Climate Action Plan
&
Integrated Resource Plan

Final Report

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Executive Summary

This report provides recommendations to Traverse City Light and Power as to how they can address climate change by reducing and eliminating elements of its power supply that emit climate pollution, eliminating climate pollution from internal operations, and by helping their customers decarbonize homes, businesses, and transportation.

To rapidly eliminate greenhouse gas emissions that cause climate change requires us to:

Generate electricity without greenhouse gas emissions;

Electrify all energy end-uses;

Use energy efficiently to minimize the cost of the energy transition;

Minimize non-energy emissions.

As an electric utility owned by and serving its community, Traverse City Light and Power is well positioned to guide and assist with this transition. The key actions we recommend include:

Migrating to 100% renewable energy as rapidly as current contractual obligations for use of fossil-fueled generation allow, while meeting obligations to support grid reliability by supplementing power generation with flexible demand and battery storage.

Creating a comprehensive customer-focused program to assist the community to use energy efficiently, replace heating fuels with efficient electrically powered technologies, electrify transportation, adopt customer-sited and community-sited solar, and integrate flexible demand and storage to assist in ensuring a reliable electricity supply and resilient community.

The customer-focused program we recommend includes:

Designing rates to provide customers price signals as to the best ways and times to use energy.

Education and outreach providing guidance to customers as to how they can effectively contribute to mitigating climate change, in a manner they can afford.

Technical assistance and new service offerings enabling customers to adopt better practices.

Financial assistance that makes it easier for customers to do the right things and to provide clear signals as to the best actions customers can take.

Eliminating climate pollution emitted to provide power to Traverse City Light and Power's customers and by Traverse City Light and Power's customers for heat and transportation will require persistence, as the use of fossil fuels and other climate pollutants is deeply embedded in our society. Doing so will not only mitigate climate change but will improve human health and be economically beneficial.

Summary of Recommendations

As we describe later in this report, we make the following recommendations to TCLP:

Take responsibility for eliminating TCLP's Scope 1, Scope 2, and Scope 3 emissions, by:

- eliminating use of fossil fuels to produce electricity, modifying TCLP's buildings so that they do not use fossil fuels for space or water heating, and replacing its vehicles with non-emitting electric vehicles.
- continuing power purchases from the wholesale market to take advantage of the reliability and cost advantages that the regional market provides but offsetting the greenhouse gas emissions embedded in grid power supply by producing or contracting for supply to the wholesale market of sufficient non-emitting power generation to offset TCLP's power purchases.
- reducing or offsetting the greenhouse gas emissions embedded in its upstream value chain and including in its customer programs efforts to reduce greenhouse gases associated with customer uses of electricity, such as refrigerants.

Since electrification is one of the key strategies for reducing greenhouse gas emissions by TCLP's customers, offer those customers assistance in electrifying their energy end-uses for both buildings and transportation.

Since using energy more efficiently is one of the key strategies for rapid and low-cost decarbonization of the economy, offer TCLP's customers assistance in efficiently using energy.

Adopt default rate designs for all customer classes that are based on both seasonal and time-of-day rates. By carefully reflecting cost causation by time, these will promote cost-effective energy efficiency, beneficial electrification, good vehicle charging behavior, and behind-the-meter solar and storage. The key to this is to volumetrically charge energy at approximately locational marginal price and minimum distribution system costs at all times and to recover costs for capacity, transmission, and distribution demand during times when those demands are likely to be at or near peaks. Customer load responses to this rate structure will also minimize TCLP power supply and transmission costs.

Create an integrated customer energy optimization program covering energy efficiency, building electrification, refrigerant management, vehicle electrification, demand response, on-site solar, and on-site storage. The customer journey (or roadmap) provided by that program will provide to customers the actions they should take to fully decarbonize their personal life or business with triggering events for or sequence of actions.

Through the integrated customer energy optimization program, provide maximum feasible assistance for customer access to federal and state tax credits and rebates.

Maintain a TCLP rebate program for Energy Star electrical devices sufficient to achieve annual incremental first-year electricity savings of 1%. We will recommend specific tailoring to maximize the social value of these rebates considering market penetration, effects of changed internal heat loads on heating and cooling requirements, GHG emissions, and an emphasis on the "most efficient" products in each category.

Offer rebates for electrical panel and other building electrical system upgrades needed for future electrification and solar, so that these upgrades can be done prior to building envelope improvements and to be ready for “emergency” electrification upon equipment failure.

Consider contracting an in-depth evaluation of creating a ground-source or water-source district heating and cooling utility in denser portions of the TCLP service territory.

Develop new program elements focused on building envelope improvements, heat pump space conditioning, heat pump water heating, and vehicle charging equipment.

> Offer generous rebates based on the smaller of TCLP avoided cost and avoided social cost for electricity efficiency and on the smaller of TCLP net revenue over marginal costs and avoided social costs for electrification. Provide on-bill repayment and other attractive financing for the balance of measure costs.
>
> For an initial period of 2 to 5 years, offer rebates for air sealing, energy-recovery ventilation, heat pump space conditioning and water heating, and demand-response-capable electric vehicle charging equipment primarily through a short list of vendors who demonstrate technical qualification, commit to maintaining in-stock equipment, and commit to marketing to achieve a certain number of installations per year.
>
> Provide a continuing education program for contractors to learn about building science and the new approach to efficiency and electrification.

If feasible, condition rebates on refrigerators, freezers, heat pump water heaters, and heat pump space conditioning on use of refrigerants with low global warming potential.

Develop a new program focused on commercial kitchen improvements, built around recurring meetings of an affinity group of customers and an offer of technical assistance in efficient and electric kitchens. Consider working with NMCC to provide a demonstration kitchen. A similar affinity group and technical assistance offer for hotels and other lodging might also be warranted, focused on room heating and cooling, hot water, and guest EV charging.

Offer assistance to develop and implement a custom energy optimization program for each primary customer and any other key accounts. Key accounts include or should include local governments and schools. Consider adding key transportation providers to key accounts to encompass fleet electrification.

As a condition for rebates on electric vehicle chargers, space conditioning equipment, electric water heaters, and perhaps other efficiency or electrification rebates, require that equipment be able to participate in a demand response program.

Provide a financial offer for customers to enroll in an automated load management program for vehicle charging, space conditioning, water heating, pumping, electricity storage, smart buildings, or commercial process load that will:

- Inform equipment operations about time-of-use rate schedules;
- Allow real-time management of demand within customer-friendly limits; and

- Allow (at customer option) emergency management of demand as needed to qualify as MISO capacity resources.

Evaluate cost-effectiveness of implementing dynamic volt-var control and conservation voltage regulation within TCLP's distribution system.

Replace net metering policy with a distributed resource policy that has the following features:

- Net billing, in which charges to the customer and credits to the customer are each calculated and then netted to determine monthly bills, with credits carried forward until such time as the customer requests payment.
- Customers are charged standard retail rates for inflow to the customer from TCLP, using the time-of-use rate schedule to which the customer would normally be assigned.
- Customers are credited for outflow from the customer to TCLP, at rates that are not less than TCLP avoided cost and not more than cost of service at the next higher voltage level above that to which the customer is connected.
- There is no limit on the size of a customer's behind-the-meter solar or storage systems.
- There is no cap on customer participation in distributed generation.

If TCLP is providing 100% renewable power to its customers, then the recommended net billing tariff properly compensates customers who implement behind-the-meter renewable generation. If TCLP is providing generic grid power to its customers, then it would be appropriate to provide a rebate of up to $1400 per kW nominal capacity for installation of a behind-the-meter solar system.

As part of the customer energy optimization program, reduce the "soft costs" of behind-the-meter solar and storage by providing each customer an annual report of the expected costs and bill savings for solar at their premises, referral to qualified vendors or automated solicitation of proposals from qualified vendors, streamlined permitting and inspections, and on-bill repayment and other attractive financing for system costs.

In tariff treatment for behind-the-meter solar and storage, provide an option for an economically equivalent community solar arrangement amongst the tenants of a multi-tenant building with a shared solar system.

To enable customer or third-party development of solar and storage resources within TCLP's service area, and in compliance with the Public Utility Regulatory Policies Act of 1978, as amended, TCLP should adopt an avoided cost rate and standard offer tariff for renewable resources, combined heat and power, and battery storage within its service area that does not require that these resources be associated with a TCLP customer.

Develop a TCLP micro-grid offer and tariff that includes the following elements:

- Clear permission for a TCLP customer to implement a micro-grid behind the meter, with associated interconnection standards;
- An offer in which TCLP provides, operates, and maintains point of separation equipment in front of the meter for one or more customers while the customer(s) provides the balance of the micro-grid behind the meter.
- An offer in which TCLP provides, operates, and maintains point of separation equipment and electricity storage in front of the meter for one or more customers while the customer(s) provides the balance of the micro-grid behind the meter.

- An offer in which TCLP provides, operates, and maintains point of separation equipment, generation, and electricity storage in front of the meter for one or more customers while the customer(s) provide load control within the micro-grid.

Use wind and solar power purchase agreements to meet annual energy needs in excess of what TCLP is already contracted to receive from other facilities. This will provide some capacity credits for resource adequacy purposes. TCLP should attempt to acquire any needed capacity credits not provided through PPAs or generation project participation by using either demand response or storage.

In-system solar and storage procurement by TCLP should be based on an identified list of opportunities to create microgrids that support community resilience in the event of grid outages, in competition with remote grid-connected solar and storage.

Near-Term Course of Action

Our recommendations are extensive and will take time to implement. We recommend acting soon as follows.

Adopt time of use rates as default or mandatory rate design for all customer classes, based on current recommendations from Utility Financial Solutions. Include in these rate designs the replacement of net metering with a net billing approach for behind-the-meter generation and storage resources.

Create a new tariff for commercial vehicle charging, allowing service line and metering separate from affiliated buildings:

- Do not use demand charges for this
- Include make-ready infrastructure using line extension policy
- Apply standard cost of service approach to revenue responsibility and rate design
- Include an option to include charging equipment provided by TCLP with costs to be recovered from site customer as fixed monthly charge, with or without charging-customer payment option

Initiate a procurement process to obtain renewable generation and capacity resources sufficient to:

- Meet all expected electricity sales in excess of the power projected to be supplied by TCLP resources that will continue to serve TCLP after 2025, including the Kalkaska CT and Belle River plants; and
- Meet MISO seasonal resource adequacy requirements at least four years forward, consistent with MCL 460.6w.
- We recommend soliciting concrete resource proposals and evaluating these proposals by modeling future values as well as costs of wind and solar. In view of current siting challenges, TCLP should be a patient buyer in order to give potential sellers sufficient time to work through the development process and provide TCLP good value.
- Capacity resources that should be considered for procurement include but are not limited to distribution system volt-var control including conservation voltage reduction, demand response program implementation, and battery storage. While TCLP should not exclude pure capacity contracts, preference should be given to these physical capacity resources.

Establish an integrated customer optimization program, which is intended to encompass energy efficiency, building electrification, refrigerant management, vehicle electrification, demand response, on-site solar, and on-site storage. For an initial implementation of this program,

- Update TCLP rebate offers and on-bill repayment programs to be inclusive of all elements of such an integrated program.
- Create a section in TCLP's web site that provides customer information and education in the form of a customer's journey to decarbonization, including guidance on all forms of assistance available to the customer, including technical guidance, federal and state tax credits and rebates, TCLP program offerings, linkage to DTE Gas offerings, and on-bill repayment.
- Implement a preferred contractor program for 2 to 5 years for the following new program areas: air sealing, insulation, energy-recovery ventilation, heat-pump space conditioning, heat pump water heating, Level 2 electric vehicle charging equipment installation, and behind-the-meter solar. TCLP should provide access to these preferred contractors through the TCLP customer journey web pages.

- Extend TCLP’s key accounts programs to all Primary customers and staff for regular outreach to these customers with a focus on encouraging and assisting them to develop and implement a custom strategic decarbonization plan while also meeting their economic goals.
- Establish an “energy coach” program for commercial and residential customers, based initially on responding to customer inquiries.

After setting up the integrated customer optimization program with a “soft launch”, begin promoting the program through broad customer communications activities.

Adopt tariff changes establishing a standard offer tariff for renewable resources, combined heat and power, and microgrid services that is consistent with the Public Utility Regulatory Policies Act.

Initiate efforts to decarbonize TCLP buildings and vehicles.

Initiate discussions with local governments and educational institutions in the TCLP service area about opportunities to jointly implement integrated customer energy optimization program elements in their facilities and operations.

Contract for an in-depth evaluation of creating a ground-source or water-source district heating and cooling utility in denser portions of the TCLP service territory.

Once the actions above are undertaken, revisit remaining recommendations.

1 Introduction

This report is structured as follows.

Our engagement and Recommendations are highlighted in the first pages of the report.

Following this Introduction, we describe how TCLP with our assistance engaged its stakeholders in the considerations leading to this report.

We then provide some background on Climate Action Policy, generally, and Climate Neutrality in Practice. These sections establish the principles on which the rest of the report is based.

We then provide a TCLP Overview describing TCLP's infrastructure, operations, and place in the overall electricity grid. A summary of TCLP Economics provides some of the foundations for the analyses presented later in the report.

The report section on Benefit-Cost Analysis of TCLP Programs explains how we develop metrics to evaluate programs for the perspectives of society as a whole, TCLP and its customers, and of TCLP customers who participate in TCLP programs. We apply these benefit-cost tools in subsequent analyses.

We construct profiles of how TCLP customers currently use energy in buildings in a section entitled TCLP Load Profiles.

Based on those profiles, we describe our work to develop recommendations through

- Building Energy Efficiency Analysis
- Building Electrification Analysis
- Transportation Electrification Analysis
- Demand Response Analysis
- Behind-the-Meter Solar and Storage Analysis
- TCLP In-System Solar and Storage Analysis.

We then formulate recommendations for an Integrated Customer Energy Optimization Program.

Based on our projections of the electricity requirements of TCLP customers, as affected by the recommended programs, we provide an Integrated Impact Assessment, describing the effects of societal trends and TCLP programs on electricity demand by TCLP customers and how that affects TCLP's electricity transmission and distribution system requirements.

Finally, we analyze the best strategy to supply TCLP customers electricity, using existing resources and new resources to meet energy requirements without climate pollution and to meet power supply reliability requirements. This Integrated Resource Plan provides those recommendations.

Numerous appendices detail our data sources and analytical methods and explain the spreadsheets and other models that we supply to TCLP for their reference and future use.

2 Stakeholder Engagement

TCLP identified Stakeholder Engagements as an essential component of its Climate Action Plan development. Because the final plan will impact not the business, but the community served, TCLP utilized a variety of tactics to encourage all members of the community to unite in a discussion about its energy future.

2.1 Stakeholder Engagement Goals

TCLP's Stakeholder Engagement strategy is based on six established goals. These goals served as a guidepost for all engagement activities to ensure consistent interactions that would identify key concerns and education gaps, while also presenting opportunities for the expression of opinions and ideas. The following are these six core goals and the meaning behind them.

- *Process & Planning Transparency*: TCLP's why and how behind Climate Action Planning.
- *Industry Knowledge Assessment:* What is the level of knowledge needed to ensure we are speaking the same language?
- *Industry Landscape:* Public education of industry trends and ideas TCLP is exploring.
- *Perspective & Goal Alignment****:*** Stakeholder goals and objectives that can be utilized as TCLP plans.
- *Insight & Feedback:* Identify what TCLP stakeholder's ideas, considerations, and priorities.
- *Opportunity Identification:* Project, initiatives, and strategy opportunities.

2.2 Stakeholder Engagement Tactics

To address the six goals outlined, TCLP engaged the public in a variety of differing formats to ensure that accessible opportunities were available to participate for all. These activities varied from public events to confidential feedback solicitations allowing folks opportunities to not just engage but do so candidly as well. TCLP's stakeholder engagement efforts worked to bring all community members to the table to discuss their desires for our energy future together. The input gathered was critical for ensuring the plan was developed in a way that would meet the expectations of the Traverse City community.

2.3 Climate Action Plan Website

In September of 2022, TCLP launched its Climate Action Website (www.TCLPCAP.org) as a hub for all things related to the planning initiative, allowing stakeholders to stay up-to-date with events, provide feedback at any time and connect with educational resources to strengthen their understanding of core clean energy terms and topics. In addition, those visiting the website have been able to sign-on to dedicated mailing lists for TCLP, participate in surveys and register to attend open house events in advance. As the planning initiative has evolved so has the website by reflecting project updates – such as the release of initial recommendations and strategies from 5LE.

2.4 Public Open House Events

From October 2022 – April 2023, TCLP hosted a series of three Open House Events at the Traverse Area District Library that invited the public to get engaged in the planning, learn more about its tactics and speak directly with its consultants.

At each event, TCLP and its consultants provided educational materials on climate action strategies, and we're on hand to answer any questions. The events also included additional ways to capture feedback on specific topics via whiteboards where attendees could offer their opinions and perspectives on topical themes.

These events were advertised heavily via commercials on digital streaming services, yard signs, email blasts, radio spots and social media. The public was also encouraged to attend for a chance to enter-to-win a Giant / Momentum E-Bike (Valued at $2,400), purchased locally at vendor cost from City Bike Shop. Leading up to these events, TCLP allowed attendees to register via the Climate Action Plan website, though the event was free to attend by all.

In total, TCLP's open house events were attended by 80-100 members of the public.

2.5 Focus Groups

In December of 2022, TCLP conducted a series of focus groups, at the Cherry Capital Airport, as part of its Climate Action Plan's Stakeholder Engagement efforts. At 4 unique sessions, select community members, ranging from customer and business owners to special interest groups and public leaders, were invited to engage in conversation surrounding 3 unique topics areas central to Climate Action and Integrated Resource Planning. These areas of focus included Distributed Energy Resources, Electrification and Energy Waste Reduction – in addition to global group discussions on sustainability and carbon reduction.

The sessions unveiled perceptions of what it means to be "Sustainable" gauged individual's understanding of climate focused energy strategies TCLP aims to explore and questioned how individuals see TCLP playing a role in the community's clean energy future. In total these focus groups saw participation from roughly 26 individuals, representing unique organizations.

2.6 1-on-1 Interviews

To directly engage with regional leaders and businesses and identify ways to align with their own energy goals, TCLP hosted 1-on-1 interviews. Individuals engaged include City of Traverse City Commissioners, TCLP's Board of Directors, special interest groups, regional business owners, representatives from surrounding utilities and TCLP Key Accounts. This engagement tactic also allowed for opportunities to connect with pertinent individuals and entities that were not able to engage in open house or focus groups events.

During these discussions participants shared details about their future energy plans, concerns, and what aspects of services they valued most significantly. This feedback is critical for TCLP to develop and identify future projects and partnerships to ensure that the implementation of suggestions from consultants also meets the needs of its customers and local leaders and harmonizes with their own objectives.

1-on-1 interviews are an ongoing piece of TCLP's stakeholder engagement efforts. As such, TCLP will be offering additional opportunities to meet with stakeholders, and capture their perspectives, through late Fall of 2023 as it segways into its corporate strategic planning endeavors.

2.7 Survey(s)

To engage with the community at large, and more specifically its direct customer-base, TCLP solicited a Climate Action Plan survey from Great Blue Research in October of 2022. Survey questions aimed to measure interest in climate action strategies, understanding of plan strategies, and gauge participant's willingness to adopt crucial changes to the way they consume energy to directly impact our region's climate health.

Two variations of the survey were created, targeting Residential Customer and Commercial Customers, with questions differing slightly in some areas to best suit their intended audience. The survey was conducted digitally, with support and outreach for participation deriving primarily from social media posts, digital advertisements, and direct calling. Participants were also able to access the digital survey via a QR code on TCLP's Climate Action Plan Website.

The survey successfully gathered responses from 386 residents and 112 commercial businesses.

2.8 Presentation at Public Board Meetings

Throughout the development of the Climate Action Plan, TCLP's Executive Leadership team and consultants engaged TCLP's Board of Directors with regular presentations focused on updates and to generate feedback on developmental direction. While these presentations were primarily produced to inform the board about key project milestones, these meetings were also open to the general public, whom were welcome to comment.

2.9 Summary of Results: Key Themes and Takeaways

The Community Envisions TCLP as a Solutions Provider: The public desires an entity that can help guide them to being more energy conscious, efficient and active participants in creating a healthier climate. Participants may understand some of the energy efficiency solutions available, but are unsure about which to pursue first, what fits their budget and most importantly how they can future-proof their investments as new technologies continue to emerge.

TCLP Needs to Promote Community Literacy: Throughout TCLP's engagement efforts there was a noted lack of understanding surrounding energy tactics, about how energy is procured regionally and how individuals can be active participants in bettering climate health. In addition, there is a general lack of understanding of the benefits of pursuing decarbonization both socially and economically. TCLP has a general concern that the community at large is not engaged with the subject or currently practicing methods to reduce personal carbon footprints.

Moving forward TCLP will need to actively work to create awareness and education opportunities about core topics. It will be critical that the public develops an understanding of terminology related to technologies, functionality of equipment and other tactics for reducing energy waste and decarbonizing homes and businesses.

TCLP should Spearhead Project Planning and Coordination for Distributed Energy Resources: Many participants feel that TCLP should be working closely with regional businesses and City Officials to create alignment for projects that support regional generation and energy storage opportunities.

Programs and Service Offerings that Incentivize Positive Climate Action: While many individuals and organizations expressed interest in pursuing ways to become more energy efficient or entertain on-site renewables, cost and knowledge are major barriers to entry. Many feel that TCLP should work to create pathways to accessibility and affordability of energy saving solutions through new programs that incentivize those who do undertake these efforts.

TCLP Needs to form relationships with Contractors and Trades industry: One obstacle that participants seeking to undertake energy efficiency enhancements often face is finding contractors and tradesfolk that do not specialize in or encourage energy efficiencies and technologies that are environmentally focused. Likewise, finding certified efficiency auditors has been a challenge. Individuals feel TCLP should create stronger relationships with contractors and trades workforce development entities to increase the availability of certified auditors and develop a workforce that encourages their customers to adopt the technologies and services that are most energy efficient.

3 Climate Action Policy

3.1 Climate Change is Mostly Caused by Greenhouse Gas Emissions

TCLP's Vision Statement declares that the goal of the company is "to build the long-term value of Traverse City Light & Power for the benefit of the City and its residents and all Traverse City Light & Power customers." The level of emissions of carbon dioxide and other greenhouse gases for which TCLP is responsible has more long-term impacts than almost any other aspect of what the company does for its city and region. TCLP's goal to significantly reduce its emissions by switching to 100% renewable energy by 2040 makes the utility a part of the larger project to cut U.S. emissions to a degree that the worst consequences of climate change can be avoided.

Greenhouse gas emissions are the main cause of climate change, and electric power is one of the biggest sources of emissions in the U.S. While TCLP is responsible for only a small portion of Michigan's total emissions, much less the total emissions of the U.S. as a whole, the company is in a sense no less important than any utility when it comes to the need to cut emissions. That is because the science of climate change is such that all emissions, regardless of source, must be reduced to a minimum amount to make a difference for the welfare of future generations. To stabilize the climate, virtually all human-caused greenhouse gas emissions must be eliminated. Stabilizing the climate before additional major changes become permanent requires that these emissions be eliminated as soon as practicable.

This science shows why, if the utility is going to fulfill its vision statement and maximize the long-term value for its city and customers, TCLP needs to realize its goal of 100% renewable energy by 2040.

3.2 The Science of Climate Change

Greenhouse gases tend to block energy that would otherwise be emitted into space. Instead, that energy is re-emitted back to the earth. The more greenhouse gases that are in the atmosphere, the more energy is re-emitted. This phenomenon is the essence of the "greenhouse effect" that is observed by scientists and accepted by scientific consensus as the primary way that humans are influencing climate change.[1] The greater the stock of greenhouse gases in the atmosphere, the more radiation is absorbed by Earth rather than reflected into space, causing the Earth to get warmer.

Temperatures have already increased by 1.1 degrees Celsius over pre-industrial levels.[2] Efforts to reduce future emissions are therefore aimed at preventing the Earth from warming even more significantly. The scientific community has coalesced around the range of 1.5 degrees Celsius to 2 degrees Celsius (C) above pre-industrial levels as the target at which consequences of climate change become orders of magnitude more harmful.

The consequences of 1.5 C warming include more intense droughts, extreme precipitation in many regions, losses of ecosystems.[3] These impacts translate to higher human mortality in several ways: deaths that are directly caused by natural disasters like flash flooding, deaths that are indirectly caused by these disasters, like delays in medical supplies, heat stroke, dehydration and increased transmission of infectious diseases, to name a few.

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[1] https://www.acs.org/content/acs/en/climatescience/climatesciencenarratives/what-is-the-greenhouse-effect.html

[2] https://www.reuters.com/business/cop/whats-difference-between-15c-2c-global-warming-2021-11-07/

[3] https://www.ipcc.ch/sr15/

But just as scientists expect warming over 1.5 C to be materially worse than warming below that threshold, warming over 2 C has materially worse consequences than warming over 1.5 C. "Robust global differences in temperature means and extremes are expected if global warming reaches 1.5°C versus 2°C above the pre-industrial levels," according to the United Nations' Intergovernmental Panel on Climate Change (IPCC).[4] These differences translate to significantly higher deaths in a 2 C world versus a 1.5 C world.[5]

As greenhouse gases continue to accumulate in the atmosphere, the likelihood of avoiding higher degrees of warming diminishes. Because nations have failed to cut their emissions enough, warming of 1.5 degrees is likely locked in, the IPCC concluded in a 2021 report.[6] But scientists also concluded in the IPCC report that if the global community acts quickly and drastically enough, the level of warming could be less than 2 degrees C over the next two decades. But the longer we wait, the worse the result: given the steps already taken by countries to cut emissions, if things continue as they are without more stringent emissions reductions, about 3 degrees C of warming will occur by the end of this century, according to the research group Climate Action Tracker.[7] If countries follow through on net-zero pledges, warming will be limited to 2 degrees C, according to the IPCC's Integrated Assessment Models, as analyzed by Climate Action Tracker.[8]

So if the planet is likely to hit the 2 degrees of warming target, are the worst impacts of climate change unavoidable? Not necessarily, because the impacts of climate change do not rise in a straight line with rising temperatures. As a result, any reductions in warming potential could potentially avoid a catastrophe.

As the Earth warns, the climate hits certain tipping points (melting of the permafrost, the release of methane deposits frozen deep in the ocean, the transformation of the Amazon rainforest into into a sparser region that cannot absorb carbon dioxide as well as it does now, the collapse of the cycle of ocean currents that circulate warm water in the Atlantic Ocean, to name a few prominent examples), that cause negative consequences of climate change to spiral.[9] The more emissions are cut, the more likely it is that these tipping points are avoided and we avoid a climate catastrophe.

3.3 Climate Action Timeline

Greenhouse gas emissions are deeply embedded in the global economy, so virtually eliminating these emissions will take time. Limiting climate change to between 1.5 degrees and 2.0 degrees C starting from our current level of emissions requires that we globally virtually eliminate greenhouse gas emissions by 2050. This is an aggressive timeline as we must transition most of our infrastructure over a period of only about 25 years, when many of our assets that contribute to climate change have expected lives of 15 years to 100 years.

3.4 TCLP's Global and Local Role

"The 1.5 target is not simply about keeping a goal alive – it's about keeping people alive," United Nations Secretary-General António Guterres said in remarks delivered at the 2022 United Nations Climate Change

[4] https://www.ipcc.ch/sr15/

[5] "The magnitude of projected heat-related morbidity and mortality is greater at 2°C than at 1.5°C of global warming." https://www.ipcc.ch/sr15/chapter/chapter-3/

[6] https://www.nytimes.com/2021/08/09/climate/climate-change-report-ipcc-un.html

[7] https://www.nytimes.com/interactive/2021/10/25/climate/world-climate-pledges-cop26.html

[8] https://climateactiontracker.org/global/temperatures/

[9] https://www.pnas.org/content/118/34/e2103081118/tab-article-info

Conference (COP27) in Egypt on Nov. 17, 2022.[10] By aligning its clean energy goals with the international community's timeline for emissions reductions, TCLP has become one of many parties participating in this global effort to meet the IPCC's emissions target and, as a result, save lives and minimize irreversible environmental harm. By joining the 2015 Paris Agreement, the U.S. has agreed to reduce its greenhouse gas emissions by 50% to 52% below 2005 levels by 2030, in line with the treaty's targeted share of global emissions reductions that the country is meant to achieve to be consistent with the goal of limiting warming to "well below" 2 degrees, a target known as the nationally determined contribution (NDC).

Achieving this national goal will require cooperation between the federal government, state governments and individual utilities like TCLP. Through executive order, Gov. Gretchen Whitmer has committed Michigan to a goal that is very similar to this national target: reducing Michigan's greenhouse gas emissions by 28% below 2005 levels by 2025 and 52% by 2030, achieving carbon neutrality by 2050 and maintaining net negative greenhouse gas emissions thereafter. In April 2022, the Michigan Department of Environment, Great Lakes and Environment (EGLE) released the MI Healthy Climate Plan, a document detailing how the state can meet the goal of 52% reduction from 2005 levels by 2030 by taking steps like increasing the share of electricity generation that comes from renewable energy, electrifying vehicles and increasing public transit, increasing energy efficiency in commercial and residential buildings, improving rates of recycling, waste reduction and use of clean fuels in industrial sectors and more.

In 2020, the City of Traverse City met its own target, as set by a Clean Energy Resolution passed by the City Commission in December 2016, for 100% of operational electricity demands to come from clean, renewable energy sources, with "renewable" defined as wind, solar, geothermal, and/or landfill gas. In 2018, With the approval of a strategic plan in August 2018, the TCLP Board complemented the City's resolution by targeting the utility power supply to be 100% renewable by or before 2040, with intermediate goals of 15% renewable by 2021 and 40% renewable by 2025.

To fulfill its vision of bringing long-term value to its community and to live up to duties as a resident of Michigan and the planet, TCLP needs to enact a climate action plan that successfully implements the goal of 100% renewable energy and substantially reduces emissions from other sources in the community.

Therefore, the details of that climate action plan, such as the types of emissions it targets, must be carefully considered.

4 Climate Neutrality in Practice

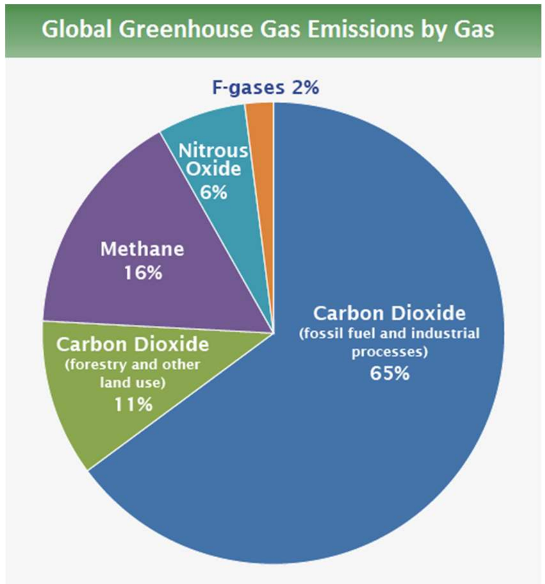
Climate analysts have arrived at a virtual consensus about what it will take to timely achieve a climate neutral society. The key principals are summarized below.

4.1 Climate neutrality and carbon neutrality

There are many greenhouse gases that contribute to atmospheric heat gain. At global scale, the key greenhouse gases emitted by human activities are carbon dioxide, methane, nitrous oxide, and fluorinated gases. Their relative importance is shown below[11]

[10] United Nations. "Secretary-General's remarks at COP27 stakeout." https://www.un.org/sg/en/content/sg/speeches/2022-11-17/secretary-generals-remarks-cop27-stakeout. Accessed Feb. 1, 2023.

[11] EPA summary of 2010 estimates from *Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*



Carbon dioxide is mostly emitted by combustion of fossil fuels, but is also emitted as a result of land use changes that reduce biomass on the land and in soils, such as the conversion of forest to agricultural land.

Natural gas is mostly methane and leaks from gas production, transmission, and distribution are a significant source. Methane is also released from coal beds during coal mining. Methane is produced from the decay of organic matter in low oxygen conditions so is commonly released from agricultural activities, waste management and biomass burning.

Nitrous oxide is produced principally from two sources. Combustion of fossil fuels and biomass produces heat sufficient to cause reactions in air that convert elemental nitrogen and oxygen into nitrous oxide. Use of nitrogen fertilizers in agriculture promotes bacterial activity and chemical reactions in soil that release nitrous oxide.

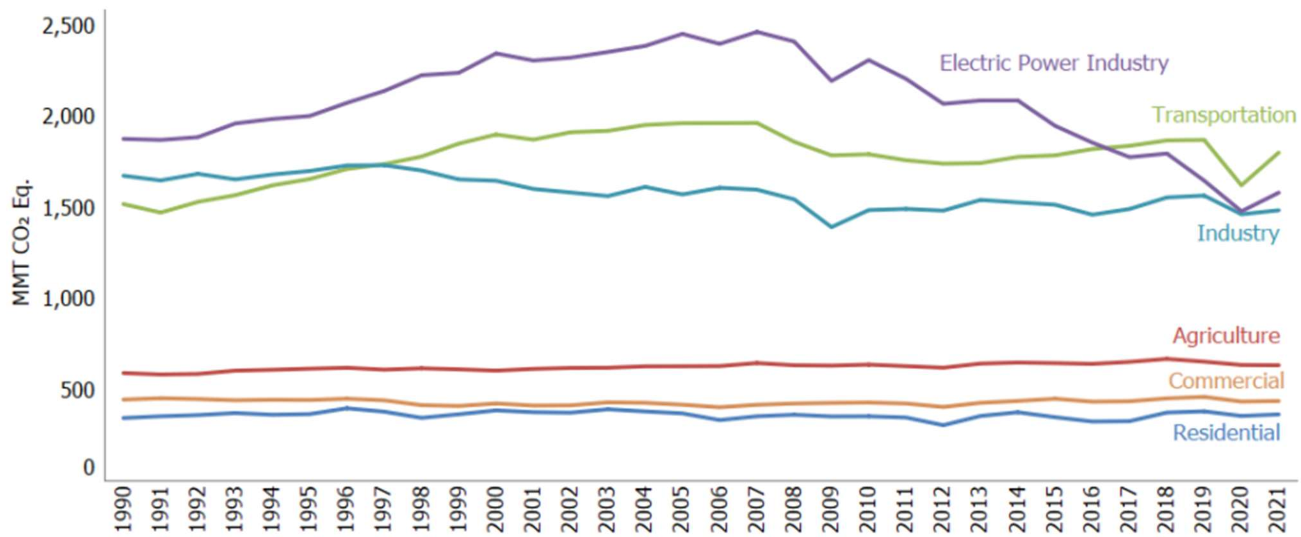
Fluorinated gases are produced and used in industrial processes and used as refrigerants and in a variety of consumer products. Hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are the most significant of these fluorinated gases.

Black carbon is an aerosol, not a gas, but also contributes to warming of the atmosphere. Black carbon is primarily the result of fossil fuel and biomass combustion.

All of these greenhouse gases will ultimately need to be addressed, but since carbon dioxide emitted from combusting fossil fuels, most methane emissions and a substantial share of nitrous oxide emissions are associated with the use of fossil fuels, and most black carbon is released from fossil fuel combustion, climate policy naturally focusses on eliminating carbon emissions. Virtual elimination of carbon emissions will also substantially eliminate these other causes of climate change.

Thus, climate neutrality requires achieving carbon neutrality plus targeted reductions in emissions of methane and nitrous oxides from agricultural activities and the production and use of fluorinated gases. Necessary climate policy is often summarized as carbon neutrality, or decarbonization. Because of its importance, it is also common to measure the effects of other greenhouse gases as equivalent to a given amount of carbon dioxide ("CO2 Eq")

Greenhouse gases are emitted from a number of economic sectors. The global pattern of emissions has also been documented.[12] The economic sectors that are responsible for emissions vary greatly between societies, so to make the sectoral sources more relevant, we focus on the inventory of greenhouse gas emissions for the United States. The US Environmental Agency ("EPA") prepares an annual inventory of greenhouse gas emissions, the most recent of which was published in 2023 and provides data through 2021.[13] From 1990 through 2021, US emissions by economic sector were as shown in the following graph.[14]



Note: Emissions and removals from Land Use, Land-Use Change, and Forestry are excluded from figure above. Excludes U.S. Territories.

Figure 4-1 Emissions by Economic Sector

The Electric Power Industry was traditionally the economic sector contributing the largest quantity of climate change from the US economy. Retirement of coal plants, replaced by natural gas and renewables, has significantly reduced those emissions and emissions from the Electric Power Industry are now below those from Transportation and on par with those from Industry. Agriculture, Commercial, and Residential Sectors emit substantial quantities of greenhouse gases and collectively are about the same level of emissions as each of the Electric Power Industry, Transportation, and Industry.

4.2 Achieving Carbon Neutrality

The consensus of climate analysts is now that to achieve carbon neutrality, we must

- Generate electricity without greenhouse gas emissions
- Electrify all energy end-uses
- Use energy efficiently to minimize the cost of the energy transition
- Minimize non-energy emissions

[12] Ibid.

[13] EPA. 2023, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2021, available from https://www.epa.gov/system/files/documents/2023-04/US-GHG-Inventory-2023-Main-Text.pdf.

[14] Ibid, Figure ES-13

Additionally, because overshoot of the necessary greenhouse gas emissions is likely and there are already harms from accumulated climate change that will get worse before the climate is stabilized, there are efforts to increase the rate at which greenhouse gases are removed from the atmosphere.

4.3 Land-use Emissions and Sequestration

Absent human use of fossil fuels and other technologies, carbon dioxide and other greenhouse gases would be in equilibrium in the atmosphere, but these gases are constantly cycled between biomass and the atmosphere and oceans. Removals from the atmosphere and oceans by plants and subsequent decay processes would be about equal. Due to historical changes in land use, such as deforestation, it is now possible for natural processes to sequester more carbon than they release by decay. This process is ultimately self-limiting but is currently producing net sequestration of carbon, acting as a carbon sink. In the US, forest regrowth is removing about 769 million metric tons of carbon dioxide from the atmosphere annually. Together with small carbon fluxes in other types of land, land use provides a net sink of about 754 million metric tons, offsetting about 12% of US gross emissions.

4.4 Carbon Offsets

The existence of significant natural carbon sinks has led to two related economic activities. First, many organizations that emit greenhouse gases and are not prepared to radically reduce their own emissions are looking for ways to offset their emissions by increasing the sequestration of carbon in natural sinks. Second, researchers are seeking ways to remove carbon dioxide from the atmosphere using industrial methods and sequester the carbon, typically in some geological form.

4.5 Carbon Offset Certifications and Markets

Because of the interest in offsetting carbon emissions by increasing sequestration, a market in carbon offset credits has developed, with multiple certifiers of credits, brokers, and trading platforms with carbon credits as a form of financial instrument.

Some market participants approach carbon offsets similarly to renewable energy credits, with the idea that one entity rather than reducing their own carbon emissions will pay another entity to reduce their carbon emissions instead. This construct makes some sense if all entities involved are required to reduce emissions by a given amount and some can do it more cost-effectively than others. In the context of a need to virtually eliminate emissions from all entities, this market construct fails because there should be no counterparty to reduce their emissions instead of the credit purchaser reducing their own.

Other market participants approach carbon offsets by financing activities that sequester or destroy greenhouse gases that would otherwise not be the responsibility of any other entity, such as plugging abandoned gas wells. There is finite known potential for such activities, but they appear to provide a net reduction in greenhouse gases in the atmosphere as compared to the counterfactual situation where those carbon offset credits are not produced.

Many offsets are offered that claim credits for protecting sinks, such as forests. These credits present a number of difficulties that are not resolved. Protecting a given forest area may not reduce carbon emissions because that forest area would not have been cut anyway due to existing institutional arrangements. Protecting a forested area from timbering may just move timbering activity to another forest, without reducing greenhouse gas emissions. Benefits of protecting a forest, or planting trees to enhance the forest, may not persist as the forest may be cut or burn at a later date and the markets are not designed to require the holder of the offset credits to lose those credits.

As a result, carbon offsets based on natural resources are controversial and not widely recommended as a climate change solution. The 5 Lakes Energy consultant team does not recommend that TCLP engage in the carbon offset credit market.

4.6 Carbon Accounting

Organizations and governments attempting to address climate change by pursuing carbon neutrality need to be able to inventory and track the emissions about which they are concerned. This is generally referred to as Carbon Accounting.

For a given source of greenhouse gas emissions, it is usually straightforward to measure or estimate emissions, though there are some processes and circumstances that make it difficult to do so. However, there are well-recognized complexities in the attribution of responsibility for reducing or eliminating greenhouse gas emissions. For example, when someone consumes gas to heat their home and emits carbon dioxide as a result, it is natural to attribute the resulting emissions to that household. However, if that household uses electricity that is produced at a power plant owned by their electric utility, is the household responsible for the emissions from power production or is the utility? Further, is the gas utility that provides gas to the household for their combustion within the house responsible for the customer's emissions?

Most organizations that voluntarily perform carbon accounting follow the Greenhouse Gas Protocol[15] a joint initiative of World Resources Institute and the World Business Council for Sustainable Development. The International Standards Organization has formally adopted standards for carbon accounting[16] that formalize the practices in the Greenhouse Gas Protocol. These standards distinguish three accounting scopes. Scope 1 emissions are those directly from the accountable organization, such as the emissions from a household's gas furnace. Scope 2 emissions are those that are produced by the organization's supplier of electricity, steam, heat and cooling, such as the household's purchase of electricity. Scope 3 emissions attribute to the organization the greenhouse gas emissions produced in the organization's value chain both upstream and downstream, which would make a household's emissions from combusting natural gas Scope 3 emissions of the gas utility.

