wholesale market. Development of a heat recovery capacity to provide cogeneration capability is something that is technically feasible, but the operating mode of the plant would not provide a stable heat resource. However, any available heat could be used for thermal services to adjacent commercial properties. The City of Boulder could potentially work with Southwest Generation to provide these services.

A localized energy utility could contract directly with Southwest Generation to provide electric power from the Valmont plant, and to explore further the opportunity for providing waste heat recovery for district heating systems as part of the arrangement. In addition, Southwest Generation indicated that they would be willing to procure pipeline biomethane as part of the fuel procurement for the plant. This would reduce the carbon footprint of the electricity produced at the plant, which would help Boulder reach its carbon reduction goals. The 80 megawatts of power would be a local generation resource that could be used to meet peak daytime demand as well as balance the variable energy production from wind and solar power. This plant is one of the largest potential local generation resources, and the natural gas or biomethane fuel would improve the current fuel mix from Xcel, which is dominated by coal.

Biomethane Availability

The availability of locally produced biomethane was examined. The full available production resource would be sufficient to power Valmont's 80 MW at about a 40% capacity factor. If half of that quantity is sold for direct use, for example, as a green gas service offered to customers, that would reduce capacity to 40 MW.

It is possible to site a new biomethane plant of any size relatively easily, as long as it is near to a natural gas transmission line, and biomethane is far more portable than solid biomass. On the other hand, Valmont is an existing facility that may already be paid down, and so using procured biomethane as a percentage of the gas burned is a more cost-effective way of using it.

Biomethane at $8 per MMBTU is double the price of natural gas today; this will result in a price of electricity of 8 cents per kWh for the fuel only—not including capital expense or O&M. By comparison, fuel today is only about 4 cents/ kwh. It is currently forecast in the model that natural gas will not get to this price until about 2026 to 2028.

Combined heat and power applications using a mixture of biomethane are also not cost effective at current or near-term natural gas prices.

Waste as a Resource

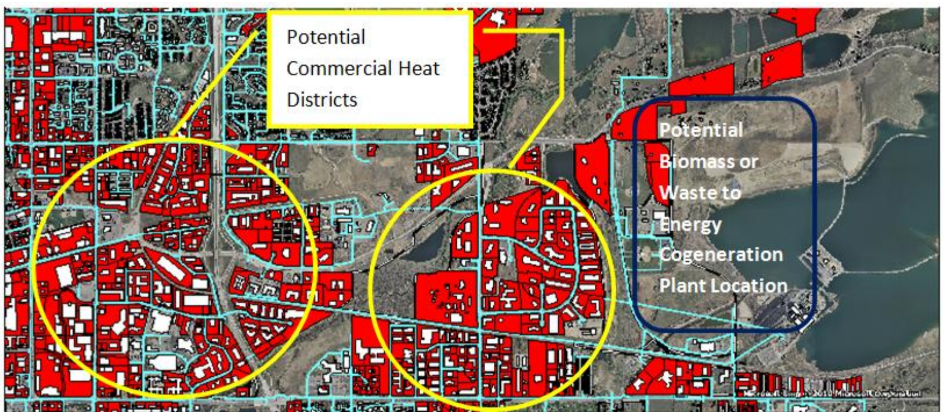
A key element of an energy localization program is to responsibly harvest the energy value in a variety of waste materials. Food waste, agricultural waste, biosolids, yard waste, municipal tree trimmings, and the organic fraction of municipal solid waste are all potentially high value energy sources. Boulder has already taken important steps to use biomethane harvested in the wastewater treatment plant to provide energy for the plant operation. The plant also uses cogeneration to provide both electricity and heat used in the plant operation.

Municipal Solid Waste (MSW)

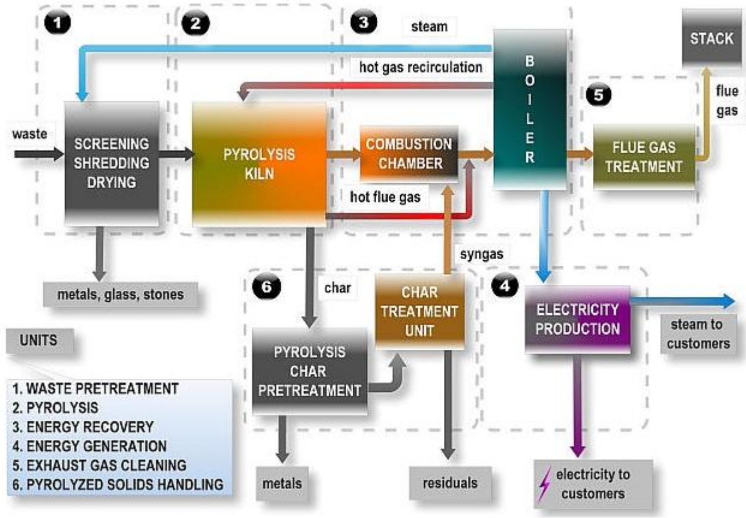
Municipal Solid Waste (MSW) is an excellent source of Refuse Derived Fuel, the organic fraction of municipal solid waste (OFMSW), and can be used either in a thermal process such as pyrolysis or a biological process such as anaerobic digestion which produces natural gas. Wood from construction and demolition waste (C&D) and yard waste is an excellent feedstock for waste to energy processes. Below are findings on energy available in non-recyclable waste and potential for energy production:

Municipal Waste Biomass Resource		
Raw Biomass	40,000	dry tons
Availability Factor	90%	
Usable Resource	36,000	dry tons
Heat Value	7,000	btu/lb
Annual Energy Supply	504,000	mmbtu
Conversion	3412	btu/kwh
Energy in kilowatt-hours	147,713,951	kwh-th
Equivalent Capacity	16,862	kilowatts-thermal
Electrical Conversion Efficiency	30%	
Heat Rate	11,373	btu/kwh
Full-Time Electric Power Equivale	5,059	kilowatts
Annual Electricity	44,314,185	kilowatt-hours
Boulder Electricity Consumption	1,400,000,000	kilowatt-hours
Share of Boulder's Electricity	3.2%	

Boulder has an opportunity for using solid biomass waste in a combined heat and power (CHP) configuration where the excess heat beyond what is consumed through generating electricity is used for heating and cooling buildings. Shown in the map below, large commercial property zones in red can be supplied with heat and cooling via pipes installed in existing water main easements, shown in blue. The opportunity for co-location of a thermal biomass plant with the Valmont facility offers the synergistic use of the plants to provide a flexible source of thermal energy.



A typical pyrolytic CHP system is shown below[xxiii]. This approach uses municipal solid waste as fuel for a high temperature, low oxygen natural gasification process that produces “syn gas”, which is primarily hydrogen and carbon monoxide. The syn gas, which burns cleanly and efficiently, is then combusted to generate steam for electricity production. The lower temperature steam available after electricity production is then supplied to customers for their thermal needs.



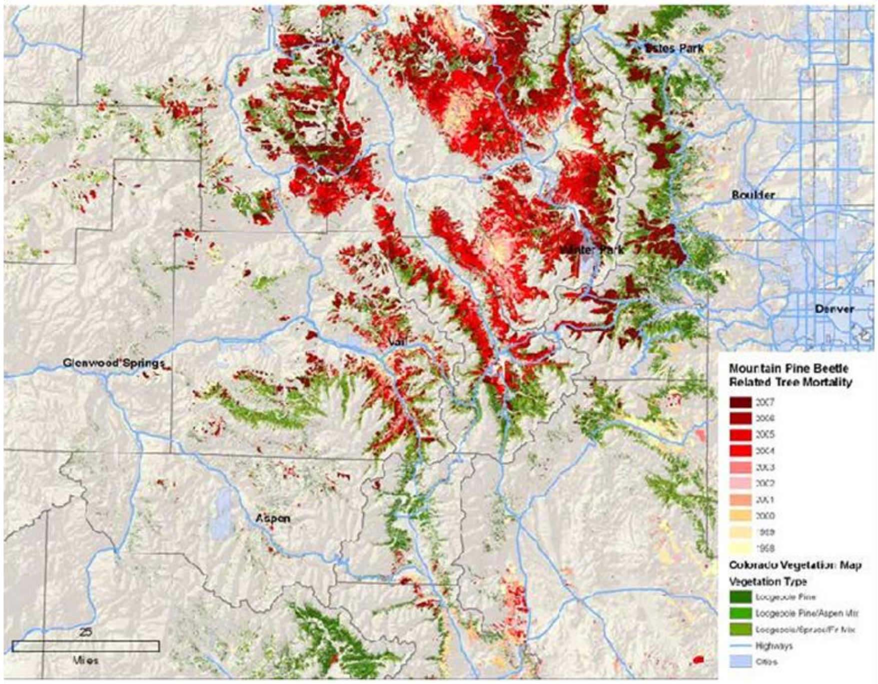
City of Boulder Access to Biomass Power Resources

The following is excerpted from the Renewable Energy Committee report prepared for the Chairman of the Colorado State Senate Majority Ad Hoc Energy Task Force, and approved by the CRES Board of Directors, October 25, 2001:

> *Recent studies indicate that Colorado has a fair biomass resource potential. An estimated 5.2 billion kWh of electricity could be generated using renewable biomass fuels in Colorado. This is enough electricity to fully supply the annual needs of 521,000 average homes, or 42 percent of the residential electricity use in Colorado. These biomass resource supply figures are based on estimates for five general categories of biomass: urban residues, mill residues, forest residues, agricultural residues, and energy crops. Of these potential biomass supplies and the quantities cited below, most forest residues, agricultural residues, and energy crops are not presently economic for energy use.*
>
> *Supplies of urban and mill residues available for energy uses in Colorado are 158,000 and 180,000 dry tons per year, respectively. The estimated supply of forest residues for Colorado is 720,000 dry tons per year. An estimated 2,524,000 dry tons per year is available from corn stover and wheat straw in Colorado.*

Availability of Biomass near Boulder

Collection of various biomass resources, both in cost and logistics, is the limiting factor in the cost-effective utilization of these resources as part of an energy portfolio. The possibility of working cooperatively with other jurisdictions to develop infrastructure for biomass collection and processing might be productive. An opportunity to develop processing of the trees killed by the Pine Beetle exists near Boulder County. As shown in the map below the extent of the tree mortality has reached areas that might allow cost-effective harvest of the dead wood.



Wood Pellets

A wood pellet manufacturing firm, Rocky Mountain Pellet Company [xxiv], was contacted regarding the cost and availability of wood pellets. A price was quoted of $130/ ton FOB factory. The heat content of this fuel is approximately 8,000 BTU/ lb, which is equivalent to low grade coal. This supplier stated in an interview that if the City of Boulder was able to either provide its own waste wood supply, or invest in an additional processing machine, the cost of the pellet could be reduced considerably – by up to half the cost.

Agricultural Waste

The County of Boulder provided high-level information from publicly-available sources on the availability of corn, wheat and barley wastes, in terms of acres planted in the County. Based on this information and yields, we estimated the following resource availability and potential for energy production:

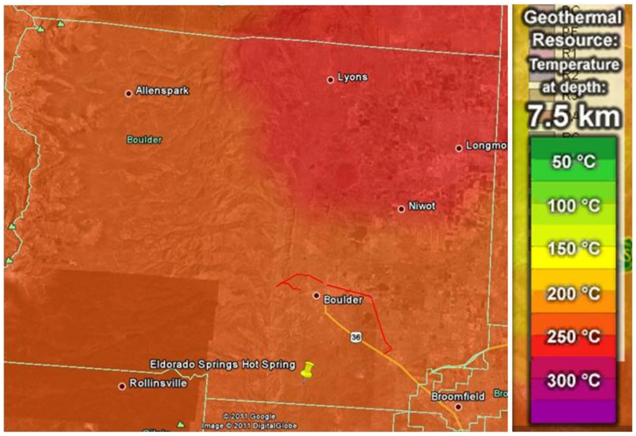
Agricultural Biomass Resource		
Raw Biomass	633,856	dry tons
Availability Factor	10%	
Usable Resource	63,386	dry tons
Heat Value	8,000	btu/lb
Annual Energy Supply	1,014,170	mmbtu
Conversion	3412	btu/kwh
Energy in kilowatt-hours	297,236,108	kwh-th
Equivalent Capacity	33,931	kilowatts-thermal
Electrical Conversion Efficiency	30%	
Heat Rate	11,373	btu/kwh
Full-Time Electric Power Equivale	10,179	kilowatts-electric
Annual Electricity	89,170,832	kilowatt-hours
Boulder Electricity Consumption	1,400,000,000	kilowatt-hours
Share of Boulder's Electricity	6.4%	

These wastes can potentially be used for an additional future biomass plant for the City of Boulder when the logistical infrastructure is more developed and other costs have come down. Biomass is a valuable resource, but the cost of collection, processing and storage, as well as the market for the raw waste, will drive up the cost of electricity production. However, a new generation facility may be able to use this resource and provide more localization, without driving up the cost electricity significantly, particularly if the new facility provides cogeneration capability.

Biomass, Cogeneration, and Heat District Integration Strategy

As mentioned earlier, there is an opportunity to co-locate a biomethane production facility and an MSW pyrolysis facility at the transfer station location near the Valmont plant. Due to the opportunity to provide heat to the nearby commercial areas, a potential cogeneration retrofit to the Valmont simple-cycle natural gas turbines could work in concert with an MSW thermal waste-to-energy plant or thermal biomass plant, sharing the same piping infrastructure for circulated heated and chilled water. The adjacency of the waste transfer station, the Valmont plant and the nearby commercial area to the west provide an excellent opportunity for synergistic development of complementary resources.

Direct Use Geothermal



Boulder is located in a region of elevated geothermal temperatures, relatively near the surface. Although there are few hydro-thermal resources, i.e., with natural water or steam available in the ground to transfer the heat, the local heat resource could eventually be tapped using Enhanced Geothermal Systems (EGS) technology. EGS involves drilling wells, fracturing the deep rock, and injecting a heat transfer fluid, such as water or liquefied CO2. These systems are undergoing development and may be feasible in the relatively near future. Geothermally heated water should be investigated, if available, either for district heating—which is likely to be the most efficient use— or for low temperature distributed geothermal electricity generation.

Enhanced Geothermal Recovery (EGR)

EGR experience has not been favorable. The drilling and fracturing of the hot rock takes huge amounts of energy, and the cracking may not persist over time. The wells are expensive to drill and earthquakes often result from the drilling. In spite of these factors, the technology for finding and tapping the heat reservoirs is improving. According to the Geothermal Resources Council,[xxv] EGR Technology is projected to decline somewhat in cost, from $0.215 per kWh to $0.104 per kWh.

Eldorado Hot Springs and Gypsum

There is a geothermal-heated spring near Boulder at Eldorado Springs. This is outside the city limits of Boulder, and appears to be a low temperature resource. However, this spring represents an opportunity for potentially fruitful geothermal exploration. There are two possibilities:

1. Drilling a deep well at the site of the spring may yield more, higher temperature water.
2. There may be hot water accessible through deep wells closer to Boulder.

The town of Gypsum, to the west of Boulder, recently[xxvi] approved a proposal by Flint Eagle LLC to drill an exploratory deep geothermal fluid well. This 4,000 ft deep well will be located at the Eagle County Regional Airport.

Obtaining approval for the well drilling involved crafting two agreements between the Town and Flint Eagle LLC;

1. A "geothermal access and surface land use agreement"
2. A "thermal supply agreement"

The first agreement leases the land to the development company and defines royalty payments on the withdrawal of geothermal fluid. The second agreement defines the responsibilities of the parties to supply equipment for the provision of heat.

All of the arrangements are contingent on the discovery of a usable geothermal resource. The developer takes all risk for the exploratory drilling.

Additional Storage Options

Distributed and utility-scale battery storage systems as a resource are secondary to more cost-effective and less environmentally-damaging technologies such as hydroelectric capacity balancing, customer-facing demand dispatch applications, and electrified vehicle V2B and managed charging.

Non-Local Renewable Resources: Wind in Eastern Colorado

The wind resources in the east of Colorado are substantial, and offer attractive levelized costs of renewable energy generation. However, wind power production is highly variable, and must be integrated into the electricity grid. To balance the variability of a large wind farm, grid operators typically ramp the generation of a single-cycle combustion turbine, powered by natural gas, up and down. This causes the overall electricity generated to not be carbon-neutral. In addition, the cost of integration is driven by natural gas prices, which are highly volatile and have typically doubled in cost every decade for the last fifty years.

If the City of Boulder chooses to increase their renewable energy supply beyond the locally-built and controlled energy resources, it should carefully assess the best way to minimize exposure to the financial risk of integration described above. One option would be for the city to offer a fixed rate per kWh for RECS to wind farm developers who propose to build new remote wind resources in eastern Colorado.

If Boulder's citizens invest heavily in energy efficiency, they will have a choice of what to do with the money they will save on their energy bills. There are several options, including rate relief, the ability to further deploy local renewables, or to tender an offer for virtual RECS.

BUILDING BOULDER'S ENERGY FUTURE

The prior section of this report identifies a range of technologies which could re-localize a significant portion of their energy supply. The scale of implementation possible, both legally and financially, is predicated upon several authorizations that the City of Boulder may adopt. While there are immediate opportunities for significant thermal projects under current regulations, key technologies and practices for the electric localization are dependent upon the City of Boulder (1) controlling power procurement at the wholesale level, (2) controlling billing, customer revenue and rate setting at the retail level, (3) operationally controlling metering and utility distribution infrastructure for all facilities within its service areas, (4) gaining full legal authority to finance electric utility investments, and/or (5) being prepared to purchase the infrastructure as necessary.

Because of the complex interdependency between all of the technologies considered, and the affect the authorities listed above have on the scale of implementation possible, the sum of the whole portfolio is greater than the individual parts. These synergies are important to consider.

The chart in Appendix A depicts the status quo potential of each technology to be deployed within existing regulations, and how democratizing the energy supply, and implementing a localized energy utility with the authorities listed above, could enable or enhance each technology.