In a world where all entities are eliminating greenhouse gas emissions, Scope 2 and Scope 3 emissions will trend to zero and each organization could do its part by focusing on its Scope 1 emissions. Because we are not yet in that world, leading organizations are taking responsibility for Scopes 2 and 3 to create market demand for greenhouse gas emissions reduction by other organizations.

4.7 Climate Neutrality Strategy Recommendations to TCLP

Reflecting both TCLP's requested scope in this engagement and our view of the essentials of climate mitigation strategy, we offer three recommendations.

Recommendation: TCLP should take responsibility for eliminating its own Scope 1, Scope 2, and Scope 3 emissions.

Sub-Recommendation: Eliminating Scope 1 emissions will require TCLP to eliminate its use of fossil fuels to produce electricity, modify its buildings so that they do not use fossil fuels for space or water heating, and replace its vehicles with non-emitting electric vehicles.

Sub-Recommendation: Eliminating Scope 2 emissions will require to eliminate or offset emissions from power plants from which TCLP purchases power; TCLP's primarily Scope 2 emissions mostly arise from

[15] See https://ghgprotocol.org/

[16] ISO 14064

bilateral power purchases and net interchange power from the wholesale power market. It is not practical, and we do not recommend, that TCLP discontinue power purchases from the wholesale market. However, TCLP can offset such purchases by producing or contracting for the supply to the wholesale market of sufficient non-emitting power generation to offset TCLP's power purchases.

Sub-Recommendation: Scope 3 emissions can be upstream or downstream of TCLP. TCLP can work to reduce or offset the greenhouse gas emissions embedded in its upstream value chain. A full accounting of TCLP's Scope 3 emissions is beyond the scope of our engagement, but we offer a few suggestions:

> A material portion of the greenhouse gas emissions upstream of TCLP are due to employee emissions of greenhouse gases in their homes and vehicles. TCLP can offer employee programs that will assist them in reducing their greenhouse gas emissions.
>
> All material goods purchased by TCLP will likely have carbon and other greenhouse gases embedded in their production and to the extent that the goods are made of organic material, will likely produce greenhouse gas emissions at end of life. TCLP can reduce these Scope 3 emissions associated with material goods by use of purchasing standards and by following circular economy[17] practices throughout the life cycle of those goods.
>
> Sulfur hexafluoride is used as an insulating gas in electrical transmission equipment, including circuit breakers. This gas is 23,500 times as powerful as a greenhouse gas as is carbon dioxide. As feasible, TCLP should be seeking alternative equipment that does not use sulfur hexafluoride.
>
> Most downstream uses of electricity do not, strictly speaking, produce significant greenhouse gases. An important exception is that cooling equipment and heat pumps use refrigerants. TCLP can encourage and assist customers to properly dispose of refrigerants and encourage the purchase of future equipment that uses refrigerants with low climate change potential.

Recommendation: Since electrification is one of the key strategies for reducing greenhouse gas emissions by TCLP's customers, TCLP should offer those customers assistance in electrifying their energy end-uses, including buildings and transportation.

Recommendation: Since using energy more efficiently is one of the key strategies for rapid and low-cost decarbonization of the economy, TCLP should offer TCLP customers assistance in efficiently using energy. Much of this report addresses strategies by which TCLP can assist customers to electrify their energy use and to use energy more efficiently.

5 TCLP Overview

5.1 Structure of the Electric Power System

The traditional view of the electric power system is illustrated in the following diagram. In this view, Generation is done at central power plants, from which power is placed at high voltage onto the Transmission System. Power flows over the Transmission System to substations where voltage is reduced and power is supplied to the Primary Distribution System. Power flows from the substation over the Primary Distribution System at an intermediate voltage to serve larger customers or to line transformers that further reduce voltage for power delivery over the Secondary Distribution System to residences and small businesses. Beyond the electric meter in this perspective are the customers of the electric power system.

[17] See https://www.epa.gov/circulareconomy/what-circular-economy.

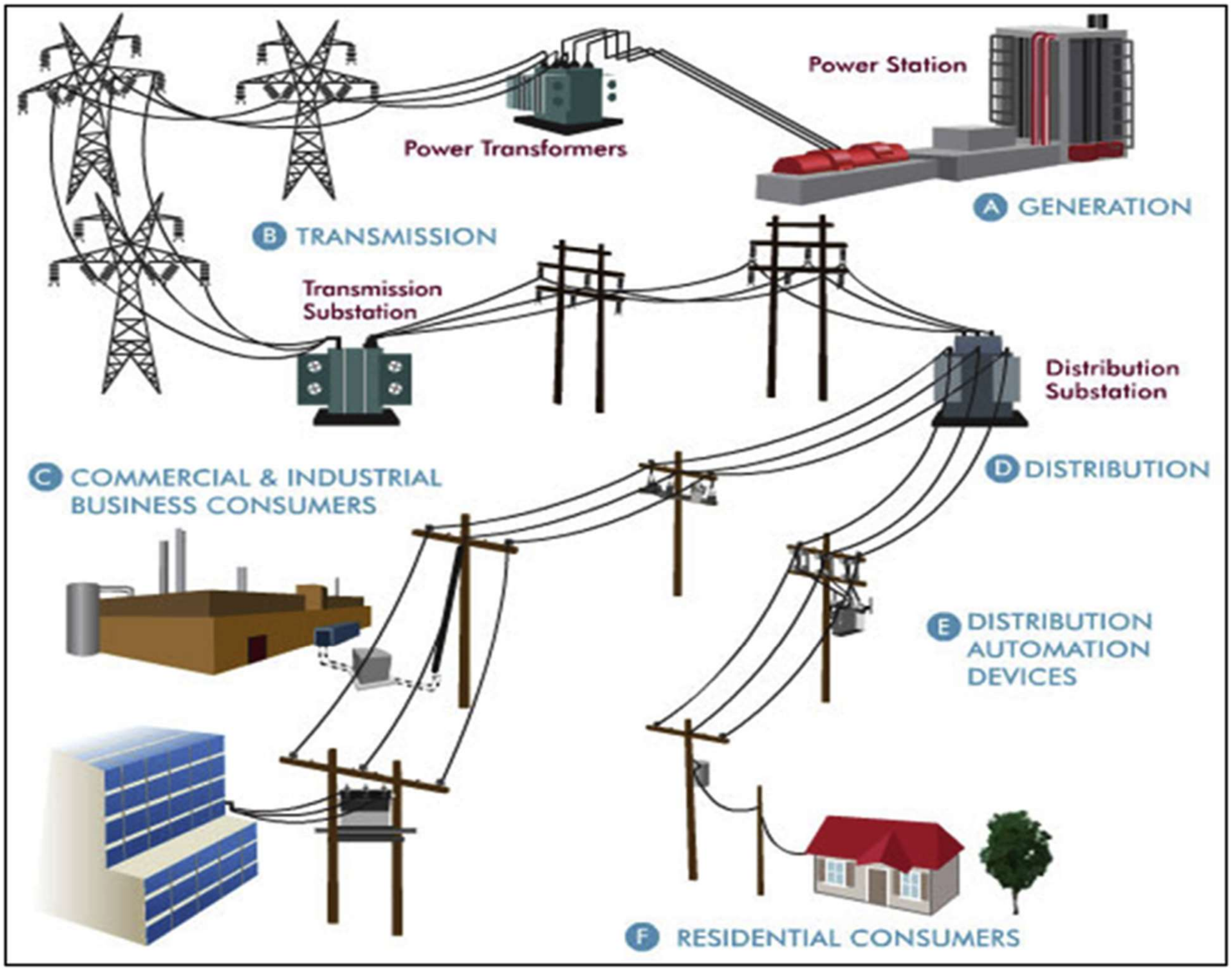


Figure 5-1: Traditional view of the structure of the electric power system.[18]

The power system is evolving beyond this traditional picture in a number of ways.

One important major change that has already occurred in most of the United States is that transmission has been regionally integrated under the operation of a Regional Transmission Organization (RTO) designated by the Federal Energy Regulatory Commission (FERC). RTOs plan and operate transmission throughout the region and this has led to greater connectivity between utility service areas. Consequently, transmission is more a network with multiple paths between any pair of locations on the grid than the simple hierarchy depicted above. In a sense, the power delivered to any one distribution substation comes from all power sources on the grid.

Most RTOs are also Independent System Operators (ISOs), who take responsibility for scheduling power generation across utilities such that the aggregate of generation satisfies the aggregate of demand, and each individual utility is no longer responsible for moment-to-moment generation or bilateral power purchases to service its own customers' demand. Instead, each utility operates within a wholesale power market

[18] Diagram obtained from Orhan, M. F., H. Kahraman, and B. S. Babu. 2016. Approaches for integrated hydrogen production based on nuclear and renewable energy sources: Energy and exergy assessments of nuclear and solar energy sources in the United Arab Emirates. International Journal of Hydrogen Energy 42.10.1016/j.ijhydene.2016.05.044

managed by the ISO, buying all of the power needed to service its customers through the ISO market and generating power for sale to the ISO market as instructed by the ISO through market-making operations. Power generation by an individual utility is not calibrated to the demand of its customers but is based on the comparative economics of all generation in the ISO market and the aggregate demand in the market.

In the last several years, wind and solar generation technologies have become cost-competitive with or even less expensive than traditional power plants. As a result, there are increasing amounts of large-scale wind and solar generation integrated into the power system and operating within regional power markets. Because the variability of wind and solar is less when averaged over a larger area, transmission networks increasingly need to support power flows over larger regions.

Customer demand for power varies considerably over time, including considerable random changes in short intervals, variation due to random weather, and broad daily and seasonal patterns. As depicted above, in a traditional utility this varying demand was satisfied through varying generation, constantly adjusted to current demand. This is still largely the case although the larger regional markets significantly smooth aggregate demand, but there has been some use of storage technology to smooth the variation in demand and allow more consistent operation of generation. The Ludington Pumped Storage Project near Ludington, Michigan that became operational in 1974 is a good example of such storage. With increasing use of wind and solar generation, which are inherently variable generation, there is even more variability in the balance between generation and demand. Recently, with advances in electrochemical battery technology, there is increasing interest in and deployment of large-scale battery systems that are integrated to the power system.

In addition to declining costs of grid-scale solar and storage that have made these competitive in the bulk power system, the costs of small-scale solar and storage have become affordable to some power system customers. Further, communication and control technologies have made it possible for customers to adjust demand based on grid conditions, a practice sometimes called demand response or flexible demand. As electric vehicles are adopted, additional opportunities to manage demand are emerging. Thus, customers are increasingly seen as active participants in the power system as opposed to recipients of its services. The following diagram is more representative of the power system of the future.

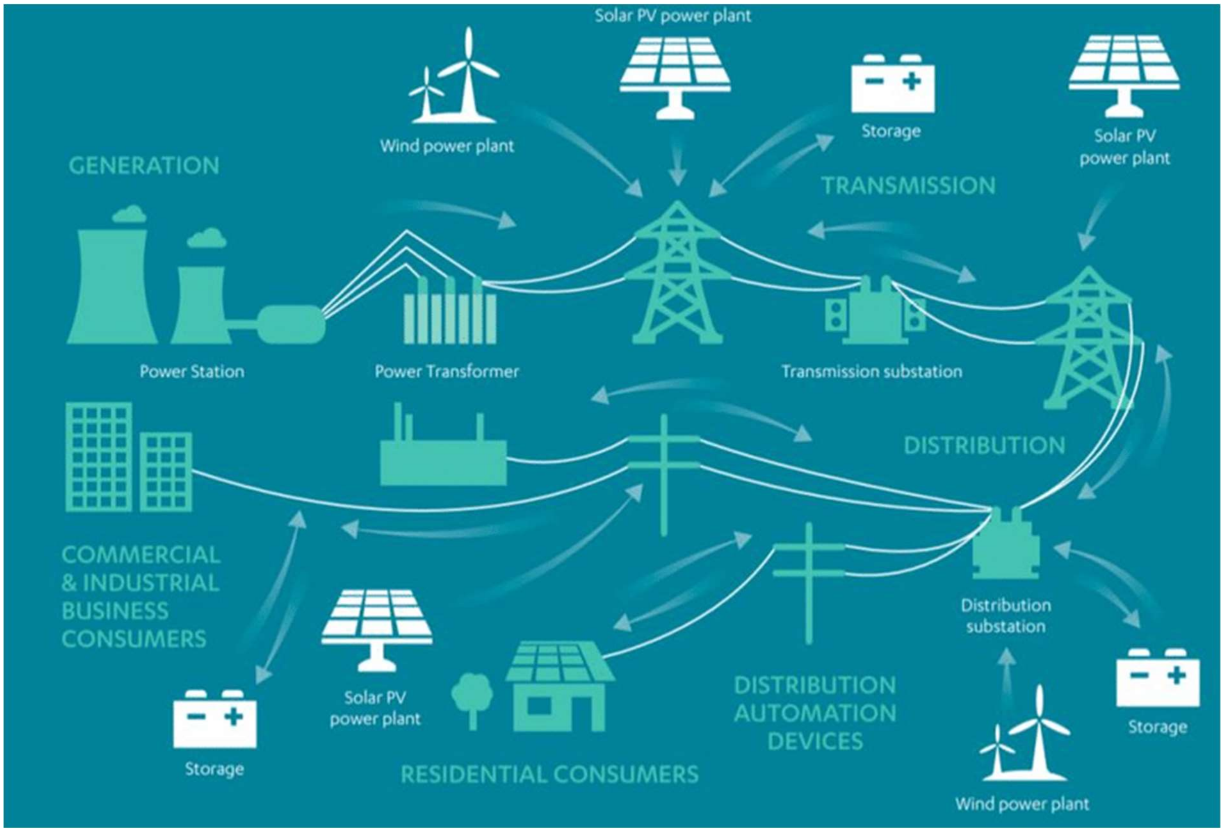


Figure 5-2 Transmission and Distribution Grid with Renewables and Storage

TCLP is a power distribution utility, whose principal role is to serve its customers by taking power from transmission and distributing that power to its customers. All power supplied to customers by TCLP is purchased from the Midcontinent Independent System Operator (MISO), which is both an RTO and ISO for the central United States and Canada. For planning and analysis purposes, MISO divides its service area into local resource zones. Lower Michigan, hence TCLP, is in MISO Zone 7. The following map illustrates MISO's service area and local resource zones.

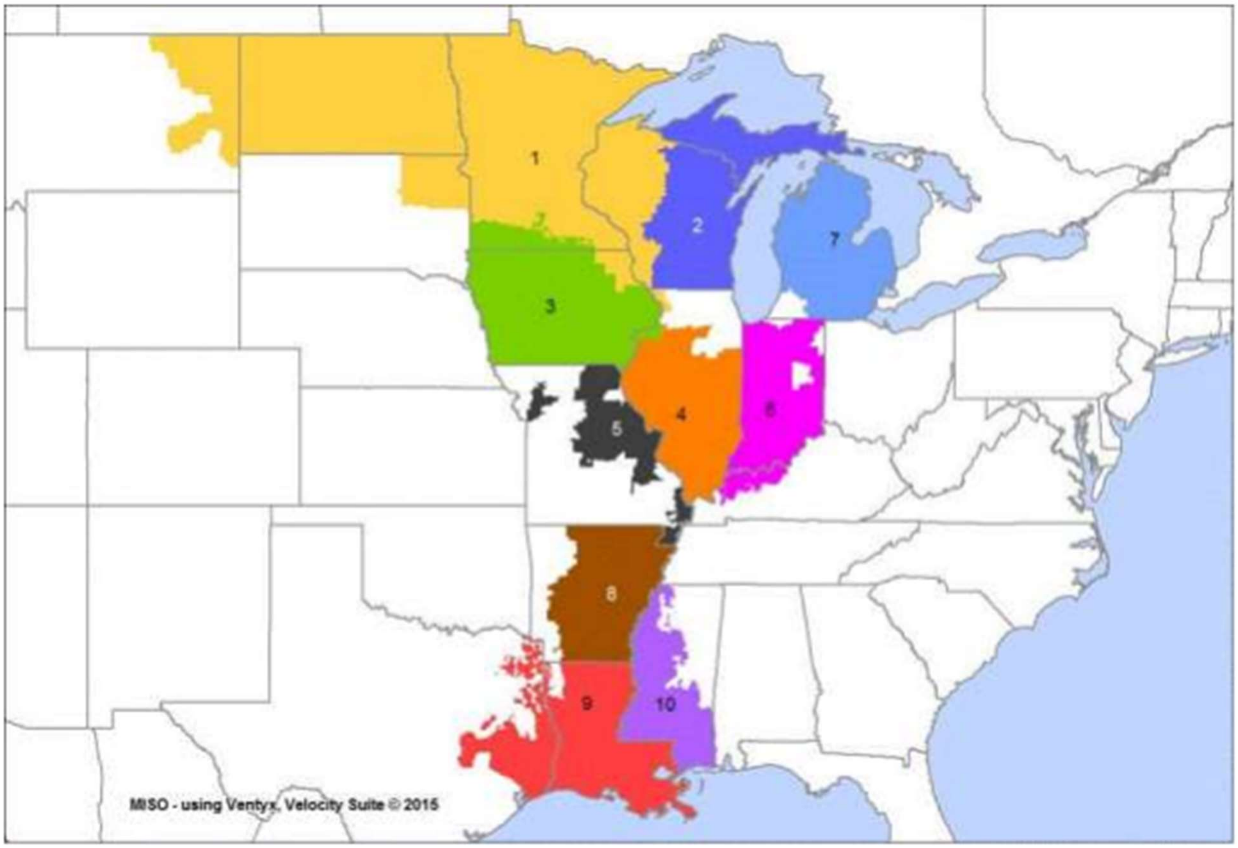


Figure 5-3 Map of Midcontinent Independent System Operator[19]

TCLP does own or participate in a number of generation facilities, with all power from those facilities sold into the MISO market.

TCLP's service area consists of most of Traverse City and portions of the neighboring townships of Blair, East Bay, East Bay Annexed, Garfield, and Peninsula.

[19] Obtained from Attachment VV of MISO tariff approved by the Federal Energy Regulatory Commission.

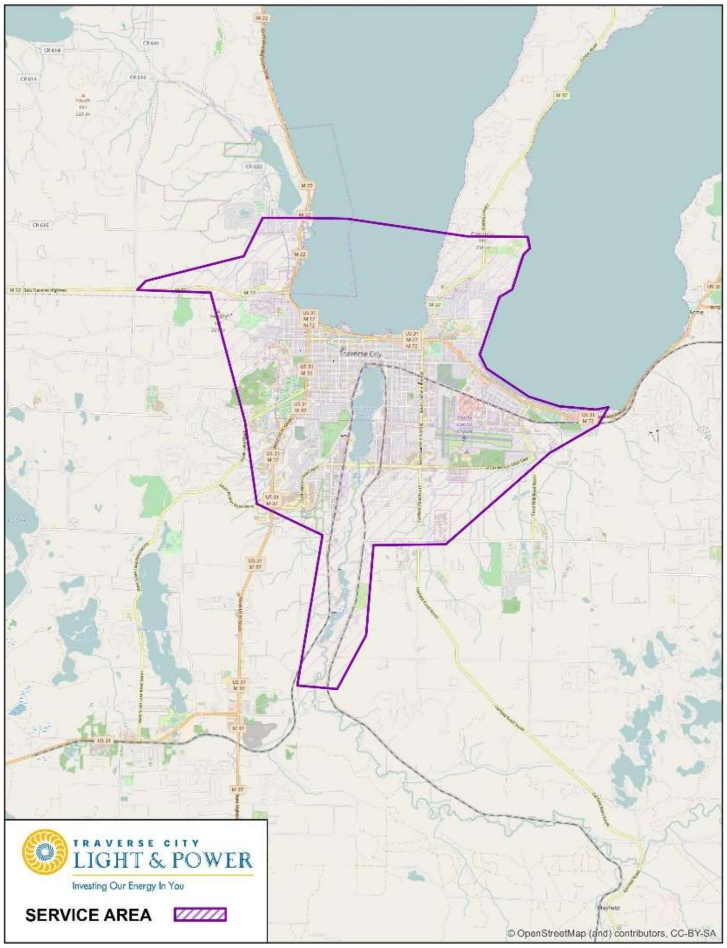


Figure 5-4 TCLP Service Territory

5.2 TCLP Customers and Electricity Sales

2021 was the last full year on record for much TCLP data when we began our work so we use that as a base year for most of our analysis. In 2021, TCLP customers and electricity sales were as summarized in the following table.

Customer Class	Customers	Energy Sales (MWh)	Revenue (1000s)
Residential	9,323	59,709	$6,236
Commercial	4,208	135,913	$13,975
Industrial	37	109,229	$8,122
Total	12,468	304,851	$28,333

Table 5-1 TCLP Electricity Sales and Revenues by customer class

5.3 TCLP Power Supply

As discussed above, TCLP buys all of the power that it delivers to its customers from the MISO wholesale market. TCLP participates in several generation projects and has several power purchase agreements. The power from these resources is sold into the MISO wholesale market. The power produced from TCLP resources is sold to MISO at a price that is close to the price that TCLP pays for power for its customers at the same times, with small differences due to locational differences in MISO power prices.

As a participant in the MISO market, TCLP is required to control by ownership or contract an amount of generation capacity that exceeds its customer's requirements by a reserve margin at times when grid capacity is stressed. This kind of requirement is called Resource Adequacy and ensures that each utility does its fair share of meeting the total requirements of the grid. If a utility happens to not have sufficient capacity under its long-term control, MISO holds an annual auction of capacity credits in which utilities and merchant plants that have excess capacity sell credits into a pool and utilities that are short of capacity buy credits from the pool, with the price determined by matching quantities bought and sold at the market-clearing price. There is also an active bilateral market in which owners of capacity will sell the capacity to utilities needing capacity, without any of the energy from their supply resources included in the transaction.

Historically, with most power plants being able to be turned on or off according to need, Resource Adequacy was based on a utility's customer demand at the time of the annual peak for the whole MISO market, which occurred in summer afternoons. Power plants were accredited as providing capacity based on their average availability throughout the year, reflecting their nominal generation capacity and the probability that they would be shutdown for maintenance or repairs. With increasing wind and solar generation, which is variable through the day and seasonally, the times of relative shortage in the grid are no longer just at summer peak load times but can occur throughout the year. Accordingly, MISO has changed its Resource Adequacy standards to a seasonal construct with Winter covering December – February, Spring covering March – May, Summer covering June to August, and Fall covering September – November.

Owning or contracting for power generation can be profitable if participation in that power resource costs less than the value of the energy and capacity they supply, or can be a net cost. On average, every well-chosen generation resource might be expected to break even on its wholesale market sales of energy and capacity, though there can be important exceptions. One of those exceptions is that until recently renewable generation was more expensive than fossil-fueled generation, so compliance with Michigan renewable energy standards required utilities to purchase power at a premium above market price. Profit from a generation resource serves to reduce customer rates below what they would be if the utility just used wholesale power and capacity. Wholesale energy and capacity prices vary year-to-year, so a utility has some price risk when it depends on the market. So, even if owning or contracting for power is profitable or a loss from year-to-year, controlling that power resource can stabilize the utility's cost of power for its customers. Reducing risk to customers by hedging power supply through ownership or contract may also be a good reason to control a generation resource. In the report section on Integrated Resource Plan analysis, later in this report, we examine these considerations for TCLP's existing and potential future power supply resources.

TCLP's 2021 power supply resources were as follows:

Campbell Unit 3: TCLP participates in a contract between the Michigan Public Power Agency (MPPA) and Consumers Energy, in which TCLP pays a share of the costs of the Campbell Unit 3 and receives a share of its energy and capacity value. Campbell is a coal-fueled power plant. Campbell will be retired early in 2025. The nominal capacity of TCLP's share of the Campbell Unit 3 is 11 MW. Annual energy depends on how much it is instructed to run in the MISO market, but in 2021 TCLP's share of energy generation was 71,345 MWhs.

Belle River: TCLP participates in a contract between MPPA and DTE Electric, in which TCLP pays a share of the costs of the Belle River plant and receives a share of its energy and capacity value. DTE Electric has proposed in a current Michigan Public Service Commission proceeding that the Belle River coal plant be converted to use natural gas as a fuel in 2025 and 2026, and to set an expected retirement date of 2040 for the converted plant. That case is not completed as of the writing of this report, but appears likely to be approved. We assume that this is the future of the Belle River plant. TCLP's current contract for the Belle River coal plant requires TCLP's continued participation in the Belle River plant after it is converted to being fueled with natural gas. The nominal capacity of TCLP's share of the Belle River plant is 12 MW. Annual energy depends on how much it is instructed to run in the MISO market, but in 2021 TCLP's share of energy generation was 60,062 MWhs.

MPPA Landfill Gas Project: Landfill gas generation consists of using pipes to gather methane gas from inside a landfill, then using that methane as fuel for an electricity generator. Using landfill gas in this way counts toward Michigan's renewable energy standard and is considered to be beneficial for climate change because methane is a more powerful greenhouse gas than is carbon dioxide, and using landfill gas for generation reduces methane leaks into the atmosphere while converting it to carbon dioxide that is released into the atmosphere. TCLP participates in an MPPA Landfill gas Project in which several landfill gas generators are shared by several municipal utilities. TCLP's share in 2021 was 1.3 MW nominal capacity with energy generation of 11,080 MWhs. The end dates of the various landfill gas generator contracts in this project vary so TCLP's share will decline from 1.3 MW through 2025, to 1.2 MW in 2026, 0.9 MW in 2027, 0.8 MW in 2028 through 2030, 0.7 MW in 2031, and then 0.5 MW from 2032 until 2041.

Stoney Corners Wind Farm: TCLP's share of the Stoney Corners Wind Farm has nominal capacity of 10 MW. Annual energy production depends on wind conditions but is expected to average 24,388 MWhs per year. TCLP's current power purchase agreement for Stoney Corners expires on 1 January 2030.

Pegasus/Huron Wind: TCLP's share of the Pegasus/Huron Wind Farm has nominal capacity of 3.6 MW. Annual energy production depends on wind conditions but is expected to average 10,881 MWhs per year. TCLP's current power purchase agreement for the Pegasus/Huron Wind Farm expires on 31 December 2039.

Assembly I Solar: TCLP's share of the Assembly I solar project is 9.8 MW nominal capacity. Annual energy production depends on solar conditions but is expected to average 18,040 MWhs per year. TCLP's current power purchase agreement for Assembly I expires on 31 December 2045.

Assembly II: TCLP's share of the Assembly II solar project is 7.6 MW nominal capacity. Annual energy production depends on solar conditions but is expected to average 14,416 MWhs per year. TCLP's current power purchase agreement for Assembly II expires on 31 December 2046.

Calhoun Solar: TCLP's share of the Calhoun solar project has nominal capacity of 12.2 MW. Annual energy production depends on solar conditions but is expected to average 25,196 MWHs per year. TCLP's current power purchase agreement for Calhoun Solar expires on 1 May 2048.

Hart Solar: TCLPs share of the Hart Solar project has nominal capacity of 13.2 MW. Annual energy production depends on solar conditions but is expected to average 28,584 MWhs per year. TCLP's current power purchase agreement for Hart Solar begins on 1 June 2025 and it expires on 1 June 2045.

Jupiter Battery Project: TCLP's share of the Jupiter Battery Project of the MPPA is 4 MWs from 2025 through 2028, then 2 MWs from 2029 through 2035. This is a capacity only contract, and Jupiter will be responsible for net energy operations of the battery system. TCLP's capacity purchase agreement for the Jupiter Battery Project begins on 1 January 2025 and will expire on 31 December 2035.

Kalkaska Combustion Turbine: TCLP jointly owns the Kalkaska combustion turbine, with TCLP's share having nominal capacity of 37.95 MW. Annual energy depends on how much it is instructed to run in the MISO market but in 2021 TCLP's share of generation was 40,007 MWhs. Kalkaska does not currently have a firm retirement date.

M-72 Solar I: TCLP has a power purchase agreement for all of the M-72 Solar I project, with nominal capacity of 1 MW. Annual energy production depends on solar conditions, but is expected to average 1,869 MWhs per year. TCLP's current power purchase agreement for M-72 Solar I expires on 31 December 2038.

M-72 Solar II: TCLP has a power purchase agreement for all of the M-72 Solar II project, with nominal capacity of 1.8 MW. Annual energy production depends on solar conditions, but is expected to average 2,438 MWhs per year. TCLP's current power purchase agreement for M-72 Solar II expires on 31 December 2041.

M-72 Solar III: TCLP has a power purchase agreement for all of the M-72 Solar III project, with nominal capacity of 1.8 MW. Annual energy production depends on solar conditions, but is expected to average 2,438 MWhs per year. TCLP's current power purchase agreement for M-72 Solar III expires on 31 December 2042.

Bilateral Energy and Capacity Purchases: TCLP purchases energy and capacity in a "laddered hedge" to meet 80% of its annual net energy requirements and any capacity shortfall. A laddered hedge is a series of overlapping multiple year contracts, such that in each year a portion of the need was purchased that year, a portion the previous year, a portion the year before that, etc… TCLP uses a 4-year ladder. In 2021 TCLP acquired 71,584 MWhs of energy through bilateral contracts.

MISO Market Net Purchases: As described above, TCLP buys all power to serve its customers from MISO and sells to MISO all of the power it generates or obtains by contract. Any difference between these quantities is TCLP's "net purchase", sometimes called "net interchange power".

5.4 TCLP Transmission

In addition to its power supply arrangements, TCLP must use transmission services to move power from where it is produced to its customers. As noted above, transmission is managed by MISO, which charges TCLP for transmission services. TCLP also has certain transmission rights, based on past investments in transmission associated with its participation in various generation plants.

Power is transmitted to TCLP at three substations at the edge of TCLP's service area, from which the power is distributed to TCLP customers. MISO charges TCLP for transmission based on TCLP's demand for power in the hour of each month when the Michigan transmission grid to which TCLP is linked has its highest power deliveries. TCLP's share of that peak load each month determines the share of transmission costs in that month that TCLP pays for. In 2021, those peak hours were as shown on the following graph. TCLP's power usage in these hours determines TCLP's transmission costs.

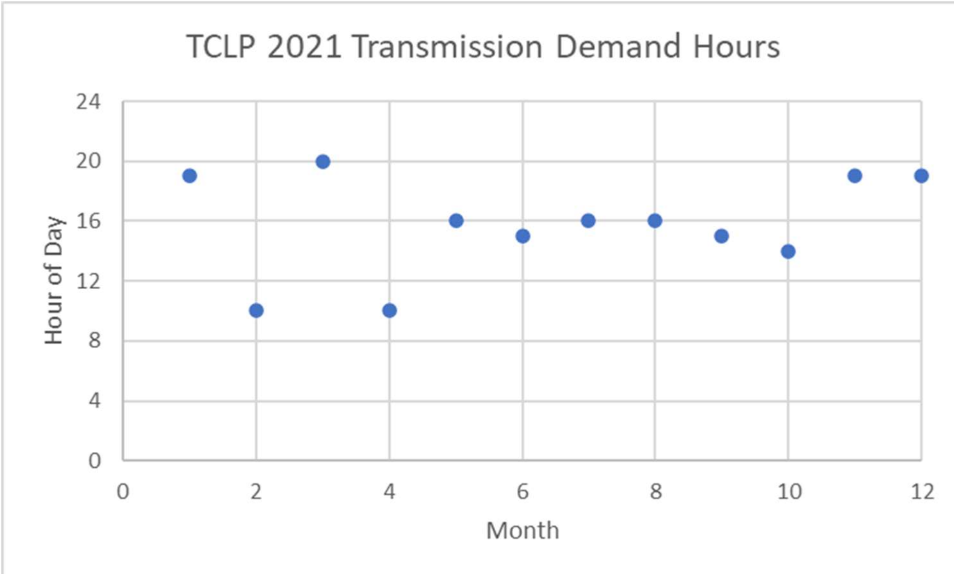


Figure 5-5 Monthly Peak Transmission Use Hours in Michigan

In general, transmission demand is determined in late afternoon of summer and fall months, and either early evening or start of the business day in winter and spring. In 2021, TCLP's annual transmission requirements were about 608 MW-months, or an average of about 51 MWs each month.

TCLP has several transmission entitlements, which offset its monthly transmission requirements and can result in net payments to TCLP when entitlements exceed requirements. These entitlements are:

- 10.637 MWs associated with Campbell Unit 3, which TCLP should be able to retain after Campbell 3 retirement;
- 10.516 MW associated with Belle River, which TCLP does not currently anticipate being able to retain after Belle River's retirement but will retain if Belle River is converted from coal to natural gas fuel;
- 37.95 MW associated with the Kalkaska plant, and
- 2.984 MW from a general transmission project of the MPPA.

Thus TCLP holds transmission entitlements totaling 62.087 MW, which usually exceeds its requirements.

5.5 TCLP Distribution

TCLP's distribution system delivers power from transmission substations to customers. Substations have a number of elements, but their core function is to transform voltage. TCLP is served by three transmission substations with transformer capacity of 672 MVA. (MVA stands for mega volt-amps, a measure of power flows that is similar to MWs but includes the alternating current power flows necessary to support the grid itself. These substations are connected to provide redundant pathways in case of a substation outage.

From these substations, power is distributed at 69 kV to and through five distribution substations along lines that radiate from the transmission substations. These distribution substations have transformer capacity of 244.8 MVA. A total of 30 distribution circuits radiate from the distribution substations at 13.8 kV and extend throughout the TCLP service area. Customers that use significant power are served directly from these 13.8 kV circuits, but most customers are served through distribution line transformers that serve a small neighborhood at 120 V. TCLP has 1,919 of these line transformers with approximately 185.1 MVA capacity. Generally speaking, if TCLP customers' electricity requirements increase by a significant amount, line transformers can be replaced by line transformers having higher capacity or the served customers can be split between two line transformers. Increases large enough to exceed the capacity of substations or primary distribution lines are more challenging but can be addressed by either increasing the voltage of the primary circuits or by splitting the network into more circuits emanating from the distribution substations. Later in this report, we provide a general assessment of the ability of TCLP's distribution system to handle projected changes in electricity demand.

6 TCLP Economics

TCLP's fundamental economics as an electric utility are important in determining a Climate Action Plan. At the most basic level, TCLP must recover its costs. It must also do so in a way that is fair to customers in that the bills customers pay have reasonable fidelity to the costs they cause. Finally, we find that the price signals to customers that are provided by rates are an important guide to align customer decisions with the underlying costs to the utility and to society of those decisions. Following, we provide an overview of TCLP's economics. To ensure reasonable consistency and avoid redundant work, we rely substantially on the work done by Utility Financial Solutions ("UFS") to develop cost of service and rate recommendations for TCLP. Recommendations in this report will not materially affect TCLP's costs and revenues in 2024, which is the first year of projections provided to TCLP by UFS in their most recent Cost of Service study. We rely on projected 2024 costs as the basis for our analyses.

In considering a utility's economics, it is important to distinguish three related but distinct concepts of "cost".

Customers generally think of TCLP's cost as the prices they pay for power from TCLP. This is correct, and reflects all of the costs that TCLP has incurred or is incurring that need to be paid for by current customers. However, it may not be helpful in thinking through scenarios that change how TCLP operates or how its customers use electricity.

In order to determine how much to charge different customers for various elements of electrical service, a utility typically develops a cost of service study such as that developed by UFS for TCLP. Such a study determines the utilities current year revenue requirements to cover current operating expenses and to appropriately pay for past investments, including depreciation to cover the incremental loss of remaining life of those past investments and the costs of the capital invested and not yet recovered from customers. These embedded costs need to be paid for by current customers, regardless of whether the current consumption by those customers drives current costs. Embedded and current costs are allocated to customer classes based on allocating costs to functions like power supply or distribution, then allocating the costs of each function to customers according to some measures of customer use of each function. This perspective on costs is referred to as the cost of service, and rates are then set to reasonably match up customer bills to customer cost of service. Mismatches between cost of service and bills (derived from rates) suggest that changes in rate design may be in order to make these match more closely. We give some attention to such mismatches later in this report, because those mismatches can create incentives to customers that adversely affect TCLP objectives or costs.

The third concept of cost is commonly called marginal cost. Marginal cost measures how total costs change with a small change in electricity use or some other factor that affects the utility's total costs. When evaluating the benefits or costs of potential program changes or power supply resources later in this report, we typically consider marginal costs and ignore accounting for all of TCLP's costs that are unchanged by the course of action we are evaluating.

6.1 TCLP Costs of Capital

Many utility costs are long-term investments that are recovered gradually from customers. While the investments are in use and not yet fully paid for by customers, that capital must be financed. Financing is typically debt, or borrowed funds, on which the utility must pay interest, or equity, using existing cash on hand, on which the utility must earn a return in order to cover the effects of inflation on future replacement costs and any risks of lost value. As a municipal utility, TCLP has few risks that it will not recover invested funds but does face lost value through inflation or obsolescence. The combined costs of borrowing and equity investments are referred to as the "costs of capital".

In our evaluation of future resource options for TCLP, we consider the cost of capital for any significant investments. When those investments are made by others and TCLP purchases power rather than owing the facilities, we assume that costs of capital are appropriate to the financial practices of the TCLP's counterparty. If the resource option is to be owned by TCLP, we assume cost of capital as determined by UFS. UFS recommends cost of capital that increases gradually from about 4.89% in 2024 to somewhat above 5% in later years. We use 5.1% as a representative cost of capital.

6.2 TCLP Required Revenue

According to UFS' projections, TCLP operating costs in 2024 will total approximately $44.946 million, of which approximately $30.163 million will be for power supply. A portion of power supply costs can be considered as being offset by revenues from MISO for power supply and transmission provided by TCLP to MISO; these total approximately $3.207 million such that the net cost of power supply is approximately $26.956 million. The remainder of TCLP's projected 2024 costs cover TCLP's distribution system, customer service, and other operations. Additional costs including interest on long-term debt and return on equity (which primarily serves to fund future reinvestments in TCLP's system) bring recommended 2024 revenues to $43.799 million.

6.3 TCLP Cost of Service

A cost of service study aims primarily to determine how much revenue should be collected through rates of various classes of customers, such as residential, small commercial, large commercial, and primary customers, although sometimes with various subcategories. To determine this revenue responsibility, costs in each functional category are allocated to these customer classes in proportion to some allocator. By calculating the amount of cost that is allocated based on a given allocator and dividing by the total TCLP quantity of the allocator, we obtain a unit cost of the allocator. These unit costs can then be applied to any load profile, whether that of a customer class, an individual customer, a specific end-use of electricity or even a change in one of these as a result of a customer decision or a TCLP program, it is possible to determine the cost of service for that specific profile. In this fashion, 5LE was able to assign cost of service (or changes in cost of service) for such things as choosing a more efficient refrigerator, charging an electric vehicle, or switching from a gas water heater to a heat-pump water heater. We assume that UFS methods for allocating cost of service are reasonable and can therefore determine how much incremental revenue should be produced by such a change and compare that to the actual amount that a customer will pay, given TCLP's rates. If the customer pays more for the change than the change in cost of service, they are effectively overpaying and might be discouraged from taking that action. On the other hand, if the customer pays less for the change than the change in cost of service, the customer is effectively underpaying and the action is subsidized.

The cost of service factors used by UFS in their work for TCLP are:

- Class 1CP, Residential – the demand by residential customers in the hour of the year when residential customer demand is highest

- Secondary System Peak – the demand by customers served at secondary voltage in the hour of the year when demand by customers served at secondary voltage is highest
- Primary System Peak – the demand by customers served at secondary or primary voltage in the hour of the year when combined demand by customers served at these voltage levels is highest
- System 1CP, Summer – the demand by all TCLP customers combined in the hour of the summer when their combined demand was highest
- System 1CP, Winter – the demand by all TCLP customers combined in the hour of the winter when their combined demand was highest
- System 1CP, Intermediate 2 – the demand by all TCLP customers combined in the hour of the Intermediate 2 period when their combined demand was highest
- System 1CP, Intermediate 4 – the demand by all TCLP customers combined in the hour of the Intermediate 4 period when their combined demand was highest
- Energy, Summer – the kWhs delivered to TCLP customers during summer
- Energy, Winter– the kWhs delivered to TCLP customers during winter
- Energy, Intermediate 2 – the kWhs delivered to TCLP customers during the Intermediate 2 period
- Energy, Intermediate 4 – the kWhs delivered to TCLP customers during the Intermediate 4 period
- Customers – the count of customers served by TCLP
- Weighted customers – the count of customers served by TCLP, weighted by relative costs of metering

In these cost of service factors, summer is the months of July and August; winter is the months of December, January, February, and March; Intermediate 2 is the months of June and September; and Intermediate 4 is the months of April, May, October, and November.

6.4 TCLP Marginal Costs

Some utility costs are relatively invariant to any changes in the utility's service to customers. For example, much of the cost of the distribution system is incurred to cover the geography of the utility service area and is not much affected by the number of customers in the service area, the amount of electricity each customer uses, etc.. Thus, to evaluate the effects of a change, we need to include only the costs that will change as a result of the change under analysis. 5LE obtained from UFS estimates of these marginal costs for the same factors used to allocate cost of service.

We note that in most of our analyses, we emulate UFS in using marginal cost of electricity supply (in kWh) based only on whether the electricity is used in broad time-slots such as summer on-peak, summer off-peak, winter on-peak, and winter off-peak. This works reasonably well because most uses of electricity occur in such general patterns so the average marginal cost in each time slot is reasonably accurate. However, when considering the economics of generation and storage, precise timing matters and we forecast and use hourly prices based on the way that wholesale power markets work; these hourly prices are discussed in the report section on integrated resource planning.

Marginal costs are relevant in our analyses in three respects. First, if TCLP is evaluating two or more alternatives, the marginal costs of those alternatives are the relevant way to compare costs of the alternatives. Second, when considering whether an action or change is good for society, marginal costs represent the overall cost to society of the resources that are consumed by the action or change. Below we describe our approach to benefit-cost analysis, which considers marginal costs along with other costs to society that are not paid for as resources. Third, the difference between the customer price paid for an incremental use of electricity and the marginal cost of that use of electricity (sometimes called the gross margin) is potentially available as a rebate to the customer for making the change, since the marginal cost needs to be used by TCLP to cover the costs of the change.

6.5 TCLP Economic Factors

The unit costs applied to determine cost of service and marginal costs in our analyses of TCLP programs are as follows:

TCLP Cost of Service Metric	Unit	COS Multiplier	MC Multiplier
Class 1CP, Residential	$/kW	74.103	0.000
Secondary System Peak	$/kW	0.620	0.000
Primary System Peak	$/kW	0.518	0.000
System 1CP, Summer	$/kW	0.028	0.028
System 1CP, Winter	$/kW	0.053	0.053
System 1CP, Intermediate 2	$/kW	0.027	0.027
System 1CP, Intermediate 4	$/kW	0.055	0.055
Energy, Summer	$/kWh	0.085	0.085
Energy, Winter	$/kWh	0.061	0.061
Energy, Intermediate 2	$/kWh	0.079	0.079
Energy, Intermediate 4	$/kWh	0.064	0.064

Table 6-1 Multipliers used to compute annual cost of service and marginal cost.

6.6 Rate Design and Customer Costs

Notwithstanding the cost of service or marginal costs of electricity consumption by a customer, the customer pays an amount based on TCLP's rates. Rates are usually simplified from the allocators used in the cost of service study. Some cost of service allocators, such as the total demand in the highest hour of each month, occur at a time that is not precisely predictable, so it isn't generally practical to charge customers for their contribution to that allocator. Other allocators are difficult for a customer to manage. Decisions about what units of electricity usage a utility will bill a customer for and at what unit price are commonly called "rate design" by utilities.

Due to limitations of metering technology, utilities long used rate designs that consisted of a fixed monthly charge, a volumetric charge, and in the case of large commercial customers a demand charge. Volumetric charges were typically uniform throughout the year but might be seasonal or be higher or lower for quantities above a basic allowance per month.

Demand charges are based on the individual customer's highest rate of electricity use during a short period such as 15 or 30 minutes at any time during the billing month or even in the year and were intended to charge customers for generation, transmission, and distribution capacity needed to serve that customer's peak demand.

TCLP has begun changing from this traditional rate design to a time of use ("TOU") rate design, like many utilities are doing now that advanced meters are available that are capable of measuring and recording electricity usage in many time intervals. The combination of these advanced meters and the communications and software infrastructure to gather and use these data are referred to as Advanced Metering Infrastructure ("AMI") TOU rates have different volumetric rates at different times, which more accurately reflects the costs caused by usage than does traditional rate design. Had TCLP not already begun this transition, we would be recommending TOU rates because they provide much better incentives to customers to take the kinds of steps that will be needed to reduce greenhouse gas emissions with least resource costs.

Because TCLP has laid out a multi-year rate transition to provide customers time to adapt, but most of our program recommendations affect customers toward or after the end of that transition, we perform our analyses based on the rate design that TCLP expects to have in place circa 2026. Those rates are summarized in the following table:

Rate Element	Residential TOU Existing Pilot	Small Comm TOU Phase 3	Comm Demand TOU Phase 5
Monthly Facilities Charge:			
All Customers	$ 7.50	$ 26.06	$ 30.00
Energy Charge:			
Summer On-Peak	$ 0.19570	$ 0.14490	$ 0.13010
Summer Off-Peak	$ 0.08000	$ 0.08956	$ 0.07170
Summer Critical-Peak		$ 0.20248	$ 0.19070
Winter On-Peak	$ 0.19570	$ 0.13063	$ 0.10880
Winter Off-Peak	$ 0.08000	$ 0.07084	$ 0.04900
Demand Charge:			
Winter			$ 4.65
Summer			$ 4.65
Power Cost Adjustment:			
All Energy	$ 0.02811	$ 0.02811	$ 0.01122

Table 6-2 Rate designs used for performing our analyses.

Because the rates we used in these analyses represent the apotheosis of TCLP's current efforts in rate re-design, any differences between revenue from an end-use and cost of service for that end-use implies opportunity for further changes in rate design once the current changes are phased in.

Based on our prior work on rate design and comprehensive awareness of both the published literature and testimony present in regulatory cases, we have concluded that time of use rates provide the most accurate match of customer bills to customer cost of service, at an individual customer level, and thereby also provide the most accurate price signals to customers about how their electricity consumption affects the utility's costs. We therefore offer the following

Recommendation: Adopt default rate designs for all customer classes that are based on both seasonal and time-of-day rates. By carefully reflecting cost causation by time, these will promote cost-effective energy efficiency, beneficial electrification, good vehicle charging behavior, and behind-the-meter solar and storage. The key to this is to volumetrically charge energy at approximately locational marginal price and minimum distribution system costs at all times and to recover costs for capacity, transmission, and distribution demand during times when those demands are likely to be at or near peaks. Customer load responses to this rate structure will also minimize TCLP power supply and transmission costs.

7 Benefit-Cost Analysis for TCLP Programs

Later in this report, we present analyses of various programs that TCLP could adopt as part of its Climate Action Plan. We then base program recommendations on those analyses. Most of these program options relate to potential offers by TCLP to help customers take actions themselves. Although we present other information as well, the primary purposes of our analyses are to determine whether a particular program is beneficial and to whom, or to optimize a program to provide maximum net benefits. We generally present analyses from three perspectives.

Societal benefits and costs serve to determine whether aggregate benefits exceed aggregate costs. Primary consideration is to the marginal change in society's economic resource uses and to externalities. Externalities are effects on other people that are not involved in the decisions to undertake a particular transaction, such as climate change or health effects from pollutants.

TCLP participating customer benefits and costs accrue to the particular TCLP customers who accept an offer from TCLP, such as a rebate for choosing a preferred product, or are directly affected by something like a rate design change.

TCLP revenue margin and cost shift analysis reflects that an offer of assistance to some customers is likely paid for by others but also that an offer that reduces electricity use by one customer may shift responsibility for certain costs to other customers while an offer that increases electricity use by one customer may shift responsibility for certain costs onto that customer and away from other customers. These cost shifts generally do not affect aggregate societal benefits or costs but nonetheless are worth considering.

We describe the accounting and analytical framework for each of these perspectives below, after covering some preliminary matters that shape those analyses.

7.1 Discount Rate and Present Value

Most of the programs we analyze take place over time, and the flow of benefits and costs also occurs over time. For example, TCLP currently offers rebates to customers for the use of more energy efficient products such as LED lights. Customer acceptance of those offers is generally only when the existing products fail, which can take many years in some product categories. A customer who accepts an offer and adopts a different product then experiences product cost immediately but benefits from energy savings over the life of the product.

Empirically, people act as though they prefer benefits sooner rather than later and they would prefer to put off costs. Economic theory generally represents this behavior as a discount rate that diminishes future benefits and costs back to the present or decision time by application of an annual discount rate. Specifically, a future benefit or cost value that will accrue in year y, which we label as v_y, is assumed to weigh in a decision in year 0 as though its value v_0 can be calculated as

$$v_0 = \frac{v_y}{(1+d)^y}$$

Where d is the discount rate. Discount rates are commonly found or assumed to be some small percentage such as 2% or 10%.

A series of benefits or costs over several years can each be brought back to the current or decision year by this method and added together to get the present value of the decision. As a formula, this is commonly written as

$$PV = \sum_{y=0}^{Y} \frac{v_y}{(1+d)^y}$$

The analyses we present later generally include estimates or projections of annual benefits and costs but we mostly focus on present values to determine whether a program or offer is beneficial or to compare alternatives.

The discount rate serves effectively as a weighting factor in considering values across time this can affect a decision. A larger discount rate gives lesser weight to the future compared to the present. Since we are usually considering a program or decision with immediate costs followed by benefits over time, a low discount rate will tend to favor that investment while a high discount rate will tend to disfavor that investment. Thus, the choice of discount rate is important in our analyses.

In many respects, discount rates are empirical in that they describe how people behave when making decisions with consequences over time. Economic theory has developed explanations for observed discount rates and normative theories about how people should discount the future. Discount rates we use in our analyses for TCLP reflect that body of knowledge. we apply different discount rates based on the benefits and costs perspective we are considering, with distinct discount rates for society, participating customers, and TCLP. Below, we discuss the particular discount rates in conjunction with discussion of benefits and costs from each of these perspectives.

7.2 Heating Fuel Economics

In our analyses of building electrification and some energy efficiency measures, changes in the use of heating fuels is an important aspect of the societal costs of energy use and of the customer's experience when responding to a TCLP offer. A few basic ideas and facts about heating fuel economics appear throughout our analyses, so we present them here.

Some TCLP customers use electricity to heat space, heat water, and cook and we report the shares of customers in various categories who do so. Most TCLP customers use natural gas for these energy end-uses. Likely, a few TCLP customers use some other heating fuel but we provide all analyses using natural gas because it is ubiquitous. In general, any other heating fuel is more expensive than natural gas, so any analyses comparing electricity to gas for these uses would be even more favorable for a customer using another heating fuel.

Natural gas is delivered to TCLP customers by DTE Gas Company.

Natural gas is typically delivered and billed in units of either therms or cubic feet. DTE Gas prices natural gas per 100 cubic feet. In many of our analyses later in this report we show gas in kWh, to make comparison to electricity more convenient. The conversion factor for these different measures of natural gas quantity 29.3 kWh per 100 cubic feet. kWh of natural gas measures the energy content of the gas and does not mean that it takes the same number of kWh of electricity to provide the same heat as gas. Because gas combustion is incomplete in common uses, it takes less electricity than gas to produce the same end use.

We use two principal economic concepts for the cost of natural gas. For the end customer, the cost of natural gas is the charge for it that appears on their bill, which includes the cost of producing the gas and the volumetric charge by the gas utility for transmission and delivery of the gas to the end customer. For society as a whole, most of the costs to the end customer of transmission and delivery are just the recovery of past investments, which are "sunk costs" that cannot be avoided as they were already incurred. Since gas transmission and delivery of gas is regulated so that customers repay the utility for such sunk costs along with return on investment until the sunk costs are repaid, any reduction in gas use by a particular customer just causes other customers to pay a bit higher rate for their gas and any increase in gas use by a particular customer just reduces the rate that other customers pay by a bit. On the other hand, a change in gas consumption leads to a change in future gas production expenditures, as current wells are used earlier or later than they otherwise would have been. We therefore refer to the cost of gas to DTE Gas as the marginal cost of gas and the total cost paid by the customer for gas delivered to their property as DTE Gas revenue.

We used the gas delivery and gas commodity rates from DTE Gas most recent rate case to establish values for revenue (customer bill) and marginal cost of gas per kWh of gas.[20]

7.3 TCLP Program Societal Benefits and Costs

When TCLP carries out a customer education and outreach effort and makes rebate offers to customers to induce different decisions about energy-using equipment or building envelope improvements, the program cost is a cost to society. The customer will be taking actions that have various costs and benefits to them, which we assume will be positive if the customer voluntarily takes action. To justify the program, net societal benefits should be positive. Positive net societal benefits can be assured if the TCLP program costs do not exceed the benefits to the rest of society. Thus, our analyses provide estimates of a monetized societal benefit for each program element.

We include in societal benefits the net marginal costs of energy, the net marginal avoided health costs due to reduced air pollution emissions, and the net marginal avoided costs of climate change. There are other potential benefits that we are not estimating, but we believe these benefits to be the largest for the program elements we examine. Our estimates of societal benefits, made up of avoided societal costs, are therefore likely an understatement.

[1] DTE Gas cost information was sourced as follows:

Parameter Used in Calculations	Source Docket
IRM Surcharge ($)	Tariff Sheet, Revised pursuant to U-21206
Customer Charge ($)	Tariff Sheet, Revised pursuant to U-21206
EWR Surcharge ($/Ccf)	Tariff Sheet, Revised pursuant to U-21206
Distribution Charge ($/Ccf)	Tariff Sheet, Revised pursuant to U-21206
Gas Cost Recovery Charge ($/Ccf)	U-21064 as reported in GCR Summary

To determine societal benefits when the avoided costs re in the future and perhaps spread over time, we determine net present value of benefits as discussed above. The discount rate we use for societal benefits is 2.5% per year. This is consistent with economic theory and is the discount rate being used by the US government for similar purposes.[21]

We estimate the changes in customer consumption quantities of electricity and gas as discussed later in this report and assign economic costs or savings to those quantity changes using the marginal costs as discussed above.

To estimate health costs, we applied EPA's Co-benefits Risk Assessment Health Impacts Screening and Mapping Tool ("COBRA").[22] This tool provides estimates of the changes in premature deaths, incidences of various disease and health care events, and monetized values of those based on changes in emissions of various pollutants. Included pollutants are particulate matter (PM2.5), sulfur dioxide (SO2), Nitrogen oxides (NOx), ammonia (NH3), and volatile organic compounds. These are the main categories of air pollutants regulated by EPA due to their health effects. The COBRA model takes account of the location of pollutant emissions, their expected spatial dispersion and population exposure, and aspects of population vulnerability, so the values it produces per unit of emissions vary geographically. For changes in customer natural gas usage due to TCLP programs, we use Grand Traverse County as the source location in COBRA and we include pollution effects anywhere in the United States (these are small except in Grand Traverse and adjacent counties). For changes in electricity usage, we use Michigan average impacts of power generation since small changes in power generation will affect all dispatchable fossil-fueled generators at various times of the year. If we assume that TCLP will provide power entirely from renewables, then we assume that a change in electricity consumption by TCLP customers has no effect on emissions for power generation since that change in electricity usage also presumably changes TCLP's plans for renewable power generation and leaves other power sources basically unchanged.

[21] EPA. 2022.Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. External Review Draft in Docket No. EPA-HQ-OAR-2021-0317. See pp 52 through 61

[22] Available from and documented at https://www.epa.gov/cobra.

To estimate climate change costs, we apply changes in greenhouse gas emissions and the estimates of the social cost of greenhouse gases using a 2.5% discount rate as presented in the EPA's most recent report on this topic.[23] The EPA's table is reproduced here for easy reference.

Table ES.1: Estimates of the Social Cost of Greenhouse Gases (SC-GHG), 2020-2080 (2020 dollars)

	SC-GHG and Near-term Ramsey Discount Rate								
	SC-CO_2 *(2020 dollars per metric ton of CO_2)*			SC-CH_4 *(2020 dollars per metric ton of CH_4)*			SC-N_2O *(2020 dollars per metric ton of N_2O)*		
Emission Year	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%
2020	120	190	340	1,300	1,600	2,300	35,000	54,000	87,000
2030	140	230	380	1,900	2,400	3,200	45,000	66,000	100,000
2040	170	270	430	2,700	3,300	4,200	55,000	79,000	120,000
2050	200	310	480	3,500	4,200	5,300	66,000	93,000	140,000
2060	230	350	530	4,300	5,100	6,300	76,000	110,000	150,000
2070	260	380	570	5,000	5,900	7,200	85,000	120,000	170,000
2080	280	410	600	5,800	6,800	8,200	95,000	130,000	180,000

Values of SC-CO_2, SC-CH_4, and SC-N_2O are rounded to two significant figures. The annual unrounded estimates are available in Appendix A.4 and at: www.epa.gov/environmental-economics/scghg.

Table 7-1 2020 Social Costs of Greenhouse Gases

At the current time, we assign health costs of $0.0039 and climate costs of $0.022 per kWh of natural gas used in Grand Traverse County for residential or commercial buildings. We assign health costs of $0.023 and climate costs of $0.063 per kWh of generic grid power, but no health or climate costs to 100% renewable energy. To the extent that TCLP offsets the power needs of its customers with renewable generation, TCLP avoids these health and climate costs. Naturally, as the generation mix on the grid evolves toward 100% clean energy, the health and climate costs of generic grid power will also decline proportionally. Pending coal plant retirements in Michigan will substantially reduce both the health and climate costs of generic grid power.

7.4 TCLP Participating Customer Benefits and Costs

A TCLP customer that participates in or responds to a TCLP program will likely change their consumption of electricity and perhaps also change their consumption of natural gas. They may receive a rebate from TCLP and the action they take may produce increases or decreases in their value for the use of the equipment or building compared to what they would otherwise have done. As an example of an increase in the customer's value for the use of equipment or building compared to what they would otherwise have done, we note that investments in air sealing and insulation of a building typically saves energy costs but also improves comfort. On the other hand, forgoing an external ice dispenser in a refrigerator might save energy but be less useful. We assume that such customer actions are voluntary, so the net benefits to the customer are positive.

We do not have a strong evidentiary basis for assessing the effects on customer use value of the various measures that we recommend TCLP promote to customers. In general, we anticipate that increases in energy plus equipment costs net of rebates will be unlikely to be taken up by large numbers of customers. We

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[23] EPA. 2022.Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. External Review Draft in Docket No. EPA-HQ-OAR-2021-0317. See Table ES-1 on p 3.

provide estimates of the effects of various measures on the customer's total utility bill as an indicator of how a participating customer might consider a TCLP offer.

To find the net present value of customer benefits and costs, we use a discount rate of 4.00%, which is the average consumption discount rate in the United States.

7.5 TCLP Revenue Margin and Cost Shifts

When a TCLP customer adopts an energy efficiency measure and reduces their use of electricity, TCLP revenue is reduced by the full retail price of the avoided electricity use but only saves the marginal cost of electricity. Because TCLP's full costs must be recovered from customers, this shifts some costs onto the remaining customers. Similarly, when a customer switches to electric heat or otherwise increases their electricity consumption, the provide incremental revenue to TCLP that shifts costs away from other customers and to the customer who electrifies heat. This shifting in prices and costs between customers is very normal in any business with high fixed or embedded costs, so is not a problematic outcome. It is also something that happens for many reasons. Changes in household occupancy will change the electricity bill for that household, with costs being shifted between the household that changes and other households. It is nonetheless helpful to understand these cost shifts.

Standard practice for energy efficiency programs is to adopt program costs that are less than the avoided marginal costs of power due to the savings measure. While this causes some cost shifts, it lowers the aggregate bill of all customers. Emerging practice for electrification, like the longstanding practice for utility line extensions to serve new customers is to rebate to the new load the margin of expected revenues over marginal costs of power, such that existing customers and end-uses do not pay more than if the new load was not added. In the case of line extensions, the new customer is expected to pay for any costs of line extension above what can be financed by the revenue margin for the new load. Similar logic supports customer rebates for electrification, reflecting the difference between revenue and marginal costs. For this reason, we calculate for each efficiency or electrification measure that we analyze below the net present value of the difference between revenue change and marginal cost change.

When there is a margin between revenue from an end use of electricity and the marginal cost of the power supplied, there are two components to that margin, One is the difference between revenue and cost of service, reflecting a mismatch between rate design and cost of service. The other is the difference between cost of service and marginal cost. We generally recommend alignment between rates and cost of service so as to avoid unintended cross-subsidization between customers. If there is such alignment, the difference between revenue and marginal costs will be close to the difference between revenue and marginal costs and this quantity is a sensible basis for setting funding levels for programs that assist customers in changing their electricity use. We calculate the net present value of the difference between revenue and marginal cost and the net present value of the difference between revenue and cost of service to aid in making decisions about rate design changes and funding levels of program offers to customers.

To find the net present value of utility revenues and costs, we use a discount rate of 5.84%, which reflects the discount rate of at-risk investments by TCLP.

8 TCLP Load Profiles

Load profiles are representations of when customers use electricity. Since customers generally don't store electricity, reliable power supply generates power at the time that it is being consumed, so understanding when electricity is consumed can be helpful in understanding generation resource requirements, but also in understanding which energy efficiency measures save electricity coincident with tight relative supply, or what electrification practices will create resource supply challenges. We therefore provide a perspective on load profiles below. Because there are 8760 hours in non-leap years and these profiles typically are done on an hourly time granularity, these are sometimes referred to as 8760 profiles. To illustrate these profiles, we use heat map graphs in which the days of the year are shown horizontally, the hours of the day are shown vertically, and the load or other quantity that is being visualized is shown as a gradation of color showing low vs high values.

8.1 System-wide Load

TCLP's current load profile is illustrated in the following heat map and the average weekly profiles in each month of the year. The heat map is intended to show visually the overall annual pattern of electricity use by TCLP's customers. Notable elements of this pattern are that usage is lowest from late night to early morning, higher during the business day, lower on weekends (note that recurring dark vertical bands every few days), somewhat higher electricity usage throughout the day in winter reflecting use of electricity for heat or heating fans, and highest usage on warm summer afternoons. The average weekly profiles by month miss some of this pattern, especially the peak load events but provide a better view of the magnitude of variation in electricity consumption and some subtleties of seasonality.

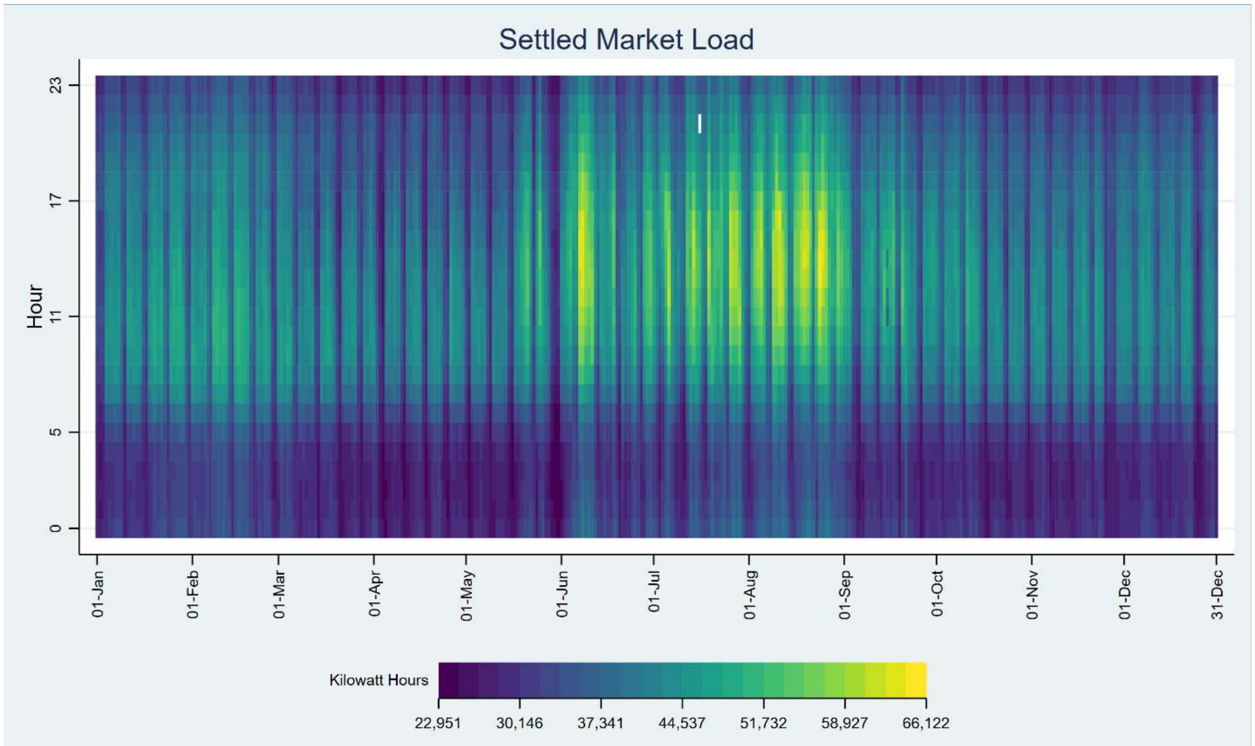

Figure 8-1 heatmap of TCLP's 2021 settled load

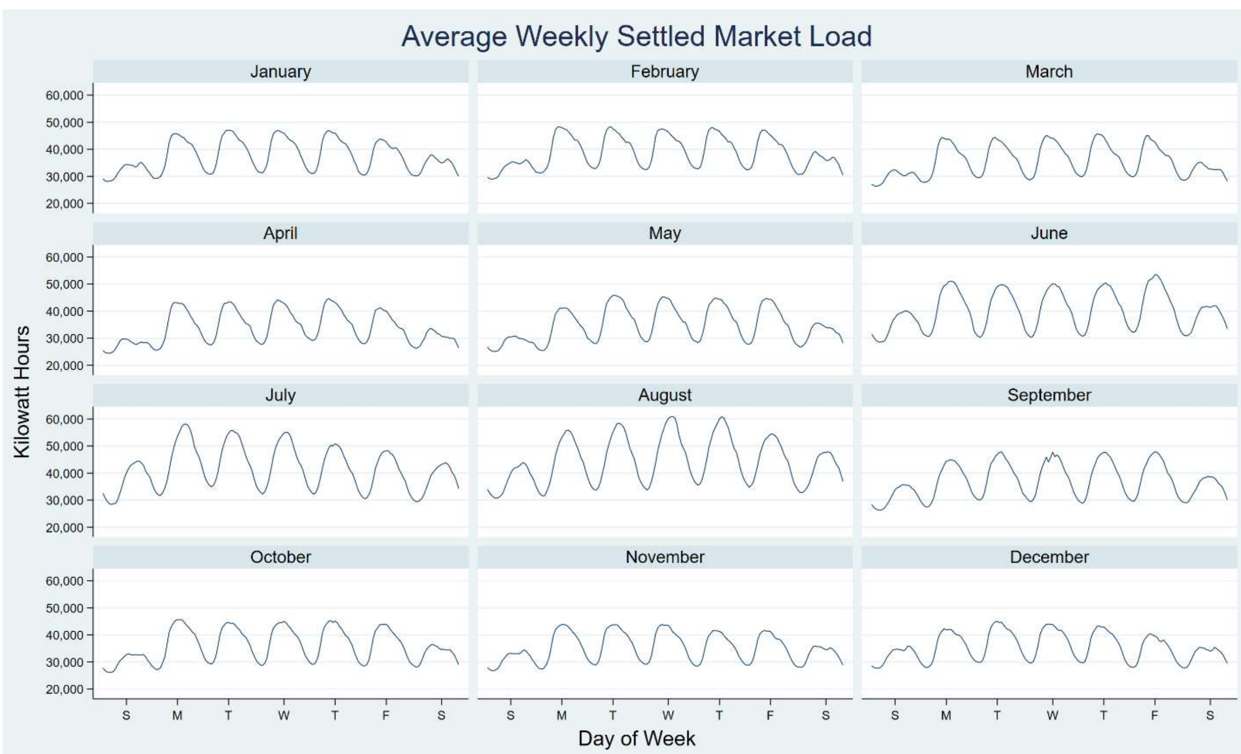

Figure 8-2 average weekly MISO sales to TCLP

8.2 Load by Rate Schedule

TCLP’s total load is made up of loads from each of its individual customers, but it is often useful to group customers who have similar total and patterns of electricity use. These are broadly captured by TCLP’s rate schedules. The following heat maps show the pattern of use by customers in each of TCLP’s major rate schedules.

The residential profile shows higher usage in the morning and evening each day, less distinction between weekdays and weekends, and the importance of heating in winter and cooling in summer.

The commercial profile shows the strong effects of business hours and weekdays vs weekends, some effects of winter heating, and particularly high usage on certain warm summer afternoons. More detailed analyses suggest that this is partly due to “tourist season” and partly due to air conditioning.

Commercial demand customers are very similar to commercial customers but are distinguished because individual commercial demand customers generally have higher electricity usage than commercial customers and their current rate design uses a demand charge. Commercial demand profile is similar to the commercial profile, though perhaps with longer business days and with less seasonal heating and cooling effects.

Primary customers are those that use enough electricity that they are served directly from TCLP’s higher-voltage primary circuits rather than from secondary voltage. These customers use rate schedules that are similar to commercial demand customers but have somewhat differing unit costs for customers that are primary but otherwise commercial demand, primary (mostly industrial) customers including TCLP’s meta melting customer, and for water pumping.

The commercial demand primary customers include a number of schools, which reduces load in summer and school vacation weeks.

Primary customers‘ profile shows some business hours effects, especially differences between weekdays and weekends, but generally more even usage levels throughout the day and less weather effects.

Pumping shows profound time of day and seasonal effects, presumably showing the effects of weather on the need for irrigation and the effects of “tourist season”.

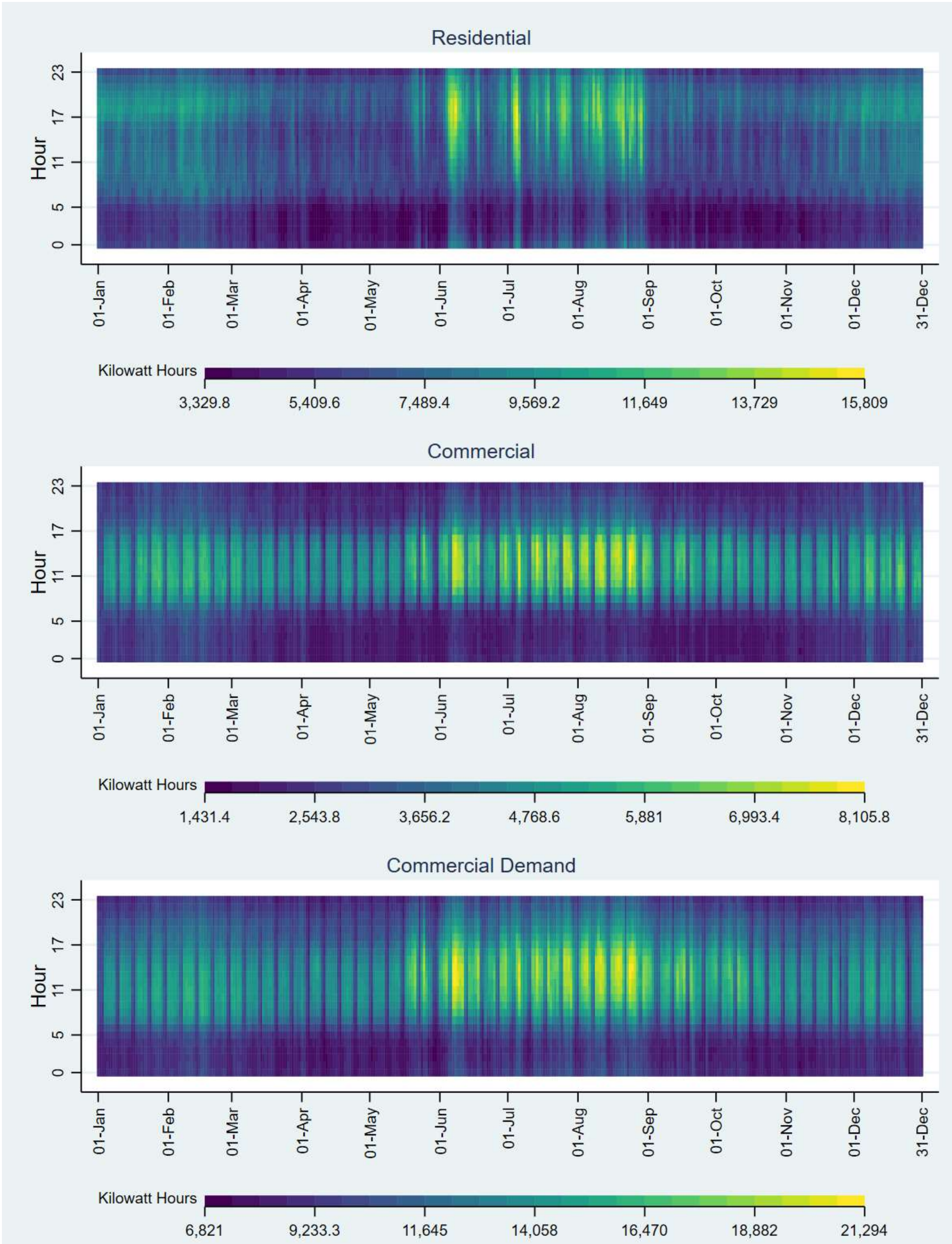

Figure 8-3 Heatmaps of TCLP Load by Customer Rate Class – Residential, Commercial, Commercial Demand

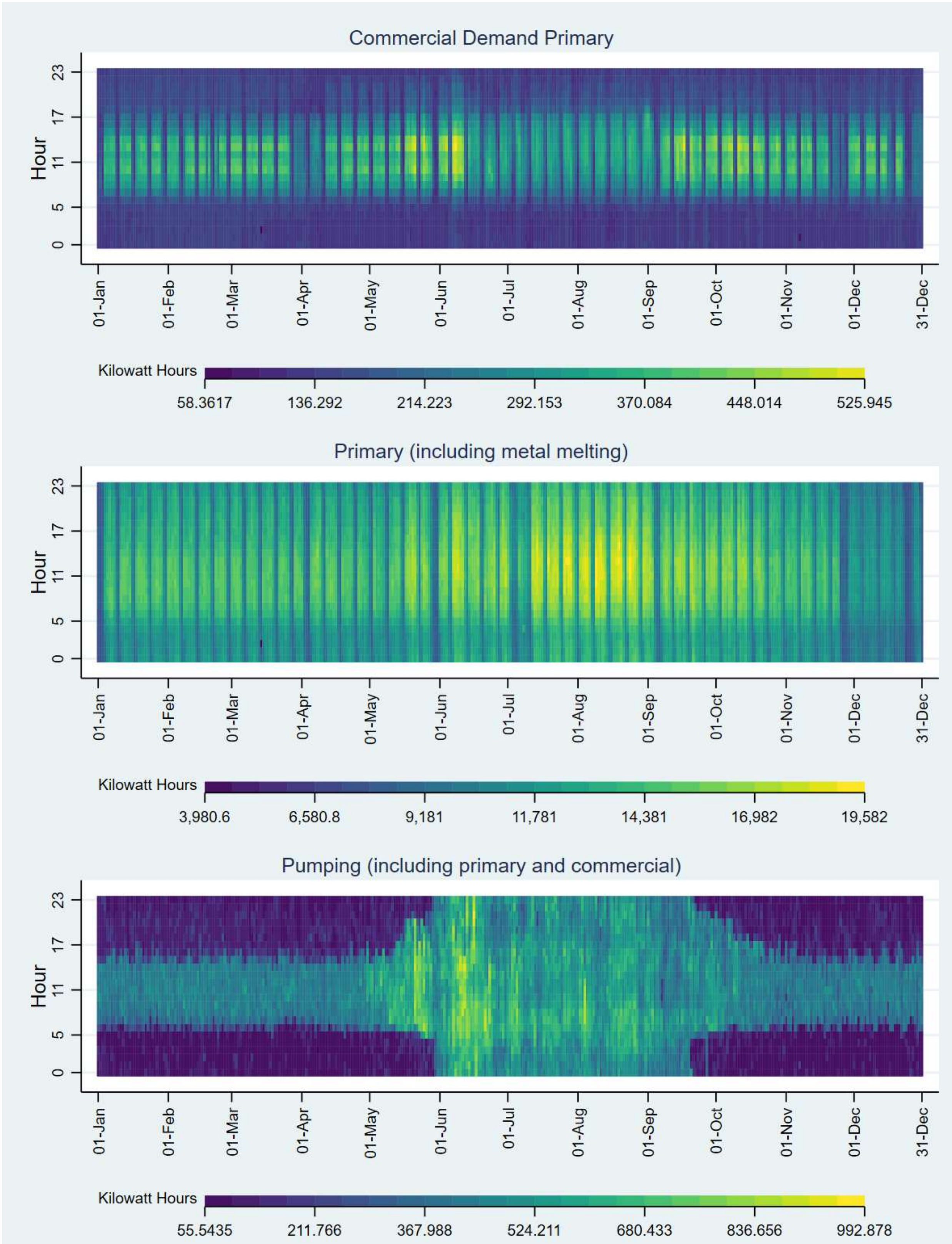

Figure 8-4 Heatmaps of TCLP Load by Customer Rate Class – Commercial Demand Primary, Primary, Pumping

8.3 Load by Distribution Voltage

When considering the effects of load changes on TCLP's distribution system, it is helpful to visualize the load at each voltage level. Since residential and commercial customers tend to be geographically separated by zoning and settlement patterns, we separate residential from secondary voltage commercial customers. The load on the primary system is made up of the aggregate loads of residential customers, secondary commercial customers, and primary customers, but this is just TCLP's total load. We present these three load profiles together here for comparison.

These profiles, while similar to those by customer class shown above, are more relevant to the design and capacities of TCLP's distribution system.

Line transformers in residential neighborhoods have high loads from mid-day to evening on a few hot days in summer, with highest loads during the hours from 4pm until 8pm

Line transformers in commercial areas have high loads throughout summer between 10am and 5pm, with a number of weeks of high load, presumably reflecting both the level of business activity during "tourist season" and weather requiring air conditioning.

Primary customers use private transformers that are not supplied by TCLP.

The total system load is served by TCLP's substations and primary distribution circuits. This load is more even than for many utilities but nonetheless has summer weekday peaks, especially in July and August.