The "Energy as a Service" Business Model

An illustrative example will help clarify the significance of integrating these authorities:

> In Xcel's territory, electricity is relatively cheap but demand (capacity) charges are more expensive. Although commercial electricity meters record usage in 15 minute intervals for billing purposes, commercial customers are not given the ability to access this data in near real-time. Allowing them to do so would enable the monitoring and management of their demand usage to drive down their overall electricity bills.
>
> A localized energy utility would offer this service by implementing Smart Buildings. A variety of value-added services could be enabled at the same time:

- The monitoring equipment and software would manage onsite peak loads, and also identify non-essential lighting and heating, for example, controlled by energy management systems that could be turned on or off for short periods of time in response to grid conditions and price signals – this is referred to as 'demand dispatch', and can be used to 'smooth out' the generation variability of certain types of renewable generation (such as when the wind decreases or increases).
- Detailed energy usage data could be used to inform targeted electricity efficiency retrofits – and while onsite, program staff could also identify and implement heat efficiency measures.
- Larger efficiency measures could be bundled into performance contracts, in which the utility takes responsibility to build and maintain the system, while other, simpler measures could be implemented through a preferred contractor or rebate program.
- Options for deploying plug-in electric vehicles would be explored, including specialized charging tariffs, Vehicle-to-Building (V2B, where the car battery supplies some of the

building power needs under certain circumstances), and managed charging (a form of demand dispatch in which the charging schedules of electric vehicles are aggregated and controlled in response to grid stability and power price signals for both customer and utility benefit).

- If a business had ample rooftop space and is in a high-density residential or commercial district, or adjacent to a critical facility (such as a fire station or retirement home), options such as deploying solar thermal and photovoltaic arrays to create a heating district or electrical microgrid for backup power would be deployed to sell renewable heat and/or power to local customers. This could be financed by the utility, and deployed in a performance contract.

This is the evolving "energy as a service" business model. It enables wide deployment of distributed generation, demand side measures, and storage, because it invests in the customer and embraces the paradigm of "energy as a system" to unlock value across different parts of the business model – especially on the demand-side. A localized energy utility would remove barriers to this approach, and enable the coordination of local energy resources with wholesale energy purchases at the portfolio level; as greater amounts of energy efficiency and distributed generation were deployed, the utility would purchase less remotely sourced electricity and natural gas. Integrating these factors, and the associated allocation of benefits, are necessary to affect energy localization on a large scale at a meaningful speed of deployment.

Authorizations Needed to Unlock Boulder's Energy Future

To implement this local energy vision and provide the full benefits of integrating local energy system planning and deployment, the City of Boulder would need several key authorities. These are listed below, with insights into how the authorities would affect the above example:

1. Wholesale Control: to procure electricity and natural gas.
    a. Deploying large percentages of local generation or efficiency decreases the electricity bought from power plants on markets or from merchant generators. However, if this expected decrease in purchased power is not coordinated with power procurement operations, the un-used power must still be paid for; this would impose a cost-penalty on all customers and is a 'perverse incentive' to continue reliance on remote energy sources that are outside the city's control. Coordinating local energy development with market power purchases, on the other hand, would allocate the associated benefits of decreased reliance on non-local energy purchases to the portfolio, and to the individual distributed energy projects.
    b. Demand dispatch, the automatic ramping of load up or down in response to price or grid stability signals, is a power service that serves to balance the electrical grid while avoiding the use of fossil fuel or other conventional power supplies. The ability to reward customers for embracing these innovative services depends on controlling wholesale power procurement, as Xcel currently does not offer any mechanism to take advantage of demand dispatch.
2. Retail Control: Billing, Revenue Control, and Rate Setting

a. Deploying targeted efficiency requires access to customer energy usage data, to gain insight into where and how energy is being wasted and plan where efficiency measures would be best deployed.

b. Control over customer billing enables the ability to enter into performance contracts with a minimum of administrative burden, and to support deployment of onsite generation and efficiency measures using on-bill financing.

c. The flexibility to capture revenue streams from energy efficiency performance contracts to subsidize less 'cost-effective' but socially-beneficial assets such as photovoltaics and micro-grids is not feasible without rate setting and revenue control authority.

d. Offering specialized rate structures or innovative services (such as V2B or managed charging) to electric vehicle owners or fleets requires rate setting authority. Currently, Xcel does not offer any of these services to the local community.

3. Operational Control: Metering and Distribution

   a. Offering customers Smart Building functionality, and the ability to monitor and manage their electric usage in near real-time, requires control over the type of electrical meter installed and the data produced and made available.

   b. Demand dispatch (described above in the example and under "Wholesale Procurement) could also be rewarded for relieving excess load or generation at specific points around the electrical grid, and this requires control of the distribution grid, as no current revenue stream is available for these resources from Xcel.

4. Financial Control: Investments

   a. Many distributed generation and demand-side measures are sound, long-term investments, but commercial customers often prefer to spend capital on their core business activities. Surmounting this financial barrier requires the corresponding financing authority.

5. Financial Control: New Community and Customer Ownership

   a. Decentralized generation and demand-side resources are deployed on customers' businesses and homes. The ability to offer public financing and support for energy systems that are community- or customer- owned is a value-add for the customer, and in line with innovation trends in the energy industry.

Key Targets in Each Approach

As detailed under the technology section of this report, the opportunity exists to serve natural gas to residential customers in Boulder under the current tariff regime. Specifically, apartment complexes with single Xcel master meters are candidates for alternative suppliers of natural gas under the deregulated market in Colorado. Such complexes are already served in some cases by alternates to Xcel natural gas. They would fall under either the Small Firm or Large Firm tariff depending on the usage of the building with Xcel providing transportation of the alternate natural gas supply to the end user. Because this natural gas revenue can be captured, and apartment buildings and multi-family dwellings present ideal development opportunities for technologies like solar thermal heating and hot water, the proposition exists to substitute natural gas procurement with onsite renewable generation and efficiency, and to finance new local renewables and realize significant carbon reductions.

Key Targets under the Status Quo Approach:

1. Commercial, institutional, and government buildings:
    a. Solar heat and thermal retrofits for large daytime loads in facilities such as hospitals and healthcare centers, hotels, grocery stores, restaurants, schools and campuses, some offices and retail complexes, and specialized sectors such as car washes and commercial laundries.
    b. District heat in high-density districts, using large facilities as "platforms" to serve the surrounding area.
2. Residential Homes
    a. Solar district heat and thermal retrofits for buildings with existing district heat systems in need of repowering (identified approximately 20 large facilities so far).
    b. Targeting of neighborhoods with furnaces nearing replacement age (housing stock analysis).
    c. Enhanced, targeted offerings for Home Businesses (large day time loads) and the small number of homes using propane (large thermal expense).

A localized energy utility could affect both heat and power localizations – this includes a municipal utility, assuming the City Council chooses to include the authority to issue revenue bonds for financing district heat, solar thermal, demand control, storage and related facilities in its proposed Charter Amendment.

Key Targets under a Localized Energy Utility Approach:

1. Commercial, institutional, and government buildings:
    a. The addition of photovoltaics and electric efficiency measures to the targets listed on the previous page under status quo.
    b. Demand response/ dispatch wherever possible, including key targets such as server farms, electric vehicle fleets, refrigerated warehouses, wastewater treatment plants, agricultural pumping, and facilities with energy management systems used to dispatch lighting and HVAC end-uses.
    c. Repowering defunct Combined Heat and Power (CHP) systems.
2. Residential Homes
    a. The addition of photovoltaics and electric efficiency measures to the targets listed on the previous page under status quo.

b. Smart thermostat to all homes, as an efficiency measure for both electric and natural gas supplied heating.

c. Home Area Networks for all homes, for targeted efficiency and automation.

d. Demand response and dispatch targeted at electric vehicles, air conditioning, and all-electric homes (25% of homes do not have natural gas service) by aggregating and controlling electric heating systems and water heaters.

Financing Energy Localization

Status Quo

The Heat Island and related concepts are technically achievable under current conditions without voter approval. This is provided that private financing is supported the City's program, which could potentially mean loss of control over the service to a private partner. As local control over energy has been included in the definition of localization, public financing is desirable to help mitigate this outcome. However, this does not preclude a role for private equity on local projects, on a case by case basis.

Initial findings indicate that the renewable district heating concepts described in this report have sufficiently independent market structure to allow some degree of implementation without public financing. However, scalability and uptake of the program would be substantially augmented by a municipal authority that can finance solar heat, hot water systems, or natural gas conservation systems. Such a financing option may be considered by the City Council as another item for voter approval in the event voters do not approve municipalization. Assuming this would be included in the charter amendment language drafted for voter approval later this year, Local Power sees no reason to draft a separate authority for voter approval as the effect might be to confuse voters.

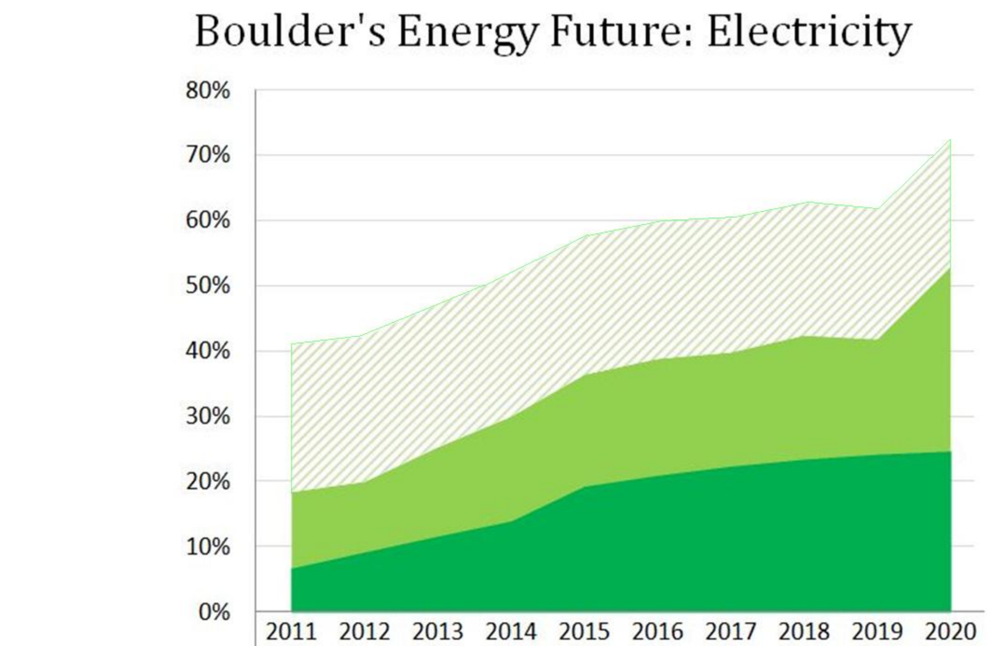
Democratizing Energy: A Localized Energy Utility

In order for Boulder to implement an electricity localization, with no Community Choice Aggregation law in place or proposed, and as yet no alternative franchise agreement put forward by Xcel that would facilitate local energy programs, a municipal utility intending to localize electricity must have sufficient bonding authority prepared to acquire Xcel's power and grid infrastructure. In order to take advantage of its bonding potential, the authority should not limit its authority to finance renewable energy or demand technologies, but should use an unlimited bonding authority subject to approval for issuance by City Council ordinance.

The authority to finance renewable heat, automation, storage, and infrastructure in the public and private sectors should also be authorized. This authority should be specified in the municipal charter, following any reference to bonds for power or "heat and power" systems. Such an authority should include both electric and gas service under a municipal energy utility as deemed necessary to finance renewable heat and hot water equipment, storage, or distribution.

THE LOCALIZATION PORTFOLIO STANDARD

The Localization Portfolio Standard (LPS) is an idea Local Power is developing for Boulder for the first time, and is conceptually similar to Colorado's Renewable Portfolio Standard (RPS). Qualifying projects are concentrated within the City of Boulder, and limited to within the County of Boulder. Below is a chart and table depicting the LPS in addition to other resources for Boulder's Energy Future:



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
RECs	23%	22%	22%	22%	21%	21%	21%	20%	20%	20%
Remote Renewables	12%	11%	14%	16%	17%	18%	18%	19%	18%	28%
Local Portfolio	7%	9%	12%	14%	19%	21%	22%	23%	24%	25%
Total	41%	42%	47%	52%	58%	60%	60%	63%	62%	73%

Eligible technologies under Colorado's RPS such as solar, small hydropower, wind, biomass, and so on would also be eligible under Boulder's RPS. In addition, the standard also includes thermal energy resources – which will be presented in a forthcoming report - a wide range of efficiency and demand-side measures, and combined heat and power – which, even though it may use natural gas fuel, recycles waste heat and thus reduces the total amount of fossil fuel consumed.

The standard could eventually include the existing Valmont natural gas plant, depending on the ability to supply the plant with significant amounts of cost-effective renewable biogas fuel and/ or utilize the plant's waste heat in a heat recovery system. In other words, Boulder's LPS excludes any technology that uses fossil fuel in a conventional way that does not include either a significant amount of renewable fuel or a significant efficiency improvement resulting in overall reduced carbon emissions. The standard does not include the combustion of coal.

While conceptually simple, the LPS is more complex than an RPS to design for technical and economic feasibility. The standard itself could be met in a variety of ways, depending on which options turn out to be the most feasible and cost-effective. The most easily achieved part of the portfolio would be to incorporate existing local infrastructure, such as the hydroelectric generation owned by Boulder but currently contracted to Xcel. Existing infrastructure could also be improved upon, such as by implementing a well-designed Smart Grid, further developing the potential for combined heat and power on the UC Boulder campus, or upgrading the hydroelectric system with increased capacity or operational changes that facilitate integration of variable renewable generation. The largest portion of the potential resources for meeting the Local Portfolio Standard is in the development of new infrastructure and new efficiency improvements.

One important dimension of the Local Portfolio Standard is in regards to when resources should be developed. Certain measures, such as efficiency improvements, the retrofitting of Boulder's building stock to create Smart Buildings, and building rooftop solar, can be implemented almost immediately. Others will require early action for planning, but will take time to develop.

Timing is also a factor with respect to what is economically feasible under the LPS. One important consideration is that it is broadly expected that Xcel's retail and wholesale power rates will increase significantly over the next decade. At this point, the assumptions regarding future costs in specific years are only estimates. Xcel is expected to retire relatively inexpensive, but polluting, existing coal plants over the next decade. This energy is being replaced with new generation plants, including natural gas and renewable energy. It is worth noting that Xcel's estimates show minimal difference in total future energy costs regardless of whether new renewables required over the next decade are procured or not, with a difference of generally less than one percent.[xxvii] Xcel's forecast of retail rates over the next decade, according to the "Draft Baseline Report" prepared for Boulder by Nexant, are expected to increase significantly. Wholesale electricity rates, which account for 70% of Xcel's retail electricity rates, are expected to increase ~24% by 2015 and ~33% by 2020. If costs are imposed on carbon emissions, the corresponding figures would be 43% and 56%. Xcel is quite vulnerable to adverse price impacts from any carbon emission costs due to its heavy reliance upon coal. Charts of these figures may be found in Appendix F.

Price trends, emerging technologies and practices, and policy developments should be monitored, as they will affect the deployment timeline of LPS technologies. The deployment of technologies that appear too expensive in 2011 may become feasible by 2015, for example.

The percentage generated and load eliminated per year in the proceeding table is put forward as a general schedule for development. The proposed LPS could be adopted as a matter of broad energy policy prior to and independent of any renegotiation with Xcel or voter initiative to authorize full municipalization.

Boulder's Energy Future:
Local Portfolio Standard - Electricity

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast Load (MWh):	1,396,324	1,421,132	1,438,528	1,460,106	1,482,007	1,508,337	1,526,801	1,549,703	1,572,948	1,600,894
Efficiency & Conservation (MWh)	-	36,896	73,957	110,447	144,447	174,945	200,510	222,492	240,058	254,614
Local Generation (MWh)	92,943	92,755	92,471	92,237	140,052	139,869	139,589	139,360	139,131	138,953
Total LPS (MWh)	**92,943**	**129,651**	**166,428**	**202,684**	**284,498**	**314,814**	**340,099**	**361,851**	**379,190**	**393,567**
Efficiency & Conservation (%)	0.0%	2.6%	5.1%	7.6%	9.7%	11.6%	13.1%	14.4%	15.3%	15.9%
Local Generation (%)	6.7%	6.5%	6.4%	6.3%	9.5%	9.3%	9.1%	9.0%	8.8%	8.7%
Total LPS (%)	**6.7%**	**9.1%**	**11.6%**	**13.9%**	**19.2%**	**20.9%**	**22.3%**	**23.3%**	**24.1%**	**24.6%**
Local LPS Portfolio (MWh)	92,943	129,651	166,428	202,684	284,498	314,814	340,099	361,851	379,190	393,567
Additional Renewables (MWh)	163,671	153,671	196,493	234,145	254,375	270,849	267,408	295,421	278,836	453,384
RECs (MWh)	315,360	315,360	315,360	315,360	315,360	315,360	315,360	315,360	315,360	315,360
Total (MWh)	571,973	598,682	678,281	752,188	854,233	901,023	922,867	972,633	973,386	1,162,311
Local Portfolio (%)	6.7%	9.1%	11.6%	13.9%	19.2%	20.9%	22.3%	23.3%	24.1%	24.6%
Additional Renewables (%)	11.7%	10.8%	13.7%	16.0%	17.2%	18.0%	17.5%	19.1%	17.7%	28.3%
RECs (%)	22.6%	22.2%	21.9%	21.6%	21.3%	20.9%	20.7%	20.3%	20.0%	19.7%
Total (%)	**41.0%**	**42.1%**	**47.2%**	**51.5%**	**57.6%**	**59.7%**	**60.4%**	**62.8%**	**61.9%**	**72.6%**

APPENDIX A: Summary Table of Authorities

		- Democratizing Energy: A Customer-Focused Utility - [1] Summary of Authorities for the City of Boulder							
Technologies & Practices:	**Status Quo**	**Wholesale Control:** Electricity Procurement[2]	**Wholesale Control:** Natural Gas Procurement[2]	**Retail Control:** Billing, Revenue, & Rate Setting	**Operational Control:** Metering	**Operational Control:** Distribution	**Operational Control:** Other Grid Upgrades	**Financial Control:** Revenue Bond Authority [3]	**Financial Control:** New Community & Customer
Heat Islands (Solar Thermal)	Possible								
Waste as a Resource (Biomass CHP)	Not Applicable								
Biomethane Pipeline Injection	Limited								
Combined Heat and Power (CHP) Retrofit	Not Applicable								
Geothermal Heat [8]	Limited								
Valmont Capacity Balancing (Natural Gas) [5]	Not Applicable								
Hydroelectric Power	Ongoing								
Hydroelectic Capacity Balancing [6]	Not Applicable								
Wind Farm on Barker Reservoir	Possible								
Solar PV	Limited								
Demand-Side Management	Limited								
Targeted Efficiency	Not Applicable								
Demand Dispatch	Not Applicable								
Electric Vehicle Technologies	Limited								
Home Area Networks - Upgrade [7]	Limited								
Thermal Gateways - Upgrade	Not Applicable								
LED Streetlights	Possible								
Storage - Distributed and Utility-Scale	Not Applicable								
Virtual Power Plant [9]	Limited								

Color Key: Light green signifies an authority that is beneficial for the technology deployment, whereas dark green connotes the necessity of the authority. Necessity generally implies that an authority is probably requires to achieve significant scale of development. Grey indicates that it is not applicable.