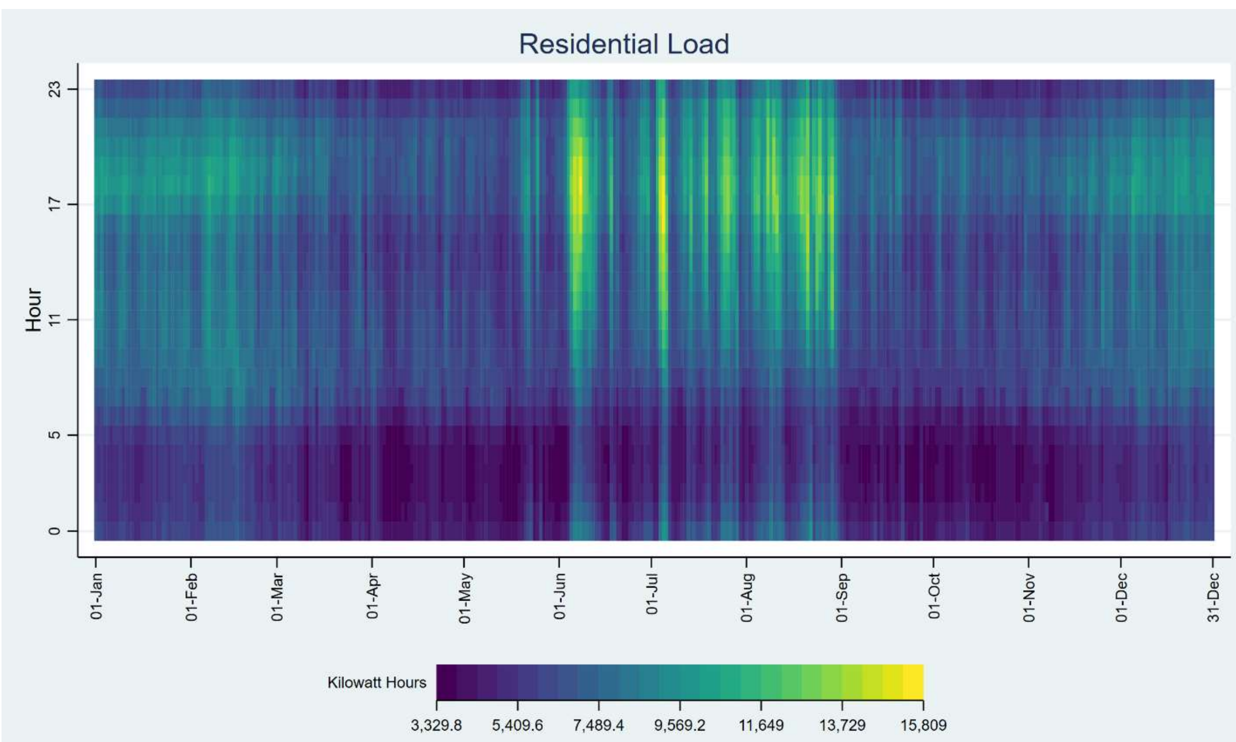

Figure 8-5 TCLP's actual 2021 residential load

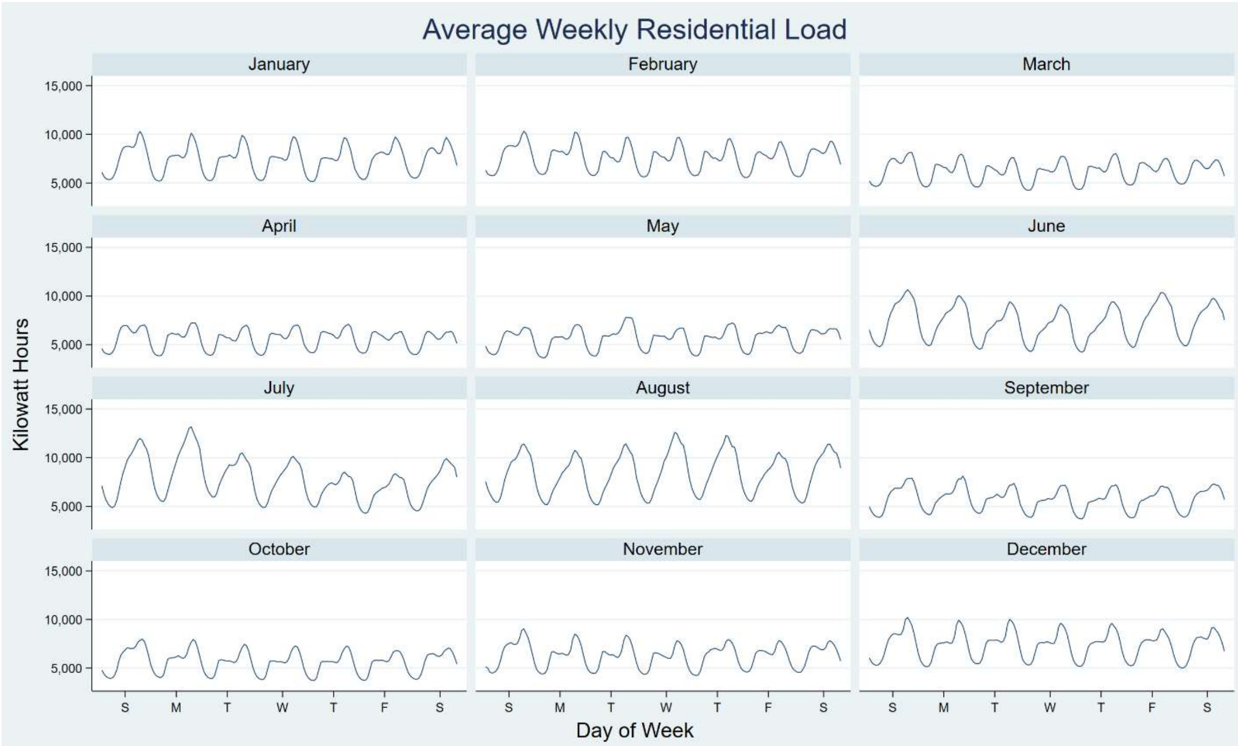

Figure 8-6 TCLP's actual 2021 residential load as average weeks in each month

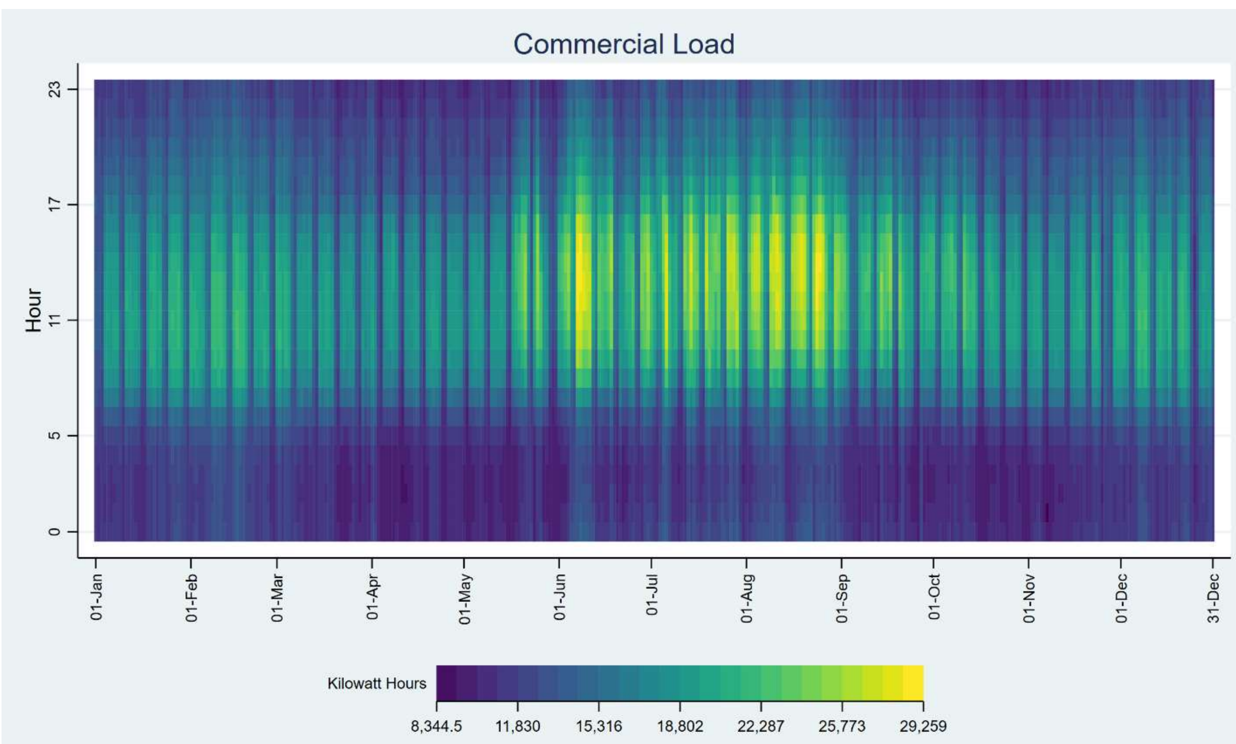

Figure 8-7 TCLP's actual 2021 commercial load (including commercial and commercial demand customers)

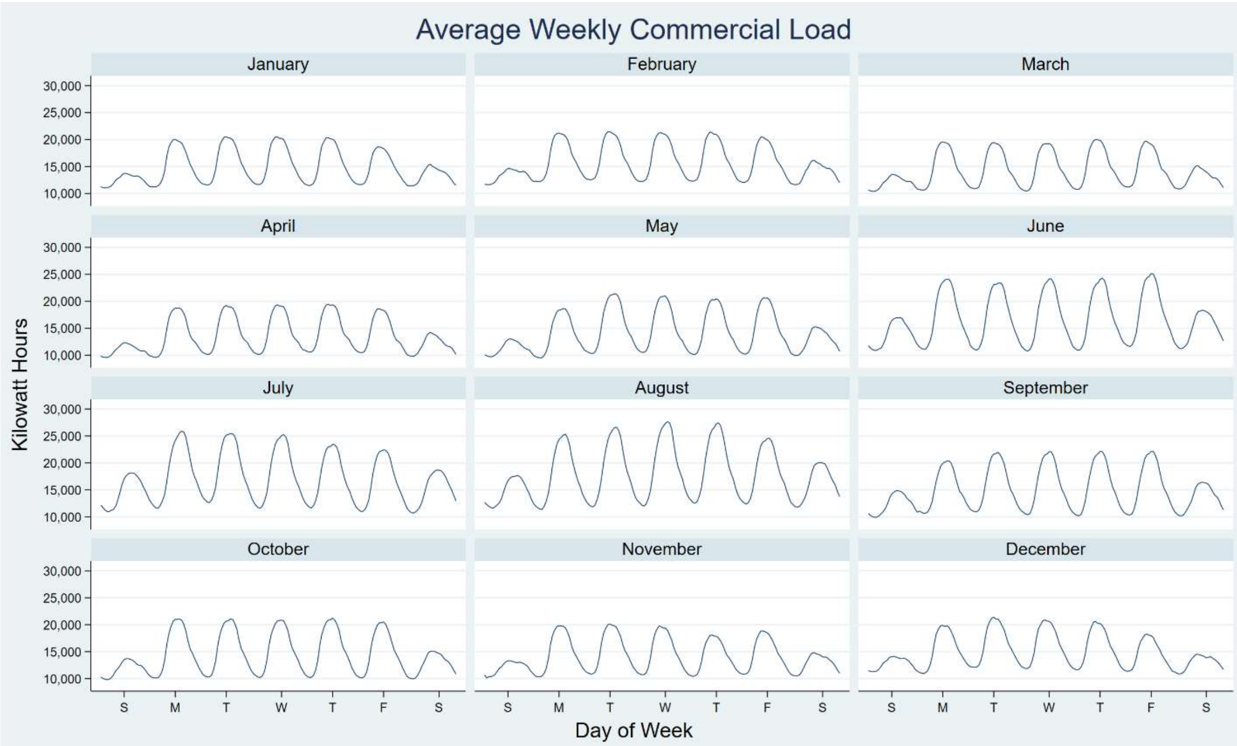

Figure 8-8 TCLP's actual 2021 commercial load as average weeks in each month (including all commercial and commercial demand customers)

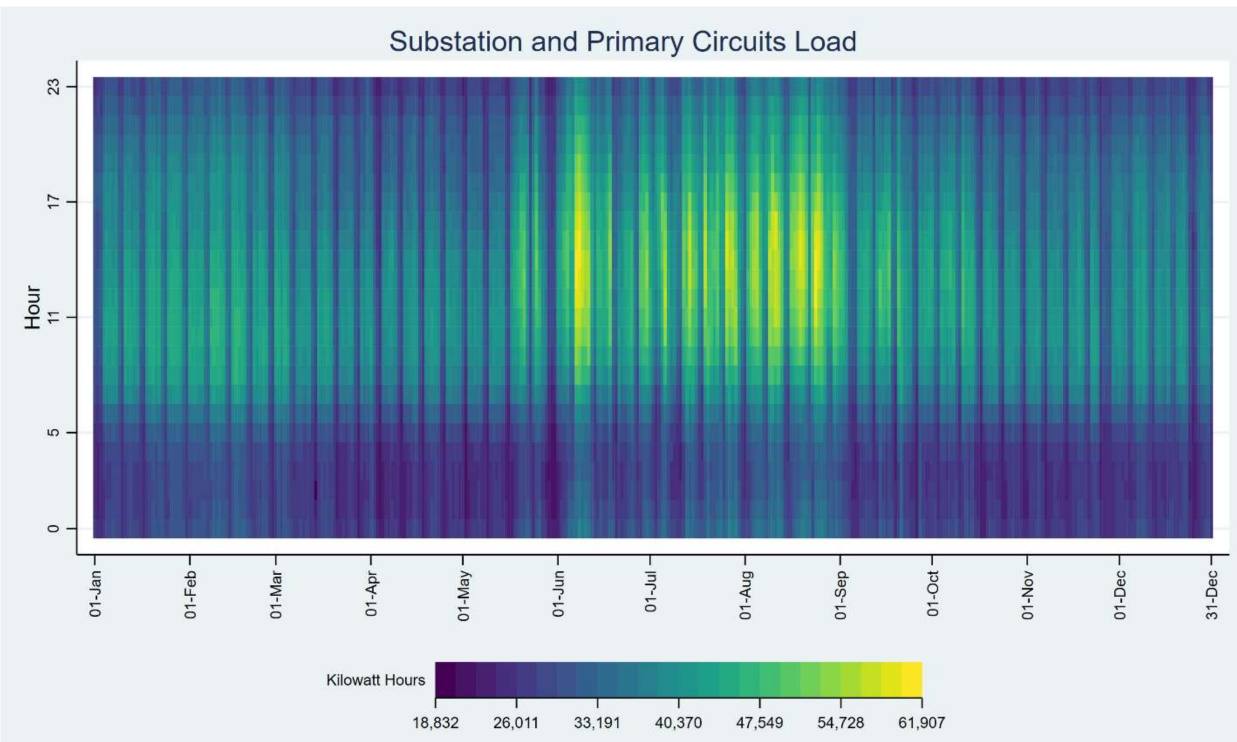

Figure 8-9 TCLP's actual 2021 primary load (including metal melting, pumping, and commercial demand primary loads)

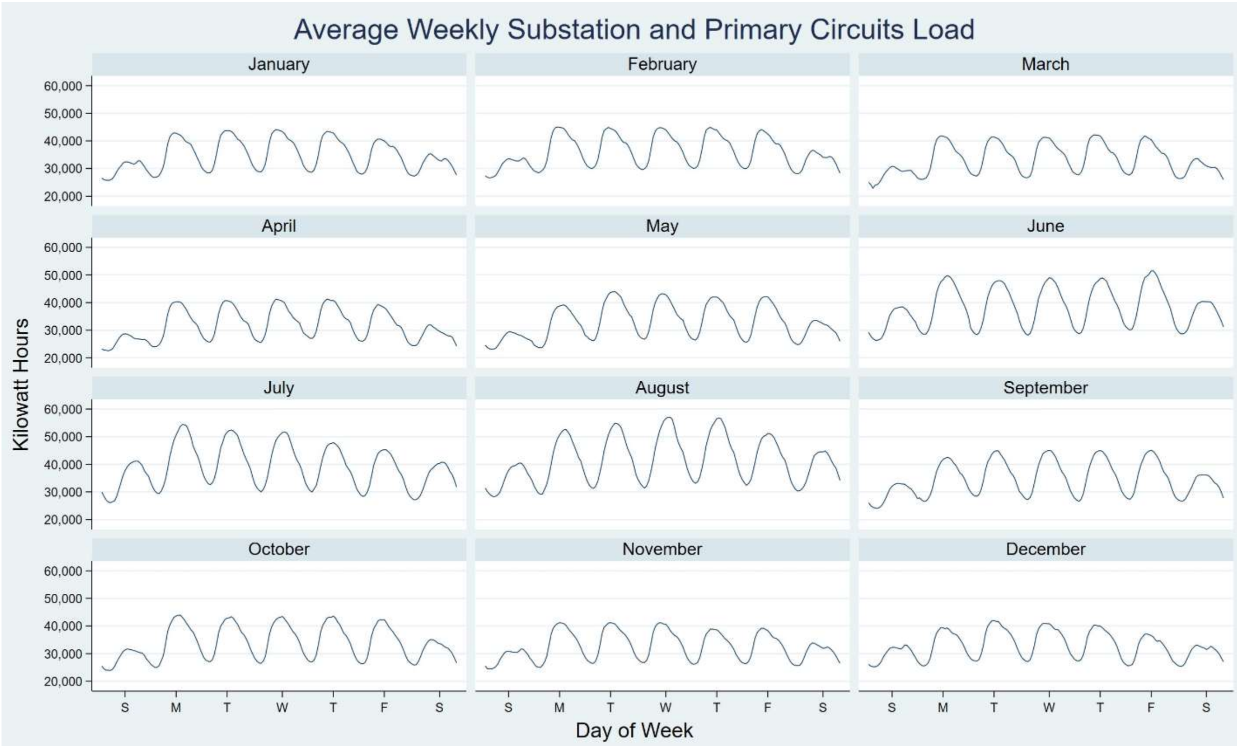

Figure 8-10 TCLP's actual 2021 primary load as average weeks in each month (including metal melting, pumping, and commercial demand primary loads)

8.4 Load by Customer Type

Within a customer class, there can be important variation in load profiles between different building types, which can be important to the design of customer programs. For example, the following heat maps show the differences amongst small offices, shops in retail strip malls, full-service restaurants, and small hotels. Note the high electricity use by full-service restaurants in evenings, the effect of sunrise and the low demand in late afternoon and early evening in small hotels, the business hours effect and the increase in lighting after sunset in retail malls, and the business hours and sunrise/sunset effects in small offices.

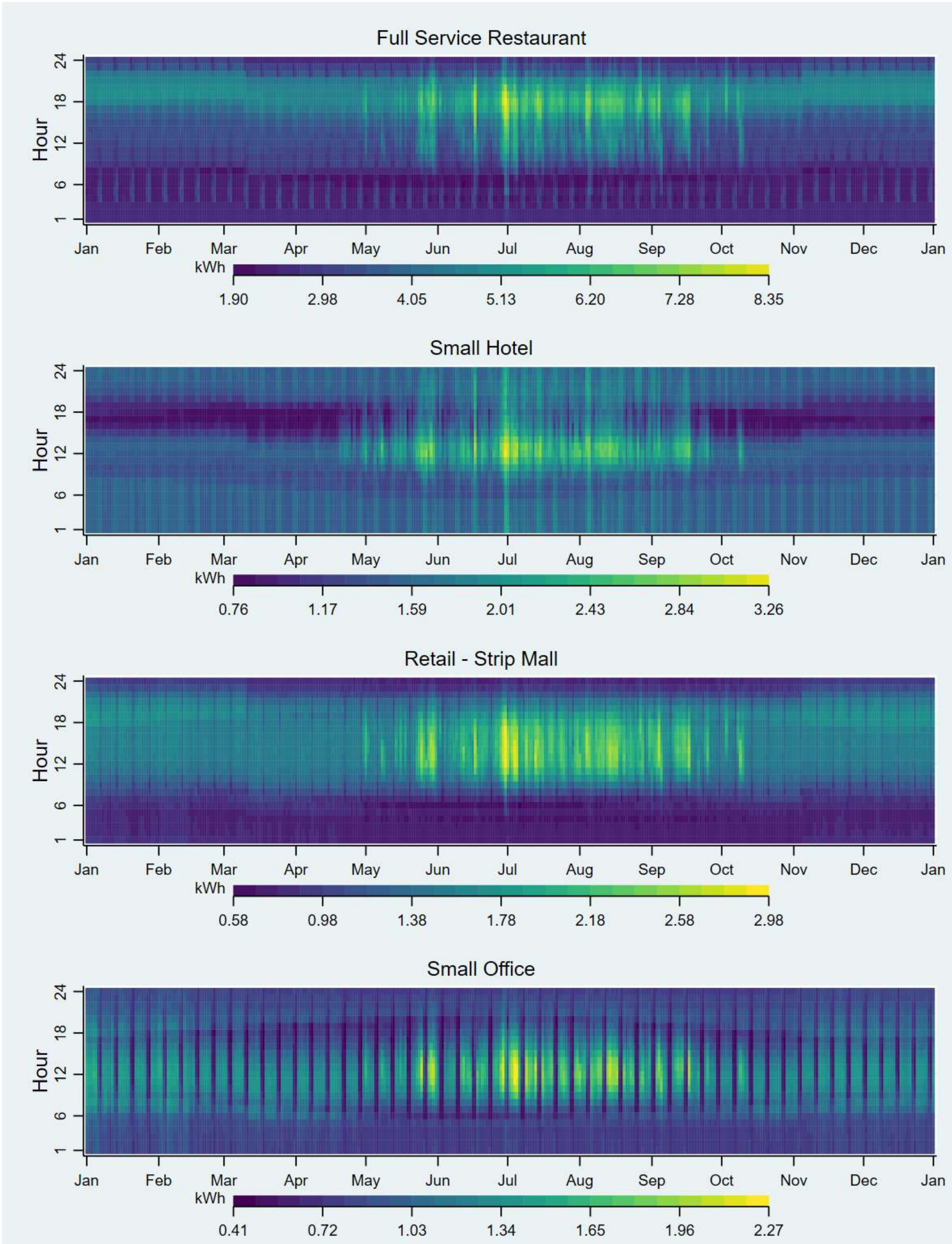

Figure 8-11 A sample of commercial building type load profiles

8.5 Load by End Use

Utility program designers and managers can benefit from knowing how and when energy is consumed by specific end uses within buildings. But even with widespread deployment of AMI, the resolution of most customer usage data is still limited to the account meter. 5LE's approach was to simulate more granular time series energy usage data with publicly available end use load profiles (EULP) developed by the U.S. National Renewable Energy Laboratory (NREL). More specifically, we applied the ResStock and ComStock datasets to TCLP's Residential, Commercial, and Commercial Demand customer classes. Together, these classes reflect most TCLP customer accounts and comprised 62.1 percent of system load in 2021.

5LE followed a series of modeling steps to create hourly electricity and natural gas EULP for the building types listed in Figure 8-12 in TCLP's service territory. For lists of specific end uses included in our analysis, and further discussion of our methodology and end use load profile results, see Section 22.1.5.

ResStock Building Types	ComStock Building Types	
Mobile Home	Full Service Restaurant	Medium Office
Multi-Family 2-4 units	Quick Service Restaurant	Small Office
Multi-Family 5+ units	Large Hotel	Primary School
Single Family Attached	Small Hotel	Secondary School
Single Family Detached	Hospital	Retail Standalone
	Outpatient	Retail Strip Mall
	Large Office	Warehouse

Figure 8-12 Building Types Represented in the ResStock and ComStock Datasets

The following panels of graphs illustrate some of these concepts. The first panel shows the hourly use of electricity by a representative TCLP residential customer that has electric resistance space heating and water heating, showing that space heating is a much larger and more varying use than water heating and all other loads, while space cooling is highly variable and seasonal but more modest than space heating. The second panel breaks out all other loads and shows the importance of interior lighting, plug loads, and fans for both heating and cooling. Our program recommendations, discussed later in this report, accordingly emphasize envelope improvements that reduce space heating and cooling requirements due to the indirect effect on these loads from fans, heat pumps for space heating and cooling, water heating, lighting and plug loads in residential customer programs.

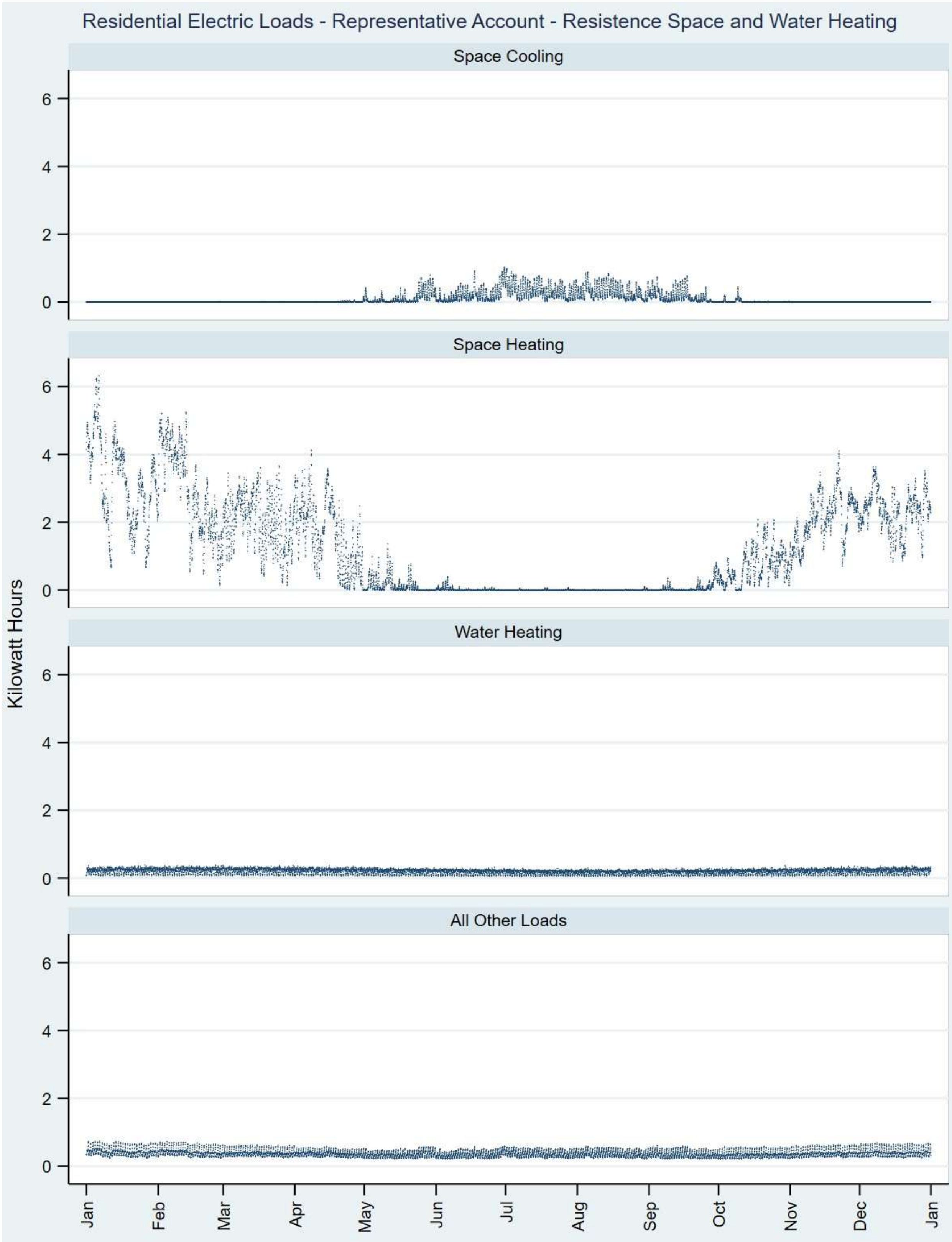

Figure 8-13 Yearly load profiles from the major end uses of a representative residential account

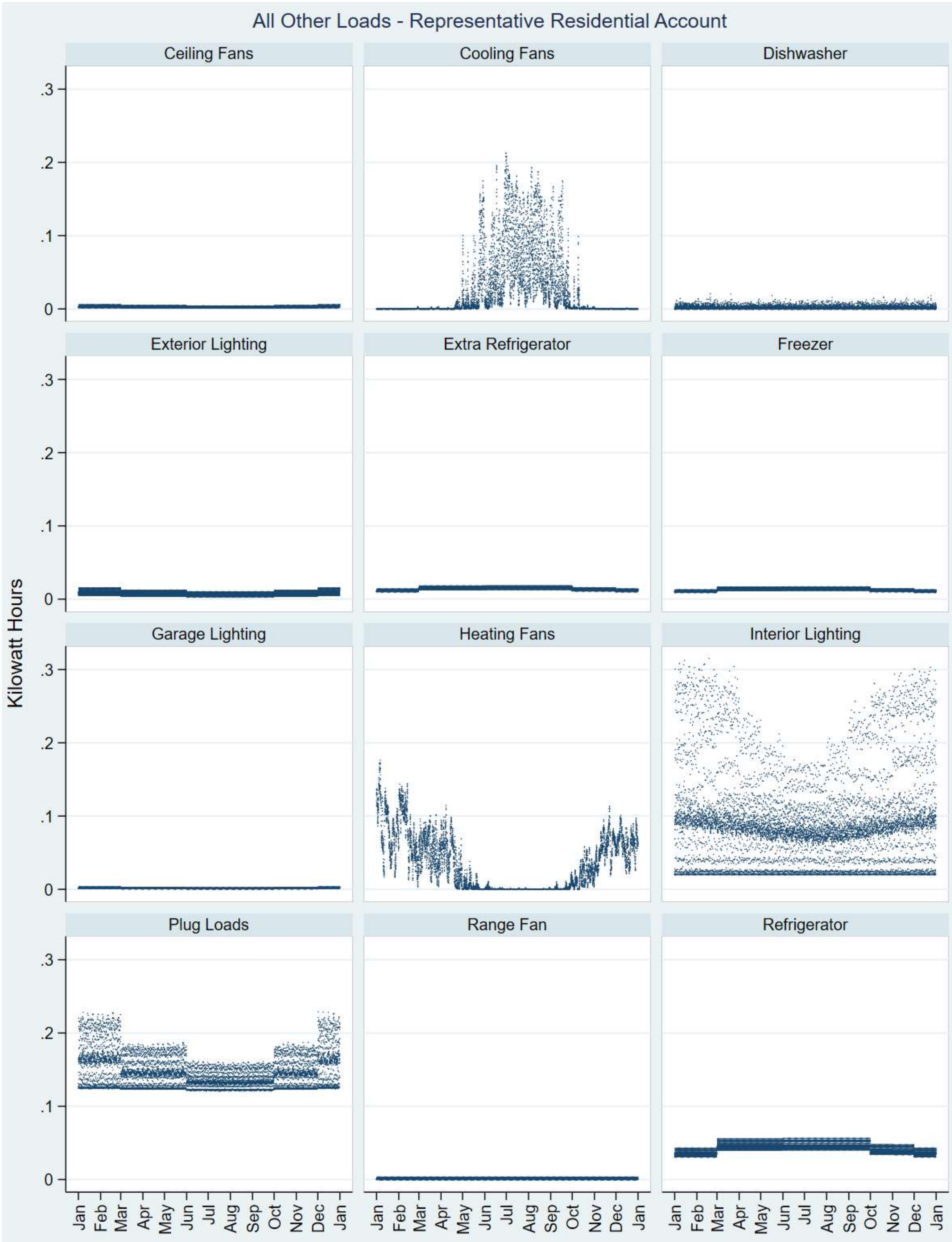

Figure 8-14 Yearly load profiles from the minor end uses of a representative residential account

8.6 Heating Fuel Loads of TCLP Customers

In addition to developing hourly EULP for electricity, 5LE used ResStock and ComStock datasets to create on-site heating fuel EULP for Residential, Commercial, and Commercial Demand buildings in the TCLP service territory. These were vital for evaluating fuel switching opportunities for TCLP customers.

To illustrate these profiles, the following two figures show the electricity loads for space heating and cooling for a representative residential customer and for a representative commercial customer using natural gas for heating with air conditioner cooling, electric resistance heating with air conditioner cooling, air source heat pump for both heating and cooling, and for ground source heat pump for heating and cooling. These figures illustrate the shift of peak load from summer to winter with electric heat, and the relative moderating effects on the load profile of an air source heat pump over electric resistance heat and of ground source heat pump over air source heat pump. These differences in profiles manifest in the benefit-cost analyses we developed for various electrification strategies.

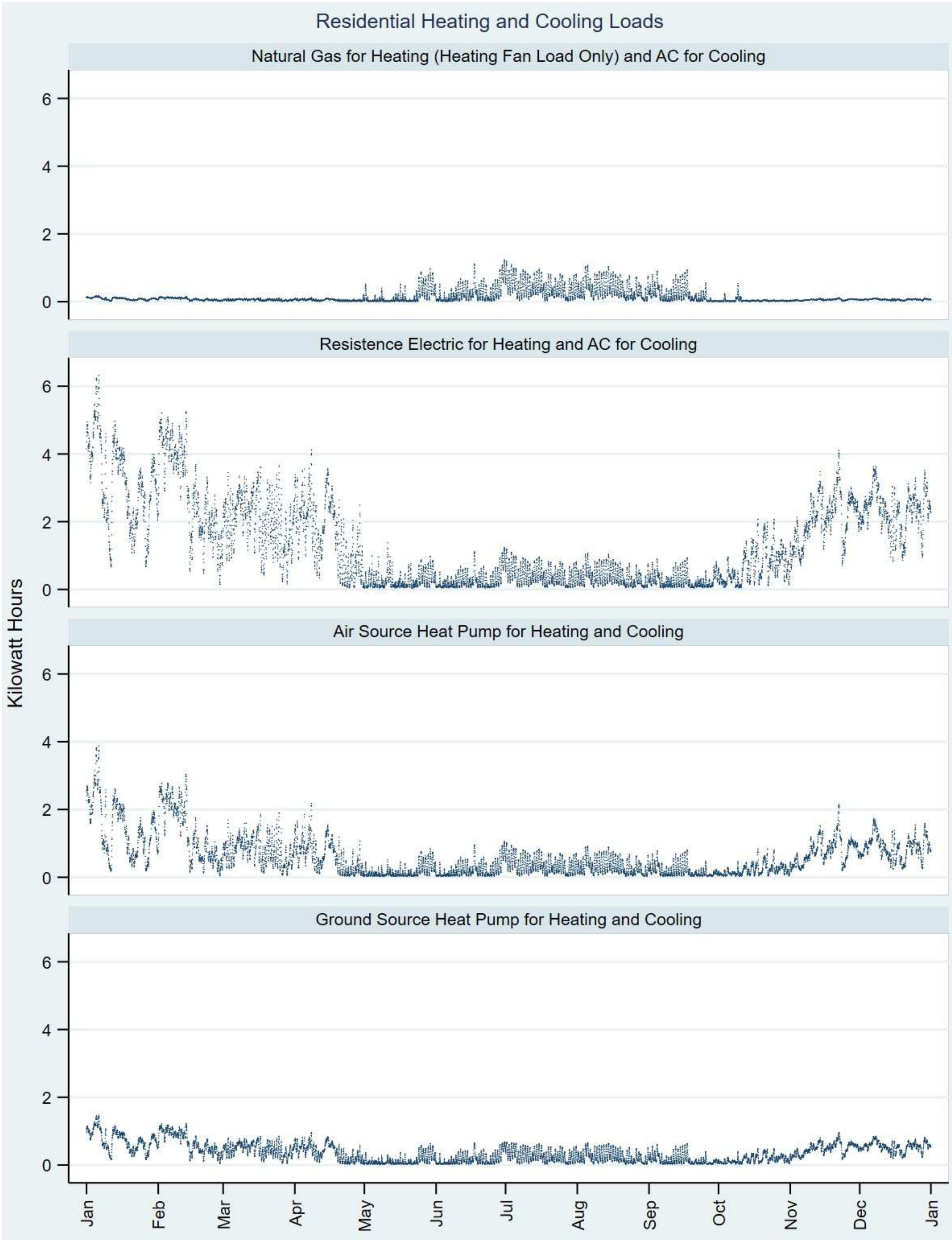

Figure 8-15 Comparison of home heating and cooling system yearly electricity use (for a representative residential account)

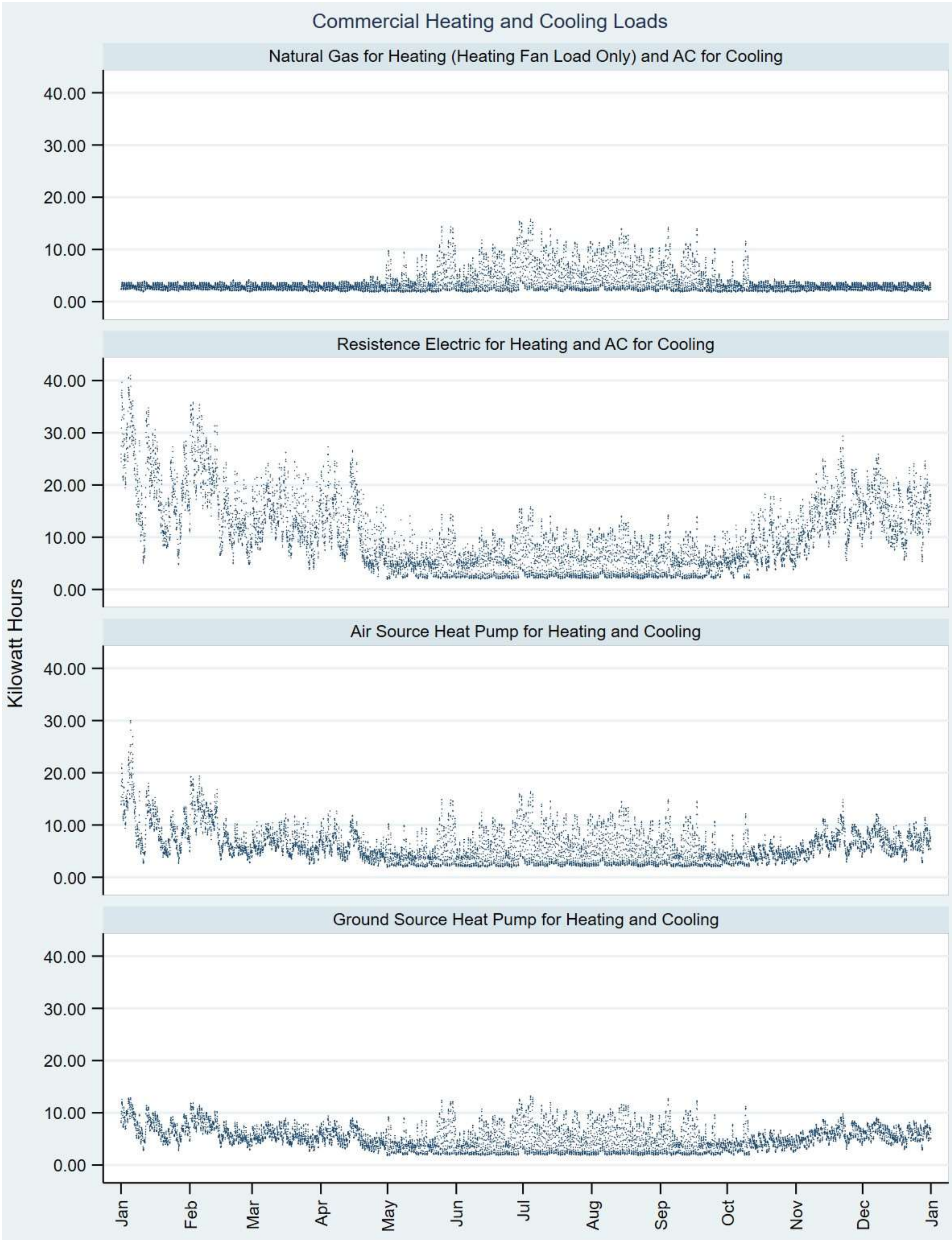

Figure 8-16 Comparison of commercial heating and cooling system yearly electricity use (for a representative commercial demand account)

9 Building Energy Efficiency Analysis

To determine building energy efficiency measures that are beneficial and to determine reasonable program expenditures and rebate levels for efficiency measures, 5LE and MEO undertook two main analytical steps. 5LE developed energy efficiency benefit factors for each end use of energy and MEO applied those factors to specific energy efficiency measures affecting each end use based on the expected energy savings from each measure.

9.1 Energy Efficiency Benefit Factors

5LE computed end use measure factors ($/kWh) for MEO to apply in its benefit/cost evaluations of energy efficiency measure options. Avoided revenue and costs scale linearly with measure kWh savings. We calculated annual unit measure savings of 1.0 percent and applied this uniformly in each hour to electricity end uses. Using the TCLP Building Electrification and Measure Model ("the model") described in Section 10, we calculated the corresponding annual results for avoided utility revenue, avoided utility cost of service (COS), avoided utility marginal cost (MC), and avoided societal emissions costs related to health and greenhouse gas impact.

5LE programmed the model to convert these various annual results to net present value (NPV) figures assuming discount rates presented above and an expected measure life of 16 years. The final step in computing the $/kWh end use measure factors was to divide these NPV figures for avoided revenue and cost by annual electricity savings in kWh Section 22.3.1 shows a table of these results for a residential cooling fan as an example. It also explains how adjustments were made to account for the effect of indoor measure savings on space heating and space cooling loads.

Conceptually, TCLP could define total program budget for an energy efficiency measure by applying one of three benefit/cost factors: (1) avoided utility MC, which is equivalent to applying the utility system resource cost test prescribed for investor-owned utilities in Michigan law; (2) avoided societal MC assuming additional electricity is 100 percent renewable; and (3) avoided societal MC including avoided emissions costs assuming additional electricity reflects the existing generation mix in MISO Zone 7. The maximum expenditures for all program costs including customer outreach and education, administration, and any rebate offerings, is calculated as the product of the selected benefit/cost factor ($/kWh) and the predicted annual energy savings for the measure (kWh).

In order to arrive at a series of incentive amounts based on the above calculated NPVs, the Michigan Energy Measures Database ("MEMD") developed by the Michigan Public Service Commission to estimate the annual energy savings for a large list of energy efficiency measures was coded to match our end-use nomenclature. Assigning these values allowed for the addition of NPV category columns to the MEMD showing maximum program level incentive for each measure. Utilizing this customized MEMD, our team compared currently offered measures and incentives, broken down on a per kWh and per unit level, against the series of NPV values. It needs to be noted that the NPV values represent a total program cost that would include incentives and administrative costs.

The spreadsheet *TCLP NPV EWR Measures* outlines the existing TCLP Residential and Commercial Energy Savers program and how the set of measures offered may be expanded to assist with beneficial electrification and decarbonization program goals. Where applicable, the existing TCLP rebate amount has been included, for comparison with modeled NPV rebate amounts on a per kWh level and per unit level.

kWh savings values for each measure are sourced from the 2023 MEMDs. Where an existing TCLP measure category encompasses an expansive set of individual MEMD measures with varying kWh savings

Category	Proposed Program Measures	kWh Savings	Size Basis	Current TCLP Rebate / kWh	Current TCLP Rebate	NPV Avoided Utility MC Factor ($/kWh)	NPV Avoided Utility MC Factor ($/Unit)	NPV Total Avoided Societal Costs with TCLP 100% Marginal RE ($/kWh)	NPV Total Avoided Societal Costs with TCLP 100% Marginal RE ($/Unit)	NPV Total Avoided Societal Cost with Generic Grid Power ($/kWh)	NPV Total Avoided Societal Cost with Generic Grid Power ($/kWh)	Specifications/Comments
ENERGY STAR Home Appliances	ENERGY STAR Air Purifier CADR 150+	517.5	device	$ 0.13	$ 65.00	$ 0.34	$ 175.56	$ 0.43	$ 220.14	$ 0.94	$ 484.54	Base: Standard efficiency air purifier, Proposed: ENERGY STAR Air Purifier
	ENERGY STAR Air Purifier CADR 50-150	298.5	device	$ 0.10	$ 30.00	$ 0.34	$ 101.27	$ 0.43	$ 126.98	$ 0.94	$ 279.49	Base: Standard efficiency air purifier, Proposed: ENERGY STAR Air Purifier
	ENERGY STAR Freezer	35.0	device	$ 0.57	$ 20.00	$ 0.38	$ 13.18	$ 0.47	$ 16.53	$ 1.03	$ 36.06	Base: Standard Compact Freezer, Proposed: ENERGY STAR Compact Freezer
	ENERGY STAR Refrigerator	34.2	device	$ 0.58	$ 20.00	$ 0.38	$ 12.88	$ 0.47	$ 16.15	$ 1.03	$ 35.23	Base: Standard refrigerator, Proposed: ENERGY STAR refrigerator
	ENERGY STAR Heat Pump Clothes Dryer	435.0	device	$ 0.46	$ 200.00	$ 0.75	$ 325.91	$ 0.94	$ 408.67	$ 2.15	$ 935.92	Base: Standard Electric Clothes Dryer, Proposed: ENERGY STAR Heat Pump Clothes Dryer
	High Efficency Clothes Washer	159.5	device	-	-	$ 0.39	$ 61.88	$ 0.49	$ 77.59	$ 1.06	$ 169.64	Base: Standard Clothes Washer IMEF = 1.71, Proposed: Clothes washer IMEF= 2.41
	Portable Room Dehumidifier	236.8	device	-	-	$ 0.34	$ 80.33	$ 0.43	$ 100.73	$ 0.94	$ 221.72	Base: Standard Dehumidifier, Proposed: ENERGY STAR Dehumidifier

Table 9-1 Example of MEMD Measures

amounts, a single measure with a kWh savings value representative of the category average is shown. A full inventory of MEMD measures with calculated NPV values is provided within the adjacent MEMD measures sheets. Where possible, MEMD measures have been assigned an appropriate Comstock/Restock category. NPV modeling was undertaken to align with these preexisting categories in the interest of streamlined program administration and implementation. Where an appropriate Comstock/Restock category could not be determined, those MEMD measures remain uncategorized, and as such do not have calculated NPV values. Measures shown without kWh savings values are included as program recommendations, but are absent from the 2023 MEMDs.

In the spreadsheet export provided above, we can examine TCLP's current measure of an ENERGY STAR Air Purifier ADR 150+. The annual kWh savings for this measure is 517.5 and is measured on a per device basis. Savings levels for other equipment may be measured per ton, horsepower, or per 1000 sq ft.