1) These categories are intended as an approximation of the relative roles of different authorities in facilitating local control and development of the various technologies though different market, operational, and financial structures and authorities.

2) New thermal end use technologies can potentially displace either electric or natural gas applications or both; thus wholesale market procurement of these resources may be affected depending on the energy resource displaced.

3) Revenue bonds can be used to fully or partially finance energy resource development, develop enabling infrastructure, or provide flexible options in structuring financing deals.

4) Valmont power is assumed to be procured from the current owner of up to 80 megawatts of natural gas generation capacity located at that site.

5) Capacity balancing implies coordination of Boulder's existing hydropower with other intermittent renewables, and may involve some system improvements.

6) Upgrades means significant expansion of demand side programs into new applications.

7) Geothermal heat means using hot ground water to provide heat to buildings and may have a variety of end uses; it does not refer to generation of electricity.

8) Virtual power plant refers only to the softward platform, not the metering or control hardware.

APPENDIX B: Colorado Renewable Energy Standard Excerpt

Requirements regarding renewable distributed generation

3655. Renewable Distributed Generation.

(a) In conjunction with the renewable energy standard set forth in paragraph 3654(a), each investor owned QRU shall generate or cause to be generated (through purchase or by providing rebates or other form of incentive) renewable distributed generation in the following minimum amounts, unless the Commission amends such minimum amounts under paragraph 3655(c):

(I) One percent of its retail electricity sales in Colorado for each of the compliance years 2011 through 2012;

(II) One and one-fourth percent of its retail electricity sales in Colorado for each of the compliance years 2013 through 2014;

(III) One and three-fourths percent of its retail electricity sales in Colorado for each of the compliance years 2015 through 2016;

(IV) Two percent of its retail electricity sales in Colorado for each of the compliance years 2017 through 2019;

(V) Three percent of its retail electricity sales in Colorado for each of the compliance years beginning in 2020 and continuing thereafter.

(b) Of the amounts of renewable distributed generation set forth in paragraph 3655(a), at least one-half shall be derived from retail renewable distributed generation unless modified by the Commission under paragraph 3655(c).

(c) The Commission may change the minimum amounts of retail renewable distributed generation and wholesale renewable distributed generation set forth in paragraphs 3655(a) and (b) pursuant to a filing under paragraph 3657(d). The Commission may reduce the minimum amounts of retail renewable distributed generation and wholesale renewable distributed generation set forth in paragraphs 3655(a) and (b) for effect after December 31, 2014 upon finding that those minimum amounts are no longer in the public interest. In the event that the Commission finds that the public interest requires an increase in such minimum amounts after December 31, 2014, the Commission shall report such findings to the Colorado General Assembly.

(d) The investor owned QRU may propose in a compliance plan filing under rule 3657, or by a separate application, that the Commission reduce the percentages set forth in paragraph 3655(a) and (b).

(e) Renewable energy credits associated with retail renewable distributed generation and wholesale renewable distributed generation will be used to comply with the renewable distributed generation requirements as set forth in this rule 3655. Eligible energy and RECs produced by renewable distributed generation shall be governed by rule 3659, unless otherwise

(f) In a final decision concerning the investor owned QRU's compliance plan, as between residential and nonresidential retail renewable distributed generation, the Commission shall direct the investor owned QRU to allocate its expenditures for the acquisition of retail renewable distributed generation according to the proportion of RESA revenues derived from each of these customer groups; except that the investor owned QRU may acquire retail renewable distribution generation at levels that differ from these group allocations based upon market response to the QRU's programs.

APPENDIX C: Solar Reward Program

Current Solar*Rewards REC Prices and MW Reviewed

The following charts reflect the current REC pricing and availability for the Solar*Rewards program. These charts will be updated daily with the current reviewed MW. REC prices are set and MW are counted when an application is marked as reviewed. Charts last updated: 04-27-2011 to reflect MW as of 04-26-2011

Total MW Reviewed- 17.119 MW

Small -- Customer-Owned (<10 kW)					
Step	Rebate (per watt)	REC Price (per kWh)	MW in step	MW Reviewed	MW Remaining in Step
1	$1.75	4¢	4	1.376	2.624
2	$1.00	9¢	5		5
3	50¢	11¢	5		5
4	0¢	14¢	6		6
			Total	1.376	

Small -- Third Party Developer (<10 kW)					
Step	Rebate	REC Price (per kWh)	MW in step	MW Reviewed	MW Remaining in Step
1		16¢	4	1.132	2.868
2		15¢	5		5
3		12¢	5		5
4		11¢	6		6
			Total	1.132	

Medium -- Tier 1 (10-100 kW)					
Step	Rebate	REC Price (per kWh)	MW in step	MW Reviewed	MW Remaining in Step
1		15¢	3	3.000	0
2		13¢	3	1.632	1.368
3		11¢	4		4
			Total	4.632	

Medium -- Tier 2 (100.1-500 kW)					
Step	Rebate	REC Price (per kWh)	MW in step	MW Reviewed	MW Remaining in Step
1		15¢	3	3.000	0
2		13¢	3	3.000	0
3		11¢	4	3.979	0.021
			Total	9.979	

Source:
[http://www.xcelenergy.com/Colorado/Residential/RenewableEnergy/Solar_Rewards/Pages/Current-MW-Submitted.aspx]

APPENDIX D: Solar Excess Generation

What are the options for my excess generation or Solar Bank credits?

A. Continuous Rollover Credits: Any excess generation from your PV system will be rolled over month to month, year to year and held in your Solar Bank. The credits will never run out, so you can use then whenever your consumption from the grid exceeds your generation. However, you cannot cash out your Solar Bank, and no credit will be given if you move or stop service. Credits can not be transferred between Xcel accounts or to a new homeowner if a customer sells their house and moves.

B. Year-End Payout: Any excess generation from your PV system will be rolled over month to month and held in your Solar Bank. At the end of the calendar year (your January billing cycle), Xcel will cash out your Solar Bank and send you a check for the excess energy. We will buy the energy at a rate of the average incremental cost of electricity (AHIC) from the previous 12 months. Previous AHIC amounts were:

   - 2010: 2.857 cents
   - 2009: 3.058 cents
   - 2008: 4.842 cents
   - 2007: 3.414 cents
   - 2006: 4.291 cents

C. Waive Decision Until Later Date: You will waive the decision until a later date and will be defaulted to the Year-End Payout option. Then you can make your one-time choice at anytime during the life of your contract.

Source:
[http://www.xcelenergy.com/Colorado/Residential/RenewableEnergy/Solar_Rewards/Pages/Solar%20Rewards%20FAQ.aspx]

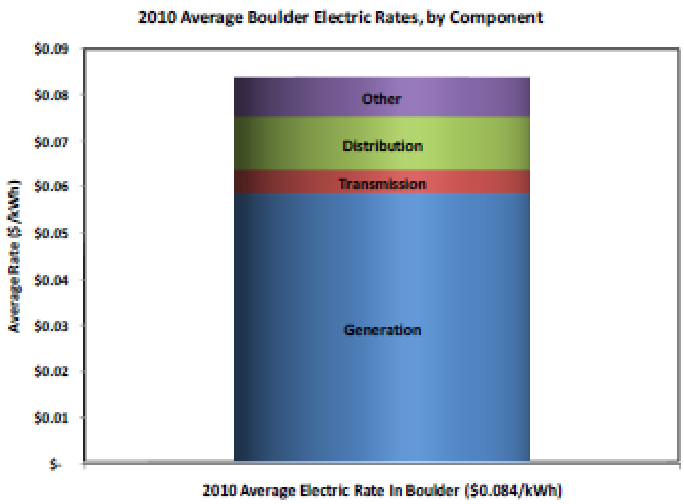
APPENDIX E: Boulder Solar PV Permit Fee

Photovoltaic System Permit Fee

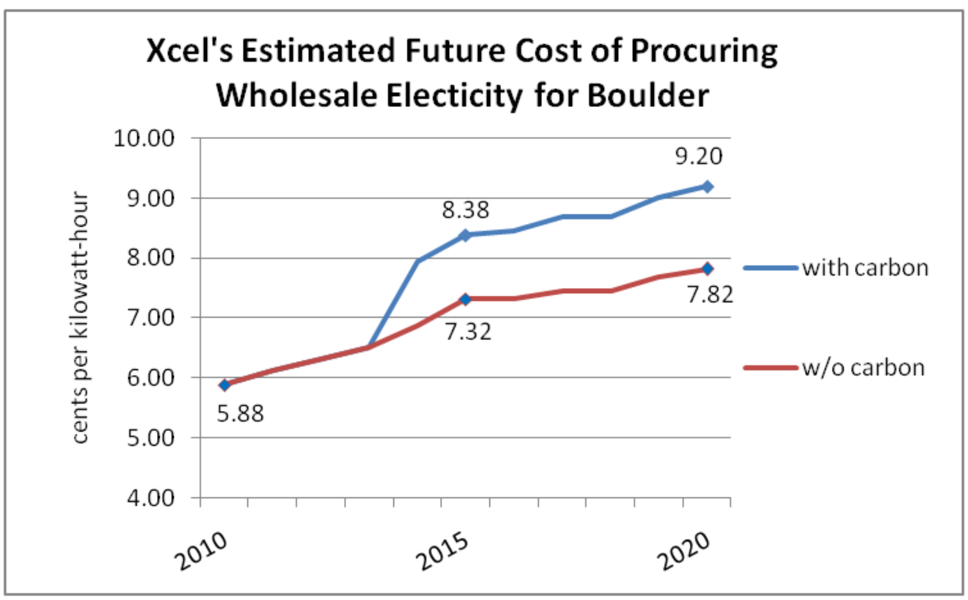
- Residential $69.60
- Nonresidential and Multifamily $139.20

Source: [http://www.bouldercolorado.gov/files/PDS/fees/2011_Schedule_of_Fees.pdf]

APPENDIX F: Projected Cost of Xcel's Wholesale Energy Cost



Wholesale energy costs are shown currently to account for 70 percent of Xcel's total retail rates in the Draft Boulder "Energy Baseline Report" from Nexant, May 4, 2011, page 27.



Wholesale rates are estimated as 70% of forecast retail rates. The "Draft Energy Baseline Report" provides Xcel's forecast of retail rates with and without carbon costs in implementing PSCo's Clean Air-Clean Jobs Emissions Reduction Plan.

APPENDIX G: Demand Side Management Potential

All Sectors: 100% Financed + Limited Emerging Tech	Boulder Localization Portfolio Standard - Electricity: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - kWh	36,895,774	73,957,497	110,447,136	144,446,916	174,945,091	200,509,913	222,491,804	240,058,461	254,613,709	266,667,793
Net Peak Demand Savings - kW	8,892	17,635	26,198	34,183	41,379	47,528	52,829	57,176	60,839	63,941
Annual Net Energy Savings - kWh	36,895,774	40,013,386	39,690,709	37,175,037	33,472,179	28,242,596	24,241,299	19,505,961	16,115,724	13,343,342
Annual Net Peak Demand Savings - kW	8,892	9,454	9,319	8,731	7,895	6,780	5,843	4,815	4,049	3,426
Measure Decay - kWh		-2,951,662	-3,201,071	-3,175,257	-2,974,003	-2,677,774	-2,259,408	-1,939,304	-1,560,477	-1,289,258
Measure Decay - kW		-711	-756	-746	-698	-632	-542	-467	-385	-324
New Savings as a Percent of 2011 Load	2.7%	2.9%	2.9%	2.7%	2.5%	2.1%	1.8%	1.4%	1.2%	1.0%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$3,109,469	$3,482,403	$3,711,764	$3,834,675	$3,871,656	$3,695,638	$3,548,788	$3,398,741	$3,264,123	$3,148,936
Marketing - Utility	$365,335	$368,145	$379,403	$393,876	$409,002	$416,321	$426,692	$437,479	$449,575	$466,498
Measure Costs - Private Sector	$12,679,500	$13,383,597	$13,300,244	$12,661,610	$11,671,307	$10,286,031	$9,028,059	$7,881,136	$6,928,876	$6,166,200
Capitalization Cost (8%, 12 year term) - Split	$7,399,475	$7,733,491	$7,693,949	$7,390,988	$6,921,199	$6,264,040	$5,667,271	$5,123,184	$4,671,442	$4,309,637
Premise Level Monitoring Equipment - Utility	$2,918,403	$2,918,403	$2,918,403	$2,918,403	$2,918,403	$2,918,403	$2,918,403	$2,918,403	$2,918,403	$2,918,403
SaaS - Private Sector	$620,320	$1,240,640	$1,860,961	$2,481,281	$3,101,601	$3,721,921	$4,342,241	$4,962,561	$5,582,882	$6,203,202
Total	$27,092,501	$29,126,680	$29,864,724	$29,680,834	$28,893,169	$27,302,354	$25,931,454	$24,721,505	$23,815,301	$23,212,877
Total - Utility	$7,777,665	$8,153,410	$8,394,028	$8,531,413	$8,583,520	$8,414,820	$8,278,342	$8,139,082	$8,016,560	$7,918,296
Total - Private Sector	$19,314,836	$20,973,270	$21,470,695	$21,149,421	$20,309,649	$18,887,534	$17,653,112	$16,582,423	$15,798,741	$15,294,580
PV Avoided Cost Benefits (not including DR)	$52,376,925	$50,293,320	$47,810,045	$43,287,176	$37,683,234	$30,904,178	$25,719,875	$20,797,403	$17,124,352	$14,113,729
PV Annual Marketing and Admin Costs	$3,474,803	$3,622,828	$3,621,574	$3,521,818	$3,354,370	$3,031,616	$2,757,657	$2,503,683	$2,280,381	$2,088,750
PV Net Measure Costs	$23,617,698	$23,403,826	$22,096,671	$20,204,842	$18,090,930	$15,782,993	$13,835,988	$12,186,363	$10,860,271	$9,803,600
TRC (Total Resource Cost test)	1.93	1.86	1.86	1.82	1.76	1.64	1.55	1.42	1.30	1.19
Naturally Occurring - kWh	7,533,425	14,785,331	21,766,285	28,414,930	34,681,281	40,536,194	45,973,239	50,826,413	55,283,451	59,372,378
Naturally Occurring - kW	1,108	2,160	3,168	4,124	5,022	5,860	6,635	7,328	7,963	8,545
Cost per First-Year kWh	$0.73	$0.73	$0.75	$0.80	$0.86	$0.97	$1.07	$1.27	$1.48	$1.74
Cumulative Bill Savings - Real	$5,231,255	$15,838,042	$31,962,269	$53,420,918	$80,013,818	$111,273,553	$146,883,391	$186,349,596	$229,360,444	$275,632,640
Demand Response Enabled by Programs:										
Annual Peak DR Capacity (MW)	3.25	6.50	9.75	13.00	16.25	19.50	22.74	25.99	29.24	32.49
Annual Peak DR Avoided Cost - Real	$636,007	$1,331,366	$2,061,586	$2,837,700	$3,661,981	$4,536,807	$5,464,662	$6,448,141	$7,489,956	$8,592,939

Residential: 100% Financed + Limited Emerging Tech	Boulder Localization Portfolio Standard - Electricity: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - kWh	11,884,134	23,806,012	35,780,165	47,423,031	58,430,358	68,484,095	77,504,510	84,309,837	89,842,608	94,183,773
Net Peak Demand Savings - kW	4,497	8,779	12,933	16,828	20,387	23,540	26,295	28,492	30,327	31,852
New Net Energy Savings - kWh	11,884,134	12,872,609	13,003,962	12,683,182	12,021,982	11,015,496	9,901,654	7,597,460	6,140,568	4,832,410
New Net Peak Demand Savings - kW	4,497	4,642	4,525	4,257	3,900	3,465	3,032	2,440	2,031	1,687
Measure Decay - kWh		-950,731	-1,029,809	-1,040,317	-1,014,655	-961,759	-881,240	-792,132	-607,797	-491,245
Measure Decay - kW		-360	-371	-362	-341	-312	-277	-243	-195	-162
New Savings as a Percent of 2011 Load - Residential	4.8%	5.2%	5.2%	5.1%	4.8%	4.4%	4.0%	3.1%	2.5%	1.9%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$1,371,981	$1,564,142	$1,712,030	$1,829,355	$1,906,115	$1,872,256	$1,846,779	$1,805,189	$1,762,539	$1,721,709
Marketing - Utility	$125,912	$128,709	$142,207	$158,961	$176,300	$186,226	$196,898	$207,947	$220,274	$237,404
Measure Costs - Private Sector	$6,515,065	$6,635,557	$6,538,477	$6,299,247	$5,938,359	$5,382,712	$4,858,965	$4,358,040	$3,945,272	$3,615,999
Capitalization Cost (8%, 12 year term) - Split	$3,496,700	$3,553,861	$3,507,807	$3,394,319	$3,223,117	$2,959,525	$2,711,065	$2,473,431	$2,277,619	$2,121,415
Premise Level Monitoring Equipment - Utility	$855,890	$855,890	$855,890	$855,890	$855,890	$855,890	$855,890	$855,890	$855,890	$855,890
SaaS - Private Sector	$116,605	$233,210.34	$349,815.51	$466,420.68	$583,025.85	$699,631.02	$816,236.19	$932,841.36	$1,049,446.53	$1,166,051.70
Total	$12,482,153	$12,971,369	$13,106,225	$13,004,192	$12,682,807	$11,956,240	$11,285,833	$10,633,338	$10,111,040	$9,718,469
Total - Utility	$2,759,808	$2,954,766	$3,116,151	$3,250,230	$3,344,329	$3,320,397	$3,305,592	$3,275,050	$3,244,728	$3,221,028
Total - Private Sector	$9,722,345	$10,016,603	$9,990,074	$9,753,961	$9,338,477	$8,635,843	$7,980,241	$7,358,288	$6,866,312	$6,497,442
PV Avoided Cost Benefits (not including DR)	$19,864,520	$18,460,265	$17,417,230	$15,965,790	$14,185,032	$12,121,737	$10,251,206	$8,155,428	$6,696,443	$5,367,962
PV Annual Marketing and Admin Costs	$1,497,893	$1,592,736	$1,641,404	$1,656,001	$1,631,803	$1,517,654	$1,417,630	$1,313,859	$1,217,538	$1,131,841
PV Net Measure Costs	$10,984,260	$10,443,072	$9,646,767	$8,744,757	$7,791,605	$6,736,247	$5,824,126	$5,029,806	$4,391,428	$3,881,610
TRC (Total Resource Cost test)	1.59	1.53	1.54	1.54	1.51	1.47	1.42	1.29	1.19	1.07
Naturally Occurring - kWh	1,705,350	3,315,538	4,882,403	6,412,343	7,904,394	9,355,289	10,763,137	11,953,611	13,095,798	14,191,784
Naturally Occurring - kW	225	426	617	802	982	1,156	1,326	1,468	1,605	1,736
Cost per First-Year kWh	$1.05	$1.01	$1.01	$1.03	$1.05	$1.09	$1.14	$1.40	$1.65	$2.01
Cumulative Bill Savings - Real	$ 2,219,347	$ 6,698,602	$ 13,518,264	$ 22,651,934	$ 34,078,446	$ 47,703,600	$ 63,421,555	$ 80,927,729	$ 100,059,839	$ 120,653,143
Demand Response Enabled by Programs:										
Annual Peak DR Capacity (MW)	0.94	1.87	2.81	3.75	4.68	5.62	6.56	7.49	8.43	9.37
Annual Peak DR Avoided Cost - Real	$183,339	$383,787	$594,284	$818,011	$1,055,623	$1,307,805	$1,575,274	$1,858,777	$2,159,096	$2,477,048