The following columns can be considered in pairs. In Green, we have TCLP's current rebate of $65.00 per device and its associated per kWh equivalent of $0.13. This is calculated by dividing the TCLP rebate amount of $65.00 by the kWh savings of 517.5.

Moving on to the Net Present Value calculations, we have the maximum level of rebate based on avoided marginal cost in orange, avoided societal costs assuming that TCLP has met 100% of marginal renewable energy goals in blue, and finally in yellow, the avoided societal cost assuming TCLP is using generic grid power.

Presenting the TCLP incentive against the NPV value categories allows TCLP to effectively compare program measures against straight avoided marginal cost and societal cost at renewable and grid level power. For example, in the color-coded Air Purifier selection, the societal value of efficiency when TCLP is offsetting grid power is valued at $0.94/kWh compared to less than half of that value at $0.43/kWh when efficiency is offsetting 100% marginal renewable energy. The avoided utility marginal cost of $.34/kWh does not consider any societal factors associated with health and climate impacts of emissions.

The NPV values per kWh and subsequent per unit derivatives are generally higher than current values with the exception of some low rebate/kWh pairs such as the ENERGY STAR Refrigerator. In the case of the refrigerator our analysis suggests that current rebate levels are high when compared to each of the NPVs. However, it may still be in the interest of TCLP to offer a rebate on refrigerators at the current level to reflect a minimum rebate when compared to cost of a new unit.

When examining each measure in comparison to current offerings, it is important to remember that a final consideration of incentive and administrative cost will still need to be determined. For example, if TCLP could use a split between incentives to customer (60%) and all other program costs of admin, marketing, and staff (40%). There is little evidence as to the relative effectiveness of rebates and customer outreach expenditures in driving customer adoption, so should be approached adaptively over time. The example below suggests that an incentive a 60% of Avoided Marginal Cost would increase customer incentives to \$0.20/kWh and \$105.34 per unit and contribute \$0.14/kWh or 70.22/unit to all other program costs.

		kWh Savings	Size Basis	Current TCLP Rebate / kWh	Current TCLP Rebate	NPV Avoided Utility MC Factor (\$/kWh)	NPV Avoided Utility MC Factor (\$/Unit)	NPV Total Avoided Societal Costs with TCLP 100% Marginal RE (\$/kWh)	NPV Total Avoided Societal Costs with TCLP 100% Marginal RE (\$/Unit)	NPV Total Avoided Societal Cost with Generic Grid Power (\$/kWh)	NPV Total Avoided Societal Cost with Generic Grid Power (\$/kWh)
Program with 60/40 split	ENERGY STAR Air Purifier CADR 150+	517.5	device	\$ 0.13	\$ 65.00	\$ 0.34	\$ 175.56	\$ 0.43	\$ 220.14	\$ 0.94	\$ 484.54
Incentive	60%					\$ 0.20	\$ 105.34	\$ 0.26	\$ 132.08	\$ 0.56	\$ 290.72
Administration	40%					\$ 0.14	\$ 70.22	\$ 0.17	\$ 88.06	\$ 0.37	\$ 193.82

Table 9-2 Example of measures with 60/40 program split

The program and rebate recommendations later in this report are based on consideration of these benefit factors for each electricity end-use and consideration of avoided electricity cost, avoided societal cost using 100% renewable electricity, and avoided social cost using generic grid power.

9.2 Additional Considerations in Measure Selection

In addition to considering the benefits of various energy efficiency and electrification measures, we also considered certain other factors.

One important factor is that often customers must make a discrete choice of one option from amongst several. If TCLP supports all options, this may not help customers to make the best choices. In some instances, we recommend excluding a measure that is beneficial on its own but that will interfere with a better option. A good example is that we recommend against rebates for more efficient air conditioners, in favor of rebates for heat pumps. A heat pump provides cooling approximately as efficiently as an efficient air conditioner but also provides electric heating.

9.3 Energy Efficiency Measure Adoption Forecasts

Accurately forecasting the adoption of energy efficiency measures is difficult. There are very few high-quality studies of the adoption process and most “energy efficiency potential studies” use quantitative models that are based on experienced guesses as to parameter values. Because utilities are usually developing these studies for compliance with energy efficiency resource standards, they are usually formulated conservatively to ensure compliance rather than aggressively to maximize accomplishments.

We based our load forecasts and program budgets on an assumption that TCLP will pursue aggressive programs designed to accomplish community-wide decarbonization. These projections are generally outside any experience from other utilities, so TCLP should anticipate revising these projections based on experience.

Our projections of efficiency measure adoption are based on linear increases in market penetration, from current levels to 100% by 2050. Our projections of building electrification adoption are based on linear increases in percentage of equipment sales that will be electrified, from current levels to 100% by 2035 and then continuing at 100% of equipment sales thereafter. These are the pathways that are necessary to meet TCLP's climate action ambition, rather than empirical projections of customer adoption.

10 Building Electrification Analysis

As discussed above, considerable reduction in greenhouse gas emissions can be achieved through energy efficiency measures. However, emissions reductions through efficiency can be only partial. Comprehensive decarbonization of buildings requires electrifying the energy uses that currently use natural gas or another heating fuel.

5LE and our partners analyzed the benefits of electrification in much the same way as we evaluated energy efficiency measures. Because heat pump space conditioning and water heating are far more energy efficient than electric resistance heat and therefore preferred as a way of avoiding resource consumption and emissions costs, we examined converting to heat pumps both buildings currently using natural gas as a heating fuel and buildings currently using electric resistance heating.

We based this analysis on the U.S. Department of Energy model of the residential building stock (ResStock) and commercial building stock (ComStock). We evaluated space conditioning and water heating options, as well as accompanying changes in cooking and clothes drying, by estimating the net present value of marginal costs of both gas and electric energy and social costs of emissions as described in our preceding discussion of energy efficiency measures. A summary of the modeling of electrification factors and subsequent NPV results is provided in Section 22.4 Building Electrification Analysis.

The building electrification program design shown in Section 17 below used these inputs along with categories of existing heating and cooling systems in homes and commercial buildings into the rebate levels. Our team modeled seven different heating configurations to determine potential program expenditures for building electrification. These include:

- Natural Gas Space Heating and Natural Gas Water Heating
- Natural Gas Space Heating and Electric Resistance Water Heating
- Electric Resistance Space Heating and Natural Gas Water Heating
- Electric Resistance Space Heating and Electric Resistance Water Heating
- Post Conversion Air Source Heat Pump
- Post Conversation Ground Source Heat Pump
- Post Conversion Water Source Heat Pump

Below is an example of how electrification incentives and program costs should be considered. We first take the energy consumption of the system being removed and multiply it by the NPV societal emissions costs plus the marginal cost of natural gas. This gives us the total NPV benefit of removing natural gas from society. We then must subtract the NPV societal marginal cost of electricity to show the net benefit to society. We do not include the NPV societal emissions costs of electricity, as we assume all new electric load will be met with 100% renewable energy by TCLP. The overall impact of this methodology will provide the highest rebates to customers that are removing the most inefficient natural gas equipment and replacing it with the most efficient electric equipment.

	Example
Natural Gas Furnace kWh	8,815
NPV Total Societal Emissions Cost Plus MC NatGas ($/kWh)	$ 0.61
Total	$ 5,391.78
Air Source Heat Pump kWh	3,227
NPV Societal MC Electricity ($/kWh)	$ 0.97
Total	$ 3,144.46
Net Benefit to Society	**$ 2,247.31**

Table 10-1 Example calculation of net benefits to society of appliance replacement

These factors were used to create rebate levels for various scenarios to retrofit a home or business. Customers will work with an "Energy Coach" to identify the best pathway. These pathways will vary in rebate size based on our NPV analysis. Our analysis shows that bundling various pathways will increase energy savings and GHG emissions savings for costumers and utility net zero carbon goals, respectively (e.g., our analysis shows the NPV of fuel conversion from natural gas to electric air source heat pump technology without insulation is low; however, added with insulation the NPV creates a value for both customer and TCLP). The building electrification analysis has led to the team to recommend Tiered bundles of rebates as described below.

Finally, included in the spreadsheet are NPV values contained on adjacent sheets. NPV values for heat pump space heating were modeled for two water heating scenarios: natural gas water heating and electric resistance water heating. The MEMD provides kWh savings by comparing consumption under a base scenario with consumption under the proposed measure. As such, each MEMD measure has a base scenario, which for weather sensitive measures (including heat pumps) specifies the base space heating system. The majority of MEMD kWh savings values are for like-for-like replacements. This sheet provides NPV values for the few examples in the MEMD of measures where the heating system type changes between the base and proposed scenarios (i.e., electric resistance heating replaced by an ASHP). Residential GSHPs are absent from the MEMD, as are examples of a gas space heating base scenario with an ASHP proposed scenario.

11 Transportation Electrification Analysis

11.1 Existing Electric Vehicle Infrastructure and Current Electricity Use

Since Traverse City Light and Power's initial investment in public electric vehicle charging infrastructure, electric vehicles have been growing in market share and use across Michigan. This is reflected by a greater demand for charging, especially during high-traffic times in Traverse City. The Blink network connected to these chargers allows us to analyze patterns in use and quantify energy needed to meet growing charging demand. Throughout the period reflected in the data, average charging demand, as measured by daily energy 'fueled' to electric vehicles, grew steadily over the course of the year.

Public charging infrastructure data were provided to NextEnergy from TCLP via Blink's station operator interface. The data begin in August 2021, when TCLP first built out the network, and continue to October 2022, providing us with a full year of use patterns to analyze. These patterns are used to evaluate current infrastructure use with respect to market EV adoption, and project future infrastructure requirements to meet greater EV adoption. Infrastructure requirements are separated into Level 2 and DC Fast vehicle chargers, which represent different power levels that affect vehicle charge time as well as capital cost. Charging patterns are used to create a load profile of energy needed to 'fuel' vehicles in Traverse City, with profiles being developed at yearly and daily scales.

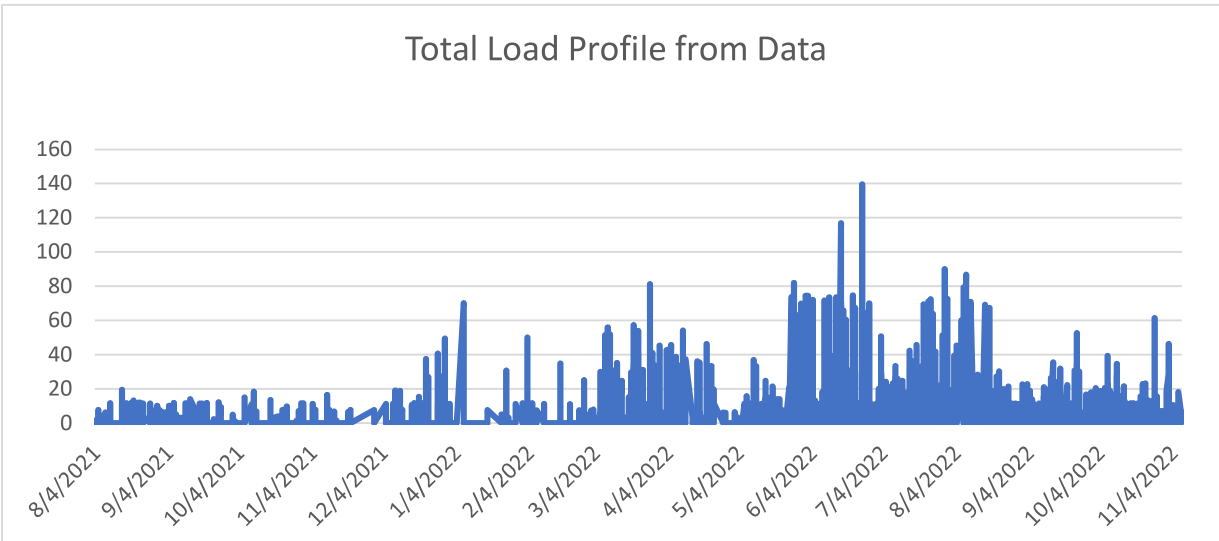

Figure 11-1 Load profile from Blink charger data in kWh

Currently, Traverse City has 3 DC fast chargers, complemented by 24 level 2 chargers. The load profile generated from the totality of the data shows what year-over-year and seasonal trends in EV charging look like. Presented below, the values plotted against the dates are electrical load in kW demanded by public vehicle charging in Traverse City.

In the first half of the data, beginning in August of 2021, the public charging infrastructure sees less use than it does one year later in August of 2022. This can be due to both greater EV adoption and wider awareness of the availability of public charging in Traverse City. The data also reveal the seasonality of EV charging use, with greater energy demanded in the midsummer to early fall months, reflecting Traverse City's tourist economy.

The daily load profile reveals that Traverse City's current public charging infrastructure is currently used predominantly for overnight charging, mimicking typical home charging use. A significant amount of the total charging activity observed in the data is at the Clinch Park Marina, representing 34.7% of the total energy used. This is a larger share than any other charging location, explained by the DC Fast charging infrastructure at the marina as well as the potential for drivers to charge their vehicles while on their boats overnight.

The figures below show the average weekend and weekday daily load profiles. The vertical axis represents the relative share of charging energy at the hour on the horizontal axis.

The majority of energy consumed by EV charging occurs outside of midday on weekends.

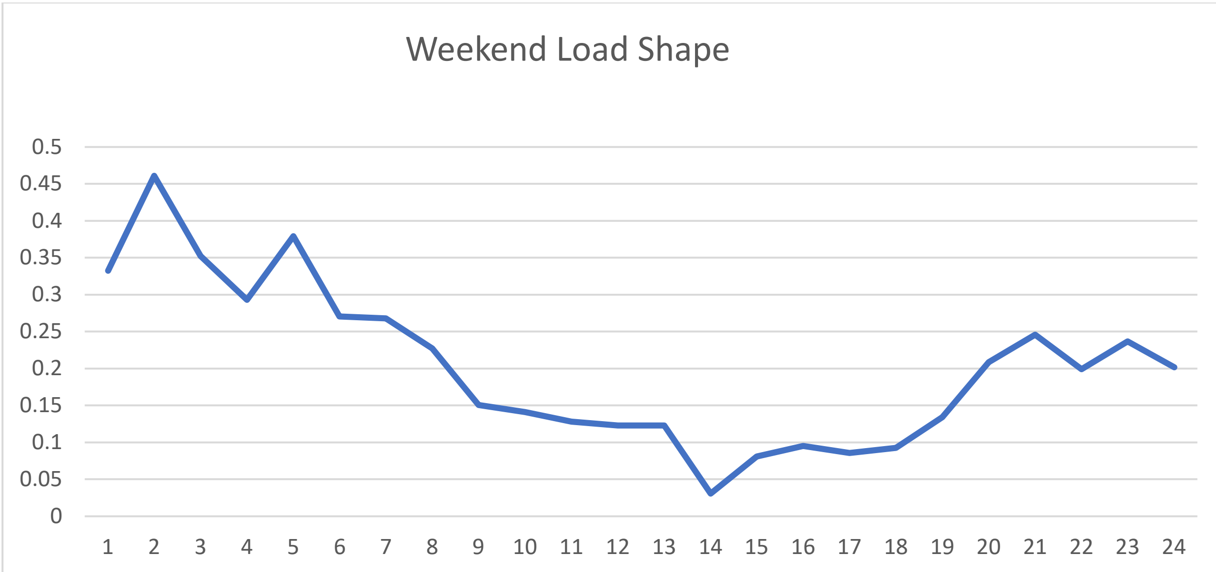

Figure 11-2 Average weekend load shape from Blink charger data

A similar curve can be seen in the graph for the weekday load profile, with most charging occurring at night. There is somewhat more charging during the midmorning hours throughout the week, though the data represents the same lack of charging during the early afternoon hours.

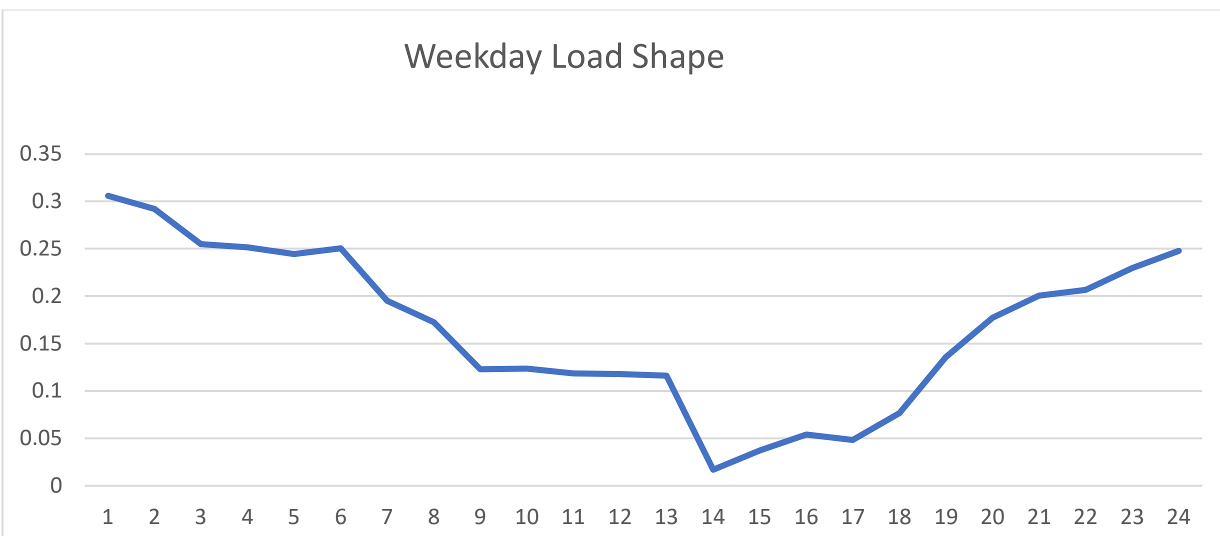

Figure 11-3 Average weekend load shape from Blink charger data

With increased use in the summer, and increased overnight use on the weekends, Traverse City's public charging infrastructure is often used by tourists to recreate a home-charging scenario. This is supported by the measure of inbound versus outbound traffic on Traverse City's main roads at week end and week start. One explanation for this behavior is that tourists travel farther to be in the city, arriving with low battery levels in their vehicles, and then choose overnight charging to maximize their battery level.

When measured on the basis of kWh used compared to kWh currently available, TCLP's current public charging capacity of 820kW is far greater than what is used. The peak use hour from the data, 6/25/2022 at 10:00pm, shows 17% of the capacity being used. It is one of five hours in the data showing capacity usage over 10%.

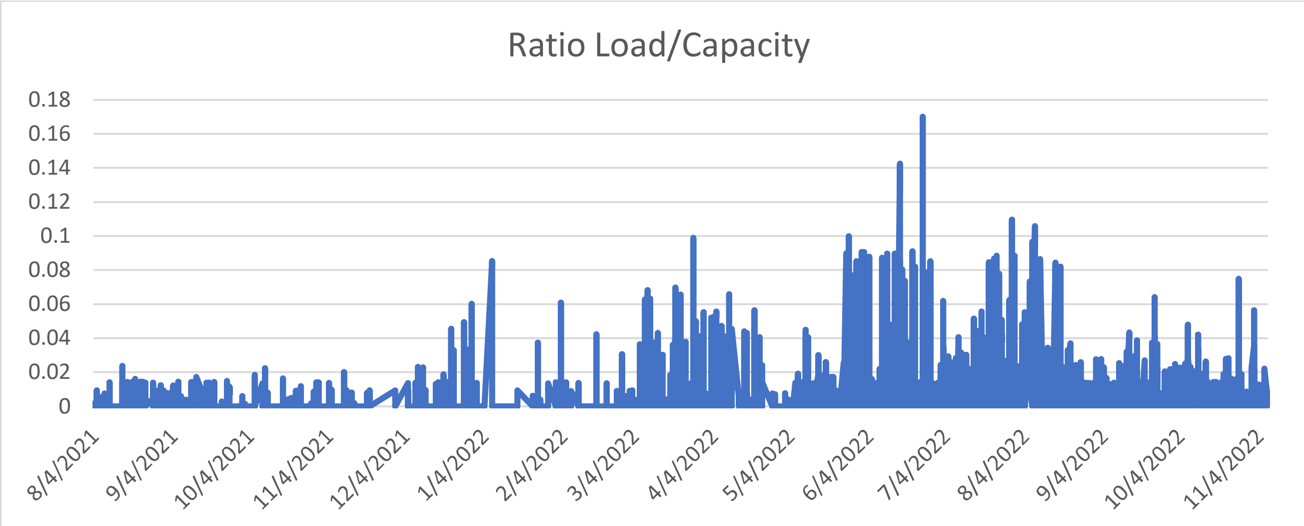

Figure 11-4 Average ratio to load capacity from Blink charger data

The above chart plots the same data as the yearlong load profile above, though here the charging demand is expressed as a percentage of the total capacity, rather than in kWh.

Traverse City's level 2 charging infrastructure, though unable to provide as much energy as its DC fast counterpart in one session, provided 79% of all charging energy in the analyzed data. Charging events on level 2 chargers are normally longer than charging events on DC fast chargers, producing smoother electrical loads. Currently, these loads are in off-peak overnight hours, as shown in the above profiles.

11.2 Modeling Future Electric Vehicle Adoption in TCLP's Service Territory

11.2.1 Determining a Baseline

Driver Type	Residents	Vehicles
Grand Traverse County Total Residents	95,860	
TCLP Total Residents - Estimated	21,452	15,482
Actual Inbound Commuters	20,019	16,683
Actual Outbound Commuters	2,701	2,251

Table 11-1 Resident and Vehicle Numbers by Drive Still and Residency

Because the U.S. Census and other state and federal agencies do not consider TCLP's service territory as a statistical area we had to extrapolate the approximate number of vehicles resident in and commuting or traveling to TCLP's service territory. Using census and regional commuting data, we approximated the number of individuals living and working in TCLP's service territory, living outside of but commuting into TCLP's service territory, and living in and commuting out of TCLP's service territory. Then, using residential accounts as a proxy for vehicles, when combined with vehicles per household, and passengers per vehicle metrics, we calculated the total number of vehicles we would expect to be in TCLPs service territory at any given time.

11.2.2 Projecting Electric Vehicle Adoption

When we requested registration data from the Michigan Department of State for Grand Traverse County in the winter of 2022, there were 201 fully electric vehicles in Grand Traverse County or about 0.3% of a total of nearly 70,000 vehicles, of all shapes and sizes, registered in the county.

Traverse City was included in March 2020 a study conducted by researchers at Michigan State University.[24] The goal of the study was to find the optimal investment strategy for DC fast charging infrastructure in the state. A regression model using data from larger urban areas was created to estimate the number of DC fast chargers needed to support EV charging at 6% statewide market adoption rate. The researchers found that Traverse City would need five fast-charging stations with ten total plugs to support a 6% EV market adoption in 2030.

EV Vehicle Sales by Vehicle Type	2030	2032
Vocational	35%	50%
Short-Haul Trucks	20%	35%
Long-Haul Trucks	10%	25%
Light Duty Cars and Trucks	47%	67%

Table 11-2 Estimated percentage of vehicle sales by type if new EPA vehicle emission standards are enacted

However, on April 12, 2023, the EPA announced new proposed tailpipe emissions standards for light and medium duty vehicles.[25] These standards are still in their public comment period, but if adopted could force the rapid deployment of EVs. Tailpipe emissions standards are tied to the U.S.DOT enforced CAFE standards which are applied as a fleet-wide average and could theoretically be met through increasing ICE vehicle efficiencies, but the more obvious path is the production of a higher number of EVs.

The proposed rules were calculated by Atlas EV HUB[26] to produce the expected percentages of EV vehicle sales shown in the adjacent table.

Working with these values, and a fleet-turnover model developed by 5 Lakes Energy that uses public data on vehicle longevity from the current edition of the Transportation Energy Data Book (TEDB) for different vehicle types and Weibull life distributions to calculate the expected number of EVs on the road in TCLP's service territory in each of our projection years. If these values are correct, we can expect nearly 20% of vehicles on the road in TCLP's service territory to be electric by 2030, a 14% increase from the MSU study.

The figure below shows our modeling of EV deployment. A good portion of TCLP's daytime charging load is expected to be inbound commuter traffic. By 2040 22% of TCLP's total load is projected to be EV Charging. However, in some hours, the percentage of TCLP's total load from EV charging could be much higher.

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[24] https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Programs/MMD/Energy/to-be-sorted/EGLE-MMD-Sustainability-Phase_II_Summary_Report.pdf?rev=20175a06ef2047f4b126c020aed1fc69&hash=28692B7C095DA1FE39FFA56A50EF11EF

[25] https://www.epa.gov/regulations-emissions-vehicles-and-engines/regulations-greenhouse-gas-emissions-passenger-cars-and

[26] https://www.atlasevhub.com/weekly-digest/epa-proposes-tight-emissions-standards-ev-sales-set-to-climb/

Model Year	Passenger Vehicle Equivalents - Living and Working in TCLP	Passenger Vehicle Equivalents - Inbound Commuters	Passenger Vehicle Equivalents - Outbound Commuters	Total EV Charging Load (kWh)	EV Charging as a % of TCLP's Total Projected Load
2025	1,032	980	130	6,764,722	2%
2030	3,055	3,224	385	20,436,206	7%
2035	6,535	7,975	823	45,077,927	15%
2040	10,352	13,942	1,303	73,052,152	22%

Table 11-3 Vehicle equivalents and energy use used in modeling future TCLP EV load

11.2.3 Charging Behavior of Passenger EV Owners

Important to the seamless integration of EVs into TCLP's service territory will be the behavior of EV owners, be they individual residents or commercial fleet managers. We modeled a range of EV charging behavior scenarios.[27]

What is clear from our modeling is that scenarios in which all vehicle owners are incentivized to begin charging at the same time produce extreme demand spikes that could be difficult to manage from the standpoint of available generation or distribution capacity. Such spikes could be caused either through inaction on the part of the TCLP—assuming the natural tendency of EV drivers will be to begin charging as soon as they arrive home, between 5PM and 8PM, or by setting a uniform off-peak charging window. If TCLP sets a time-of-use, or even EV-specific rate that begins at the same time for all customers, EV drivers responding to this rate in unison might create a spike similarly treacherous, and perhaps even more pronounced than that of drivers' natural tendencies, given that drivers return from work at a range of hours. Depending on its scale, this spike could strain TCLP operations, even in a conventionally off-peak hour.

Strategies for controlling the charging load of passenger EVs is discussed below in sections 12.2.2 and 13.3.2.

11.2.4 Modeled Charging Profile

There was no clear way for us to determine the realistic charging behavior of future customers when the infrastructure and programs that will govern how and when people charge their vehicles are still uncertain. Consequently, for purposes of resource planning we modeled a realistic, but also optimistic charging profile. Our profile assumes charging demand is both well-managed and daytime focused, assuming a solar heavy future, with most home charging performed at level 1, minimizing demand spikes.

As is evident in the Figure 11-5 below, the highest hours of charging are in the daytime. This is also the result of TCLP's commuter population, a substantial portion of which we model as charging within TCLP's service territory while at work. The table below shows that, in terms of total load, we find workplace charging to be the largest single category.

Charger Type	Home Level 1	Home Level 2	Public Level 2	Public DC Fast	Work Level 1	Work Level 2
Percent of Total	28%	9%	22%	7%	4%	30%

Table 11-4 Energy use by charger type

[27] The full range of range of modeled scenarios can be seen in Table 22-20

An unexpected factor in our modeled charging profile was the counteracting effects of cold weather and TCLP's tourist economy. EVs, which we assume to be parked in unconditioned spaces, operate and charge substantially less efficiently in cold weather, an effect which is captured in our modeling. This, to some extent, counteracts what we expected to be higher charging demand in the summer, given our modeling of Traverse City's seasonal economy. Thus, the modeled charging peak is seen on a Friday in October, towards the end of the tourist season, but on a cold day, rather than during peak tourist season in August.

The average week profiles in 2030 and 2040, seen in Figure 11-6 below, show the growth of demand and its spikiness even under a while managed charging regime. In the scenarios we modeled with less managed charging, peaks were even more pronounced. While charging in 2040 is modeled as 22% of total TCLP load, in a peak charging hour it can be as much as 38%.

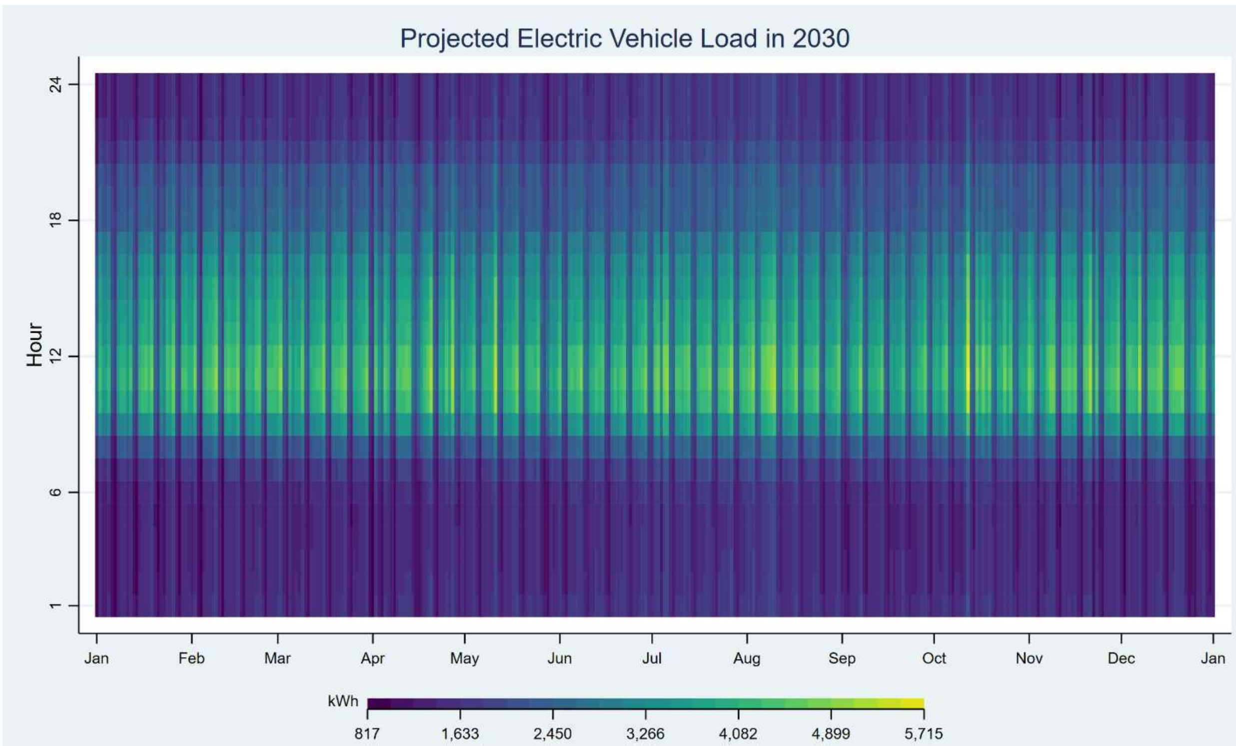


Figure 11-5 Heatmap of projected TCLP projected EV load in 2030

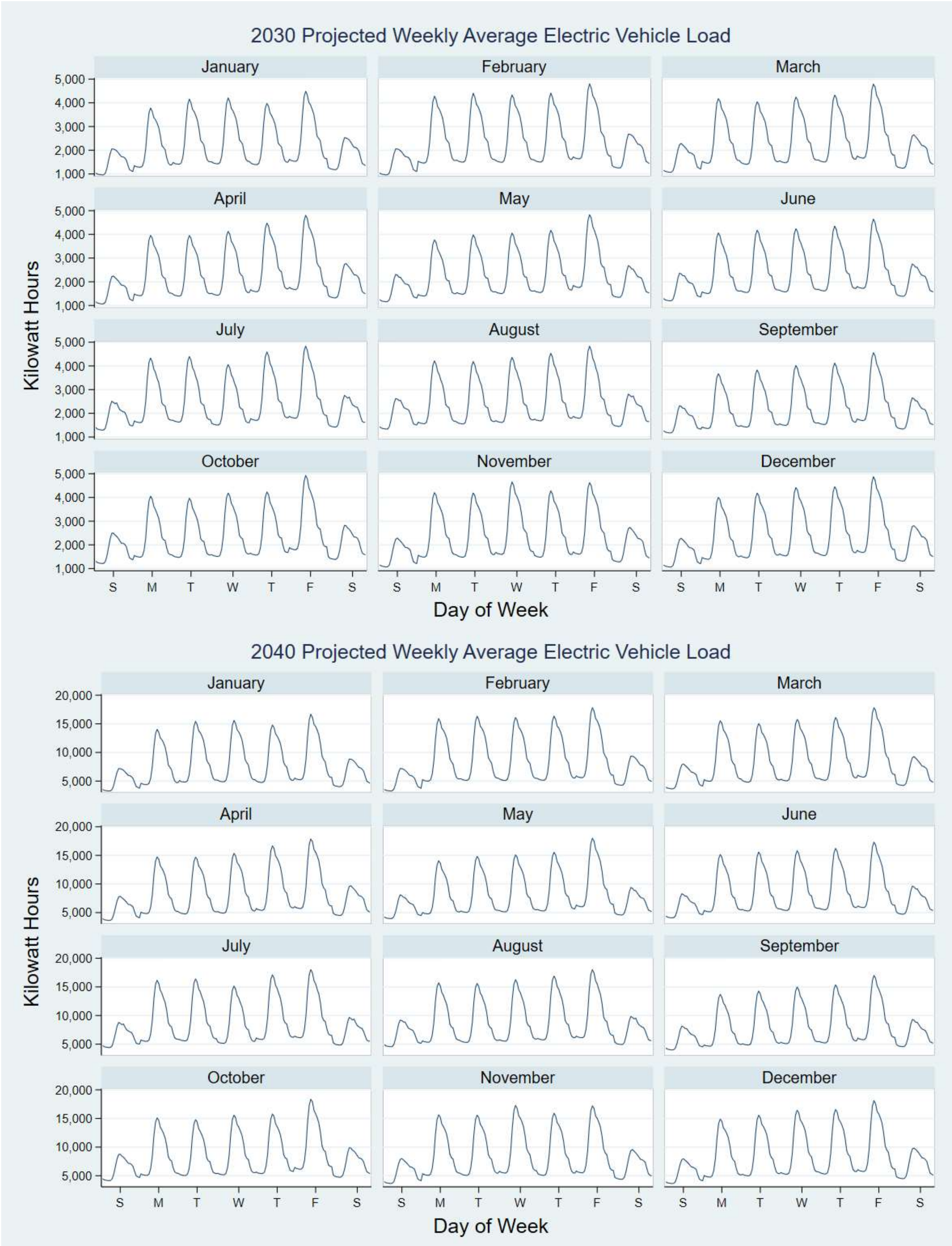


Figure 11-6 Average weekly EV Loads in 2030 and 2040

11.3 Projected EV Charger Requirements

The transition to EVs from ICE vehicles will require investment in public charging infrastructure. TCLP, whether or not it subsidizes or is directly involved in deploying public chargers, will have a role in bringing wires and power to this new infrastructure. The EVI-Pro Lite model we used to develop projected load profiles also allows us to model future charger needs. We included both incoming commuters and residents of TCLP's service territory in our analysis of charger needs. We have not included specific analysis of regional tourism which might be assumed to increase the outside boundary of potential public charger demand. However, overall, we have taken a generous approach in developing our assumptions around EV deployment growth.

It is expected that most residents within the TCLP service territory, as well as commuters into the TCLP service territory will charge their vehicles at home. We assume that homeowners will charge with a mix of level one and level two chargers, but that commuters and visitors will be charging at level two, or even at fast chargers. As is plain in the table below, the portion of the population that does not own their own home and have personal access to vehicle charging, but does own an electric vehicle, has a substantial effect on the number of public chargers needed.

Although this is not represented in the EVI-Pro model, one reasonable expectation of EV adoption is that, both for logistical and economic reasons, homeowners will adopt EVs first, as the high price point of new EVs means they are mostly the purview of an economic class that aligns with the economic means to own a home. Furthermore, the lack of public charging infrastructure means that individuals who cannot charge directly at their places of residence are unlikely to purchase EVs. However, as EVs become a greater part of both the used and new vehicle market, with lower price points, we might expect individuals without direct access to an EV charger at home to be more likely to purchase and EV, if they believe the infrastructure is available to support their driving habits.

	Assuming 100% Access to Home Charging				**Assuming 90% Access to Home Charging**			
Year	**2025**	**2030**	**2035**	**2040**	**2025**	**2030**	**2035**	**2040**
# Vehicles	2,012	6,279	14,510	24,294	2,012	6,279	14,510	24,294
Public or Workplace Level 2	68	175	345	458	101	292	617	938
Public DC Fast Chargers	13	27	42	57	19	44	67	92

Table 11-5 Differences in public charging needs assuming 100% vs 90% home charging access

Table 11-5 above, displaying the number of public chargers eventually needed in the TCLP service territory, is not a guide to the number of public chargers that TCLP should work to see deployed, it is an estimate of the number of chargers that may eventually be deployed. The pace and scale of deployment is ultimately subject to market forces. TCLP's role is to facilitate their deployment by creating smart and effective programs to serve the development of charging infrastructure.

12 Recommendations for EV Programs

What follows is a suite of recommendations aimed at helping Traverse City support the development of EV infrastructure and the deployment of EVs more broadly, without working against its own interests in managing its seasonal peaks and over burdening its distribution infrastructure.

12.1 Charger Locations and Public Awareness

Investment decisions between Level 2 and DC Fast charging infrastructure should be made based on location. Given that the bulk of public charging usage in Traverse City currently occurs overnight, build out L2 infrastructure nearby locations suitable for overnight parking. (i.e. hotels, the marina, and near other places visitors stay). Build out DC Fast charging infrastructure where users of public chargers will be parked for shorter amounts of time, such as restaurants and entertainment venues.

For privately-owned lots, provide make-ready site upgrades to encourage greater EV charging infrastructure investment. A specific focus of this should be workplace charging, where L1 and L2 charging are suitable for the length of parking time. With the expectation of a future with high solar deployment, workplace charging presents an opportunity for TCLP to move load into daytime hours when energy may be more abundant.

Increase awareness of public charging infrastructure through traditional communication channels and partnerships with Traverse City DDA and tourism groups. As use increases TCLP will have a greater pool of data to help inform future investment decisions.

12.2 Residential

12.2.1 Chargers

We do not recommend direct incentives for level 2 chargers at individual residences. Many homeowners will want to install level 2 chargers which they are free to do at their own expense, or with other incentives. From the utility's standpoint level 1 charging will generally be preferred due to its lower demands on infrastructure and capacity.

12.2.2 Demand Response / Managed Charging

TCLP should begin exploring the development of a demand response/managed EV charging program. There are several companies that sell these services. TCLP should open entry level conversations with service providers to understand the cost, process, and timeline associated with building a residential program. Demand response programs for EVs exist but are currently still small. Managed charging programs, wherein a customer would give broader permission to TCLP to control vehicle charging outside of singular grid-straining events, are currently theoretical. However, because of the expectations that EVs will grow as a share of vehicles on the road, managed charging programs are expected to become a necessary reality in the short to medium term and will likely be developed by the same providers of demand response services.

TCLP should incentivize enrollment in a managed charging program by determining the appropriate flat monthly dollar incentive for program enrollment. Below we recommend developing an EV charging rate for commercial customers, but for simplicity of implementation and customer communication, a flat benefit is likely preferable for residential charging.

The demand response potential for EVs is quantified below in Section 13.3.2.

12.2.3 Rate Design

Time-of-use rate designs, discussed in Section 6.6 should naturally help control charging load, especially as EV software becomes more intelligent and easily programmable.

12.3 Commercial/Municipal

12.3.1 Commercial/Municipal Charging Tariff

We recommend the development of a tariff for EV Charging that could be used by commercial customers interested in hosting chargers. This tariff would be available for chargers in municipally owned lots as well as privately owned lots.

To facilitate easy deployment of this rate we suggest that TCLP meter parking lot chargers separately from attached businesses. It can be difficult and expensive to get wires from existing panels/meters to the parking lot EV chargers. Furthermore, we expect that in some cases it will be necessary to build additional transformers and distribution infrastructure to serve parking lots hosting many chargers. Finally, separate metering and line drops for parking lot charging will simplify cost allocation for the charging tariff.

12.3.2 Commercial Managed Charging

Use of a commercial charging tariff, or a discounted commercial charging tariff, could be predicated on enrollment in a commercial managed charging program. However, managed charging programs, including demand response programs, for public chargers do not currently exist at a meaningful scale. Conceptually, they have the potential to conflict with the business model of selling reliable charging services. If TCLP chooses to develop a managed charging program for home charging, discussing the potential and logistics of a commercial managed charging program with its chosen contractor is suggested. Although most charging for the foreseeable future is expected to be at homes. Public charging, especially fast-charging, has the potential to produce severe and unpredictable spikes in demand, and getting a handle on management of commercial charging early—before it poses issues to grid stability—is worth some investment.

12.3.3 Chargers as a Service

Some businesses may want to own and operate their own chargers to be able to provide charging for free, for instance in a hotel parking lot, or to maximize their own profit from selling charging to customers. However, some parking-lot owners may want to host chargers but not own or maintain them. Typically, a business in this position would negotiate with a third-party owner that would own and operate chargers in the host's parking lot for their own profit. We recommend TCLP include EV chargers as a commercial offering in the Integrated Customer Energy Optimization Program.

12.3.4 Level 1 Charging

When discussing EV charging infrastructure and programs we mostly consider level 2 and DC Fast Charging. However, most drivers, including future EV drivers drive less than 40 miles a day. Depending on the size and efficiency of an EV, it can charge 2-5 miles of range an hour with a level 1 charger. Thus, in an 8–10-hour period overnight, or while at work, EVs can charge in the range of 16-50 miles of range and could recover the day's driving range without level 2 charging. By incentivizing the use of level 1 charging, TCLP can help naturally even out potential charging spikes. This could look like developing incentives for workplaces and parking lot owners to build level 1 charging infrastructure as well as level 2. Furthermore, street-level level 1 chargers could be a low-cost way to allow renters, or homeowners without easy access to an EV charger, to charge vehicles overnight or during the workday.

13 Demand Response Analysis

13.1 Customers' demand response capability

All TCLP customers are capable of participating in demand response. TCLP has installed advanced metering devices on 100% of customers' buildings. TCLP uses Eaton's Operational Data Management Systems software with its advanced metering infrastructure. Hardware deployed consists of

- Landis & Gyr Focus AXE AMI
    - Real-time rate input (communication module required)
    - Over-the-air firmware upgrades (communication module required)
    - Pre-pay ready (communication module required)
- Honeywell A3R Alpha meter

Automated communication capabilities are necessary to optimize efficacy of demand response events.

13.2 Demand Response Scenarios

Demand Response is based on utilities having technology capable of accessing and adjusting power delivery to a customer. Demand Response is also very much based on customer willingness to participate in Demand Response programs and events. Thus, our analysis considers Demand Response ***Potential***, as the measure of usage is based on the potential or possibility of customer participation in the event based on technical capability to curtail usage. We classify the Demand Response (DR) scenarios as different available options. Those options most recognized are:

- Commercial & Industrial Capacity Reduction – H ere the customer formally commits to reduce its load by a set amount during DR events. ($/kW or $/kWh payment)

- Demand Bidding – The customer voluntarily reduces load during DR event ($/kWh payment)

- Critical Peak Pricing (CPP) – The customer will incur higher pricing due to usage during historical peak load times of year, which could be changed to "tight hours" of the year based on the balance of demand and supply of electricity

- Direct Load Control Switch - The customer agrees to the utility's control of space heating and cooling, and electric water heating with a remotely operated load control switch.

- DLC Smart thermostat, Bring your own t-stat (BYOT) - The customer agrees to the utility's control of space heating and cooling through use of smart thermostats, through small adjustments in temperature settings

- Smart Appliances Control, BYOD – Smart appliances are controlled by utility via WiFi or smart plugs

- Time of Use – Customer's charged rates are based on customer's use during the time of day and season

- Peak Time Rebate – Charged rates are discounted for reducing load during a DR event

- Behind the Meter Battery Dispatch – Charged rates are discounted for customer use of BTM battery during DR event

- EV Managed Charging – Charging of electric vehicles is managed by utility during DR event.
- Behavioral DR – Peak demand can be affected by customer's behavior during periods conducive to DR events

- Real Time Pricing – Rates change hourly or at other intervals based on grid conditions and the customer responds either behaviorally or through automated building controls

- Voltage Optimization –Demand is reduced by lowering or raising site voltage or by improving site power factor. Requires installation of equipment such as capacitors, solid state transformers, etc.

13.3 Demand Response Potential

13.3.1 Michigan Demand Response Potential Study

A draft of the Michigan Demand Response Potential Study was completed by Guidehouse in August 2021 and submitted to the Michigan Public Service Commission. Guidehouse compiled customer data and load data from Michigan utilities, and conducted customer surveys to determine customer interest in enrolling in DR programs and to determine what DR technologies actually permeate the customer market. The two established market segments are residential customers and commercial and industrial customers.

Guidehouse divided the segments further into an Upper Peninsula market and a Lower Peninsula market. Traverse City in the Lower Peninsula market. Though geographically and climatologically it has commonalities with the UP, Traverse City receives power from MISO Zone 7 as opposed to the UP's source being MISO Zone 2. Therefore, our analysis uses data from Guidehouse's findings for the Lower Peninsula.

Guidehouse obtained data from the following utilities:

- Alpena Power Company
- Consumers Energy
- DTE Energy
- Indiana Michigan Power
- Michigan Gas Utilties
- Northern States Power
- SEMCo Energy Gas Co
- Upper Michigan Energy Resources Corporation
- Upper Peninsula Power Company

The general findings of the Guidehouse study relevant to TCLP are:

The top four DR options as determined by surveys and actual usage as recorded by utilities:

- C&I capacity reduction
- BYOT (bring your own thermostat)
- Critical peak pricing
- Direct Load Control switch

The least cost-effective options are:

- BYOD (bring your own device/appliance)
- Thermal energy storage

Reduction of peak demand in the Lower Peninsula due to demand response events in 2021 was 300 MW. Guidehouse projects program participation under cost-effective customer offers will increase this to 1,850 MW in 2040.

Residential non-low-income customers constitute approximately 60% share of electrical DR potential while large C&I customers constitute the remaining 40% share of electrical DR potential. C&I customers potential is mostly from C&I Capacity Reduction.

Energy waste reduction rebates coupled with DR participation is shown to increase customer interest in DR and reduces payback period. Bring Your Own Thermostat DR potential will increase along with expected continued adoption of smart thermostats.

13.3.2 Traverse City Achievable Demand Response Potential

We used the DR potential for the lower peninsula from the Guidehouse study as a base for the potential for TCLP. TCLP recorded a total peak demand for 2021 of 67 MW. Using the figure as the base for TCLP and projections from the Guidehouse study, 67 MW was then extrapolated to project estimates of the DR potential energy reduction for TCLP for the years 2021, 2030 and 2040. Following trajectories predicted for the Lower Peninsula, the peak demand for Traverse City is predicted to be 61.42 MW in 2030, and 82.63 MW in 2040. These values will be affected by our other program recommendations but will be approximately correct. The winter peak demand for Traverse City is forecast to be 38.89 MW in 2030 and 53.15 MW in 2040.

MICHIGAN L.P. SUMMER Achievable Potential

	Year	MI Lower peninsula total peak demand(MW)[1]	Michigan lower peninsula total DR reduction (MW)[2] [3]	C&I Capacity Reduction (MW)[2] [3]	Smart T-stat BYOT (MW)[2] [3]	Critical Peak Pricing (MW)[2] [3]	Direct Load Control Switch (MW)[2] [3]	Time of Use rates (MW)[2] [3]	Peak Time Rebate (MW)[2] [3]	BTM Battery Dispatch (MW)[2] [3]	EV Managed Charging (MW)[2] [3]	Demand Bidding (MW)[2] [3]	Behavioral DR(MW)[2] [3]	Real Time Pricing (MW)[2] [3]	Voltage Optimization (MW)[2] [3]	
Description of DR option				fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, Water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF	
Year	2021	15000	300	100	20	105	50	10	5	2	0	2	2	2	1	
	% of 2021		2	33.333	6.667	35.000	16.667	3.333	1.667	0.667	0.000	0.667	0.667	0.667	0.333	
Year	2030[3]	13750	1620	420	180	420	205	75	75	25	20	2	2	2	2	
	% of 2030		11.782	25.926	11.111	25.926	12.654	4.630	4.630	1.543	1.235	0.123	0.123	0.123	0.123	
Year	2040[3]	18500	1850	465	390	374	270	111	74	74	50	5	5	5	5	
	% of 2040		10	25.135	21.081	20.216	14.595	6.000	4.000	4.000	2.703	>1	>1	>1	>1	

MICHIGAN L.P. WINTER Achievable Potential

		MI Lower peninsula total peak demand[5]	Michigan lower peninsula total DR reduction (MW)[4]	C&I Capacity Reduction	Smart T-stat BYOT	Critical Peak Pricing	Direct Load Control Switch	Time of Use	Peak Time Rebate	BTM Battery Dispatch	EV Managed Charging	Demand Bidding	Behavioral DR	RTP	Voltage Optimization	
Description of DR option				fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, Water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF	
Year	2021	not avail	190.000	50.000	5.000	75.000	40.000	5.000	5.000	2.000	0.000	2.000	2.000	2.000	1.000	
	% of 2021		not avail.	26.316	2.632	39.474	21.053	2.632	2.632	1.053	0.000	1.053	1.053	1.053	0.526	
Year	2030[4]	not avail	1050.000	380.000	90.000	200.000	205.000	75.000	50.000	20.000	15.000	2.000	2.000	2.000	2.000	
	% of 2030		not avail.	36.190	8.571	19.048	19.524	7.143	4.762	1.905	1.429	0.190	0.190	0.190	0.190	
Year	2040[4]	not avail	1190.000	392.700	178.500	178.500	238.000	59.500	47.600	71.400	47.600	11.900	11.900	11.900	11.900	
	% of 2040[5]		not avail.	33.000	15.000	15.000	20.000	5.000	4.000	6.000	4.000	1.000	1.000	1.000	1.000	

Table 13-1 Guidehouse summer and winter achievable demand response potential for the upper and lower peninsulas

Traverse City SUMMER Achievable Potential

		Traverse City total peak demand(MW)[6]	Traverse City total DR reduction (MW)[2]	C&I Capacity Reduction (MW)	Smart T-stat BYOT (MW)	Critical Peak Pricing (MW)	Direct Load Control Switch (MW)	Time of Use (MW)	Peak Time Rebate (MW)	BTM Battery Dispatch (MW)	EV Managed Charging (MW)	Demand Bidding (MW)	Behavioral DR (MW)	Real Time Pricing (MW)	Voltage Optimization (MW)	
Description of DR option	Year			fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, Water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF	
Year	2021	67.000	1.340	0.447	0.089	0.469	0.223	0.045	0.022	0.009	0.000	0.009	0.009	0.009	0.004	
	% of 2021		2.000	33.333	6.667	35.000	16.667	3.333	1.667	0.667	0.000	0.667	0.667	0.667	0.333	
Year	2030	61.417	7.236	1.876	0.804	1.876	0.916	0.335	0.335	0.112	0.089	0.009	0.009	0.009	0.009	
	% of 2030		11.782	25.926	11.111	25.926	12.654	4.630	4.630	1.543	1.235	0.123	0.123	0.123	0.123	
Year	2040	82.633	8.263	2.077	1.742	1.671	1.206	0.496	0.331	0.331	0.223	0.083	0.083	0.083	0.083	
	% of 2040		10.000	25.135	21.081	20.216	14.595	6.000	4.000	4.000	2.703	1.000	1.000	1.000	1.000	

Traverse City WINTER Achievable Potential

		Traverse City total peak demand	Traverse City total DR reduction (MW)	C&I Capacity Reduction (MW)	Smart T-stat BYOT (MW)	Critical Peak Pricing (MW)	Direct Load Control Switch (MW)	Time of Use (MW)	Peak Time Rebate (MW)	BTM Battery Dispatch (MW)	EV Managed Charging (MW)	Demand Bidding (MW)	Behavioral DR (MW)	RTP (MW)	Voltage Optimization (MW)	
Description of DR option				fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, Water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF	
Year	2021	42.433	0.849	0.223	0.022	0.335	0.179	0.022	0.022	0.009	0.000	0.009	0.009	0.009	0.004	
	% of 2021			26.316	2.632	39.474	21.053	2.632	2.632	1.053	0.000	1.053	1.053	1.053	0.526	
Year	2030	38.897	4.690	1.697	0.402	0.893	0.916	0.335	0.223	0.089	0.067	0.009	0.009	0.009	0.009	
	% of 2030			36.190	8.571	19.048	19.524	7.143	4.762	1.905	1.429	0.190	0.190	0.190	0.190	
Year	2040	53.153	5.315	1.754	0.797	0.797	1.063	0.266	0.213	0.319	0.213	0.053	0.053	0.053	0.053	
	% of 2040[5]			33.000	15.000	15.000	20.000	5.000	4.000	6.000	4.000	1.000	1.000	1.000	1.000	

Table 13-2 summer and winter achievable demand response potential for Traverse City

The potential for peak demand reduction in Traverse City by participation in DR events is:

- 2021 - 1.34 MW
- 2030 - 7.24 MW
- 2040 - 8.26 MW

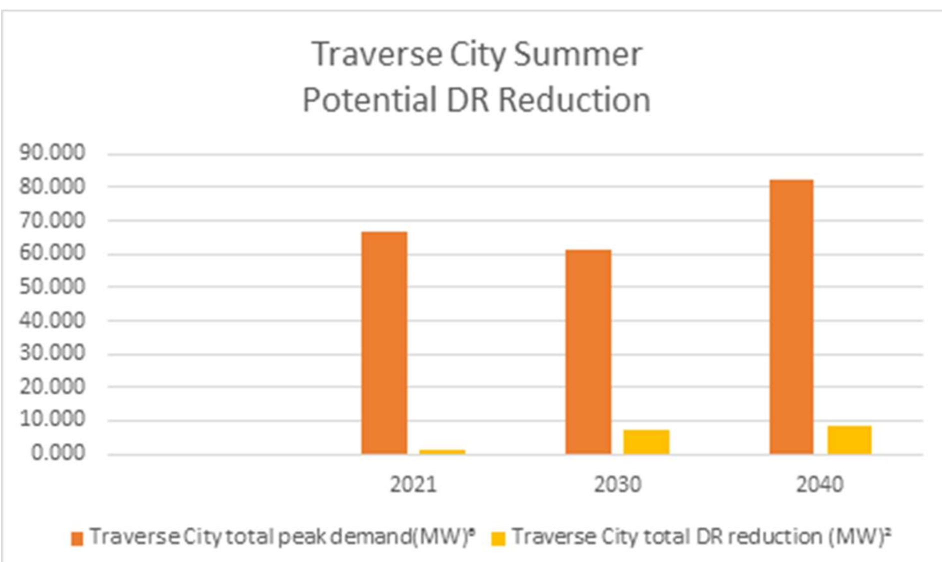


Figure 13-1 Potential for summer demand response in Traverse City

Large and very large rate customers who are chiefly commercial and industrial customers are expected to be the major participants in demand response programs in the immediate future. Commercial and industrial customers use the most energy and will thus contribute to the greatest energy reduction. C&I capacity reduction programs will contribute the most to demand reduction through 2040. TCLP should also note the specific opportunity to work with pumping customers to achieve an almost 0.75 MW of demand response during all peak period hours through most of the year.

According to Guidehouse, smart thermostat (BYOT) adoption will increase in residential and commercial settings and increased BYOT adoption will increase opportunity to participate in DR events and is projected to be the second-most important DR option through the year 2040. In Guidehouse's study, in which most heating is assumed to be done with natural gas, demand response potential is lower in winter than in summer, with summer peak demand in 2040 projected at 82 MW and winter peak demand at 53 MW in 2040. With building space heating and water heating electrification, these uses will also present large opportunities for future demand response programs and could result in greater DR potential in winter than summer.

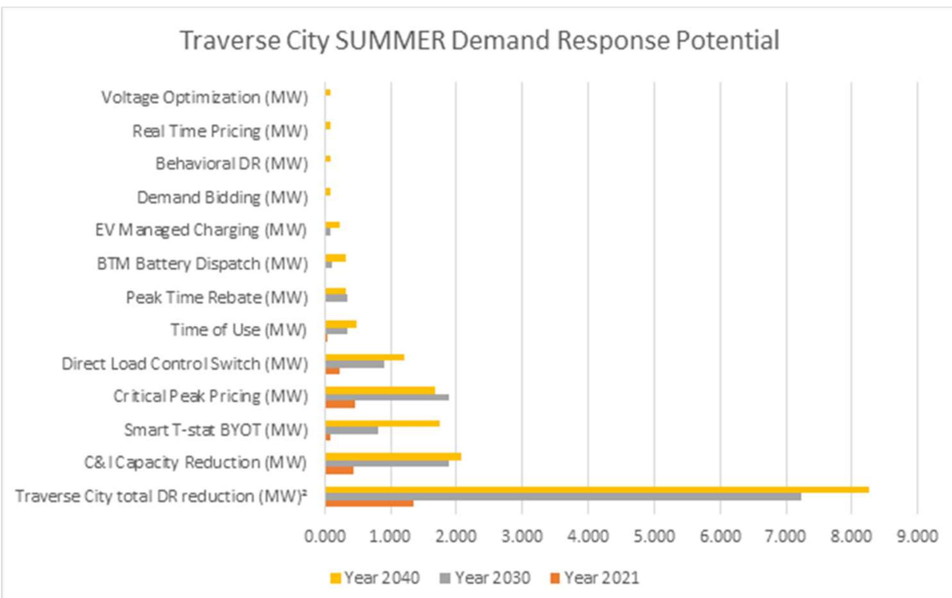


Figure 13-2 Sources of summer demand response potential by year

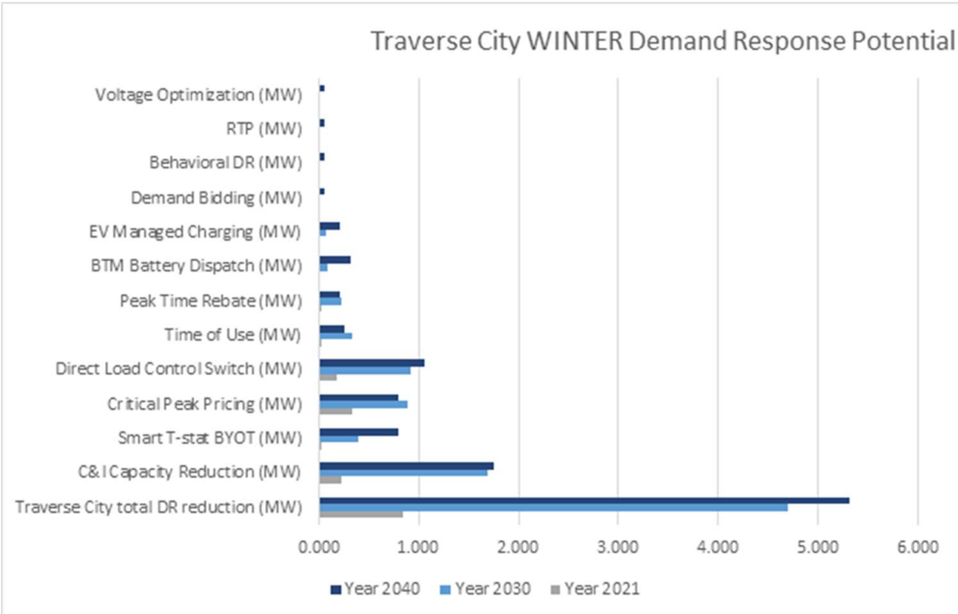


Figure 13-3 Sources of winter demand response potential by year

In Guidehouse's study, EV managed charging and BTM battery dispatch more than double with expected penetration of EVs and battery storage in the market. We note that this assessment is based on modest rates of EV adoption and the adoption rate we now forecast suggests that EV charging will play a much larger role in demand response than forecast by Guidehouse.

All other DR options do not individually constitute more than 4% by 2040. Demand bidding, behavioral response, real time pricing and voltage optimization do not reach one percent by the year 2040. However, we note that voltage optimization is entirely within the utility's control and has repeatedly been found to be the most cost-effective capacity resource in integrated resource planning.[28]

In summary, we note that demand response potential is large enough to present a material alternative source of capacity.

13.3.3 Implementing Demand Response

Demand response based on behavioral response by customers is difficult to implement and sustain, particularly with participation by large numbers of smaller customers. We recommend focusing entirely on automated demand response.

Automated demand response requires that customers have devices that are capable of responding to demand response requests from the utility, that the utility have the infrastructure to initiate demand response events, and that customers be enrolled to participate in demand response. We further note that managing electric vehicle charging, which we discussed above, has great similarity to demand response and these strategies can be undertaken as a single load management program.

Unlike other forms of demand response, dynamic volt-var control and conservation voltage reduction can be implemented entirely by the utility without engaging customers. As a result it is amongst the forms of

[28] Jester, D. 2014. Least-cost implementation of the Clean Power Plan in Michigan. Consumers Energy Integrated Resource Plan in Michigan Public Service Commission Case No. U-20165. DTE Electric Integrated Resource Plan in Michigan Public Service Commission Case No U-20471

demand response that is quickest and most cost-effective to implement. We therefore recommend as follows:

Recommendation: As a condition for rebates on electric vehicle chargers, space conditioning equipment, electric water heaters, and perhaps other efficiency or electrification rebates, require that equipment be able to participate in a demand response program.

Recommendation: Provide a financial offer for customers to enroll in an automated load management program for vehicle charging, space conditioning, water heating, pumping, electricity storage, smart buildings, or commercial process load that will:

a. Inform equipment operations about time-of-use rate schedules;
b. Allow real-time management of demand within customer-friendly limits; and
c. Allow (at customer option) emergency management of demand as needed to qualify as MISO capacity resources.

Recommendation: Evaluate cost-effectiveness of implementing dynamic volt-var control and conservation voltage regulation within TCLP's distribution system.

14 Behind-the-Meter Solar and Storage Analysis

14.1 Framework for Behind-the-Meter Tariff Design

Our analysis of behind-the-meter resources, including but not limited to solar and storage, is premised on our understanding that Michigan electric utility customers have, and should have, a right to self-supply, including on-site supply provided by third parties other than the customer and the utility.[29] That right extends to non-discrimination in the rates that apply to utility services to the customer. For this reason, we recommend against the practice sometimes called buy-all and sell-all, in which the customer is required to buy all of the power they consumer from the utility and sell all of the power they produce behind the meter to the utility, typically with a high price differential.

Beginning with 2005 amendments to the Public Utility Regulatory Policies Act, which encouraged use of net metering, net metering became a common practice. Under a net metering protocol, the customer bill is based on the net of inflow to the customer from the utility and outflow from the customer to the utility, both at the retail price. Commonly, the retail price was assumed to be constant so that the price applied to inflow and outflow was the same. In 2008, Michigan adopted Public Act 295, which required utilities to offer net metering to customers with behind-the-meter generation less than 20 kW nominal capacity and modified net metering for customers with behind-the-meter generation between 20 kW and 150 kW nominal capacity, but with the limitation that the behind-the-meter generation for a single customer could not exceed their annual electricity consumption, and with an overall program limitation that the utility was only obligated to allow net metering for a total system behind-the-meter capacity up to 1% of the utilities annual peak demand. This program cap was further subdivided 50% for systems less than 20 kW, 25% for systems between 20 kW and 150 kW, and 25% for anaerobic digestion methane gas generators. This law was silent as to what would be utility obligations once the program caps were reached.

In 2016, Michigan law was changed by Public Acts 341 and 342 to retain the size limitations of the net metering program but require the Michigan Public Service Commission to adopt a new tariff design reflecting cost of service. The Commission adopted what it labeled as an inflow-outflow design, specifying that inflow should be charged at the appropriate retail rate and that outflow should be credited at a rate

[29] See MCL 460.10a (4)

reflecting its contribution to cost of service. At the time, the Commission acknowledged that it had an insufficient basis for setting the outflow rate to reflect cost of service and proposed that until modified in future proceedings, the outflow rate should be set equal to the portion of the retail rate that is based on production and transmission but not include the portion of the rate that is based on distribution. That formulation continues to be contested but remains the practice amongst regulated utilities in Michigan. Since different rates may apply at different times, as in a time of use rate design, the Commission's inflow-outflow approach constitutes net billing, in that customers are billed the net monetary values of inflow and outflow without any netting on an energy basis. Most regulated utilities have exceeded one or more of these program caps and have voluntarily increased the cap under pressure from stakeholders. The Commission has opined to the legislature that because the Commission's approach to distributed generation tariffs reflects cost of service, there is no need for a program cap.

Although TCLP is not subject to the jurisdiction of the Michigan Public Service Commission for most purposes, the language of the distributed generation program requirements is, in our view, ambiguous as to whether it applies to utilities not regulated by the Commission.

The Public Utility Regulatory Policies Act of 1978, as amended, requires all electric utilities to purchase power generated by small renewable generators (generally less than 20 MW, though a utility can petition the Federal Energy Regulatory Commission to lower that to 5 MW if such facilities have reasonable access to wholesale markets), at the utility's avoided cost. In the case of generators less than 100 kW and larger if decided by the regulatory authority, and of outflow from customers, FERC regulations require that the utility provide a standard offer tariff reflecting the avoided cost attributable to the aggregate of all such small generators rather than the performance of each individual facility. Particularly, this requires that generation capacity be accredited to small facilities based on the statistical average contribution of such facilities. The Public Utility Regulatory Policies Act does apply to TCLP.

Thus, absent the Michigan requirement that each utility offer a distributed generation tariff or in the event that program participation exceeds the cap on a utility's obligation to offer a distributed generation tariff, each utility is effectively obligated to offer a net billing program in which outflow prices are not less than the utility's avoided cost.

Under MISO's tariffs, outflow is treated as negative load for purposes of determining market energy purchases, resource adequacy, and transmission demand. This leads to the following guidelines for determining avoided cost.

Since outflow is negative load at the meter, it should be adjusted upward by marginal line losses between the transmission substation and the customer to obtain power supply avoided at the substation and multiplied by locational marginal price at the time of outflow to determine avoided energy cost.
Since outflow is treated as negative load for purposes of MISO resource adequacy, outflow in tight hours of each season should be adjusted for marginal line losses between the transmission substation and the customer to obtain power supply avoided during tight hours and further increased by MISO's applicable reserve margin to determine TCLP's avoided resource capacity. Avoided cost of capacity should reflect the current cost of new capacity of the kind that TCLP would choose if it needed incremental capacity, but can be reasonably approximated as 75% of the Cost of New Entry ("CONE") that MISO determines each year as the cost of new combustion turbine capacity. Use of 75$ of CONE reflects that CONE is the revenue requirement in the first year of a new generator, but that declines over time and on a life-cycle basis averages approximately 75% of CONE.

Since outflow is treated as negative load for purposes of MISO transmission charges, outflow at the time the monthly demand is determined, again adjusted for marginal line losses, is TCLP's avoided transmission requirement and should be credited at the monthly unit cost of transmission demand.

Application of these guidelines typically leads to an avoided cost for outflow that is very close to the production and transmission components of retail rates, which justifies simply using that value for outflow as is the Commission's practice.

Distributed generation can cause or reduce the cost of distribution, particularly to the extent that outflow coincides with distribution system peaks. Outflow from any customer will generally flow to an electrically adjacent customer that needs inflow at that time. Where multiple customers share a line transformer, this reduces the flow across the transformer. Aggregate outflow by all customers on a primary circuit reduces flow through the substation transformers. These reduced flows may reduce required transformer size and cost, but more commonly will reduce thermal aging of the transformer and lengthen its life. The Commission has acknowledged this possibility and has assigned an avoided cost for such phenomena in determining avoided costs for energy efficiency programs but has not yet adopted an avoided distribution cost for distributed generation.

Upon a demonstration that this is an avoided cost, the Commission will be obligated to include it in PURPA rates, though not in the legislatively-mandated distributed generation program that is required to reflect cost of service. Whether and how outflow should be reflected in distribution cost of service remains a contested issue, about which TCLP may make its own judgement. Given that outflow from one customer typically flows to an electrically adjacent customer using the portion of the distribution system at their own voltage level but reduces use of the distribution system at the next higher voltage level, a reasonable approximation of a cost of service approach would be to treat outflow as a negative load at the next higher voltage level from the customer.

Our view is that a principled approach to compensating outflow from customers is to implement net billing with outflow credit not less than the avoided cost required by the Public utility Regulatory Policies Act and not more than cost of service if outflow is treated as negative load at the next higher voltage level in the cost of service study. Within that range, TCLP can reasonably consider other factors.

Assuming that credits for outflow are economically reasonable, there is no particular reason to limit customer system size nor to limit customer participation in distributed generation, until and unless limits are required by electrical conditions on the distribution system under specific circumstances that should be determined through interconnection studies.

We therefore offer the

Recommendation: Replace net metering policy with a distributed resource policy that has the following features:

a. Net billing, in which charges to the customer and credits to the customer are each calculated and then netted to determine monthly bills, with credits carried forward until such time as the customer requests payment.
b. Customers are charged standard retail rates for inflow to the customer from TCLP, using the time-of-use rate schedule to which the customer would normally be assigned.
c. Customers are credited for outflow from the customer to TCLP, at rates that are not less than TCLP avoided cost and not more than cost of service at the next higher voltage level above that to which the customer is connected.
d. There is no limit on the size of a customer's behind-the-meter solar or storage systems, except as necessary for protection of the distribution system.
e. There is no cap on customer participation in distributed generation.

14.2 Societal Benefits of Distributed Solar and Storage

If behind-the-meter solar is a substitute for utility-provided renewable power, then the avoided social cost due to the behind-the-meter solar is just the avoided cost of utility-scale solar and its delivery to the customer, which is reasonably well compensated by the tariff recommendation we make above.

If behind-the-meter solar is a substitute for generic grid power, then the solar supplied avoids the societal cost of climate change and health costs due to emissions from power generation using fossil fuels. In our evaluation of the societal benefits of energy efficiency and electrification above, we assessed that the NPV of emissions associated with generic grid power is approximately $1.05 per annual kWh avoided. Based on annual production of 1,335 kWh per kW nominal capacity of a rooftop solar system in Traverse City, we assess that behind-the-meter solar generation that displaces generic gird power has an avoided societal cost, or societal benefit, of about $1,400 per kW capacity, excluding the avoided costs of electricity supply and delivery already addressed through our tariff recommendation.

Recommendation: If TCLP is providing 100% renewable power to its customers, then the recommended net billing tariff properly compensates customers who implement behind-the-meter renewable generation. If TCLP is providing generic grid power to its customers, then it would be appropriate to provide a rebate of up to $1400 per kW nominal capacity for installation of a behind-the-meter solar system.

14.3 Costs of Behind-the-Meter Solar and Storage

Our analysis in this report is based on estimates of the future cost of distributed solar systems in the Traverse City region. The Modeled Market Price (MMP) is estimated on a bottom-up basis for overnight capital costs. The overnight cost is a representative cash cost. To this we have included an estimate of financing costs (i.e., interest and equity). Total prices were estimated on a kWh basis for both rooftop and ground mount systems, although HOMER © modeling of building types only used the rooftop prices. Future prices through the 2040 modeling period were estimated by adjusting the 2022 base price using the ratio of expected change in market prices that the National Renewable Energy Laboratories (NREL) projected in its 2022 Annual Technology Baseline Report. These changes in price were founded on historical trends in improved efficiency of solar PV panels under the NREL moderate scenario.

SOLAR PV - MODELED MARKET PRICE ($kWh)						
Commercial Solar Rooftop	MMP	%		Commercial Solar Ground Mount	MMP	%
Module (incl. supply chain cost)	$0.447	44.97%		Module (incl. supply chain cost)	$0.447	39.97%
Inverter Only	$0.057	5.68%		Inverter Only	$0.057	5.05%
Structural BOS (Balance of System)	$0.135	13.56%		Structural BOS (Balance of System)	$0.172	15.37%
Electrical BOS (Balance of System)	$0.206	20.69%		Electrical BOS (Balance of System)	$0.285	25.44%
Install Labor & Equipment	$0.150	15.10%		Install Labor & Equipment	$0.158	14.17%
Total Equipment and Labor (NREL)	**$0.99**	100.00%		**Total Equipment and Labor**	**$1.12**	100.00%
EPC Overhead	$0.176	17.75%		EPC Overhead	$0.120	10.69%
EPC Profit	$0.120	12.10%		EPC Profit	$0.143	12.83%
Developer Profit	**$0.199**	**20.00%**		**Developer Profit**	**$0.224**	**20.00%**
Developer Overhead	**$0.160**	**16.11%**		Developer Overhead	**$0.177**	**15.85%**
Total Developer Overhead and Profit (NF	**$0.66**	65.96%		**Total Developer Overhead and Profit**	**$0.66**	59.37%
Total Direct Equipment Related Costs (NF	**$1.65**			**Total Direct Equipment Related Costs (NI**	**$1.78**	
Permitting, Inspection, Interconnection	$0.082	5.00%		Permitting, Inspection, Interconnection	$0.089	5.00%
Sales Tax (Michigan)	**$0.099**	**6.0%**		**Sales Tax (Michigan)**	**$0.107**	**6.0%**
Contingency (4%)	$0.066	4.00%		Contingency (4%)	$0.071	4.00%
Legal	**$0.016**	**1.0%**		**Legal**	**$0.018**	**1.0%**
Insurance	**$0.003**	**0.2%**		**Insurance**	**$0.004**	**0.2%**
Total Additional Soft Costs	**$0.27**	16.20%		**Total Additional Soft Costs**	**$0.29**	16.20%
Land Acquisition	$0.000	0.00%		Land Acquisition	$0.000	0.00%
Additional Construction Costs	**$0.082**	**5.00%**		**Additional Construction Costs**	**$0.000**	**0.00%**
Additional Hard Costs	**$0.08**			**Site Prep**	**$0.18**	**10.00%**
				Fencing	**$0.04**	**2.00%**
				Additional Hard Costs	**$0.21**	
Total Capital Cost 2021 $	**$1.92**			**Capital Cost 2021 $**	**$2.29**	
Inflation 2022	**8.20%**			**Inflation 2022**	**8.20%**	
Capital Cost 2022$ (Rooftop)	**$2.07**			**Total Capital Cost 2022$ (Groundmount)**	**$2.47**	
Interest/Equity Cost	**$0.21**	**10%**		**Interest/Equity Cost**	**$0.25**	**10%**
Total Capital Costs* - Rooftop	$ 2.28			Total Capital Costs* - Ground Mount	$ 2.72	
*Overnight Cash Cost Plus Financing Cost						

Table 14-1 Modeled market price for distributed solar in Michigan

A notable aspect of the cost of solar in the United States is that the "soft costs" of sales, planning, permitting, and inspection are substantial and much higher than some other countries. These costs reflect a regulatory system that is not designed to encourage behind-the-meter solar. We therefore offer the

Recommendation: As part of the customer energy optimization program, reduce the "soft costs" of behind-the-meter solar and storage by providing each customer an annual report of the expected costs and bill savings for solar at their premises, referral to qualified vendors or automated solicitation of proposals from qualified vendors, streamlined permitting and inspections, and on-bill repayment and other attractive financing for system costs.

14.4 Customer Adoption of Distributed Solar and Storage

Modeling of behind-the-meter (BTM) distributed generation resources was performed using HOMER®, (Hybrid Optimization of Multiple Energy Resources) software, leased through UL Solutions. HOMER® has several unique software offerings, and the one used for modeling TCLP BTM applications is called HOMER Grid®. It was designed for evaluating the economic benefits of BTM resources and includes powerful engineering/financial optimization functions.

Modeling was performed on 20 classifications of commercial building types and for residential single family detached. It should be noted that commercial building types (e.g., supermarket, small office, etc.) were not modeled as a whole building, but based on the average annual kWh load per TCLP account. A single building may have multiple accounts, and in some cases, under both the Small Commercial and Commercial Demand rate schedules. With respect to commercial building accounts, the 8,760-hour load profiles were estimated using the NREL Comstock data for Grand Traverse County and for the State of Michigan. Some building types used CBECS load shapes.

Prior to modeling, a Solar PV price forecast was made from 2022 through the 2040 timeframe. It was assumed that market prices would rise with inflation (be fixed on a constant dollar basis) through the 2025 timeframe due to supply constraints in the industry. Starting in 2026, prices would follow a downward trend (in constant dollars) consistent with the Moderate Scenario in the NREL 2022 Annual Technology Baseline, and in partial recognition of historical increases seen in panel efficiencies, (and thus lower prices). Fixed O&M costs were assumed to follow a similar trend.

The core purpose of BTM modeling was: (1) to establish the economic impact of expected declining solar PV costs over the projected 2025 through 2040 timeframe; (2) to develop an understanding of how TCLP's existing small commercial and commercial demand rate schedules impact the adoption of BTM solar PV adoption; (3) to determine how an aggressive time-of-use (TOU) rate design would impact the economic level of solar PV for both small commercial customers and large commercial demand customers; and (4) to establish the impact of a change in the distributed generation pricing model from true net metering, which is currently used by TCLP, to an net billing pricing model, including an understanding of the interplay of that change with a move to a TOU retail rate design.

As previously stated in this report, the Michigan Public Service Commission has adopted a Net Billing approach that uses instantaneous power inflows and outflows (no netting on energy). The hourly net billing approach used in the HOMER BTM modeling is a close approximation to the instantaneous "Inflow and Outflow" mechanism, and thus the results should provide TCLP an accurate picture of what to expect, should the utility choose to adopt such an instantaneous pricing mechanism for its retail DG (Distributed Generation) customers.

The following four charts delineate the numeric results of the HOMER Grid® BTM modeling of commercial buildings in the TCLP service district, The charts summarize the modeling year 2025 results. The results for 2030 through 2040 can be found in the report appendices.