Commercial: 100% Financed + Limited Emerging Tech	Boulder Localization Portfolio Standard - Electricity: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - kWh	17,711,791	35,643,697	53,566,332	70,464,671	85,741,278	98,120,050	108,761,315	117,727,084	125,258,384	131,632,566
Net Peak Demand Savings - kW	3,263	6,602	9,979	13,206	16,169	18,656	20,818	22,664	24,236	25,582
New Net Energy Savings - kWh	17,711,791	19,348,850	19,470,542	18,455,982	16,753,086	13,719,018	11,738,787	9,904,872	8,323,689	7,040,078
New Net Peak Demand Savings - kW	3,263	3,600	3,665	3,521	3,245	2,746	2,381	2,037	1,735	1,485
Measure Decay - kWh		-1,416,943	-1,547,908	-1,557,643	-1,476,479	-1,340,247	-1,097,521	-939,103	-792,390	-665,895
Measure Decay - kW		-261	-288	-293	-282	-260	-220	-190	-163	-139
New Savings as a Percent of 2011 Load - Residential	2.7%	3.0%	3.0%	2.9%	2.6%	2.1%	1.8%	1.5%	1.3%	1.1%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$1,395,414	$1,564,799	$1,668,853	$1,716,070	$1,722,423	$1,620,793	$1,530,393	$1,441,983	$1,361,598	$1,292,997
Marketing - Utility	$166,121	$166,172	$163,973	$161,739	$159,575	$157,019	$156,770	$156,558	$156,374	$156,212
Measure Costs - Private Sector	$4,558,150	$5,070,177	$5,224,979	$5,085,895	$4,744,944	$4,168,694	$3,628,015	$3,107,165	$2,639,847	$2,242,162
Capitalization Cost (8%, 12 year term) - Split	$3,108,430	$3,351,330	$3,424,766	$3,358,787	$3,197,043	$2,923,677	$2,667,184	$2,420,099	$2,198,408	$2,009,751
Premise Level Monitoring Equipment - Utility	$1,994,341	$1,994,341	$1,994,341	$1,994,341	$1,994,341	$1,994,341	$1,994,341	$1,994,341	$1,994,341	$1,994,341
SaaS - Private Sector	$484,965	$969,930	$1,454,895	$1,939,860	$2,424,825	$2,909,790	$3,394,755	$3,879,720	$4,364,685	$4,849,650
Total	$11,707,420	$13,116,750	$13,931,808	$14,256,692	$14,243,150	$13,774,314	$13,371,459	$12,999,867	$12,715,253	$12,545,112
Total - Utility	$4,501,969	$4,671,406	$4,773,261	$4,818,243	$4,822,432	$4,718,246	$4,627,597	$4,538,976	$4,458,406	$4,389,643
Total - Private Sector	$7,205,451	$8,445,344	$9,158,547	$9,438,449	$9,420,718	$9,056,067	$8,743,861	$8,460,891	$8,256,846	$8,155,469
PV Avoided Cost Benefits (not including DR)	$24,068,640	$23,723,279	$23,148,428	$21,421,472	$19,009,699	$15,480,784	$13,052,049	$10,792,729	$8,909,447	$7,404,202
PV Annual Marketing and Admin Costs	$1,561,535	$1,628,602	$1,622,451	$1,563,964	$1,474,753	$1,310,724	$1,170,328	$1,043,277	$932,105	$837,253
PV Net Measure Costs	$10,145,885	$10,542,387	$10,372,926	$9,826,756	$9,085,816	$8,164,617	$7,363,088	$6,652,564	$6,049,542	$5,550,714
TRC (Total Resource Cost test)	2.06	1.95	1.93	1.88	1.80	1.63	1.53	1.40	1.28	1.16
Naturally Occurring - kWh	4,575,153	9,070,024	13,431,302	17,580,843	21,460,619	25,036,916	28,298,346	31,247,228	33,896,930	36,268,778
Naturally Occurring - kW	699	1,383	2,045	2,674	3,261	3,802	4,295	4,741	5,141	5,499
Cost per First-Year kWh	$0.66	$0.68	$0.72	$0.77	$0.85	$1.00	$1.14	$1.31	$1.53	$1.78
Cumulative Bill Savings - Real	$ 2,288,977	$ 6,959,422	$ 14,105,854	$ 23,668,368	$ 35,563,733	$ 49,509,721	$ 65,362,447	$ 82,973,315	$ 102,212,533	$ 122,968,012
Demand Response Enabled by Programs:										
Annual Peak DR Capacity (MW)	1.24	2.49	3.73	4.97	6.22	7.46	8.70	9.95	11.19	12.44
Annual Peak DR Avoided Cost - Real	$243,413	$509,542	$789,013	$1,086,049	$1,401,519	$1,736,334	$2,091,443	$2,467,842	$2,866,567	$3,288,702

Industrial: 100% Financed + Limited Emerging Tech	Boulder Localization Portfolio Standard - Electricity: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - kWh	7,299,849	14,507,788	21,100,639	26,559,215	30,773,455	33,905,768	36,225,979	38,021,539	39,512,717	40,851,453
Net Peak Demand Savings - kW	1,132	2,254	3,286	4,149	4,823	5,332	5,716	6,020	6,276	6,508
New Net Energy Savings - kWh	7,299,849	7,791,927	7,216,205	6,035,872	4,697,111	3,508,082	2,600,857	2,003,629	1,651,467	1,470,854
New Net Peak Demand Savings - kW	1,132	1,212	1,129	953	750	569	430	338	283	254
Measure Decay - kWh		-583,988	-623,354	-577,296	-482,870	-375,769	-280,647	-208,069	-160,290	-132,117
Measure Decay - kW		-91	-97	-90	-76	-60	-46	-34	-27	-23
New Savings as a Percent of 2011 Load - Residential	1.6%	1.7%	1.6%	1.3%	1.0%	0.8%	0.6%	0.4%	0.4%	0.3%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$342,074	$353,462	$330,881	$289,250	$243,119	$202,589	$171,616	$151,569	$139,986	$134,230
Marketing - Utility	$73,302	$73,264	$73,222	$73,177	$73,127	$73,075	$73,024	$72,975	$72,927	$72,883
Measure Costs - Private Sector	$1,606,285	$1,677,863	$1,536,788	$1,276,468	$988,005	$734,625	$541,079	$415,931	$343,758	$308,039
Capitalization Cost (8%, 12 year term) - Split	$794,345	$828,300	$761,376	$637,883	$501,039	$380,838	$289,022	$229,653	$195,415	$178,471
Premise Level Monitoring Equipment - Utility	$68,173	$68,173	$68,173	$68,173	$68,173	$68,173	$68,173	$68,173	$68,173	$68,173
SaaS - Private Sector	$18,750	$37,500	$56,250	$75,000	$93,750	$112,500	$131,250	$150,000	$168,750	$187,500
Total	$2,902,928	$3,038,561	$2,826,691	$2,419,950	$1,967,213	$1,571,800	$1,274,163	$1,088,301	$989,009	$949,295
Total - Utility	$515,888	$527,238	$504,616	$462,939	$416,759	$376,177	$345,153	$325,057	$313,426	$307,626
Total - Private Sector	$2,387,040	$2,511,323	$2,322,074	$1,957,011	$1,550,453	$1,195,623	$929,010	$763,244	$675,583	$641,669
PV Avoided Cost Benefits (not including DR)	$8,443,764	$8,109,776	$7,244,387	$5,899,914	$4,488,503	$3,301,657	$2,416,620	$1,849,246	$1,518,463	$1,341,566
PV Annual Marketing and Admin Costs	$415,375	$401,489	$357,720	$301,853	$247,814	$203,238	$169,699	$146,547	$130,738	$119,656
PV Net Measure Costs	$2,487,553	$2,418,367	$2,076,978	$1,633,329	$1,213,509	$882,128	$648,774	$503,994	$419,300	$371,276
TRC (Total Resource Cost test)	2.91	2.88	2.98	3.05	3.07	3.04	2.95	2.84	2.76	2.73
Naturally Occurring - kWh	1,252,923	2,399,769	3,452,580	4,421,744	5,316,268	6,143,989	6,911,756	7,625,574	8,290,723	8,911,816
Naturally Occurring - kW	184	352	506	648	780	901	1,014	1,119	1,218	1,309
Cost per First-Year kWh	$0.40	$0.39	$0.39	$0.40	$0.42	$0.45	$0.49	$0.54	$0.60	$0.65
Cumulative Bill Savings - Real	$ 722,931	$ 2,180,018	$ 4,338,150	$ 7,100,615	$ 10,371,640	$ 14,060,232	$ 18,099,388	$ 22,448,551	$ 27,088,072	$ 32,011,485
Demand Response Enabled by Programs:										
Annual Peak DR Capacity (MW)	1.07	2.14	3.21	4.28	5.35	6.41	7.48	8.55	9.62	10.69
Annual Peak DR Avoided Cost - Real	$209,254	$438,037	$678,289	$933,640	$1,204,839	$1,492,669	$1,797,945	$2,121,522	$2,464,293	$2,827,189

APPENDIX H: Glossary of Terms

Ancillary Services: refers to several fast- or instantaneous- electric response services necessary to maintain the reliable operation of the interconnected power grid. Several of these services are typically supplied by natural-gas fired single-cycle combustion turbines, a portion of which may be more economically supplied – with an environmental benefit – by demand-side resources.

Biomethane: biologically-produced gas sourced from biomass waste feedstocks, and injected into natural gas pipelines.

Community Choice Aggregation (CCA): a legal framework enabled by legislation in several states that allows local governments to contract for electric power from a third party provider that serves all customers in the local government's jurisdiction; customers are given the right to opt out and return to the primary utility service if they choose to do so.

Combined Heat and Power (CHP): also known as "cogeneration", recovers the waste heat that would otherwise be lost from conventional central station power plants, and delivers this heat to one or more customers; CHP implies that the generator is at or near the point of energy use to allow highly efficient delivery of both electricity and heat.

Demand Dispatch: is an expanded form of demand response, which typically sheds customer load in response to peak electrical grid demand periods, and refers to the ability to turn appliances on or off in response to price or grid stability signals in all time periods.

Demand Response (DR): market-based or automated reductions in peak demand; frequently used in power emergencies to keep the grid stable, while avoiding the use of power plants.

Energy Management System (EMS): also called a Building Management System, refers to a computer system which is designed for monitoring and controlling features of building systems such as lighting, heating, ventilation, and so on. These systems may be used to trend energy usage, perform optimization or diagnostic routines to conserve energy, or interface with the electrical grid through an aggregator to respond to price and/ or grid reliability signals for demand management.

Home Area Network (HAN): refers to a network within a home in which smart appliances and thermostats respond to price, grid reliability, or control signals from an aggregator, to optimize customer comfort, save money during periods of peak demand, or act as a demand resource for the grid.

Heat Islands: district heating systems - using solar thermal, ground-source heat pumps, and in limited cases, combined heat and power systems - integrated and offered with thermal appliance retrofits and programmable controllable thermostats, and served by both natural gas and biomethane (biologically-produced gas sourced from agricultural waste and injected into natural gas pipelines).

Localization Portfolio Standard (LPS): Similar to an Renewable Portfolio Standard, but including heat and demand-side resources in addition to electrical energy resources, defined in discrete geographic boundaries.

Managed Charging (or smart charging): is the coordination of when plug-in electric vehicles draw power from the grid to recharge. This is performed by the grid operator or an aggregator, and in accordance with the PEV owner's specified preferences.

Open Automated Demand Response (OpenADR): is a non-proprietary standard and linux server platform developed by Lawrence Berkeley National Laboratory to facilitate fully automated demand response and dispatch in reaction to grid signals. It is currently being adopted in national standards.

Thermal Gateway: refers to advanced offerings using smart thermostats (programmable controllable thermostats, which offer two-way communication) such as optimizing customer's heating or cooling schedules against variations in weather, price, and (for electric heating systems and all cooling systems) grid stability signals.

Vehicle to Building (V2B): is when a PEV owner's home or business draws a portion of power for the building from the vehicle battery, at the customer's discretion and in observance of grid conditions and price signals.

END NOTES

[i]Local Power Boulder Energy Localization Interview Summary memo has been delivered separately for staff reference. The summaries are for review purposes only and all names have been deleted and commercially sensitive information withheld to protect the confidentiality of interviewees.

[ii] For more detailed information, see the American Council for an Energy Efficient Economy's State Energy Policy Database, available from [http://www.aceee.org]

[iii] "Colorado DSM Market Potential Assessment," KEMA, Inc., 12 March 2010. Available: [http://www.xcelenergy.com/SiteCollectionDocuments/docs/CODSMPotentialStudyOverview.pdf]. Accessed 25 April 2011.

[iv] Note that these figures do not include savings from emerging technologies such as light emitting diodes and the 'Coolerado' indirect-direct evaporative cooler, which were modeled in separate analyses.

[v] For a leading example, see the Northwest Energy Efficiency Alliance and Bonneville Power Authority's "NorthWest Energy Efficiency Technology Roadmap", March 2011. Available: [http://www.bpa.gov/corporate/business/innovation/docs/2010/NW%20Energy%20Efficiency%20Technology%20Roadmap%20March%202010.pdf]

[vi] This equipment allows monitoring electrical loads by end use or appliance, by installing current transformers at appropriate locations which communicate energy usage back to a central energy management system and on into analytical software to support efficiency pattern recognition, demand response, and demand dispatch. The cost was modeled for monitoring usage at: the main switch, HVAC, lighting, refrigeration, plug-loads, server-data centers, and a "miscellaneous" large piece of equipment.

[vii] National Institute for Standards and Technology (NIST) Smart Grid Interoperability Panel (SGIP) Priority Action Plan (PAP) 09, which is due out in April 2011 but will likely be delayed until June 2011. NIST will then pass OpenADR 2.0 to FERC for consideration for a national Smart Grid DR communication standard (as mandated by EISA 2007).

[viii] "Technical Training for PG&E's Intermittent Renewable Resources and OpenADR Integration Pilot" Lawrence Berkeley National Laboratory Demand Response Research Center, 8 February 2011. Available: [http://www.reuters.com/article/2010/12/15/idUS248511430620101215]. Accessed on 25 April 2011.

[ix] Electric rates for commercial customers are relatively high for demand and low for energy. Customers' peak demand charges are set by the greater of: their greatest peak demand over a 15 minute averaged period each month, or a 75% percent of the highest peak demand over the preceding 11 month period. Small commercial customers in particular may not realize how significant their demand charges are. (Source: the Southwest Energy Efficiency Partnership.)

[x] See Lawrence Berkeley National Laboratory's Demand Response Research Center publications, available at [http://drrc.lbl.gov/publications/integrating-renewable-resources-california-and-role-automated-demand-response], and the Integrating Renewable Resources (IRR) pilot taking place from Janurary through December 2011 in Pacific Gas and Electric's territory.

[xi] "Demand Dispatch: Moving Beyond Demand Response to Use Real-Time Control of Loads to Balance Gen-

eration and Load," by Alec Brooks, Ed Lu, Dan Reicher, Charles Spirakis, and Bill Weihl, Google, Inc., IEEE Power

& Energy, June 2010.

[xii] "One Million Electric Vehicles by 2015: February 2011 Status Report," United States Department of Energy. Available: [http://www.energy.gov/media/1_Million_Electric_Vehicle_Report_Final.pdf]

[xiii] "Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems", KEMA, Inc., March 2010. Available: [http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_Report_Assessment_of_Plug-in_Electric_Vehicle_Integration_with_ISO-RTO_Systems_03232010.pdf]. Accessed on 25 April 2011.

[xiv] Local Power has identified a number of potential technology options that may upgrade the functionality of Xcel's existing and experimental SmartGridCity network (covering 24,000 meters). There are several alternative communications modules for the Focus AL meter manufactured by Tantalus, Elster, Eschelon, Trilliant, Itron, Cooper Power Systems, Aclara, Silver Springs Network, and Current Group. These include the Landis+Gyr Gridstream PLC TS2 AMR module, the EMS Technologies TS2 module, the Aclara STAR Network RF AMR, and the Aclara TWACS UMT AMR. These options will continue to be explored. In addition, Local Power is investigating relatively inexpensive, innovative platforms which deliver much of the functionality of the smart grid but are independent of this infrastructure.

[xv] Draft Energy Baseline Report; Nexant, May 4, 2011, p. 46.

[xvi] Hydroelectric Power in a Municipal Water System, John Cowdrey, Sept. 2001, p. 11

[xvii] Integration of Water Supply Reliability and Hydropower Generation Final Draft Feasibility Report, TCB-AECOM, July 2005.