Building Type	PV Max. Nameplate	PV Cost $/kW	Optimal PV Capacity kW (DC)	Net Present Worth $	IRR	Payback Years	PV Production kWh	Retail Purchases kWh	PV Outflow kWh
	TCLP 2025 Modeling Year								
	Small Commercial Rate C (Account)								
Primary School	3.7	$ 2.28	3.7	$ 1,577	9.1	9.4	4,657	2,484	2,526
Secondary School									
Quick Service Restaurant	3.8	$ 2.28	3.8	$ 1,620	9.1	9.4	4,782	11,021	1,256
Full Service Restaurant	6.3	$ 2.28	6.3	$ 2,685	9.1	9.4	7,929	23,288	651
Hospital									
Outpatient	6.6	$ 2.28	6.6	$ 2,813	9.1	9.4	8,306	6,152	3,157
Small Hotel	5.5	$ 2.28	5.5	$ 2,344	9.1	9.4	6,922	8,683	2,549
Large Hotel	53.0	$ 2.28	53	$ 22,591	9.1	9.4	66,702	43,425	40,374
Retail Standalone	13.6	$ 2.28	13.6	$ 5,797	9.1	9.4	17,116	8,899	8,810
Retail Strip Mall	5.5	$ 2.28	5.5	$ 2,344	9.1	9.4	6,922	6,550	2,360
Small Office	6.6	$ 2.28	6.6	$ 2,813	9.1	9.4	8,306	4,750	4,765
Medium Office	42.7	$ 2.28	42.7	$ 18,201	9.1	9.4	53,739	33,287	30,085
Large Office									
Warehouse	19.0	$ 2.28	19.0	$ 8,099	9.1	9.4	23,912	14,224	14,133
Midrise Apartment	7.4	$ 2.28	7.4	$ 3,154	9.1	9.4	9,313	6,581	5,152
Religious Worship	6.3	$ 2.28	6.3	$ 2,685	9.1	9.4	7,929	4,817	4,748
Retirement Community	35.0	$ 2.28	35	$ 14,919	9.1	9.4	44,048	32,229	25,289
Service									
Supermarket	5.2	$ 2.28	5.2	$ 2,217	9.1	9.4	6,544	21,560	54
Other	1.5	$ 2.28	1.5	$ 639	9.1	9.4	1,888	3,226	679

Table 14-2 Small Commercial – Existing Tariff – Rate C

Building Type	PV Max. Nameplate	PV Cost $/kW	Optimal PV Capacity kW (DC)	Net Present Worth $	IRR	Payback Years	PV Production kWh	Retail Purchases kWh	PV Outflow kWh
	TCLP 2025 Modeling Year								
	Small Commercial Rate C (Account)								
Primary School	3.7	$ 2.28	3.6	$ 1,827	9.7	8.9	4,560	2,497	2,441
Secondary School									
Quick Service Restaurant	3.8	$ 2.28	3.8	$ 3,146	12.0	7.5	4,782	11,021	1,256
Full Service Restaurant	6.3	$ 2.28	6.3	$ 6,537	13.3	6.8	7,929	23,288	651
Hospital									
Outpatient	6.6	$ 2.28	6.6	$ 4,479	10.9	8.1	8,306	6,152	3,157
Small Hotel	5.5	$ 2.28	5.5	$ 3,716	10.9	8.1	6,922	8,683	2,549
Large Hotel	53.0	$ 2.28	37.5	$ 17,881	9.5	9.1	47,247	45,903	23,397
Retail Standalone	13.6	$ 2.28	11.9	$ 6,320	9.9	8.8	14,976	9,184	6,956
Retail Strip Mall	5.5	$ 2.28	5.5	$ 3,876	11.1	8.0	6,922	6,550	2,360
Small Office	6.6	$ 2.28	5.0	$ 2,733	10.0	8.7	6,230	4,994	2,933
Medium Office	42.7	$ 2.28	33.8	$ 17,946	9.9	8.8	42,543	34,629	20,232
Large Office									
Warehouse	19.0	$ 2.28	13.5	$ 7,396	10.0	8.7	16,938	15,050	7,984
Midrise Apartment	7.4	$ 2.28	5.6	$ 2,968	9.9	8.8	6,985	6,883	3,125
Religious Worship	6.3	$ 2.28	4.7	$ 1,936	9.0	9.5	5,947	5,074	3,023
Retirement Community	35.0	$ 2.28	27.7	$ 13,056	9.5	9.1	34,872	33,472	17,355
Service									
Supermarket	5.2	$ 2.28	5.2	$ 5,840	13.9	6.6	6,544	21,560	54
Other	1.5	$ 2.28	1.5	$ 984	10.8	8.2	1,888	3,226	679

Table 14-3 Small Commercial – TOU Tariff – (Phase3)

Building Type	TCLP 2025 Modeling Year								
	Large Commercial Rate CD (Account)								
	PV Max. Nameplate	PV Cost $/kW	Optimal PV Capacity kW (DC)	Net Present Worth $	IRR	Payback Years	PV Production kWh	Retail Purchases kWh	PV Outflow kWh
Primary School	102.7	$ 2.28	7.5	$ 1,103	7.0	11.3	9,424	120,354	234
Secondary School	507.5	$ 2.28	74.0	$ 9,181	6.9	11.5	93,144	553,270	6,240
Quick Service Restaurant	18.3	$ 2.28	0.0	$ -	-		-	70,912	-
Full Service Restaurant	23.9	$ 2.28	0.0	$ -	-		-	115,386	-
Hospital	22.8	$ 2.28	1.0	$ 132	7.0	11.4	1,196	42,692	0
Outpatient	36.9	$ 2.28	0.4	$ 73	7.4	10.9	484	62,290	0
Small Hotel	133.1	$ 2.28	9.7	$ 1,579	7.2	11.2	12,214	304,821	0
Large Hotel									
Retail Standalone	81.5	$ 2.28	1.3	$ 38	6.1	12.4	1,603	101,261	0
Retail Strip Mall	25.9	$ 2.28	1.6	$ 47	6.1	12.4	2,037	50,432	0
Small Office	59.6	$ 2.28	3.1	$ 494	7.1	11.2	3,907	71,252	0
Medium Office	98.7	$ 2.28	4.1	$ 827	7.5	10.9	5,176	126,419	0
Large Office	66.1	$ 2.28	0.7	$ 18	6.1	12.4	6,119	99,985	0
Warehouse	120.1	$ 2.28	1.9	$ 425	7.7	10.7	2,362	149,191	0
Midrise Apartment	76.9	$ 2.28	1.6	$ 284	7.3	11.0	2,016	110,160	0
Religious Worship	97.7	$ 2.28	6.1	$ 937	7.1	11.2	7,685	115,523	0
Retirement Community	75.4	$ 2.28	0.4	$ 12	6.1	12.3	494	109,442	0
Service	97.1	$ 2.28	0.0	$ -	-		-	122,549	-
Supermarket	119.5	$ 2.28	6.2	$ 177	6.1	12.4	7,833	637,188	0
Other	119.1	$ 2.28	0.0	$ -	-	-	-	351,128	-

Table 14-4 Large Commercial – Existing Tariff – Rate CD

Building Type	TCLP 2025 Modeling Year								
	Large Commercial Rate CD (Account)								
	PV Max. Nameplate	PV Cost $/kW	Optimal PV Capacity kW (DC)	Net Present Worth $	IRR	Payback Years	PV Production kWh	Retail Purchases kWh	PV Outflow kWh
Primary School	102.7	$ 2.28	102.7	$ 40,646	8.9	9.5	129,250	69,916	69,622
Secondary School	507.5	$ 2.28	507.5	$ 217,545	9.2	9.4	638,700	331,571	330,097
Quick Service Restaurant	18.3	$ 2.28	18.3	$ 8,477	9.4	9.2	23,031	53,823	5,942
Full Service Restaurant	23.9	$ 2.28	23.9	$ 13,207	10.0	8.7	30,079	87,822	2,514
Hospital	22.8	$ 2.28	22.8	$ 10,638	9.4	9.1	28,694	25,437	10,244
Outpatient	36.9	$ 2.28	36.9	$ 16,477	9.3	9.3	46,439	34,110	17,776
Small Hotel	133.1	$ 2.28	133.1	$ 59,630	9.3	9.2	167,509	210,965	61,439
Large Hotel									
Retail Standalone	81.5	$ 2.28	81.5	$ 30,708	8.8	9.7	102,570	53,175	52,880
Retail Strip Mall	25.9	$ 2.28	25.9	$ 11,786	9.4	9.2	32,596	30,949	11,075
Small Office	59.6	$ 2.28	59.6	$ 21,437	8.7	9.8	75,008	43,088	42,937
Medium Office	98.7	$ 2.28	98.7	$ 35,414	8.6	9.8	124,216	76,927	69,549
Large Office	66.1	$ 2.28	66.1	$ 24,421	8.7	9.7	83,188	60,226	42,563
Warehouse	120.1	$ 2.28	120.1	$ 40,239	8.5	9.9	151,149	89,795	89,390
Midrise Apartment	76.9	$ 2.28	76.9	$ 25,832	8.5	9.9	96,780	69,859	54,463
Religious Worship	97.7	$ 2.28	97.7	$ 37,520	8.8	9.6	122,958	67,889	67,640
Retirement Community	75.4	$ 2.28	75.4	$ 26,179	8.6	9.8	94,893	66,630	51,586
Service	97.1	$ 2.28	97.1	$ 28,761	8.2	10.2	122,203	76,877	76,531
Supermarket	119.5	$ 2.28	119.5	$ 68,731	10.2	8.6	150,393	499,541	4,913
Other	119.1	$ 2.28	119.1	$ 51,182	9.2	9.4	149,890	246,690	45,452

Table 14-5 Large Commercial – TOU Tariff (Phase 5)

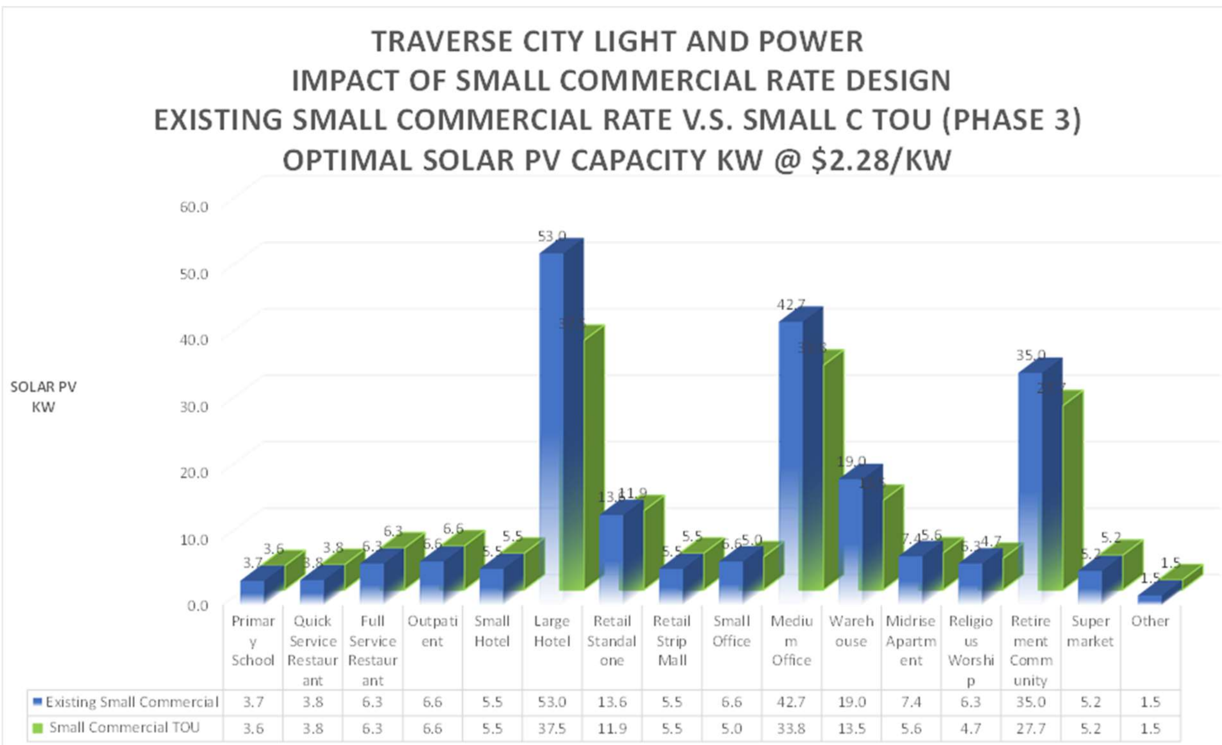
Commercial Accounts – Homer Modeling Assumptions

HOMER modeling required the setting of a physical limit to the level of solar capacity. That limit was defined to be the lesser of the net zero PV capacity (in kW) or the kW capacity of a panel area equal to the maximum available roof area. The net zero capacity is the nameplate kW (DC) of PV capacity that would produce an annual generation output, kWh (AC), equivalent to the annual load of the customer account. It is a "net" value considering the mismatch between the 8760-hour customer load profile and the 8760-hour generation load profile. That mismatch causes either an import of energy from the grid, or an export of energy to the grid at any moment. Thus, despite the PV array (at net zero) generating enough energy to meet the building's load over a 12-month period, the utility must balance a customer's generation output and electric usage instantly. It is standard practice for electric utilities to set *net zero* as a tariff limit for BTM distributed generation programs.

HOMER modeling quantified the *generation capacity factor* to be approximately [0.144 kWh (AC)] / [nameplate kW (DC)] for rooftop solar PV arrays located in Grand Traverse County. Thus, the net zero limit (kW DC) was calculated as the average hourly demand (kWh AC) divided by the generation capacity factor.

The kW capacity of a panel area equal to the maximum available roof area was estimated from Comstock building data, by calculating an annual energy intensity, (kWh/sq. ft. floor space) and dividing that into a sample-average kWh load for a representative account. The resulting available roof area per representative account was converted into a kW PV capacity using the area and efficiency of a typical panel (i.e., 21.42 sq. ft., and 21.25% efficiency).

The following figure depicts the combined impact on the economic level of solar PV capacity caused by a move to aggressive TOU rates and Net Billing DG mechanism for TCLP small commercial accounts. The figures provide a visual window into the interplay of retail tariff structures and DG pricing models associated with the key objectives listed above.



	Primary School	Quick Service Restaurant	Full Service Restaurant	Outpatient	Small Hotel	Large Hotel	Retail Standalone	Retail Strip Mall	Small Office	Medium Office	Warehouse	Midrise Apartment	Religious Worship	Retirement Community	Supermarket	Other
Existing Small Commercial	3.7	3.8	6.3	6.6	5.5	53.0	13.6	5.5	6.6	42.7	19.0	7.4	6.3	35.0	5.2	1.5
Small Commercial TOU	3.6	3.8	6.3	6.6	5.5	37.5	11.9	5.5	5.0	33.8	13.5	5.6	4.7	27.7	5.2	1.5

Figure 14-1 Impact of small commercial TOU Tariff (PHASE 3)

Interpretation of HOMER BTM Commercial modeling results.

First, it should be noted that the existing TCLP Small Commercial rate (Rate C), with net metering, yields an economic level of solar PV capacity that matches the modeling limit of the smaller of net zero, or PV capacity based on available roof area for all small commercial building types. That can be explained primarily by the relatively low cost of solar in the 2025 and later timeframe, and significantly by the availability of true net-metering.

True net-metering compensates DG customers by the full retail rate for all exports to the grid, which are, theoretically, distributed back to them later when generation falls short of electric load requirements. However, TCLP is physically required to serve the full amount of such later load imbalance in a manner that is indistinguishable from any other retail power inflows. In essence, the utility provides a type of "grid as storage service" at no compensation. The economic incentive provided by true net-metering, (for small commercial customers not having demand charges), is a powerful incentive for BTM solar PV adoption.

Regarding the alternative of an aggressive TOU rate design, combined with hourly net billing, the modeling results show nearly identical results as with the existing rate structures, with respect to the economic level of deployed solar PV capacity. For approximately 50% of the building types, the economic level is slightly lower, and for the balance, the economic level of PV capacity is the same. Importantly, modeling revealed that the change in present worth to customers of an investment in solar PV would in most cases be larger, and in a few cases (e.g., large hotel) be moderately lower with a change in rate structure to TOU/net billing. It can be concluded that for TCLP's small commercial customers, a change in rate structure to TOU plus net billing with have insignificant impact on the existing strong incentives to deploy solar PV.

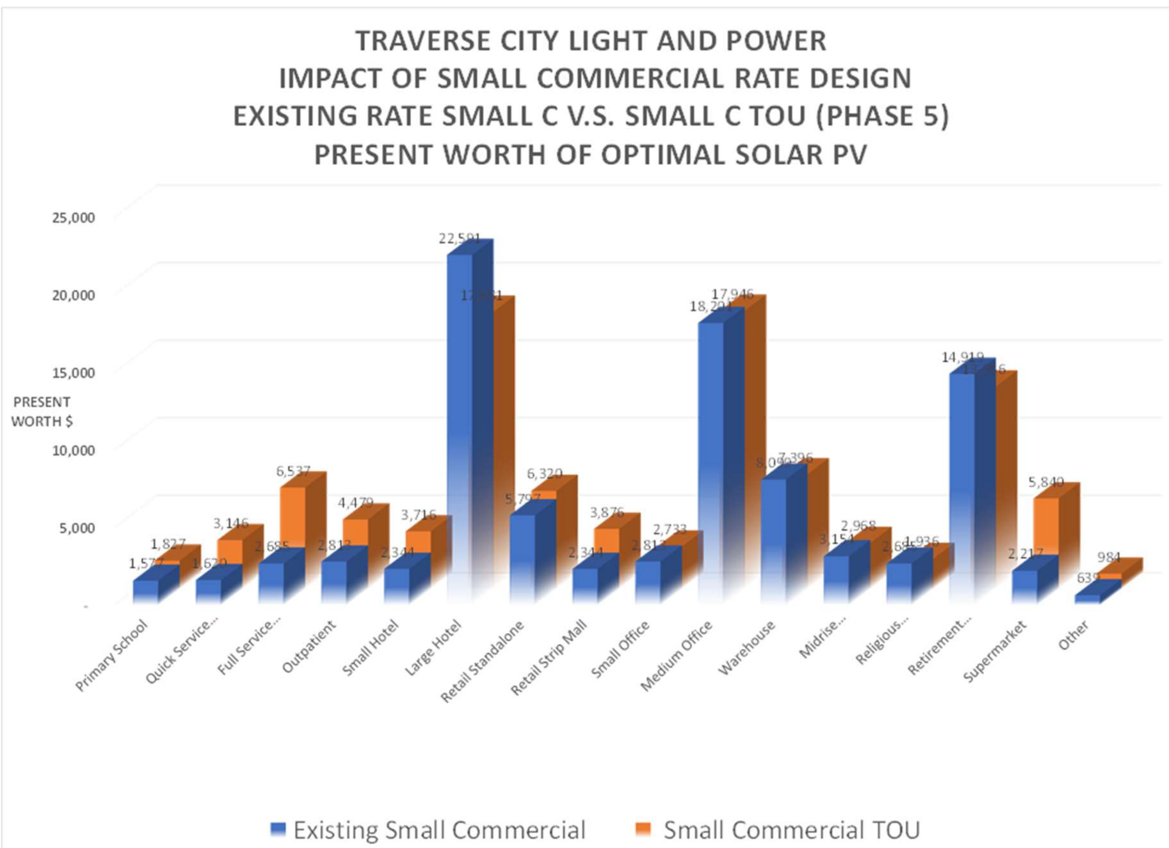


Figure 14-2 Impact of small commercial TOU Tariff (PHASE 5), Present worth of Optimal Solar PV

With respect to TCLP's large commercial accounts, HOMER modeling results were strikingly different. In contrast to small commercial accounts, TCLP's existing Commercial Rate CD provides poor economic incentives for large demand customers to deploy BTM solar PV. HOMER modeling revealed very low levels of economic solar for all large commercial demand account types.

It can be concluded that economic incentives derived from true net-metering for these large commercial customers is far overshadowed by the inability of solar PV generation profiles to offset peak electric loads underlying demand charges. As demand charges constitute a sizable portion of customer monthly bills, the net present worth of solar PV investments is low. HOMER modeling also revealed that a TCLP movement away from a demand-based rate-structure, to an aggressive TOU rate structure combined with net billing, yields vastly larger economic levels of BTM solar, and commensurately larger net present worths for investment on solar PV. This was true for all large commercial building types. See the blue and yellow bars in the graph below.

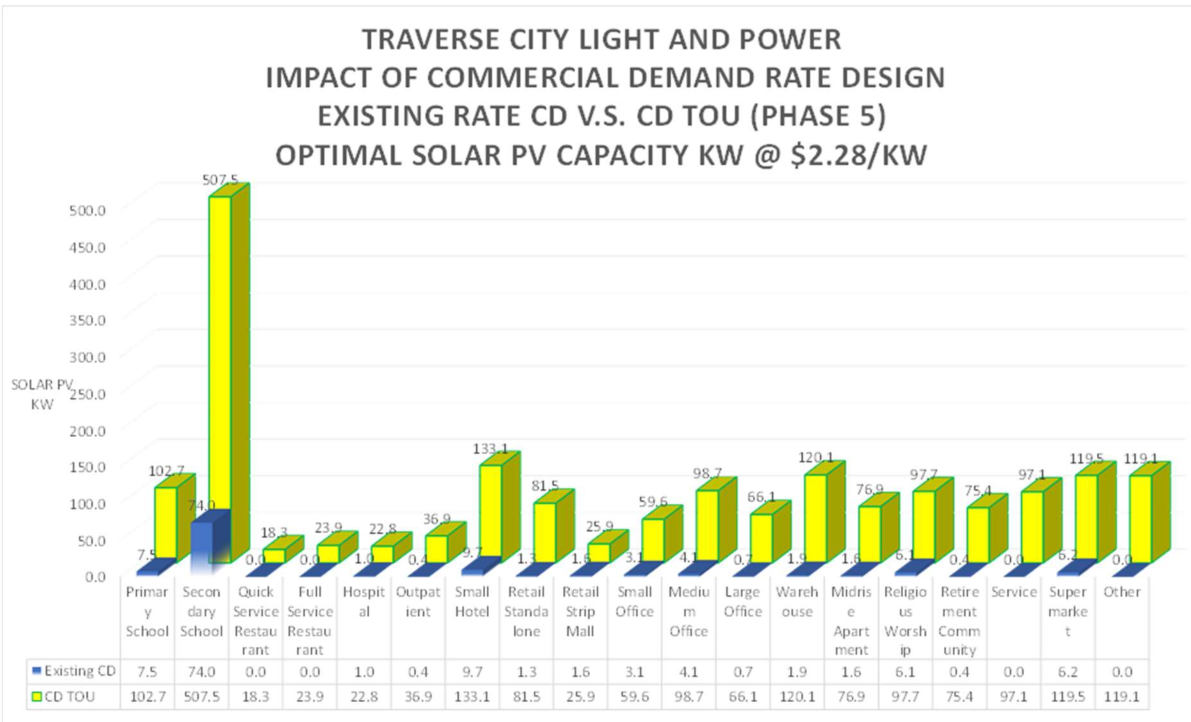


Figure 14-3 Impact of CD TOU Tariff (PHASE 5), Optimal solar PV capacity

An order of magnitude increase in net present worth associated with the increased level of solar PV capacity can be seen in the following graph. The question of the relative difference in the net present worth of solar PV investment on an assumption of the same solar PV capacity under both rate structures was investigated. It was found that the TOU rate schedule combined with net billing yielded a significantly higher net present worth. The fundamental reason for such superior value of TOU rate design relates to the fact that avoided retail purchases (via solar generation) have strong cost-of-service attributes. Costs that would be otherwise recovered in demand charges are now recovered principally in high-cost pricing periods (i.e., super peak, and peak periods). Net billing for power outflows, also compensates customers for such energy with higher costs during peak pricing periods, as outflow credits are priced using the core costs imbedded in the retail prices (power supply including transmission) plus a scaling factor to recognize avoided transmission and distribution losses. See the following graph for a visualization of the improved net present worth to large demand customers.

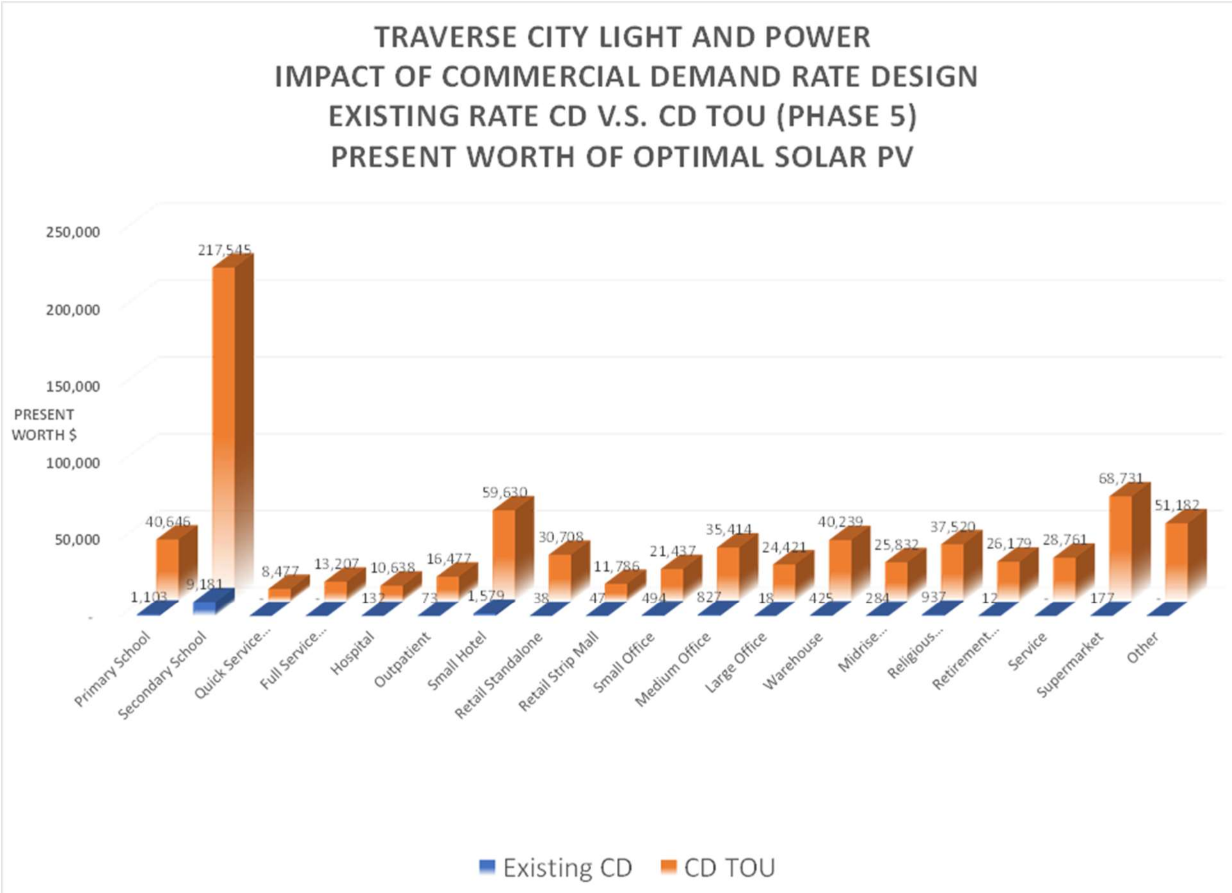


Figure 14-4 Impact of CD TOU Tariff (PHASE 5), Present worth of optimal solar PV

Residential Modeling Results

Modeling of residential BTM solar was performed using HOMER Grid®, as was done for commercial building accounts. However, with respect to residential sector, two scenarios were used: a 2025 limited electrification scenario, and a 2040 full electrification scenario. For each scenario, three retail rate designs were employed. The TCLP existing residential Rate R, which is a one-part commodity rate (having no time differentiation and a tiered rate structure set to 16 kWh per month.) The Rate R retail structure includes true net metering. TCLP currently has a residential TOU pilot, with two time-of-use periods, no seasonal differentiation, and for which it was assumed that true net metering would apply to DG customers. The third retail rate structure modeled was the current residential TOU pilot, but with Hourly Net Billing for DG customers, rather than True Net Metering. A net zero limit for solar capacity was set at 6.66 kW (DC) for the limited electrification scenario, and 7.77 kW (DC) for the full electrification scenario. Residential solar PV prices are significantly higher than for commercial customers, thus modeling used constant dollar prices of $3.19 per watt for 2025, and $2.007 per watt for 2040. The 2025 price was based on current market prices, and the 2040 price was based on the same price decline used for the commercial building modeling. The HOMER Grid® results are as follows:

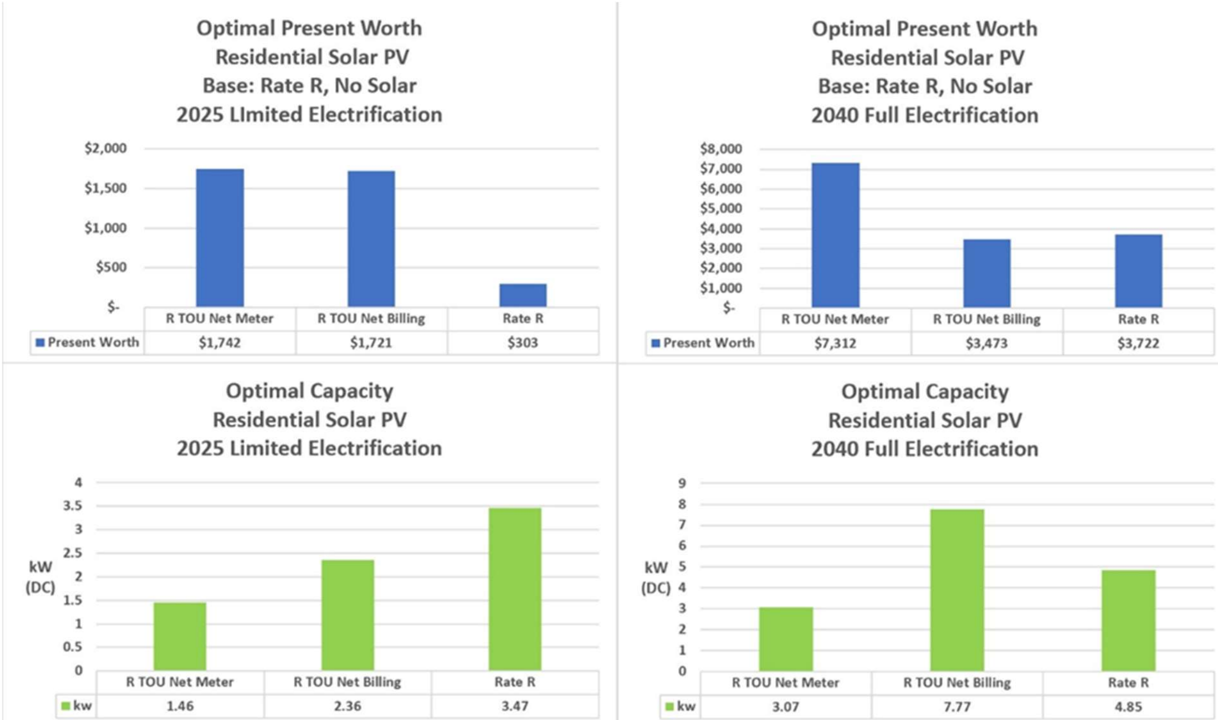


Figure 14-5 Comparison of key solar PV parameters in 2025 and 2040

As can be seen in the upper left of the above chart, the limited electrification scenario yielded a strong positive response in Present Worth for the Residential TOU pilot, irrespective of whether the DG mechanism was True Net-Metering or Hourly Net Billing. Both combinations had near identical values for present worth, and both were vastly greater than under the existing Rate R/True Net-Metering combination. The trend in optimal PV capacity can be seen in the bottom left of the chart. It is apparent that the trend in PV capacity is the inverse of the trend in Present Worth. Herein, the largest economic solar PV capacity was with the existing TCLP Rate R, the middle capacity value with the TOU Pilot/Net Billing combination, and the lowest with the TOU Pilot/Net Metering approach. Even though the optimal PV capacity for the TOU Pilot/Net Billing combination had the mid value, the substantially greater Present Worth of this rate structure over the existing TCLP Rate R/Net Metering approach (as seen in the top left chart) should induce a commensurately larger adoption of BTM solar by residential customers, and thus is the preferred approach.

With respect to the Full Electrification scenario, (the right side of the above chart), it was found that the TOU Pilot combined with Net Billing, yielded the best Present Worth and the best optimal PV capacity, vis-à-vis the two alternative DG pricing structures, and did so by a wide margin. Remarkably, this rate structure yielded an optimal kW capacity at the implicit net zero cap.

The core reason for the improved results under Net Billing over True Net Metering is likely associated with the time differentiated retail rates for both power imports and power exports under a TOU rate design. Despite the fact that power outflows are priced at less than the full retail rate (exports were priced at the full retail cost-of-service less distribution, e.g., power supply inclusive of transmission), the meaningful level of matching of solar generation with electric load in the on-peak periods yielded a larger economic benefit for displaced retail purchases, and a comparatively high price for power exports.

On the basis of the residential modeling results, it is recommended that TCLP investigate the use of a three-period residential TOU rate (super peak, on-peak and off-peak), similar to that developed by UFS for

TCLP's Small Commercial and Commercial-Demand TOU rate designs, as opposed to the limited on-peak and off-peak structure of the existing Residential TOU Pilot. The more flexible three-part time block may produce even stronger economic incentives for solar PV adoption, and solid incentives for residential customers to deploy PV arrays at the net zero cap for PV capacity. This is particularly important given the larger electric loads associated with building and EV electrification.

14.5 Resilience Value of Distributed Solar and Storage

Distributed generation and storage can provide resilience value to customers with these resources, and if those customers are important to sustaining members of the community during a power outage can provide community resilience.

TCLP has relatively low outage rates, which implies a comparatively lower resilience value of distributed solar and storage than in places with higher outage rates. Nonetheless, there can be significant resilience value.

Solar and storage only provide resilience value if they can support electrical loads during a grid outage, which is often described as being islandable. Most solar systems are designed to stop producing usable power when the grid is out, and therefore do not provide any resilience value. Storage systems are generally designed to provide backup power during a grid outage. To provide material resilience value, solar and storage need to be integrated into a micro-grid.

A microgrid is a combination of generation, storage, loads and controls capable of operating interconnected to the grid most of the time but also capable of detaching from the grid either when the grid is experiencing a power outage or in demand response. The key features in addition to solar and storage behind the meter is an automated point of separation from the grid and the control system to balance supply and load within the micro-grid when it is disconnected from the grid.

In general, behind-the-meter solar and behind-the-meter storage will be more costly per unit than grid-tied resources, due to economies of scale, but can provide additional value that offsets the incremental cost. Micro-grids are technically complex and may not be readily available in a small market. If micro-grids are wanted in TCLP service area, we recommend that TCLP offer specific services to customers wanting a microgrid. We do not recommend that TCLP foreclose a customer adopting a micro-grid completely behind the meter. However, we advise layering microgrid services from TCLP to reflecting both the benefits of some functions being in front of the meter and the complexities of tariffs for behind-the-meter storage. We therefore offer the following:

Recommendation: Develop a TCLP micro-grid offer and tariff that includes the following elements:

a. Clear permission for a TCLP customer to implement a micro-grid behind the meter, with associated interconnection standards;
b. An offer in which TCLP provides, operates, and maintains point of separation equipment in front of the meter for one or more customers while the customer(s) provides the balance of the micro-grid behind the meter.
c. An offer in which TCLP provides, operates, and maintains point of separation equipment and electricity storage in front of the meter for one or more customers while the customer(s) provides the balance of the micro-grid behind the meter.
d. An offer in which TCLP provides, operates, and maintains point of separation equipment, generation, and electricity storage in front of the meter for one or more customers while the customer(s) provide load control within the micro-grid.

15 TCLP In-System Solar and Storage Analysis

15.1 Framework for Front-of-Meter Solar and Storage

In addition to opportunities for behind-the-meter solar and storage, TCLP has options for front-of-meter solar and storage resources within TCLP's service area, similar to the existing M-72 Solar facility. Such facilities could be owned by TCLP or TCLP could purchase power from another party that owns the facility.

Sometimes, such facilities are developed as "community solar", which has become a contested term. For purposes of our analysis, we parse the meaning of community solar as follows. Ownership of a community solar facility can be by members of the community in a cooperative, limited liability corporation, condominium, and perhaps other legal arrangements. Power from the community solar facility flows to the utility, and payment for that power is in the form of bill credits to the owners of the community solar facility. Some utilities offer customers shares in the output of a utility-owned facility based on a pre-payment for the power and then provide bill credits for those output shares; we consider this a form of voluntary renewables purchasing and not "community solar". The utility could purchase power from a facility under an ownership structure as described and simply pay for the power, which we consider a power purchase agreement. Only when ownership is combined with bill credits to the owners for the power do we consider a facility to be community solar.

Although we do not suggest that TCLP be resistant to community solar, we anticipate little interest in grid-integrated community solar in an environment in which TCLP is committed to providing renewable power for all of the electricity it delivers to customers. However, we identify one circumstance warranting consideration and tariff treatment by TCLP. Solar on the roof or grounds of a multi-tenant building, whether the tenants are commercial or residential presents a complexity. The amount of power from such a facility may be too large for any one tenant, and it is not generally practical nor advisable to electrically subdivide the solar facility to have a portion of the power flow to behind-the-meters of multiple tenants. As a result, multi-tenant buildings may be institutionally unable to take advantage of a distributed generation tariff like we described above. Further, if you consider that a solar system on a multi-tenant building is electrically equivalent to a rooftop system for a single-tenant building aside from the multiple metering (i.e., has the same inflow-outflow characteristics and grid impacts), it would be fair to provide a similar tariff treatment for a solar system at a multi-tenant building as a single-tenant building. If the tenants are viewed as collectively owning or leasing a share of the solar system and TCLP provides bill credits based on those shares, this is a form of community solar. We therefore offer the

Recommendation: In tariff treatment for behind-the-meter solar and storage, provide an option for an economically equivalent community solar arrangement amongst the tenants of a multi-tenant building with a shared solar system.

As we discussed in the preceding section, TCLP has a "must-purchase" obligation for small renewable generation under the Public Utility Regulatory Policies Act, in which TCLP must have a standard offer to purchase power from such a facility within its service area, at the utility's avoided cost.

Recommendation: To enable customer or third-party development of solar and storage resources within TCLP's service area, and in compliance with the Public Utility Regulatory Policies Act of 1978, as amended, TCLP should adopt an avoided cost rate and standard offer tariff for renewable resources, combined heat and power, and battery storage within its service area that does not require that these resources be associated with a TCLP customer.

Avoided cost for a front-of-meter facility are different than for a behind-the-meter facility, because the facility will be viewed by MISO as a generator and not as producing negative load.[30] For this reason, in contrast to outflow from behind-the-meter systems described above, avoided cost of energy is not increased to reflect avoided line losses, avoided capacity is not increased to reflect avoided line losses and is not increased by MISO's planning reserve margin, and no transmission costs are avoided. In essence, the avoided cost for an in-system generator is the cost to obtain the same power amounts and profile from a similar technology outside of the utility's system. Since capacity credits inside MISO Zone 7 are differentiated from MISO capacity credits located in another zone, avoided capacity costs from a system within TCLP's service area should reflect the cost of capacity elsewhere in Zone 7. In other words, the avoided cost for an in-system solar facility is the cost of power from a solar power purchase agreement elsewhere in Michigan.

Although TCLP is legally obligated to provide for a power purchase agreement under the Public Utility Regulatory Policies Act in which someone develops the facility and requests a power purchase agreement on a "walk-in" basis, the is no obligation for TCLP to passively wait for in-system front-of-meter facility development. If such facilities will have value to TCLP, TCLP can solicit them through a request for proposals.

15.2 Societal Benefits of Front-of-Meter Solar and Storage.

Societal benefits from front-of-meter solar and storage are not materially different than for behind-the-meter solar and storage, on a per kWh basis.

15.3 Resilience Value of Front-of-Meter Solar and Storage

As with behind-the-meter solar and storage, front-of-meter solar and storage provides resilience value only if is developed as a micro-grid associated with certain loads, and will be most valuable if providing resilience value for key facilities in the community. We therefore offer the

Recommendation: In-system solar and storage procurement by TCLP should be based on an identified list of opportunities to create microgrids that support community resilience in the event of grid outages, in competition with remote grid-connected solar and storage.

16 Integrated Customer Energy Optimization Program Measures

The following sections will provide a list of recommendations for an integrated TCLP Energy Savers, or similar, program encompassing several areas including building electrification, building energy efficiency, transportation charging infrastructure, demand response, and solar and storage programs. These recommendations are designed to align with TCLP's overarching goals of energy efficiency, carbon reduction, and customer satisfaction. By implementing these recommendations, TCLP can strengthen its position as a leader in sustainable energy solutions while delivering significant benefits to its customers and the community.

It is important to note that the recommendations in this section are presented within the context of promoting electrification for all customers. For our purposes, electrification refers to the transition from fossil fuel-based energy sources to cleaner and more sustainable electric-powered alternatives. These include space and water heating, cooking, and the shift from gasoline engines to electric motors.

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[30] We consider the MISO tariff to be unfair in requiring a utility to pay transmission on power supplied by a resource that is within the utility's distribution system, but that is the current tariff.

In general, our recommendations involve several key steps. Firstly, we suggest leveraging and expanding TCLP's Energy Savers programs to enhance the energy efficiency of buildings. This includes actions such upgrading equipment to ENERGY STAR, LED lighting, or implementing newly suggested measures such as adding insulation to minimize heat loss and upgrading to energy-efficient equipment. Our recommendations will also include a variety of potential programs that may help to focus goals and maximize customer participation.

The next step is building electrification. Within current Energy Savers programs, we suggest expanding programs to actively mention benefits for switching from natural gas appliances to heat pumps for space and water heating as well as cooking. To further encourage the decarbonization transition, we recommend incentivizing customers to enroll in demand response programs and time-of-use rates. By enrolling customers in demand response programs with appropriate equipment, TCLP can effectively manage and reduce peak electricity demand, resulting in improved grid reliability and lower overall energy consumption. Time-of-use rates incentivize customers to shift their energy usage to off-peak hours when electricity demand is lower.

In addition to building electrification, we will provide program recommendations on electric vehicles and charging infrastructure. TCLP can play a vital role in the promotion of a robust transportation charging infrastructure by encouraging customers to install EV charging facilities across customer class locations. Finally, our recommendations will discuss the benefits and opportunities for customer-owned behind-meter solar.

To ensure the success of an integrated program, a comprehensive education and marketing approach is essential. We recommend developing targeted marketing campaigns that educate and engage customers about the benefits of energy efficiency, electrification, demand response, solar, and EV adoption. These campaigns should highlight the financial incentives, environmental advantages, and long-term cost savings associated with participating in TCLP's programs.

16.1 Current Measure Review and Future Program Recommendations

Recommendation: Maintain a TCLP rebate program for Energy Star electrical devices sufficient to achieve annual incremental first-year electricity savings of 1%. We will recommend specific tailoring to maximize the social value of these rebates considering market penetration, effects of changed internal heat loads on heating and cooling requirements, GHG emissions, and an emphasis on the "most efficient" products in each category.

16.2 Measure Review and Recommendations

The following is a list and description of electrification, efficiency, and carbon reduction categories and potential measures for TCLP's future residential and commercial energy prescriptive incentive programs. These measures and recommendations are based upon several factors, including current program offerings, energy efficiency, electrification opportunities and potential for Demand Response inclusion.

16.2.1 Residential Measures

Potential measures for consideration are under several categories, including HVAC: Space Cooling, Space Heating; Building Envelope: Insulation/Air sealing and Ventilation; Hot water systems; Range Cooking; Clothes Washing/Drying; Refrigerator/Freezer; Plug Load/Appliances; Electric Vehicles and Charging; PV Solar Systems; Electric Yard Equipment; Demand Response Controls, and Electric Panel Upgrade.

16.2.1.1 Lighting

Switching from incandescent to LED lighting has been one of the easiest and lowest cost methods to reduce energy consumption for residential customers. Current market conditions are such that LED lighting options are now the majority of the market, have become more cost effective and soon may no longer require a rebate to incentivize customers to upgrade to higher efficiency lighting. ENERGY STAR is planning to sunset their specification for residential lamps, luminaires and ceiling fan lighting kits at the end of 2024.

Current measures: LED Common Bulbs, LED Can Lights, LED Outdoor Lights

Recommendation: Continue to offer basic general LED lighting measures until measures are removed from the Michigan Energy Measures Database.

Note: TCLP should consider updating their Energy Savers application requirements to include both replacing incandescent lights and CFLs. The MEMD has deemed savings levels for CFLs. For accuracy in reporting and future carbon calculations, TCLP applications should be updated to allow customers to self-report change type.

Recommended Measures for Consideration	Specs/Comments
Lighting	
LED Common Bulbs	Offer until MEMD removal
LED Can Lights	Offer until MEMD removal
LED Outdoor Lights	Offer until MEMD removal

Table 16-1 Recommended residential lighting efficiency measures

16.2.1.2 HVAC Space Heating and Cooling

Current measures: Air to Air Heat Pump SEER 17-19, Mini-Split Heat Pump SEER 18+, Cold Climate Heat Pump, and Smart thermostats.

Recommendation: Maintain current offerings and add options for Ground Source Heat Pumps. Consider specifying smart thermostats that support Demand Response. Consider Air-to-Water Heat Pumps for aging boiler replacement.

Note: Air-to-water Heat Pump models are currently limited and may only want to be considered in the future.

Recommended Measures for Consideration	Specs/Comments
HVAC: Space Heating and Space Cooling	
Air-to Air Central Air-Source Heat Pump	17-18.9 SEER. AHRI Certificate Required
Air-to Air Central Air-Source Heat Pump	19+ SEER. AHRI Certificate Required
Air-to-Air Mini/Multi-Split Ductless Air-Source Heat Pump	Minimum 18 SEER
Cold Climate Heat Pump	Operation ranges under 5 degree outside temperature 16-17 SEER HSPF 10-11
Ground Source Heat Pump	EER 17-19 Note: Higher Cost/lower market penetration may be cause to not consider
Ground Source Heat Pump	EER 20A+ Note: Higher Cost/lower market penetration may be cause to not consider
Air to Water Heat Pump	Future Consideration
Wi-Fi Enabled Thermostat Must Control Electric Heat/Central AC	Consider limiting to models that support Demand Response Programing

Table 16-2 HVAC space heating and cooling measures

16.2.1.3 Building Envelope: Insulation and Air Sealing

The building envelope refers to the physical barrier that separates the interior conditioned air of a building from the unconditioned external environment. A well-insulated and air-sealed building envelope can help to reduce energy costs by reducing heat loss in the winter and heat gain in the summer. By controlling the flow of heat, air, and moisture through the building envelope, homeowners can improve the energy efficiency of their buildings and reduce their carbon footprint. In addition to improving energy efficiency, insulation and air sealing can improve indoor air quality, reduce noise pollution, and increase the overall comfort and health of the residents.