[xviii] Conventional hydropower potential needs to be evaluated independently of the potential for adding pump storage, about which LPI has only gathered limited information. There is excellent potential from the standpoint of large differential in proximate elevations as well as existing reservoirs and hydropower infrastructure; however, water availability, siting, financial, and engineering challenges would need to be addressed.

[xix] ibid.

[xx] From Boulder County Land Use Code – Article 4, Section 4-101

[xxi] Jamacha Road 36-Inch Potable Water Transmission Main, Otay Water District, Spring Valley, CA
As Prime Consultant, LEE & RO provided engineering, design, and construction phase engineering services for a $16.5 million, 20,000 feet long, 36 inch CML&C potable water transmission main from the San Diego County Water Authority's No. 14 Flow Control Facility in El Cajon to the 640-1 and 640-2 Reservoirs located in the District's regulatory site in Campo Road, Spring Valley. The main has a capacity of 16 mgd. The project also included a replacement of 3,500 feet of 12-inch steel with PVC pipe along the Jamacha Road . To determine the most feasible alignment, LEE & RO employed the "Analytic Hierarchy Process (AHP) also called Pairwise Comparison Method (PCM). The AHP reduces complex criteria to a series of one-on-one criteria comparisons. One of the project challenges was to obtaining permit from the Caltrans for the encroachment along the Jamacha Road (SR54/S17). Construction began May 2009 and expected to be complete in early summer 2010.

[xxii] See Appendix B: Colorado Renewable Energy Standard Excerpt

[xxiii] Illustration of a Splainex MSW to energy system (http://www.splainex.com)

[xxiv] Rocky Mountain Pellet Company, Inc., P.O. Box 715, Walden, Co. 80480, Phone: 970-723-3760

[xxv] Geothermal Resources Council (http://www.geothermal.org)

[xxvi] Gypsum goes geothermal, Glenwood Springs Post Independent, March 25, 2011

[xxvii] Refer to Xcel's 2010 Renewable Energy Standard Compliance Plan, Public Service Company of Colorado, Volume 2, revised 1/27/2010; Table 7.1 and 7.2 show alternative scenarios for total system cost for Xcel both with and without a 20 percent renewable requirement for 2020. Available: [http://www.xcelenergy.com/staticfiles/xe/Regulatory/2010RES-Tables[1].pdf]

Boulder's Energy Future

- Localization Portfolio Standard -

Natural Gas

Local Power.

13 JULY 2011

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report covers the potential for the localization of resources displacing onsite natural gas combustion for Boulder's Energy Future. A separate report, "Boulder's Energy Future: Localization Portfolio Standard – Electricity" has been issued for electricity resources, although there is some overlap in both reports. The electricity report includes more detail on Local Power's research methodology, and under the 'Building Boulder's Energy Future' section and Appendix A, the authorities the city would require to deploy the resources in both portfolios and the 'energy as a service' business model.

The City of Boulder is responding to core issues affecting the city's energy supply – chiefly diminishing fossil fuel supplies, increasing prices, the environmental effects of fossil fuel based energy, and the opportunity to nurture an innovative energy industry – and leading a community effort to define Boulder's Energy Future. Central to this discussion is estimating the available local energy resources, how far and how fast Boulder could localize its power and heat supply by deploying these resources, and the general cost of this effort in relation to utility rates and customer bills.

This report outlines pathways for the City of Bolder to transform its energy supply along three overall themes, while maintaining competitive costs of service and grid reliability:

1. Democratizing energy decision making, so customers and the local community have more direct control and involvement in decisions about their energy.
2. Decentralizing energy generation and management, reducing reliance on external energy sources.
3. Decarbonizing the energy supply, by using local renewable and clean fuel sources as much as possible.

Substantial energy localization opportunities exist within Boulder, and within the Denver Boulder Metro Region. The local standard is defined by technologies that either provide renewable fuels, heat, and energy efficiency within these geographic boundaries, which may be deployed without raising customers' bills.

Key Energy Resource Opportunities

Key findings of the natural gas localization report include opportunities for:

- Energy efficiency and demand-side management, the largest and most cost-effective local resource, with the potential to save 12 percent or more of forecast natural gas demand by 2020.
- Customer- and community-owned distributed solar thermal systems.
- Regionally-sourced biomethane injected into natural gas pipelines. Biomethane is biologically-produced gas sourced from biomass waste feedstocks, which is cleaned and injected into natural gas pipelines.
- Biomass-fueled combined heat and power (CHP), using both non-recyclable municipal solid waste and regional biomass resources.

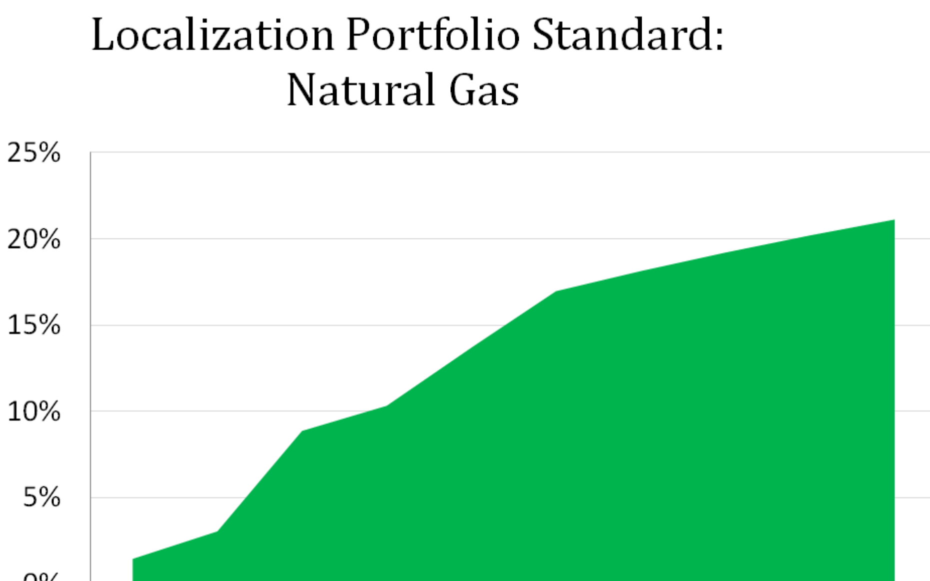
Not all of the available opportunities should necessarily be developed at the same time. Some are more expensive than others, and this will affect the timing that is optimal for deployment.

As prices for natural gas grow more expensive, more sources of renewable energy and efficiency become cost-effective. In addition, further investigation will be needed to discover in finer resolution the availability, cost and technical feasibility of the various local resource options.

The Localization Portfolio Standard & Additional Resources

The Localization Portfolio Standard (LPS) depicted below is an idea Local Power is developing for Boulder for the first time, and is conceptually similar to Colorado's Renewable Portfolio Standard (RPS). Qualifying projects are concentrated within the City of Boulder and County of Boulder, though biogas sourced from waste materials in the Denver-Boulder Metro Region is also permitted.

Boulder's Localization Portfolio Standard has been designed to meet or beat the incumbent energy economics. The City of Boulder can re-localize a substantial portion of their energy supply while customers receive bills that are the same or lower than what they would have been under Xcel Energy. By itself, this methodology is insufficient to account for Boulder's ability to localize its energy supply. The citizens of Boulder are environmentally-conscious and civically-minded, as evidenced by the far above-average solar photovoltaic installation rates in the city. The portfolios presented are thus the minimum level of achievable energy localization.



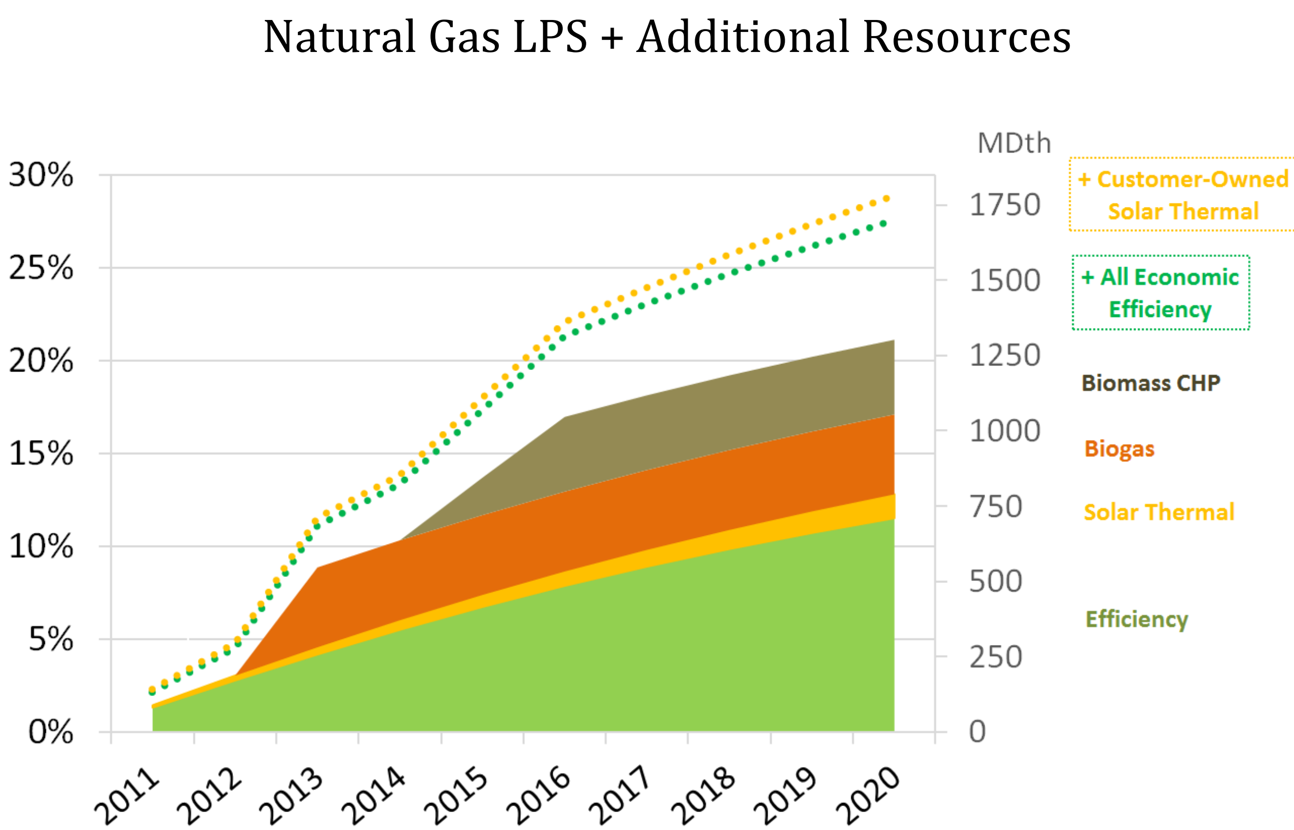
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Natural Gas LPS	1%	3%	9%	10%	14%	17%	18%	19%	20%	21%

The proposed LPS could be adopted as a matter of broad energy policy prior to and independent of any renegotiation with Xcel or voter initiative to authorize full municipalization.

The programs for energy efficiency and distributed renewable technologies described in these reports are designed to remove many of the barriers which typically constrain public participation in the construction of energy supplies. These programs 'level the playing field' between distributed energy resources and central power plants by providing long-term financing via municipal revenue bonds, investing heavily in ‘Smart Buildings’, allowing customer ownership directly and through community sharing programs, lowering transaction costs by aggregating customers, streamlining city permitting procedures, and identifying and mitigating various market and non-market barriers. As such, this graph below depicts a higher level of public participation in Boulder’s Energy Future than the lower-bound level presented for the Localization Portfolio Standard.

These blends are not presented to constrain the City of Boulder as it develops its local energy portfolio, as it is anticipated that the actual resource mix will vary from what is presented here. In addition, the charts depict resources *beyond the LPS*, including:

1. The energy efficiency resources which are economically cost-effective to deploy but are not included in the LPS are denoted by the dotted line. The energy efficiency included in the LPS was derived by adapting Xcel’s most recent potential study, and is comparable to current or pending statewide goals in Illinois, Massachusetts, Arizona, and New York. The higher level of savings may well be achievable within the program design advanced in the energy efficiency section, which should structurally solve several barriers known to hinder the adoption of energy efficiency technologies.
2. Solar thermal resources above the LPS target which are privately financed by homeowners, similar to the current photovoltaics market.



Energy Resources Framework

The potential of each renewable generation or demand technology in this report is characterized first within the "status quo" and then within a "localized energy utility" scenario, in which the utility is focused on maximizing local heat resources.

The cost natural gas in Boulder is currently relatively inexpensive compared to the cost of deploying local resources such as biomethane and solar hot water systems. This posed challenges in developing a cost-effective localized energy portfolio. Demand-side resources comprised of efficiency, conservation, and demand-response technologies and practices that cost less than procuring energy comprise a majority of the portfolio. Also, the in-city biomass plant proposed in the electricity LPS was included in this report as well, which anticipates that the waste heat is captured and distributed in a combined heat and power (CHP) application to adjacent customers.

The strategic business model to deploy biomethane and solar thermal proposed in this report takes advantage of the competitive wholesale purchase of natural gas to reduce the cost of fuel for certain customers, and uses the savings to offset the higher-cost renewable sources. The renewable sources would be blended into the service package, supplying a portion of the customer's energy use so that the cost of the renewable energy would be balanced out by the savings achieved through a gas commodity price reduction. Customers could elect which type of service they would like to receive, either biomethane or solar hot water, and could also 'opt up' to an even greener product for a premium.

Our findings indicate that this kind of offer is only beneficial for certain market segments under a status-quo scenario: multi-family residences with a master meter and commercial customers. Industrial and large commercial customers already largely benefit from discounted rates though direct purchases of natural gas from independent suppliers, and single family residential customers cannot legally be served by third-party providers. A localized energy utility could aggregate single family customers and procure discounted natural gas from a competitive supplier.

The cost of biomethane and solar thermal can be affected to a certain degree by the scale of development. Larger commercial solar hot water systems may provide lower cost hot water, and a very large-scale deployment in the city, where tens of thousands of solar collectors are used and customers are aggregated to issue design-build-operate-maintain performance contracts, could further reduce the cost. Similarly, large-scale purchases of biomethane, or the financing of a biomethane plant to serve Boulder, could reduce the cost by 20 to 30 percent. Most forecasts show that future natural gas prices will continue to increase, drawing closer to price-points where higher percentages of biomethane and solar thermal become more competitive.

A second facet of the strategic model is to deploy solar heating systems on groups of adjacent buildings and create a 'Heat Island', which is a kind of mini-district heating system focused on solar hot water that would be distributed between the buildings to the extent that this would be feasible and cost-effective. The benefits of scale, and the integration of customers with differing heating load requirements, might offer options for additional use of the resource beyond hot water. For example, heating air with solar energy could ordinarily be a rather expensive proposition. However, if the solar heat system produces a steady supply of hot water and then provides some portion of building heat this might be more cost-effective. A way to improve this model is to focus the solar building heat on customers that currently use electric power for heating, since electric power is significantly more expensive than natural gas when measured in terms of equivalent heat energy supplied.

A detailed mapping survey was conducted which identified 150 Heat Island sites composed 523 multifamily buildings, 32 industrial facilities, and 337 commercial customers. While site-specific load data was not available for these sites, they are estimated to account for approximately half of the solar thermal deployment under the LPS. The Heat Island strategy outlined in this report may serve as a component of a localized energy utility, or as a strong stand-alone program that provides an additional source of revenue and marketing for Boulder's continuing energy localization efforts.

BOULDER’S LOCAL ENERGY RESOURCES

Overview

The potential of each renewable generation or demand technology in this section is characterized first within the “status quo” and then within a “localized energy utility” scenario, in which the utility is focused on maximizing local heat resources.

In our research, the technical feasibility of status quo energy localization is defined primarily by the ability, under existing conditions (without municipalization or another change in state laws and regulations), to provide service from a renewable resource or demand technology. Economic feasibility of the localization of energy resources under a status quo scenario is defined by the ability of a technically feasible energy technology to provide service at a competitive rate with equivalent conventional supply. In heat, the price-points for this criterion are defined by natural gas prices.

Under a localized energy utility, technical feasibility is defined primarily by the ability of the technology to be deployed and provide energy locally. Economic feasibility of energy localization under this scenario is defined by the ability of a locally-deployed technology to satisfy two criteria:

1. Provide energy at a price-point that is competitive with Xcel's retail natural gas rate for customers receiving direct energy service from the technology.
2. Support the community's natural gas requirements as part of a broader portfolio of technologies deployed at a cost that is price-competitive with non-local energy supplies available.

There are many available energy sources in the area in and around the City of Boulder:

- Energy Efficiency and Conservation;
- Solar Thermal;
- Biomass Combined Heat and Power (CHP);
- Biomethane.

These resources should be developed as part of the localized energy portfolio according to the degree that opportunities arise and are cost-effective. Over time, resources that previously appeared to “cost too much” are likely to require a closer look as energy costs continue to increase over time. Timing of resource deployment is thus a crucial variable that should be used to advantage.

Demand-Side Management (DSM)

Demand-side management chiefly comprised of energy efficiency and conservation technologies and practices, represents the greatest cost-effective energy localization potential for displacing onsite natural gas combustion in the City of Boulder. Appendix B provides detailed tables of modeling results at the residential, commercial, industrial, and portfolio levels. The results achieve a 12 percent reduction in forecast demand by 2020. Boulder’s maximum cost-effective economic potential, according to Xcel’s most recent potential study, is 18% of forecast load. This figure cannot account for the emergence of new technologies and practices, and as such, understates the level of cost-effective efficiency potential over time.

The "Boulder's Energy Future: Localization Portfolio Standard – Electricity" report contains a number of relevant sections on DSM, including:

1. Boulder's current 'status-quo' demand-side programs;
2. Applicable codes and ordinances;
3. The methodology by which Xcel's most recent DSM market potential study was adapted to Boulder's baseline;
4. A 'Smart Building' program design combining on-bill financing, onsite audits, and Smart Grid technologies and software analytics;
5. Modeling results of this portfolio for the electric side.
6. The importance of the distinction between customers' rates and their overall bills, in relation to DSM programs.

Program Design and Market Penetration

As explained in detail in the electricity report, LPI modeled a 'strawman' program which:

1. Makes every building in Boulder into a 'Smart Building' with smart meters, end-use monitoring equipment, and analytical software paid for annually as SaaS (software-as-a-service);
2. Finances all efficiency measures using capital borrowed at 8% and repaid over 12 years;
3. Recoups investments using on-bill financing so that the customer does not incur any upfront cost;
4. Provides every home with an energy audit and every commercial or industrial business with a retrocommissioning audit.

This is an inherently conservative approach, since in practice not all buildings will warrant this level of investment. Furthermore, our results included the costs of 'Smart Buildings' but did not include the savings which could be expected to accrue beyond those captured in the Xcel potential study. An example given in the electricity report bears repeating here: in Xcel's study, measures such as boiler tune-ups are modeled with a two year measure life, after which the savings degrade. In a Smart Building, energy analytic software would recognize the patterns associated with a needed boiler tune-up, and notify maintenance personnel promptly.

This approach fundamentally enhances the market for demand-side resources and lays the groundwork for continuous efficiency improvements beyond those anticipated in typical utility programs. Instead of relying on marketing and word-of-mouth, 'Smart Building' energy monitoring and analytics would be essentially sales channels for the placement of efficient technologies and practices where they are most cost-effective.

The core idea behind the approach taken was to prove that, using conservative assumptions, the efficiency portfolio would still be cost-effective even given this level of investment and innovative design. When Boulder gains access to customer account records and conducts a more detailed baseline analysis, a more specific program design should be able to more accurately capture the costs and savings anticipated from this approach. The program design would remove several significant barriers to the deployment of demand-side technologies, and the portfolio should achieve greater savings at a lesser cost than what is reflected in our results.

Barriers to Adoption and Program Design

It is well-known that energy efficiency is an untapped energy resource offering solid returns on investment, but that deploying energy efficiency has historically been difficult due to a variety of market and nonmarket barriers. The two key barriers that are overcome by this innovative program design are:

1. Access to capital to deploy efficiency measures, or the opportunity cost of capital, in which a firm has the necessary funds to deploy efficiency but chooses instead to invest in their core business. Even if the efficiency measures would net a higher rate of return on invested funds, many businesses invest strategically to protect or expand their market and rank investment opportunities accordingly.
2. The lack of certainty surrounding many energy efficiency savings. The ability to continuously monitor, verify, and enhance building and appliance performance also overcomes the split-incentive barrier – for example, a tenant will be more amenable to paying for ‘negawatts’ if usage and performance is continuously monitored, and the savings are proven in a transparent fashion, allowing the landlord and tenant to negotiate sharing the savings.

Overcoming these barriers will allow innovative energy companies and investors to push the envelope of investment-grade energy efficiency deployments in Smart Buildings. In this way, Boulder could leverage their funds to unlock far more efficiency than if rebates and audits were offered for free – by changing the market in a structural and meaningful fashion.

Baseline Issues

For the electricity baseline, LPI was provided with an analysis by Nexant which disaggregated electricity usage into customer classes such as ‘large single family households’, ‘hospitals’, and so on. No such study was commissioned to examine the onsite natural gas combustion baseline. LPI estimated the types of customers which receive natural gas service using the data provided by Xcel for their annual franchise reports to the City of Boulder, as well as databases provided the City of Boulder and the County of Boulder’s Tax Assessor office. However, without access to the actual customer accounts, both the electricity and natural gas baselines are an approximation. This is a source of inaccuracy in the results of this study, which nonetheless should be sufficiently accurate at the portfolio level to inform the annual LPS targets. If the City of Boulder gains access to these customer account records, a thorough baseline inventory should be conducted for the purposes of demand-side management program targeting. In addition, data provided by third-party providers may contain more accurate square footage estimates and industry classification codes than those maintained by the City of Boulder and Boulder County, and also offer broad credit classifications by business which would be useful for targeted deployments using on-bill financing, and should be examined.

Natural Gas Service

Approximately three-quarters of buildings in Boulder are connected to natural gas pipelines. Natural gas supplies 55% of the energy overall (heat and power combined) in Boulder's residential and commercial sectors, much of it for heating.[ii]

The wholesale natural gas market in Colorado provides a context for Boulder to implement a heat energy localization program. Companies like Tiger, Spark Energy and Seminole Energy provide alternative supplies of natural gas to larger commercial and industrial customers in Boulder. Using Xcel's natural gas pipelines, these competitors claim to offer significant discounts. The range of discounts available varies based on the size of the customer. Competition for larger customers yield discounts around 20% annually, while the customer acquisition, transactional costs, and corresponding decrease in competitive activity to acquire medium-sized customers depress discounts into the range of 7% to 8% annually. If Boulder were to aggregate smaller customers to procure large volumes of natural gas, the discount would likely average 15% annually.

Xcel provides special delivery rates for customers that only use its gas lines but purchase the gas commodity from an alternative supplier; these customers choose the Large or Small Transport rate. Xcel is attempting to limit the choice so that customers electing to use one of Xcel's competitors have to buy at the more expensive Small Transport rate. However, Xcel claims it wants only to be a distributor of natural gas in the future, in which case all customers would obtain their natural gas from competitive suppliers which would be delivered using Xcel's pipelines.

In 2009, tariff changes opened the competitive market to smaller commercial and multi-family residential customers with master meters with significant natural gas usage. It should be noted that under current regulations, a new building must be served by Xcel for one year before an independent supplier may offer service to that customer.

This competitive market provides the potential to offer certain customers discounts for natural gas, and offer a blended product that includes a percentage of local renewable heat at costs that are competitive with Xcel's natural gas service. The local renewable heat could be either solar thermal or biomethane. The scope and economic viability of such a program would be different under the status-quo and a localized energy utility, as the latter could also aggregate the load of single-family residential customers, which are not eligible to contract individually with a competitive provider under current law.

Boulder would have the opportunity to expand access to these discounts by targeting and aggregating customers as a part of their local energy program. Outside of service for large industrial customers, there is a lack of robust competition for the retail natural gas market; this is typical for both natural gas and power markets following restructuring in the 1990s that opened up the possibility for customers to purchase these energy commodities from alternative suppliers to the previous utility monopoly. With no marketing funds to promote competitive products, vendors depend on word of mouth. Another challenge for expanding competition is that the process for customers to change suppliers is complicated. Companies market their ability to lock in a fixed price for a commercial customer's natural gas bill, allowing a business manager to forecast and budget expenses for an extended period of time. One natural gas supply company offers a free estimate, with no monthly service charge and no minimum monthly purchase requirement.

The business model of natural gas marketers is focused on buying in volatile natural gas markets and beating the price offered by the utility. This natural gas program is recommended not as a means of selling natural gas at a discount, but as a retail channel for the deployment of local energy resources.

Challenges are commonplace for natural gas and power marketers offering only conventional service based on discounts. Initial findings indicate that a City of Boulder-sponsored program could provide service by targeting and aggregating customers, obtaining discounts from independent natural gas suppliers, sourcing biomethane and installing solar hot water and thermal efficiency measures. By focusing on situations where these technologies will work well, Boulder can build a significant program around solar heat, biomethane, and energy efficiency that builds up a localization of energy in the energy sector that is currently served by natural gas.

Solar Thermal

Solar thermal energy is captured by collectors and utilized in a variety of ways. The application proposed for Boulder is primarily focused on heating water that is currently heated by natural gas. A secondary application might be found in displacing a small amount of electric power used to heat water, and to displace a small amount of space heating that is supplied by electric power in commercial buildings. These electric applications should be considered because the energy cost of electricity is much higher than natural gas, and this market would provide an extra measure for displacing electricity with a locally available zero carbon resource. However, the displacement of electricity is not considered as part of the natural gas LPS due to the fact that it is not replacing retail consumption of natural gas. The energy efficiency results for the electricity LPS contained savings from solar thermal systems on commercial buildings, as Xcel's most recent demand-side management potential study found solar thermal cost-effective in certain commercial building types.

System Design Considerations

Collectors are placed at a tilted angle, ideally facing toward the south, in order to maximize the amount of energy received from sunlight. It is crucial that shading of the collectors be avoided to the greatest feasible degree, especially during the middle hours of the day. For this reason parallel rows of collectors must have adequate spacing to allow sun to fall on each row. On a flat roof, about 50 percent of the area will be spaces between the rows. Obstructions such as air conditioners or trees must be avoided as well. For these reasons the actual coverage of rooftops with solar collectors will generally be significantly less than half the total roof area for flat rooftops. Furthermore, rooftops must be suitable for supporting collectors, for example in having sufficient structural strength and not having a complex surface, both of which would increase the complexity and cost of installing solar collection systems.

Financial Assumptions

In order to take advantage of economies of scale and the ability to obtain discounts on natural gas purchases from competitive suppliers under the status-quo scenario, the proposed market target would be larger commercial applications and multi-family residences with at least 4 units. Aggregation of buildings and customers would support a project size with from dozens to hundreds of collectors. This would be put out to bid in competitive solicitations to drive down installed costs. A bulk purchase program for tens of thousands of collectors might allow a further discount on equipment. Interviews with representatives from the industry suggest a cost range of between $65 and $110 per square foot of collector for the full installed system. A well-designed program should screen and target sites, provide sufficient volume, and exercise market power to guide prices toward the lower portion of this price range.

Several other factors affect the cost of solar hot water. Solar collection systems have significant efficiency losses and extra pipe adds further cost while creating further losses of heat.

Solar hot water is relatively expensive when measured against the current cost of using natural gas to heat water. With retail natural gas rates in Xcel's territory ranging between $4.50 and $6.00 per million BTU, it is impossible for solar hot water to compete directly. LPI estimates that only low market penetrations of solar hot water are economically feasible in the current market. The market can be expanded by utilizing the natural gas discounts for commercial and multi-family residential customers. A discount of 15 percent would allow a customer to obtain between 30% and 40% their hot water load from solar thermal. The economic penetration would increase over the next decade if retail natural gas prices reach $8 or higher.

Subsidies

A limited amount of state and local subsidies are available, but the most significant subsidies by far are the federal 30% investment tax credit and five year accelerated depreciation. Public agencies cannot take the tax credits since they do not pay taxes. Use of government bonds or other low interest loan sources can partially offset the loss of the tax credits.

Program Options

Under the status-quo, the amount of solar hot water that can be developed will be limited compared to the total volume of natural gas sales. However, the program could still develop solar hot water projects for hundreds of customers, as described in more detail under the "District Heat Island Program" below. A localized energy utility is likely to be able to deploy greater numbers of solar hot water installations due to a variety of factors, including: the ability to aggregate and obtain discounts for single-family customers not currently permitted to be served by competitive gas suppliers, access to low cost financing, ability to adjust product blends between natural gas and solar hot water, and the ability to more easily facilitate potentially complex transactions in Heat Islands that would involve multiple customers.

District Heat Island Program

"Heat Islands" are defined here as micro-district heating systems providing service to multiple customers in close proximity to one another. The design for these Heat Islands is focused here on using solar thermal collectors to supply hot water, integrated with energy efficiency retrofits, with the primary heat source supplied by natural gas. By aggregating small and medium sized customers, Boulder would be able to:

1. Secure discounts on natural gas service from competitive suppliers for eligible customers, and use the discount to offset the additional cost of solar thermal installations.
2. Bundle the sites into large design-build-operate-maintain performance contracts, to be put out for competitive bid to lower overall costs.

The heat services would be augmented by the City's ability to deploy 'Smart Building' retrofits, in order to capture savings from heating system automation technologies and practices, such as smart thermostats optimized against weather patterns in real time.

The energy elements of a Heat Island include:

- Natural gas providing the primary thermal energy supply;
- Solar thermal collectors providing a portion of hot water needs currently provided by natural gas;
- Energy efficiency and thermal appliance automation technologies in 'Smart Buildings,' described in the demand-side management section;
- The potential development of other alternative energy sources, such as combined heat and power, geothermal heat, and biomethane.

Product design factors that would affect the cost of providing these heat services were examined. This research included:

- Interviewing solar thermal firms;
- Establishing general criteria for site selection;
- Identifying candidate locations;
- Quantifying the potential customer base;
- Estimating the capital cost of solar thermal projects;
- Determining the cost and applicability of shared pipe networks in dense neighborhoods;
- Evaluating the potential for smart thermostats (programmable controllable thermostats);
- Modeling the cost of service for heat sold for representative projects.

The Heat Islands focus on the potential for development of solar hot water on the rooftops of buildings that appear to have sufficient size for deploying enough solar collectors that there would be some benefit from economy of scale. Customers should be targeted that have significant needs for hot water.

Density of buildings and mixed commercial and residential development are also important criteria that make the Heat Island concept feasible for physical deployment. Heat Islands would be located in dense urban areas where there are commercial buildings with larger rooftops;

these would preferably be located in proximity to dense multi-family residential neighborhoods. The targeting of mixed-use high density sites also has significance from the standpoint of marketing, where neighborhood interest and participation would need to be established.

Metering Solar Hot Water

Deploying Heat Islands requires the ability to accurately measure hot water flows with reliable equipment. Recent standards and programs have advanced the market for this equipment, and there are several suppliers which provide accurate metering and web-based reporting equipment for solar hot water applications. The California Solar Initiative has published programmatic standards based on the "International Recommendation for Heat Meters" (OIML R75-1 Edition 2002),[vi] and maintains a list of approved metering and reporting providers, available online.[vii]

Heat Island Site Survey

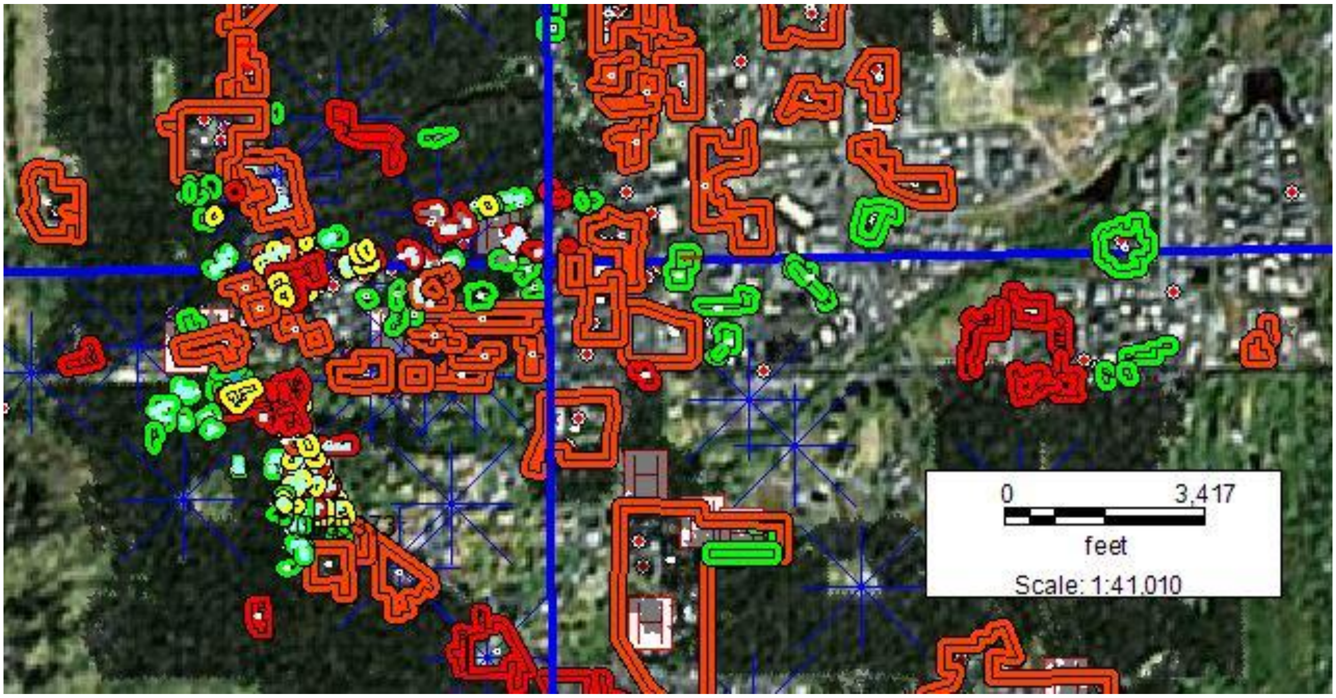
Local Power's research has identified 150 candidate areas totaling approximately 900 buildings in close proximity to one another that that may be further investigated for potential to be developed as Heat Islands in Boulder. While site-specific load data was not available for these sites, they are estimated to account for approximately half of the solar thermal deployment under the LPS.

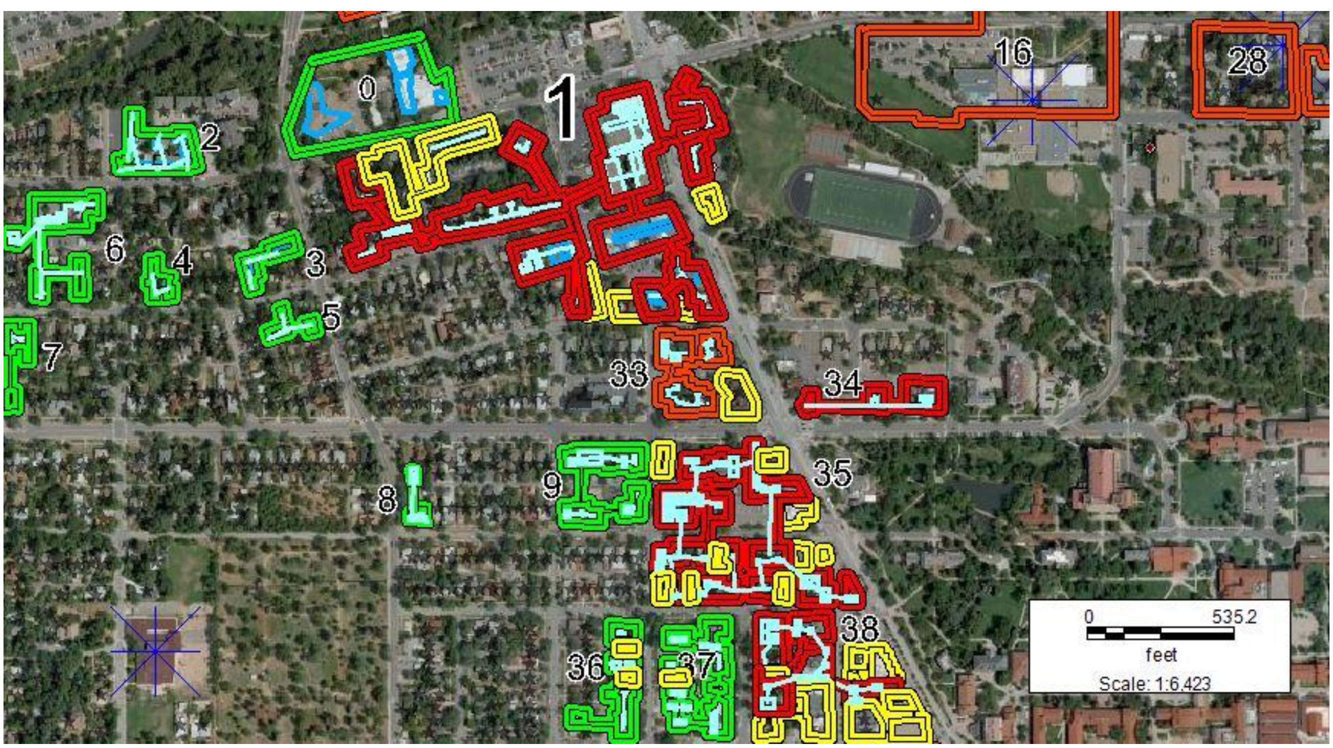
The survey identified 523 multifamily buildings, 32 industrial facilities, and 337 commercial customers as strong Heat Island candidates. The commercial customers are disaggregated into building types in the table below:

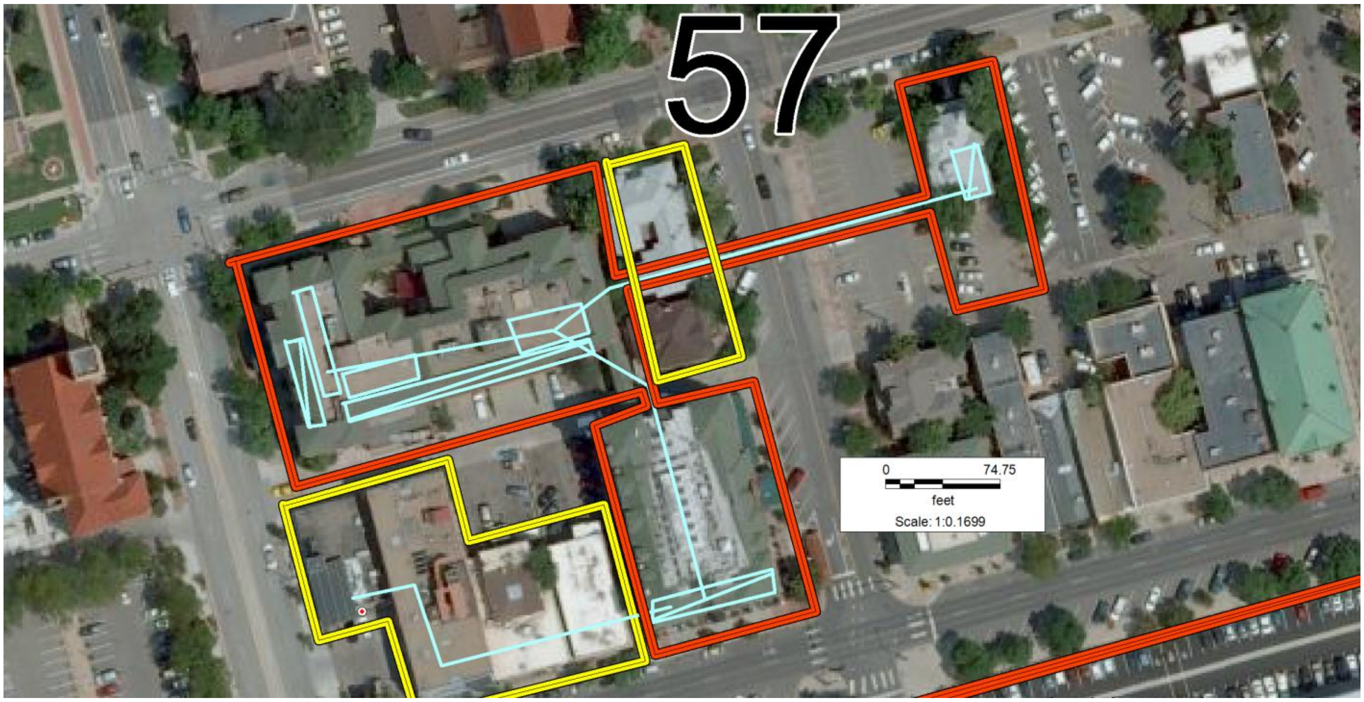
	Heat Island Analysis - Commerical		
Building Type	**Survey**	**Boulder**	**% Boulder**
Grocery	4	127	3%
Lodging	17	74	23%
Office	90	2,871	3%
Other	45	679	7%
Restaurant	63	388	16%
Retail	69	1,995	3%
School	16	266	6%
Warehouse	33	241	14%
Total Commercial	337	6,641	5%

The survey concentrated on combinations of adjacent complementary and optimal load types based on building usage, rooftops and adjacency. Several measurements were taken for each customer, including the type of roof, the square footage available for mounting solar thermal panels and, for buildings which would not be able to host panels because of shading or other issues, the length of pipe required to connect that building to the Heat Island distribution system.

The four screenshots below depict the Heat Island portfolio and sites, in decreasing scale:



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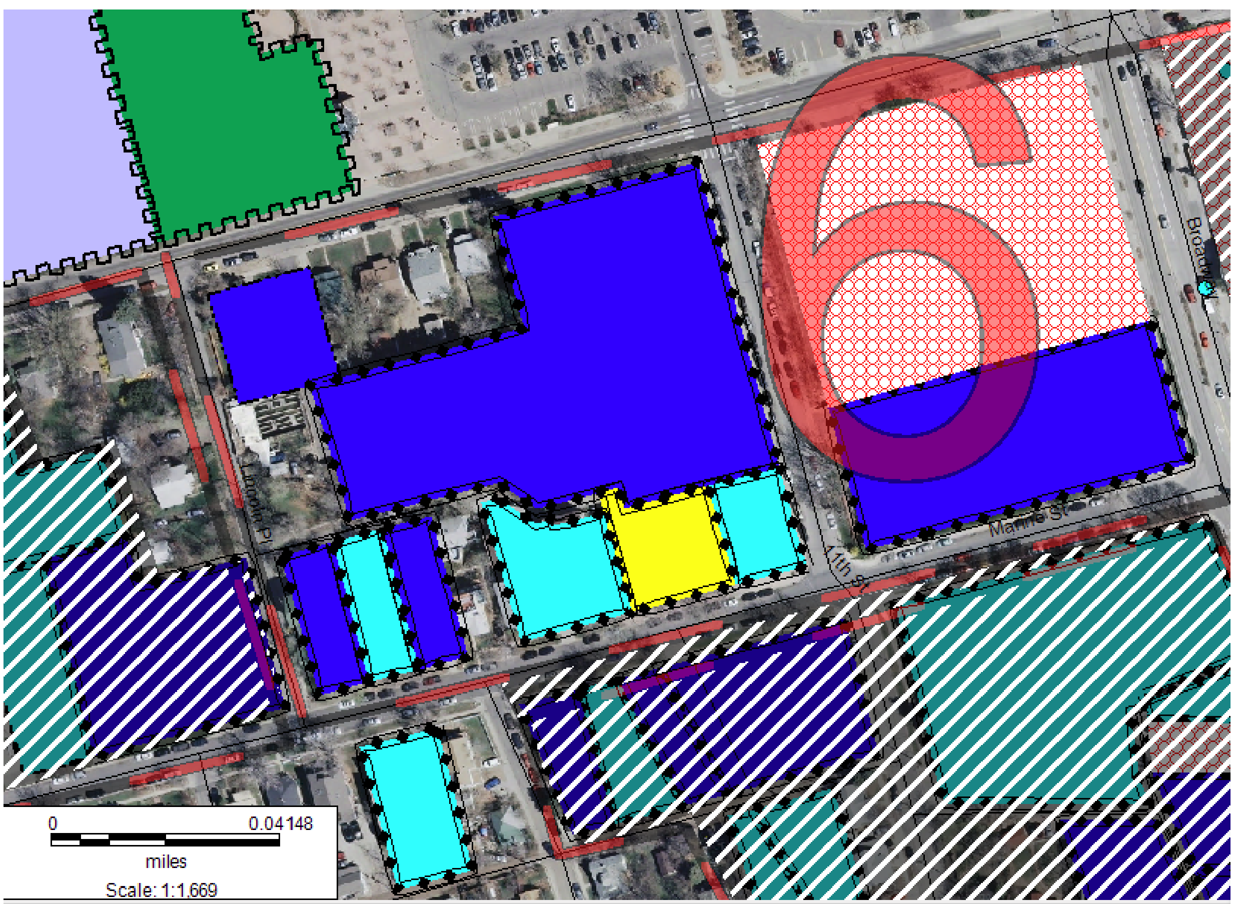
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miles
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Boulder's Heat Island Program

Preparing the districts for commercial development requires collecting building- and business-specific utility bills, conducting a screening analysis to define the economical balance between load served and rooftop capacity based on the mapping, and conducting customer outreach, acquisition, and preliminary site surveys. One or more solicitation documents to design and then develop the portfolio under design-build-operate-maintain performance contracts could be prepared over a six month period, with negotiations requiring approximately another three months. Installations on all sites may take between five and seven years to complete.

As this program is likely able to be implemented without regulatory or other barriers, it may serve as a component of a localized energy utility, or as a strong stand-alone program that provides an additional source of revenue and marketing for Boulder's continuing energy localization efforts.

Under the status-quo, Boulder may be able to contract with a supplier to provide natural gas to the jurisdiction on an "opt-in" revenue-sharing basis, then phase in customers as heat sources and district heating infrastructure was installed. This type of arrangement may allow for revenue bonds to be used by the city to deploy the Heat Islands. The city could also seek private financing as an alternative, which would be eligible for the tax incentives detailed under the preceding section on solar thermal.

A localized energy utility would benefit from revenue bond financing, lowering transactional costs, deploying greater targeted demand-side measures, and could further offer service to single-family homes by aggregating these customers and receiving discounts on fuel purchases from competitive suppliers. It is worth noting that this would roughly double the maximum achievable market for solar thermal in Boulder, though actual implementation would depend upon neighborhood adoption and the willingness of neighbors to share solar thermal systems in areas where shade trees would otherwise preclude participation.

Streamlining Heat Island Permitting

In the City's ongoing review of its permitting procedures, staff should consider further streamlining the process for solar thermal projects and Heat Island programs; the potential to reduce delays or permit fees should be evaluated. This would help to reduce the cost of solar thermal energy.

Biomethane

Biomethane is biologically-produced gas sourced from waste streams, which can be cleaned and injected into natural gas pipelines. There are a limited number of biomethane suppliers in the Denver Boulder Metro Region. While the overall volume of biomethane produced regionally is approximately four times the level of demand accounted for in the LPS biomethane target, it remains uncertain whether Boulder would be able to secure adequate supplies from the market currently. However, the estimated waste streams in the region which could be captured to supply an additional volume of biomethane is sufficient to serve the LPS target approximately seven times over. If sufficient supplies cannot be procured from the market, Boulder could develop a biomethane plant, sized to serve its LPS target.

It is possible to site a new biomethane plant of any size relatively easily, as long as it is near to a natural gas pipeline. The price of biomethane ranges from approximately $8 to $11 per MMBTU, with the lower range associated with using revenue bond financing to develop a new plant. Biomethane at $8 per MMBTU is approximately double the price of natural gas currently.

Under a status-quo scenario, Boulder's ability to procure biomethane in any volume would be compromised. Target sectors would be in practice limited to small and medium commercial customers and multi-family buildings with master meters. As an opt-in program, the acquisition of many small- and medium-sized customers would pose a logistical barrier and added cost. Furthermore, the ability to procure biomethane on the market or to finance the construction of a new plant would be dependent upon having a sufficient volume of demand, which poses a 'chicken and egg' dilemma for an opt-in program.

The LPS assumes that Boulder aggregates all eligible customers (i.e. those not already served by competitive suppliers) and purchases biomethane at the higher $11 per MMBTU price-point, using the discount anticipated from competitive natural gas procurement to offset the additional cost in the blend supplied to customers. Customers could also be offered the option of using a higher mixture of biomethane for a price premium. Voter approval of a municipal revenue bond authority to help finance a biomethane collection, digester and pipeline-injection facility would reduce biomethane costs and expand the potential market biomethane in Boulder.

Biomass Combined Heat and Power

A detailed section on biomass is included in the electricity LPS report.

Boulder has sufficient non-recyclable waste streams which could be captured to supply approximately 5 MW of power. Developing this resource would not be feasible under a status-quo scenario. If developed and used in a combined heat and power configuration, the waste heat in excess of what is consumed through generating electricity may be distributed and sold to adjacent facilities. The heat supply would be equivalent to approximately 200 therms per hour. The plant would have to be sited next to one or more large industrial facilities to be able to distribute this volume of thermal energy.

Direct Use Geothermal

An expanded section on geothermal resources is included in the electricity LPS report.

Boulder is located in a region of elevated geothermal temperatures, relatively near the surface. Although there are few hydro-thermal resources, i.e., with natural water or steam available in the ground to transfer the heat, the local heat resource could eventually be tapped using Enhanced Geothermal Systems (EGS) technology. EGS involves drilling wells, fracturing the deep rock, and injecting a heat transfer fluid, such as water or liquefied CO_2. These systems are undergoing development and may be feasible in the relatively near future. Geothermally-heated water should be investigated, if available, either for district heating -which is likely to be the most efficient use - or for low temperature distributed geothermal electricity generation.

Combined Heat and Power

Combined heat and power (CHP), also known as cogeneration, burns natural gas to produce electricity in a heat engine such as a turbine, and captures the waste heat for onsite thermal applications or for local distribution. Industrial applications in particular are well suited to deploy CHP, as the waste heat may be used to offset process heating and boiler loads. By recycling the waste heat, CHP achieves approximately 40% greater use of the energy embodied in the natural gas, reducing the total amount of fossil fuel consumed. This portion of added efficiency would be eligible for inclusion under an LPS. However, the cost of electricity and natural gas in Colorado is currently too low to permit cost-effective deployment of CHP.

Under a localized energy utility, long-term financing and the integration of power output into wholesale markets could facilitate CHP deployment. Fuel prices, technology trends, and opportunities to integrate CHP into industrial facilities as equipment is replaced should be monitored.

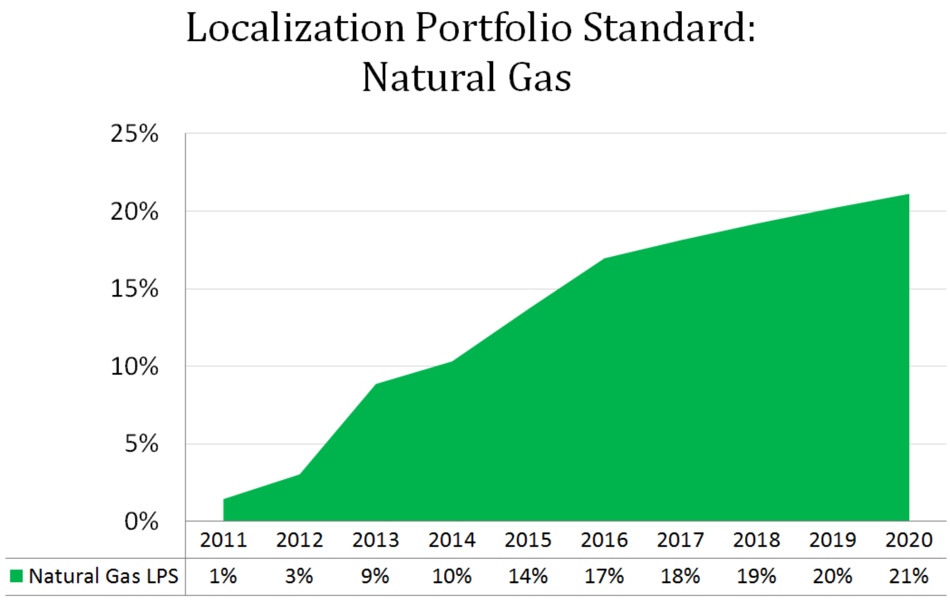
BUILDING BOULDER'S ENERGY FUTURE

The prior section of this report identifies a range of technologies which could re-localize a significant portion of their energy supply. The scale of implementation possible, both legally and financially, is predicated upon several authorizations that the City of Boulder may adopt.

Refer to "Boulder's Energy Future: Localization Portfolio Standard – Electricity" for this section of the report.

THE LOCALIZATION PORTFOLIO STANDARD

The Localization Portfolio Standard (LPS) is an idea Local Power is developing for Boulder for the first time, and is conceptually similar to Colorado's Renewable Portfolio Standard (RPS). Qualifying projects are concentrated within the City of Boulder and County of Boulder, but biogas sourced from waste materials in the Denver-Boulder Metro Region is also permitted.



One important dimension of the Local Portfolio Standard is in regards to when resources should be developed. Certain measures, such as efficiency improvements, the retrofitting of Boulder's building stock to create Smart Buildings, building rooftop solar thermal, and sourcing biogas from competitive suppliers can be implemented almost immediately. Others will require early action for planning, but will take time to develop, such as the construction of a 5 MW biomass plant, appropriately sited to sell the waste heat to neighboring customers in a combined heat and power application, or the construction of a biomethane plant if Boulder is unable to procure sufficient quantities of biomethane from competitive suppliers.

Fuel and technology price trends, emerging technologies and practices, and policy developments should be monitored, as they will affect the deployment timeline of LPS technologies. The deployment of technologies that appear too expensive in 2011 may become feasible by 2015, for example.

The percentage generated and load eliminated per year in the proceeding table is put forward as a general schedule for development. The proposed LPS could be adopted as a matter of broad energy policy prior to and independent of any renegotiation with Xcel or voter initiative to authorize full municipalization.

Year:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Forecast Load (1,000 Dth):	6,142	6,148	6,155	6,161	6,167	6,174	6,180	6,187	6,193	6,200
Local Energy as Share of Forecast Local Load										
Efficiency	1%	3%	4%	6%	7%	8%	9%	10%	11%	12%
Solar Thermal	0.1%	0.3%	0.4%	0.5%	0.6%	0.8%	0.9%	1.0%	1.2%	1.3%
Biomass CHP	0.0%	0.0%	0.0%	0.0%	2.0%	4.0%	4.0%	4.0%	4.0%	4.0%
Biogas	0.0%	0.0%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
Natural Gas LPS	**1%**	**3%**	**9%**	**10%**	**14%**	**17%**	**18%**	**19%**	**20%**	**21%**

APPENDIX A: Demand Side Management Potential - Natural Gas

All Sectors: 100% Financed	Boulder Localization Portfolio Standard - Natural Gas: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - Therms	807,183	1,710,043	2,572,559	3,393,267	4,156,012	4,862,329	5,507,726	6,098,628	6,640,886	7,139,543
New Net Energy Savings - Therms	807,183	967,435	939,910	895,901	834,417	773,070	707,242	647,481	594,057	546,181
Measure Decay - Therms	0	-64,575	-77,395	-75,193	-71,672	-66,753	-61,846	-56,579	-51,799	-47,525
New Savings as a Percent of 2010 Load	1.3%	2.8%	4.2%	5.5%	6.8%	7.9%	9.0%	9.9%	10.8%	11.6%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$431,413	$556,955	$582,221	$599,885	$608,462	$613,734	$613,562	$612,251	$610,299	$606,117
Marketing - Utility	$61,620	$72,243	$71,093	$70,075	$68,978	$68,251	$67,400	$66,667	$66,026	$65,448
Measure Costs - Private Sector	$3,014,164	$3,601,129	$3,495,301	$3,361,789	$3,179,177	$2,993,057	$2,785,823	$2,595,891	$2,424,163	$2,267,797
Capitalization Cost (8%, 12 year term) - Split	$1,429,886	$1,708,336	$1,658,133	$1,594,796	$1,508,167	$1,419,874	$1,321,564	$1,231,462	$1,149,996	$1,075,818
Premise Level Monitoring Equipment - Utility	(All costs included in LPS - Electricity calculations.)									
SaaS - Private Sector										
Total	$4,937,084	$5,938,664	$5,806,748	$5,626,545	$5,364,784	$5,094,916	$4,788,349	$4,506,272	$4,250,484	$4,015,179
Total - Utility	$493,034	$629,198	$653,315	$669,960	$677,440	$681,986	$680,962	$678,918	$676,324	$671,565
Total - Private Sector	$4,444,050	$5,309,466	$5,153,434	$4,956,585	$4,687,344	$4,412,931	$4,107,387	$3,827,354	$3,574,159	$3,343,614
PV Net Avoided Cost Benefits	$7,485,499	$8,020,625	$7,302,832	$6,637,062	$5,897,924	$5,233,350	$4,588,373	$4,036,595	$3,564,004	$3,157,960
PV Annual Marketing and Admin Costs	$493,034	$554,318	$532,892	$513,887	$488,522	$463,053	$435,110	$408,698	$383,645	$358,992
PV Measure Costs	$3,204,957	$3,350,107	$3,027,836	$2,739,843	$2,431,893	$2,150,590	$1,877,648	$1,642,073	$1,438,403	$1,261,799
TRC	2.02	2.05	2.05	2.04	2.02	2.00	1.98	1.97	1.96	1.95
Naturally Occurring - Therms	124,415	239,944	346,920	445,584	536,265	619,410	695,559	765,265	829,123	887,784
Cost per First Year Therm	$ 6.12	$ 6.14	$ 6.18	$ 6.28	$ 6.43	$ 6.59	$ 6.77	$ 6.96	$ 7.16	$ 7.35
Cumulative Retail Savings - Real (Transport rates approximated)	$ 595,585	$ 1,886,542	$ 3,868,774	$ 6,537,101	$ 9,872,153	$ 13,854,223	$ 18,457,539	$ 23,659,564	$ 29,440,736	$ 35,783,854

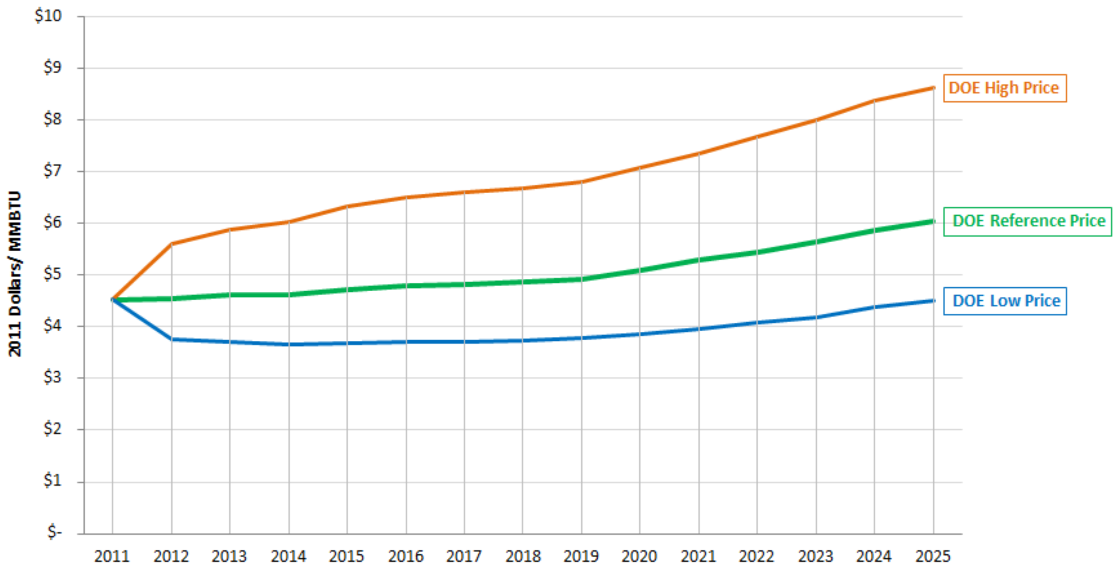
Residential: 100% Financed	Boulder Localization Portfolio Standard - Natural Gas: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - Therms	458,365	960,925	1,425,071	1,860,129	2,259,410	2,629,475	2,967,507	3,279,208	3,568,461	3,837,121
New Net Energy Savings - Therms	458,365	539,228	507,285	475,641	437,332	405,051	370,436	341,335	316,560	293,985
Measure Decay - Therms		-36,669	-43,138	-40,583	-38,051	-34,987	-32,404	-29,635	-27,307	-25,325
New Savings as a Percent of 2010 Load	2.1%	1.6%	2.3%	3.0%	3.7%	4.3%	4.8%	5.3%	5.8%	6.2%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$221,390	$276,669	$278,427	$279,096	$275,678	$272,550	$266,399	$260,665	$255,232	$247,892
Marketing - Utility	$24,709	$29,615	$28,494	$27,492	$26,401	$25,673	$24,809	$24,058	$23,386	$22,767
Measure Costs - Private Sector	$2,047,284	$2,377,676	$2,237,375	$2,111,845	$1,967,321	$1,838,162	$1,697,502	$1,576,824	$1,472,441	$1,377,422
Capitalization Cost (8%, 12 year term) - Split	$971,209	$1,127,943	$1,061,386	$1,001,836	$933,276	$872,004	$805,276	$748,028	$698,510	$653,434
Premise Level Monitoring Equipment - Utility	(All costs included in LPS - Electricity calculations.)									
SaaS - Private Sector										
Total	$3,264,593	$3,811,903	$3,605,682	$3,420,269	$3,202,677	$3,008,388	$2,793,986	$2,609,576	$2,449,569	$2,301,515
Total - Utility	$246,099	$306,284	$306,920	$306,588	$302,080	$298,222	$291,208	$284,723	$278,618	$270,659
Total - Private Sector	$3,018,493	$3,505,619	$3,298,762	$3,113,681	$2,900,597	$2,710,165	$2,502,778	$2,324,853	$2,170,951	$2,030,856
PV Net Avoided Cost Benefits	$4,395,468	$4,604,450	$4,049,507	$3,619,652	$3,171,061	$2,810,795	$2,458,972	$2,174,607	$1,938,034	$1,731,731
PV Annual Marketing and Admin Costs	$246,099	$268,973	$249,327	$234,602	$217,404	$202,375	$185,980	$171,462	$158,194	$144,820
PV Measure Costs	$2,156,630	$2,241,592	$1,957,911	$1,738,775	$1,519,277	$1,334,983	$1,157,337	$1,010,983	$887,656	$780,279
TRC	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.84	1.85	1.87
Naturally Occurring - Therms	12,076	22,808	32,393	40,989	48,726	55,725	62,088	67,902	73,241	78,170
Cost per First Year Therm	$ 7.12	$ 7.07	$ 7.11	$ 7.19	$ 7.32	$ 7.43	$ 7.54	$ 7.65	$ 7.74	$ 7.83
Cumulative Retail Savings - Real	$ 363,929	$ 1,142,071	$ 2,319,060	$ 3,885,972	$ 5,827,135	$ 8,131,237	$ 10,783,338	$ 13,772,387	$ 17,089,884	$ 20,728,204

Commercial: 100% Financed	Boulder Localization Portfolio Standard - Natural Gas: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - Therms	207,581	482,450	766,115	1,050,420	1,326,420	1,588,330	1,833,045	2,059,599	2,268,511	2,461,212
New Net Energy Savings - Therms	207,581	291,475	306,984	308,864	300,710	285,967	267,592	247,961	228,749	211,001
Measure Decay - Therms		-16,606	-23,318	-24,559	-24,709	-24,057	-22,877	-21,407	-19,837	-18,300
New Savings as a Percent of 2010 Load	1.1%	2.5%	4.0%	5.4%	6.9%	8.2%	9.5%	10.7%	11.7%	12.7%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$156,626	$228,486	$254,742	$275,040	$290,467	$302,153	$311,119	$318,167	$323,952	$329,016
Marketing - Utility	$23,042	$28,753	$28,721	$28,703	$28,694	$28,693	$28,700	$28,710	$28,723	$28,744
Measure Costs - Private Sector	$677,315	$945,479	$999,838	$1,015,756	$1,002,494	$969,314	$924,382	$874,167	$823,594	$776,170
Capitalization Cost (8%, 12 year term) - Split	$321,311	$448,525	$474,312	$481,864	$475,572	$459,832	$438,516	$414,695	$390,704	$368,207
Premise Level Monitoring Equipment - Utility	(All costs included in LPS - Electricity calculations.)									
SaaS - Private Sector										
Total	$1,178,294	$1,651,243	$1,757,614	$1,801,362	$1,797,227	$1,759,992	$1,702,717	$1,635,740	$1,566,973	$1,502,137
Total - Utility	$179,668	$257,239	$283,464	$303,742	$319,160	$330,846	$339,819	$346,877	$352,675	$357,760
Total - Private Sector	$998,626	$1,394,004	$1,474,151	$1,497,620	$1,478,066	$1,429,145	$1,362,898	$1,288,863	$1,214,298	$1,144,377
PV Net Avoided Cost Benefits	$1,871,086	$2,375,920	$2,342,449	$2,245,907	$2,088,122	$1,901,001	$1,706,581	$1,519,705	$1,349,433	$1,200,303
PV Annual Marketing and Admin Costs	$179,668	$228,576	$232,556	$233,901	$230,914	$225,067	$217,497	$209,003	$200,141	$191,302
PV Measure Costs	$708,784	$823,404	$819,839	$786,947	$732,107	$664,753	$594,664	$526,356	$463,490	$408,109
TRC	2.11	2.26	2.23	2.20	2.17	2.14	2.10	2.07	2.03	2.00
Naturally Occurring - Therms	71,651	141,950	209,786	274,283	334,891	391,352	443,636	491,850	536,216	577,077
Cost per First Year Therm	$ 5.68	$ 5.67	$ 5.73	$ 5.83	$ 5.98	$ 6.15	$ 6.36	$ 6.60	$ 6.85	$ 7.12
Cumulative Retail Savings - Real	$ 150,006	$ 505,586	$ 1,081,483	$ 1,886,825	$ 2,924,028	$ 4,190,773	$ 5,681,805	$ 7,390,491	$ 9,309,983	$ 11,434,009

Industrial: 100% Financed	Boulder Localization Portfolio Standard - Natural Gas: Achievable Local Energy Efficiency Resources									
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Net Energy Savings - Therms	141,237	266,669	381,372	482,718	570,182	644,523	707,173	759,821	803,915	841,209
New Net Energy Savings - Therms	141,237	136,731	125,642	111,397	96,375	82,052	69,214	58,185	48,748	41,195
Measure Decay - Therms		-11,299	-10,938	-10,051	-8,912	-7,710	-6,564	-5,537	-4,655	-3,900
New Savings as a Percent of 2010 Load	0.7%	1.3%	1.9%	2.4%	2.8%	3.2%	3.5%	3.7%	3.9%	4.1%
Program Costs - Real - for Utility and Private Sector										
Administration - Utility	$53,397	$51,800	$49,052	$45,749	$42,317	$39,031	$36,043	$33,418	$31,115	$29,209
Marketing - Utility	$13,869	$13,875	$13,878	$13,880	$13,882	$13,886	$13,891	$13,899	$13,916	$13,937
Measure Costs - Private Sector	$289,564	$277,975	$258,087	$234,188	$209,362	$185,582	$163,940	$144,900	$128,128	$114,204
Capitalization Cost (8%, 12 year term) - Split	$137,366	$131,868	$122,434	$111,096	$99,319	$88,038	$77,771	$68,739	$60,783	$54,177
Premise Level Monitoring Equipment - Utility	(All costs included in LPS - Electricity calculations.)									
SaaS - Private Sector										
Total	$494,197	$475,518	$443,452	$404,913	$364,880	$326,537	$291,646	$260,956	$233,942	$211,527
Total - Utility	$67,266	$65,675	$62,931	$59,629	$56,200	$52,917	$49,934	$47,317	$45,031	$43,146
Total - Private Sector	$426,931	$409,843	$380,521	$345,284	$308,680	$273,620	$241,711	$213,638	$188,911	$168,381
PV Net Avoided Cost Benefits	$1,218,944	$1,040,255	$910,876	$771,504	$638,742	$521,554	$422,820	$342,283	$276,538	$225,927
PV Annual Marketing and Admin Costs	$67,266	$56,769	$51,009	$45,384	$40,205	$35,611	$31,633	$28,234	$25,310	$22,871
PV Measure Costs	$339,542	$285,111	$250,086	$214,120	$180,509	$150,854	$125,647	$104,735	$87,257	$73,411
TRC	3.00	3.04	3.03	2.97	2.89	2.80	2.69	2.57	2.46	2.35
Naturally Occurring - Therms	40,688	75,186	104,740	130,312	152,648	172,334	189,834	205,513	219,666	232,537
Cost per First Year Therm	$ 3.50	$ 3.48	$ 3.53	$ 3.63	$ 3.79	$ 3.98	$ 4.21	$ 4.48	$ 4.80	$ 5.13
Cumulative Retail Savings - Real (Transport rates approximated)	$ 81,650	$ 238,885	$ 468,231	$ 764,305	$ 1,120,991	$ 1,532,213	$ 1,992,395	$ 2,496,686	$ 3,040,869	$ 3,621,640

APPENDIX B: Natural Gas Price Forecasts

Forecast trends from the Department of Energy are depicted in the graph below.



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Prices are shown in terms of 2011 dollars (real), which does not account for the effect of inflation on the nominal price of natural gas in a given year.

Another factor that could significantly accelerate the date of cost-effectiveness of larger amounts of local green energy would be imposing a cost on carbon. A carbon price of $30 to $50 per ton will certainly make more investments in green energy cost-effective and practical.

The price of natural gas has become increasingly volatile over the past few decades, a trend that is likely to continue for the foreseeable future. Some factors could increase future natural gas prices, such as restrictions on domestic drilling, reduction of Canadian imports, or increased demand.

APPENDIX C: Glossary of Terms

Biomethane: biologically-produced gas sourced from biomass waste feedstocks, and injected into natural gas pipelines.

Community Choice Aggregation (CCA): a legal framework enabled by legislation in several states that allows local governments to contract for electric power from a third party provider that serves all customers in the local government's jurisdiction; customers are given the right to opt out and return to the primary utility service if they choose to do so.

Combined Heat and Power (CHP): also known as "cogeneration", recovers the waste heat that would otherwise be lost from conventional central station power plants, and delivers this heat to one or more customers; CHP implies that the generator is at or near the point of energy use to allow highly efficient delivery of both electricity and heat.

Energy Management System (EMS): also called a Building Management System, refers to a computer system which is designed for monitoring and controlling features of building systems such as lighting, heating, ventilation, and so on. These systems may be used to trend energy usage, perform optimization or diagnostic routines to conserve energy, or interface with the electrical grid through an aggregator to respond to price and/ or grid reliability signals for demand management.

Heat Islands: district heating systems - using solar thermal, ground-source heat pumps, and in limited cases, combined heat and power systems - integrated and offered with thermal appliance retrofits and programmable controllable thermostats, and served by both natural gas and biomethane (biologically-produced gas sourced from agricultural waste and injected into natural gas pipelines).

Localization Portfolio Standard (LPS): Similar to an Renewable Portfolio Standard, but including heat and demand-side resources in addition to electrical energy resources, defined in discrete geographic boundaries.

Thermal Gateway: refers to advanced offerings using smart thermostats (programmable controllable thermostats, which offer two-way communication) such as optimizing customer's heating or cooling schedules against variations in weather, price, and (for electric heating systems and all cooling systems) grid stability signals.

END NOTES

[ii] Figures derived from consumption figures reported in Boulder's 2009 carbon inventory, with one therm equal to 29.300111 kWh. Note that while natural gas accounts for 55% of overall energy usage (heat and power) in the commercial and residential sectors (47% in commercial facilities and 77% in residential homes), it accounts for only 20% of the carbon footprint of these sectors.

[vi] Available from: [http://www.oiml.org/publications/R/R075-1-e02.pdf]

[vii] The metering installation guide is available from: [http://www.gosolarcalifornia.org/documents/CSI_Supporting_info/CSI_Thermal_Metering_Installation_Guide.pdf], and the list of approved metering and reporting providers is available from: [http://www.gosolarcalifornia.org/equipment/perf_data.php].

[ix] Data from the Department of Energy's Annual Energy Outlook 2011. 'High' and 'Low' price scenarios are taken from 'High Shale EUR' and 'Low Shale EUR' price scenarios.