16.2.1.3.1 Insulation/Air Sealing Measures

Current measures: TCLP does not currently incentivize building envelope improvements. However, it is an important segment to be considered for energy and carbon reduction. Opportunities currently exist to add incentives when paired with the electrification of residential HVAC systems.

Recommendation: Develop a new program focused on building envelope improvements.

For an initial period of 2 to 5 years, offer rebates for air sealing, energy-recovery ventilation, heat pump space conditioning and water heating, and electric vehicle charging equipment primarily through a short list of vendors who demonstrate technical qualification, commit to maintaining in-stock equipment, and commit to marketing to achieve a certain number of installations per year.

Provide a continuing education program for contractors to learn about building science and the new approach to efficiency and electrification**.**

Create a new program category for Insulation and Air Sealing Measures. Consider matching DTEs insulation requirements. Current insulation contractors are already familiar with those requirements. Initially, some current TCLP and DTE customers may have the opportunity to receive rebates from both utilities. This dual incentive may serve as a catalyst for building improvement and will help contractors size future heat pump equipment appropriately. Measures include: attic insulation, attic hatch insulation, above-grade wall insulation, below-grade basement wall insulation, rim joist insulation, crawl space insulation, and knee wall insulation. Options for DIY and Contractor installed may be necessary.

Air sealing measures for consideration: Reduction of air infiltration by a minimum of 10%. This measure likely requires contractor blower door assisted air sealing. Note: Air sealing may tighten a home to a point where mechanical ventilation is required.

Recommended Measures for	Specs/Comments
Building Envelope: Insulation and Air Sealing	
Attic Insulation	Insulate to R49 or greater. Must insulate a minimum of 500 square feet of attic area
Attic Hatch	Insulate to R38 or greater
Above Grade Wall Insulation	Add min R5. Must insulate a minimum of 500 square feet of wall area
Basement Wall Insulation	Insulate to R10 minimum. Must insulate a minimum of 500 square feet of wall area
Crawlspace Insulation	Insulate to R10 minimum. Must insulate a minimum of 200 square feet of wall area
Rim Joist Insulation	Insulate to R20. Must insulate all accessible rim joist areas
Knee Wall	insulate to R20. Must insulate 100 square feet.
Air Sealing	Reduce air infiltration by minimum 10%
Windows	ENERGY STAR Certified
Windows	ENERGY STAR Most Efficient
Doors	ENERGY STAR Certified
Air Sealing	Minimum 10% Air Sealing-may require ventilation

Table 16-3 Insulation/air sealing measures

16.2.1.3.2 Ventilation

As residential buildings become tighter through insulation and air sealing and there are fewer opportunities for air infiltration, it will become necessary to introduce appropriate ventilation systems to improve indoor air quality and reduce energy costs by exchanging heat and moisture between incoming and outgoing air.

Current measures: TCLP does not currently offer incentives for the purchase of ventilation.

Recommendation: Create a new program category for ventilation and include Energy Recovery Ventilators (ERVs) and Heat Recovery Ventilators (HRVs). Equipment should have a minimum SRE (Sensible Recovery Efficiency) of 70%.

Note: Ventilation also includes exhaust only systems, such as bath and range fans, that are Energy Star qualified; however, in the interest of retention of conditioned air and potential moisture control, ERV and HRVs are the preferred whole home ventilation system. It's worth noting that HRVs and ERVs serve similar purposes, but their key distinction lies in the transfer of moisture. HRVs focus on heat recovery only, while ERVs also exchange moisture between the air streams. A local contractor will be able to work with homeowners to determine their needs.

Recommended Measures for Consideration	Specs/Comments
Ventilation	
Heat Recovery Ventilator	Tiered based on percentage SRE (Sensible Recovery Efficiency) Tier 1: min 70 %effective Tier 2: 80%+ effective
Energy Recovery Ventilator	Tiered based on percentage SRE (Sensible Recovery Efficiency) Tier 1: min 70 %effective Tier 2: 80%+ effective

Table 16-4 Ventilation measures

16.2.1.4 Domestic Water Heating

Water heating is an important factor in energy and carbon reduction. According to the US Department of Energy, water heating accounts for approximately 20% of the average American household's energy use. Hot water systems are an important area where energy and carbon savings can be achieved by using more efficient technology.

Current measures: Heat pump water heater and solar water heater

Recommendation: Maintain offerings of heat pump water and solar water heaters. Consider demand response ready requirements for heat pump rebates.

Some residents may not have the required space for heat pump water heaters. TCLP may also want to make considerations for offering a highly insulated electric resistance high durability plastic water heater. Electric on-demand options may also support electrification efforts where heat pump water heaters lack the required space.

Recommended Measures for Consideration	Specs/Comments
Domestic Water Heating	
Heat Pump Water Heater	55 Gallon or smaller, UEF of 2.2 or greater or ENERGY STAR Certified. Consider demand response ready requirments
Electric Resistance Water Heater High durability plastic tank	Plastic tank water heaters are leak free and heavily insulated May be option for those who cannot install heat pump
On-demand Electric water heater-whole home/point of use	May be option for those who cannot install heat pump
Solar Water Heater	Solar Water Systems must be new and OG 300 certified as tested by the Solar Rating and Certification Corporation (SRCC)

Table 16-5 Domestic water heating measures

16.2.1.5 Induction Cooking

Induction cooking is energy efficient compared to electric coil and gas ranges. Induction uses a magnetic field to heat cookware directly, rather than transferring heat via conduction. This direct method of heating cookware is more is more efficient as less energy is lost to surrounding air. According to the US Department of Energy, induction ranges are up to up to 10% more efficient than conventional electric stoves and three times more efficient than gas stoves.

Current measures: TCLP does not currently incentivize induction ranges/cooktops.

Recommendation: Create a new measure category to include Induction Cooktops with a minimum of three elements or free standing or slide in induction ranges. This measure can serve as a gateway to whole home electrification.

Recommended Measures for Consideration	Specs/Comments
Induction Cooking	
Induction Range or Cooktop	No hybrid induction. Cooktops must have min of three elements. must replace natural gas or propane. Could consider electric replacements.

Table 16-6 Induction cooking measures

16.2.1.6 Clothes Washing and Drying

Heat pump clothes dryers are a more efficient option compared to conventional dryers. Heat pump dryers use a closed loop system by removing moisture from the hot air produced during the drying process and reusing the heat, which reduces the energy required to dry clothes. Heat pump dryers can use up to 28% less energy than conventional dryers and do not require venting.

High-efficiency clothes washers use less water and energy to wash clothes, which reduces their environmental impact and energy costs. According to ENERGY STAR, high-efficiency clothes washers can use up to 30% less water and 20% less energy than conventional models. This results in lower water bills and energy costs.

Current measures: ENERGY STAR Heat pump clothes dryer. TCLP does not currently incentivize high efficiency clothes washers.

Recommendation: Maintain the offering of ENERGY STAR Heat pump clothes dryer. Add category for ENERGY STAR washing machine. Add a second tier of rebates for ENERGY STAR Most Efficient to incentivize the highest energy savings.

Note: Consideration of requiring electric water heat as a condition of the rebate may be required.

Recommended Measures for Consideration	Specs/Comments
Clothes Washing and Drying	
Heat Pump Clothes Dryer	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient
High Efficiency Clothes Washer	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient

Table 16-7 Clothes washing and drying measures

16.2.1.7 Refrigerators and Freezers

ENERGY STAR refrigerators and freezers are 9-10% more efficient than conventional models. This savings is achieved through high-efficiency motors, insulation and improved control mechanisms.

Current measures: ENERGY STAR refrigerators, ENERGY STAR freezers, refrigerator recycling, freezer recycling. Window A/C and Dehumidifier Recycling.

Recommendation: Maintain offerings of ENERGY STAR Refrigerators, ENERGY STAR Freezers, Refrigerator Recycling and Freezer Recycling. Maintain window A/C and dehumidifier recycling. Add new tier of ENERGY STAR Most Efficient refrigerators and Freezers.

Note: Recycling programs come with additional expenses, but they can be well-received by customers. Considering an average lifespan of 12 years, Refrigerator and freezer recycling initiatives will soon encounter units manufactured in 2011. It is important to acknowledge that recycling programs may experience diminished energy savings due to the improved efficiency of units produced during this period. Moving forward, it is crucial to carefully evaluate the allocation of program funds, striking a balance between program popularity and increasing incentives for measures that foster electrification and decarbonization. Program environmental benefits associated with proper removal of liquid refrigerants should be carefully considered prior to attributing benefits to a recycling program. This is largely due to the federal removal requirements that must be met prior recycling. In addition, insulating foam disposal methods may release emissions that contribute to GHGs that offset the value of refrigerant capture alone. Careful vetting of recycling contractors is necessary to ensure program success.

Recommended Measures for Consideration	Specs/Comments
Refrigerators and Freezers	
Refrigerator	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient
Freezer	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient
Appliance Recycling	Review costs/benefits yearly

Table 16-8 Refrigerator and freezer measures

16.2.1.8 Plug Loads/Appliances

ENERGY STAR electronics and small appliances consume less electricity while in use and often have additional controls such as wi-fi allowing consumers to interact with devices even when away from the home.

Current measures: ENERGY STAR Air Purifiers

Recommendation: Maintain offering of ENERGY STAR Air Purifiers. Add measures and tiers for ENERGY STAR and ENERGY STAR Most Efficient for Air Cleaners, Dishwashers, and Dehumidifiers. Consider offering a rebate for Energy Star Most Efficient Window A/C units to provide options for lower income individuals who may not be able to invest in centrally ducted or mini split heat pumps.

Recommended Measures for Consideration	Specs/Comments
ENERGY STAR Home Appliances	
Air purifier	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient
Portable Room Dehumidifier	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient
Dishwasher	Tier 1: ENERGY STAR Certified Tier 2: ENERGY STAR Most Efficient
Room Air Conditioner	ENERGY STAR Most Efficient Certified-consider addition to give options to lower income individual. Specify most efficient models only

Table 16-9 Plug load/appliance measures

16.2.1.9 Electric Vehicles (EV) and EV Charging:

Electric vehicles emit no greenhouse gases and are less expensive to maintain over time. Level 2 EV chargers can be installed at homes to make charging convenient and less expensive.

Current measures: Level 2 EV chargers

Recommendation: Maintain Level 2 EV chargers measures. Require that EV charging equipment be able to participate in a demand response program. Add additional measure categories for New and Used EVs. Opportunities for future electrification programs may include electric bicycles as transportation methods.

Note: Level 2 charging stations use a 220V connection may require an upgrade of electric panels (Electric panel upgrades are a suggested new measure)

Recommended Measures for Consideration	Specs/Comments
Electric Vehicles and Chargers	
EV Charging level 2	Consider requiring Demand Response capability
New and Used Electric Vehicles	Tier 1: Used Electric Vehicle Tier 2: New Electric Vehicle
Electric Bicycles	Consideration for future programing

Table 16-10 EV and EV charging measures

16.2.1.10 Photovoltaic (PV) Systems

PV solar panels convert sunlight into electricity and behind-the-meter systems can help to reduce energy costs for customers. This renewable source of energy reduces carbon emissions and excess energy generated by customers can be a distributed resource on the grid.

Current measures: New solar panel installations per kW installed.

Recommendation: Maintain offering of incentives for new solar panel installations per kW installed.

Note: Net Metering application must be submitted and approved before installation.

Recommended Measures for Consideration	Specs/Comments
Photovoltaic (PV Systems)	
Behind the Meter PV installation	Requires interconnection agreement

Table 16-11 Solar PV measures

16.2.1.11 Yard equipment

Small gas engines in lawn care equipment do not have stringent emission controls and can create significant pollution despite their small size. Electrification of these small engines can reduce the emissions released into the environment. This new measure is intended to remove small gasoline engines from the TCLP territory.

Current measures: TCLP does not currently incentivize yard equipment.

Recommendation: Create a new measure category of cordless electric Yard Equipment to include incentives for electric lawn mowers, electric leaf blowers, electric trimmers, electric chainsaws, and electric snow blowers.

Note: Branded equipment often has interchangeable batteries. This creates an opportunity for programmatic multipliers. To enhance decarbonization, TCLP could consider offering a tiered approach where customers would be rewarded with an additional incentive for recycling the gas version of their new product. The City of Holland currently offers a similar program in which a higher rebate is paid to customers who submit a receipt of recycling from their recycling partner.

Recommended Measures for Consideration	Specs/Comments
Yard Equipment	
Electric Lawn Mower	Tier 1: New Electric tool Only Tier 2: New Electric tool with Recycled Gas tool. Work with local recycler to provide receipts of tool recycling.
Electric Trimmer	Tier 1: New Electric tool Only Tier 2: New Electric tool with Recycled Gas tool. Work with local recycler to provide receipts of tool recycling.
Electric Leaf Blower	Tier 1: New Electric tool Only Tier 2: New Electric tool with Recycled Gas tool. Work with local recycler to provide receipts of tool recycling.
Electric Chainsaw	Tier 1: New Electric tool Only Tier 2: New Electric tool with Recycled Gas tool. Work with local recycler to provide receipts of tool recycling.
Electric Snow blower	Tier 1: New Electric tool Only Tier 2: New Electric tool with Recycled Gas tool. Work with local recycler to provide receipts of tool recycling.

Table 16-12 Yard equipment measures

16.2.1.12 Electric Panel upgrade

As homeowners adopt beneficial electrification measures such as heat pumps, EV charging and solar, it may become necessary to upgrade a home's electric panel.

Recommendation: Offer rebates for electrical panel and other building electrical system upgrades needed for future electrification and solar, so that these upgrades can be done prior to building envelope improvements and to be ready for "emergency" electrification upon equipment failure. Consider the addition of a Smart Panel into measures. Smart Panels allow for real-time energy monitoring, remote access and control, load management, and integration with other smart home systems.

Recommended Measures for Consideration	Specs/Comments
Electric Panel Upgrade	
Electric Panel Upgrade	installed by qualified electrician to accommodate approved electrification measure such as heat pump, EV charger, or Solar.

Table 16-13 Electrical panel upgrade measure

16.2.1.13 Natural Gas Cessation

To reach carbon goals, it will likely be necessary for a certain percentage of Traverse City's population to switch from natural gas applications in HVAC and water heating to electric applications of cold weather heat pumps and heat pump water heaters.

Recommendation: Consider additional incentives for the removal of natural gas furnace or water heater when replacing with a heat pump for space heating or water heating.

Recommended Measures for Consideration	Specs/Comments
Natural Gas Cessation for consideration	
Removal of natural gas appliance	must be fully replaced with heat pump for space heating or water heating

Table 16-14 Natural gas cessation measure

16.2.2 Commercial & Industrial Measures

Unlike the limited number of residential measures offered (20), the Commercial and Industrial energy programs provide a comprehensive selection of over 120 measures in the prescriptive rebate program. These measures are categorized into the following categories to address diverse energy-saving customer needs:

16.2.2.1 Lighting

Includes interior and exterior energy-efficient lighting fixtures and lamps designed to reduce electricity consumption in commercial spaces. Lighting has been majority of savings for the CI program for the last several year. Lighting upgrades in commercial spaces will continue to provide savings in the near future.

Recommendation: Maintain currently offered Lighting measures. Consider adding Indoor Agricultural LED Lighting to prescriptive measures; significant energy savings exist within this growing category of lighting. Consider adding a permanent lamp removal measure. This measure refers to needing fewer fixtures when retrofitting to LED lamps/tubes.

Recommended Measures for Consideration	Specs/Comments
Screw-In Lamps (A-Line, PAR, M16, Exit Sign)	ENERGY STAR
Linear Fluorescent: LED Tubes/Fixtures	Tier 1: ENERGY STAR /DLC list Tier 2: Non-Rated lamps
Interior Lighting — All High Bay Lighting, ceiling height 15ft or higher	Wattage Reduced Calculations for Rebate
Exterior HID Replacement to LED	Wattage Reduced Calculations for Rebate Tiered by Wattage
Garage 24 Hour HID Replacement to LED	Must be in operation 24 hrs./day Must be at least 40% reduction
Lighted Signs	LED replacing Incandescent, Fluorescent or Neon Sign
Indoor Agricultural LEDs	Tier 1: >4,000 operating hours Tier 2: >6,000 operating hours
Permanent Lamp Removal	Reduction in Lighting Fixtures during LED retrofits

Table 16-15 Commercial & industrial lighting measures

16.2.2.2 Lighting Controls

Offers solutions for advanced lighting control systems, such as occupancy sensors, daylight sensors, and programmable controls, to optimize energy usage.

Recommendation: Maintain currently offered Lighting Controls.

Recommended Measures for Consideration	Specs/Comments
Lighting Controls	
Occupancy Sensors	No Previous Controller. Tiered based on Sq Ft controlled
Occupancy Sensors	No Previous Controller. Tiered based on Sq Ft controlled
Occupancy Sensors	No Previous Controller. Tiered based on Sq Ft controlled
Occupancy / Daylight Combo Sensors	No Previous Controller. Tiered based on Sq Ft controlled
Occupancy / Daylight Combo Sensors	No Previous Controller. Tiered based on Sq Ft controlled
Occupancy / Daylight Combo Sensors	No Previous Controller. Tiered based on Sq Ft controlled
Central Lighting Control	No Previous Controller. Tiered based on Sq Ft controlled
Daylight Sensors	No Previous Controller. Tiered based on Sq Ft controlled

Table 16-16 Commercial & industrial lighting controls measures

16.2.2.3 Air Conditioning and Heat Pump Equipment

Focuses on high-efficiency air conditioning and heat pump systems to enhance cooling and heating efficiency in commercial buildings.

Recommendation: Maintain currently offered measures. Phase out air conditioning specific prescriptive and custom rebates and shifting focus towards promoting heat pumps. Heat pumps offer both cooling and heating capabilities and are highly energy-efficient compared to traditional air conditioning systems.

Recommended Measures for Consideration	Specs/Comments
Air Conditioning and Heat Pump Equipment	
PTAC - Heat Pump	10% efficiency improvement over existing system
High Efficiency CRAC Unit	SCOPE = 2.1 for existing, 2.7 for new
Mini-Split Heat Pump	21 SEER Mini-Split Heat Pump System
Heat Pump Water Heater <= 55 Gal.	ENERGY STAR - UEF ≥ 2.0

Table 16-17 Commercial & industrial air conditioning and heat pump equipment measures

16.2.2.4 HVAC Controls

Provides measures for the installation of energy-efficient HVAC control systems that optimize temperature and airflow for improved comfort and reduced energy consumption.

Recommendation: Maintain currently offered HVAC control measures and consider requiring demand response capabilities for HVAC control systems to enable load management and enhance grid reliability during peak demand periods.

Recommended Measures for Consideration	Specs/Comments
HVAC Controls	
Energy Management System	Web based energy management system
Optimized Snow Melt Controls	Snow melt system must shut down completely when no precipitation is present. Controller must monitor forecasts and raise the slab temperature to 32 degrees F eight hours before expected precipitation. A slab moisture sensor must be used to signal controller to raise slab temperature to 40 degrees F when precipitation is present.
Hotel GREM Controls - A/C with Electric Heat	For sensors which automatically control HVAC equipment. Incentive is for new controls only and is offered per room install. Consider Demand Response requirements
Hotel GREM Controls - A/C with Gas Heat	Consider Demand Response requirements

Table 16-18 Commercial & industrial HVAC measures

16.2.2.5 Variable Frequency Drives (VFD) & Variable Speed Drives (VSD)

Encourages the use of VFDs and VSDs to optimize the speed and power output of motors, resulting in energy savings.

Recommendation: Maintain currently offered VFD and VSD measures

Recommended Measures for Consideration	Specs/Comments
Variable Frequency Drives (VFD)& Variable Speed Drives (VSD)	
VFD and VSD Application (HVAC Fan, HVAC Pump or Process Pump)	Drives must be used in primary pumping or air handling application related to HVAC or for process pumping applications. VFDs must be automatically controlled by a variable signal and have load diversity that will result in savings through motor speed variation. HVAC Pump motor size < 100 HP and operated > 1,800 hours. Process Pump motor size < 50 HP and operated > 2,000 hours.

Table 16-19 Commercial & industrial VFD and VSD measures

16.2.2.6 Pumps

Offers measures for energy-efficient pumps, including circulation pumps used in various commercial applications.

Recommendation: Maintain currently offered pump measures.

Recommended Measures for Consideration	Specs/Comments
Pumps	
ECM Pump Motor for DHW, Heating or Cooling Water Circulation	Adding an ECM pump motor where one was not existing previously. Tier 1: < 100w Tier 2: 100w-500w Tier 3: >500w

Table 16-20 Commercial & industrial pump measure

16.2.2.7 Tools and Equipment

Provides incentives for the adoption of pneumatic tools and equipment in commercial and industrial settings.

Recommendation: Maintain currently offered measures. Consider adding electric forklifts, industrial high-frequency battery chargers, electric lawn equipment, and high efficiency welders to prescriptive program.

Recommended Measures for Consideration	Specs/Comments
Tools and Equipment	
Pneumatic Tools to Cordless Electric	
Pneumatic Tools to Electric	
Pneumatic Motors to Electric	
Compressed Air Replaced with Air Blowers	
Electric Lawn Equipment	Commercial grade 0 Turn or Push Mower Tiers
Electric Forklift	Switch from LP or Diesel. OSHAR Class 1 & 2 Forklift. Tier 1: New Tier 2: New Tier 3: Leased
Industrial 3-Phase High-Frequency Battery Charger	New 3-phase high frequency charger with ≥92% power conversion efficiency. New charger must replace a ferroresonant or silicon controlled rectifier (SCR) charger. Applicable only to battery charging for forklifts.
High Efficiency Welder	Replace transformer-rectifier power source welder with new inverter power source welder. Welding process (on/ready) must be used ≥1,000 hrs/yr.

Table 16-21 Commercial & industrial tools and equipment measures

16.2.2.8 Compressed Air Equipment

Focuses on reducing energy waste in compressed air systems by promoting energy-efficient compressors, nozzles, and tanks.

Recommendation: Maintain currently offered compressed air equipment measures.

Recommended Measures for Consideration	Specs/Comments
Compressed Air Equipment	
VSD Air Compressor (< 300 HP)	Replacement of constant speed compressor with rotaryscrew
Engineered Nozzles	Must replace open tube assembly
Compressed Air Storage Tank	Existing system must have less than 3 gal/cfm of storage.New storage tank
No-loss Drains	Replacing manual or timer drains.

Table 16-22 Commercial & industrial compressed air equipment measures

16.2.2.9 Compressed Air Energy Audit and Leak Reduction

Encourages commercial customers to conduct energy audits of their compressed air systems to identify potential energy-saving opportunities and offers rebates for implementing leak reduction measures.

Recommendation: Maintain currently offered Compressed Air Energy Audit and Leak Reduction measures.

Recommended Measures for Consideration	Specs/Comments
Compressed Air Energy Audit and Leak Reduction	
Compressed Air Energy Audit and Leak Reduction	Incentives are available for repairing 50% of documented leaks in a compressed air system. The customer must present pre-approval evidence of needed repairs through a qualified audit and a detailed spreadsheet. Upon completion, evidence of repairs must be provided through leak repair tags and a spreadsheet, with tags kept in place for 30 days for post-inspection verification.

Table 16-23 Commercial & industrial compressed air energy and leak reduction measures

16.2.2.10 Commercial Kitchen Systems

Addresses energy efficiency in commercial kitchens through incentives for energy-saving equipment, such as ENERGY STAR griddles, dishwashers, and steam cookers.

Recommendation: Maintain currently offered kitchen measures and consider adding high-efficiency pre-rinse sprayer to prescriptive program.

Recommended Measures for Consideration	Specs/Comments
Commercial Kitchen Systems	
ENERGY STAR® Steam Cooker	ENERGY STAR
ENERGY STAR® Commercial Refrigerator	ENERGY STAR, Solid Door, Glass Door
ENERGY STAR® Commercial Freezer Check one: Solid Door Glass Door	ENERGY STAR, Solid Door, Glass Door
ENERGY STAR® Ice Machine	ENERGY STAR
ENERGY STAR® Fryer & Griddles	ENERGY STAR
ENERGY STAR® Hot Holding Cabinets	ENERGY STAR
ENERGY STAR® Dishwasher	ENERGY STAR
Pre-Rinse Sprayer	≤0.68 gpm Electric water heating required for both primary and booster

Table 16-24 Commercial kitchen systems measures

16.2.2.11 Commercial Refrigeration Systems

Promotes energy-efficient refrigeration systems and equipment, including refrigerators, freezers, display case lighting, and door gaskets.

Recommendation: Maintain currently offered refrigeration measures. Consider adding evaporator fan demand controls and no heat reach-in case door replacements to prescriptive measures.

Recommended Measures for Consideration	Specs/Comments
Commercial Refrigeration Systems	
LED Grocery Case Lighting	Replace T12 or T8 with LED lighting
Occupancy Sensor for LED Case Lighting	Sensors which automatically turn on LED cooler lighting when motion is detected.
Walk-In or Case Cooler/Freezer ECM	Replacement of PSC or shaded pole motors with an ECM motor.
Cooler Strip Curtains	Installation of new curtains isolating a cold storage area.
Freezer Strip Curtains	Installation of new curtains isolating a freezer storage area.
Cooler/Freezer Door Gaskets	Installation of new gaskets to reduce air
Auto Door Closer	Applies to walk in Coolers and Freezers
High Efficiency Hand Dryer	Replacing standard dryer
Evaporator Fan Demand Controls	Controls for walk-in cools/freezers. Must reduce fan motor power by at least 75% during off cycle
No Heat Reach-in Case Door	Replace existing anti-sweat heater equipped case door with special glass door that requires no anti-sweat heat.

Table 16-25 Commercial refrigeration system measures

16.2.2.12 Photovoltaic (PV) Systems

PV solar panels convert sunlight into electricity and behind-the-meter systems can help to reduce energy costs for customers. This renewable source of energy reduces carbon emissions and excess energy generated by customers can be a distributed resource on the grid.

Current measures: Commercial systems are not currently offered in the prescriptive rebate.

Recommendation: Consider adding commercial PV systems to prescriptive rebates.

Note: Net Metering application must be submitted and approved before installation.

Recommended Measures for Consideration	Specs/Comments
Photovoltaic (PV Systems)	
Behind the Meter PV installation	Requires interconnection agreement

Table 16-26 PV system measure

16.2.2.13 Commercial Electric Vehicles (EV) and EV Chargers

Electric vehicles emit no greenhouse gases and are less expensive to maintain over time and offer benefits to commercial fleets. EV chargers can be installed onsite for fleet charging, employee EV charging, and in public parking to make charging convenient.

Current measures: No current prescriptive measures for EV or charging currently exist for commercial EVs or Charging.

Recommendation: Add Level 2 EV on-site chargers measures. Require that EV charging equipment be able to participate in a demand response program. Consider adding measures to promote commercial fleet electrification. Consider adding transportation account customers to key accounts to encompass fleet electrification among Traverse City commercial accounts.

Recommended Measures for Consideration	Specs/Comments
Electric Vehicles and Chargers	
EV Charging level 2	Consider requiring Demand Response capability
Fleet Electrification	Consider incentivizing the Electrification of commercial fleet vehicles

Table 16-27 Commercial EV and EV charger measures

16.2.2.14 Custom Measures

Additionally, the current programming allows commercial, commercial demand, and key accounts to claim savings and rebates under the custom program. This program enables customers to calculate energy savings for equipment not covered by the prescriptive program. It offers flexibility by allowing customers to propose and receive preapproval from TCLP staff for energy-saving measures that fall outside the existing prescriptive program, ensuring that customers have access to a wide range of potential measures tailored to their specific needs.

Recommendation: Continue offering and expand custom program incentives for unique energy-saving projects or equipment not covered by the standard prescriptive programs. Add Building Envelope Improvements for roof and wall insulation to prescriptive measures.

17 Program Recommendations

The current TCLP Energy Savers program treats efficiency upgrades as standalone rebates, providing individual incentives for specific energy-saving measures. To achieve decarbonization, TCLP should provide more wholistic approaches to help buildings reduce energy consumption, electrify systems and appliances, integrate electric vehicle charging and solar production, and become more grid-interactive through onsite energy storage and demand response capable devices. This can be accomplished by encouraging building owners to implement multiple energy-saving measures at once, or in a sequence over a brief period. These opportunities include the implementation of a Multi-Measure Incentive program, a Comprehensive Whole Home program for residential customers, a Comprehensive Building program for commercial customers, Sector Specific commercial programs, and Income qualified and multifamily programs. The goal of all these programs is to help customers “do the right things, in the right order,” so they optimize their outcomes in a way that also optimizes TCLP’s outcomes. To enable this, we suggest an “Energy Coach” approach to all sectors.

17.1 Energy Coach

With the introduction of new wholistic programs it is recommended to introduce an Energy Coach that will further enhance the customer energy upgrade experience. Energy Coaches will serve as trusted advisors, guiding customers through the potential complexities of measures and helping them plan and make informed decisions.

Services offered by an Energy Coach can include, but are not limited to:

- Energy upgrade planning to assist customers in developing a comprehensive energy upgrade plan, considering factors such as budget, desired outcomes, and available incentives. The plan will ensure customers “do the right things, in the right order” to optimize both their outcomes and the outcomes for TCLP.
- Integrated program guidance to assist customers in understanding and navigating TCLP requirements, eligibility criteria, and the application process.

- Recommending or referring qualified contractors specializing in energy-efficient upgrades. Contractors may be part of a preferred contract network established by TCLP or through existing channels such as Michigan Saves.
- Providing educational resources and training materials to help customers understand the benefits of energy efficiency measures and new electrification technologies. The coach may also provide additional education on the added sustainability carbon reduction benefits of measures.
- Providing basic financial guidance by assisting customers in understanding available incentives, rebates, and financing options to maximize savings and make informed decisions. This may include providing awareness of the Inflation Reduction Act tax credits and rebates to show compounding value of program measures.
- Conducting post-upgrade quality insurance inspections to verify that the installed measures meet the required energy efficiency standards and provide the expected energy savings. QA will be limited to an acceptable percentage determined by TCLP to ensure ongoing program viability.

17.2 ENERGY STAR and ENERGY STAR Most Efficient

As noted in measure recommendations, TCLP should consider offering two tiers of rebates to incentivize the use of ENERGY STAR-certified products. The first tier would provide rebates for equipment that meets the ENERGY STAR criteria, ensuring energy savings compared to standard models. In addition to the base tier, we recommend the introduction of a second tier of rebates for ENERGY STAR Most Efficient products. ENERGY STAR Most Efficient is an elite designation reserved for the top-performing products in their respective categories. These products represent the cutting edge of energy efficiency and provide significant energy savings compared to even other ENERGY STAR-certified models.

By offering two tiers of rebates, TCLP can provide customers with a choice to prioritize energy efficiency according to their needs and budget. This approach not only promotes the adoption of energy-efficient technologies but also encourages the selection of the most efficient options available in the market.

17.3 Multi-Measure Incentives

To promote a more holistic approach to energy efficiency, we recommend the introduction of a Multi-Measure Incentive program. This program would reward home and commercial building owners who undertake multiple qualifying measures with increased incentives. By combining measures such as insulation upgrades, HVAC system improvements, and appliance replacements, participants can earn additional cash back while achieving higher energy savings, lower carbon emissions and a more sustainable living or working environment.

This program could be easily integrated into either customer application where each additional installed efficiency measure would increase the incentive amount by a predetermined multiplier. For example, the first measure receives the base incentive, the second measure receives a 1.2x multiplier, the third measure receives a 1.4x multiplier and so on. The program could be arranged so that low-cost measures such as lighting, often done in multiples, do not qualify for the multiplier.

17.3.1 Tiered Incentive approach

An alternative to the multi-measure multiplier, TCLP could consider a tiered/bundled incentive approach. As shown in the table below a tiered bonus incentive program is recommended to maximize the carbon and utility cost savings. A whole home electrification approach should be encouraged through the following EWR and electrification measure tiers. Note: A bonus could be paid out as a percentage or as a fixed bonus.

Tier	EWR / Electrification / Demand Response Measure Bundles	Bonus
Tier 1	Insulation/Heat Pump Space Heating/Heat Pump Water Heating/Water Efficiency/Demand Response	Percentage Multiplier or Fixed Rate
Tier 2	Insulation/Heat Pump Space Heating or Water Heating/Water Efficiency	Percentage Multiplier or Fixed Rate

Table 17-1 Tiered bonus incentives for multiple measure adoption

17.4 On-bill Credits

Consider automatic on-bill credits for rebate payments under $75. This will reduce check processing and administrative costs and may result in greater customer satisfaction. TCLP could consider allowing customers to opt-out of credits on application.

17.5 Whole Home (Residential) and Comprehensive Building (Commercial)

Building on the Multi-Measure Incentive program, the Energy Savers programs can enhance its offerings by creating a Whole Home program for residential customers and a Comprehensive Building program for commercial clients. These comprehensive programs aim to address energy efficiency, electrification, and demand response on a broader scale, incorporating a wide range of measures tailored to specific needs and requirements. From advanced insulation and high-efficiency heat pump systems to intelligent lighting, smart building controls, and enrollment in demand response programs, participants in these programs would be eligible for additional incentives and comprehensive support from the Energy Coach program throughout their energy upgrade journey. The Whole Home program and Comprehensive Building program recognize the interdependence of various energy-saving measures and the importance of demand response for grid reliability and efficiency. They provide a roadmap for achieving optimal energy performance, sustainability, and carbon reduction while actively engaging customers in managing their energy consumption and contributing to a more resilient energy future.

17.5.1 Home Electrification Plan

The TCLP Energy Coach will provide homeowners a personal journey to decarbonization with an assessment of their home while providing additional support for low-income homes. Provide a roadmap that outlines the best practices for integrating energy efficiency, building envelope improvements, electrification, solar, EV charging, and demand response into their long-term planning. For many homes an electric panel upgrade will be required. Providing rebates for smart panels is recommended to help shift loads. We recommend building a program around a pool of pre-qualified contractors who are trained and ready to implement decarbonization solutions and who are directly connected to on-bill financing for ease of lending for projects.

Based on our building electrification analysis, the benefits of electrification measures vary depending on the customer's current space heating system. The Energy Coach and TCLP website should communicate that rebates for electrification measures, such as replacing a natural gas furnace with an air source heat pump, will be lower compared to replacing baseboard electric heat with an air source heat pump. To help customers understand the potential benefits, it is recommended to develop an online calculator that utilizes specific building information to provide personalized estimates. Additionally, a tiered rebate approach is proposed, combining measures like air source heat pumps and insulation, to increase customer rebates for those with natural gas systems. The details of tiered rebates are discussed further in the Whole Home Electrification Incentives section below.

17.5.2 Zero Over Time Multifamily Planning

Multifamily property owners, especially affordable housing owners, make decisions on different timelines than single family homeowners or commercial building owners. There are windows of opportunity to make big changes to buildings, but also natural points in between to make incremental changes to units or systems. Owners of multiple multifamily properties, often called "portfolios," have opportunities to aggregate similar energy upgrades across their portfolios to maximize their buying power and simplify the contracting process. By working with the Energy Coach, individual property owners and portfolio owners can build a plan to achieve zero carbon emissions over time by integrating energy upgrades into their operations planning.

17.5.3 Comprehensive Commercial and Sector Specific Programming

Commercial building owners make decisions to benefit their business. To assist them in moving towards decarbonization, the Energy Coach program will establish a long-term relationship with key decision-makers to help them identify both individual program offering they may be interested in and custom incentives for making comprehensive upgrades to their buildings and operations.

Building on the idea of a commercial comprehensive program, TCLP could consider offering sector specific programming such as commercial kitchens. Programs targeting these sectors may require industry specific knowledge about kitchen layout, ventilation, guest room management, amongst others. Brief outlines and targets for each sector program are below:

17.5.3.1 Commercial Kitchen Program

The Commercial Kitchen Program would be a sector specific energy efficiency initiative designed to assist commercial customers in the food service industry in reducing energy consumption, enhancing kitchen performance and efficiency while lowering overall operating costs in their kitchen facilities. This program would target restaurants, cafes, catering services, institutional kitchens, and other food-related businesses.

Recommendations: Develop a new program focused on commercial kitchen improvements, built around recurring meetings of an affinity group of customers and an offer of technical assistance in efficient and electric kitchens. Consider working with Northern Michigan Community College to provide a demonstration kitchen. A similar affinity group and technical assistance offer for hotels and other lodging might also be warranted, focused on room heating and cooling, hot water, and guest EV charging.

The following components may be included:

- Energy Assessments: Participating businesses receive comprehensive energy assessments conducted by qualified professionals. These assessments will evaluate the existing kitchen equipment, systems, and operational practices to identify potential energy-saving opportunities in existing and custom measures.
- Prescriptive Rebates: The Energy Savers program currently provides prescriptive rebates for the installation of energy-efficient equipment commonly found in commercial kitchens. This includes incentives for high-efficiency cooking equipment, such as ovens, griddles, fryers, and steamers, as well as energy-efficient refrigeration units and dishwashers.
- Customized Solutions: In addition to prescriptive measures, the program offers custom incentives for unique energy-saving projects or equipment not covered by the standard measures. This allows businesses to explore and implement innovative energy efficiency solutions tailored to their specific needs. This could include kitchen layout and specialty equipment.
- Technical Assistance: a TCLP's Energy Savers program specialty Energy Coach would provide technical guidance and support throughout the program, assisting businesses in selecting the most

suitable energy-efficient equipment, optimizing kitchen layouts, and implementing best practices for energy management and maintenance.

- Training and Education: The program could include training sessions to educate kitchen staff and managers on energy-efficient practices, proper equipment usage, and maintenance techniques to enhance energy-conscious behaviors and ensure sustained benefits of the program.
- Monitoring and Reporting: Program may be designed to track energy consumption and provide regular reports to participants. This enables businesses to monitor their energy performance, identify trends, and make data-driven decisions to further optimize their kitchen operations.

17.5.3.2 Commercial Lodging Program

In a similar fashion to the Commercial Kitchen program, a Commercial Lodging Program would be a comprehensive energy efficiency initiative designed to assist commercial customers in the lodging industry, including hotels, motels, resorts, and other hospitality establishments. This program would help businesses reduce energy consumption, improve guest comfort, and lower operational costs, while promoting sustainable practices within the lodging sector. Potential Program Features include:

- Energy Assessments: Participating lodging establishments receive detailed energy assessments conducted by qualified professionals. These assessments evaluate various aspects of the building, including guest rooms, common areas, lighting systems, heating, ventilation, and air conditioning (HVAC) systems, water heating systems, and overall energy usage patterns. Energy assessment recommendations may include:
- Lighting Upgrades: The program encourages and provides incentives for upgrading lighting systems to energy-efficient alternatives, such as LED lighting. This includes retrofitting guest rooms, corridors, lobbies, and exterior lighting with high-efficiency lighting fixtures and controls to enhance energy savings and guest experience.
- HVAC System Optimization: the program would offer expertise with trusted contractors and offer incentives for optimizing HVAC systems in commercial lodging facilities. This may involve upgrading to high-efficiency HVAC equipment, implementing advanced controls and thermostats, and ensuring proper maintenance and insulation to achieve optimal energy performance and guest comfort.
- Water Heating Solutions: The program promotes the installation of energy-efficient water heating systems, such as heat pump water heaters or solar water heaters, to reduce the energy consumed for hot water production in guest rooms, kitchens, laundry facilities, and swimming pools.
- Guest Room Management: a TCLP's Energy Savers program specialty Energy Coach would offer guidance on energy-saving practices within guest rooms, including recommendations for occupancy sensors, smart thermostats, energy-efficient appliances, and guest education materials. These measures contribute to energy conservation without compromising guest comfort and satisfaction.
- Energy Management Systems: The program encourages the adoption of energy management systems (EMS) that allow lodging establishments to monitor and control energy usage in real-time. EMS solutions provide insights into energy consumption patterns, enable remote monitoring and control of HVAC and lighting systems, and facilitate energy-saving strategies.
- Employee Training: The program could offer training and educational resources for lodging staff, focusing on energy-saving practices, efficient equipment operation, and sustainability initiatives. This training empowers employees to actively participate in energy conservation efforts and maintain a culture of energy efficiency within the establishment.

17.5.3.3 Fleet Electrification

For businesses that utilize fleets of vehicles for their operations (e.g., trucks, vans, forklifts, scissor lifts, etc.), provide incentives for both the switch from fossil fuel powered vehicles and the electric charging infrastructure needed to support their integration into the businesses' operations.

17.6 New Construction Program

Create a standalone New Construction Program that incentivizes energy-efficient design, building electrification, electric vehicle- and solar-readiness for new commercial buildings. By engaging with projects early in the design phase, this program emphasizes the optimal time to incorporate energy-saving measures and electrification which helps in reducing costs while lowering the carbon footprint of new construction projects. Building electrification, as well as EV and RE readiness, are much more cost effective to accomplish with new construction and should be considered as to not lock a building into natural gas use from the beginning.

17.7 Income Qualified Program

Establish an Income Qualified Program to provide energy-saving solutions and assistance to eligible households. Income guidelines should be developed to maximize participation in Inflation Reduction Act programming. This program would seek to address the energy challenges faced by these households, improve energy efficiency, and reduce the burden of energy costs. The program would consist of five elements: 1) collaboration with community partners; 2) Home Energy Assessments; 3) potential installation of selected high-efficiency lighting, water heating, or appliances measures at no cost to the resident; 4) in-home education about energy- efficient practices, and 5) additional financial options that may be available. The pending Federal IRA Electrification rebates may cover up to 100% of a total qualified project's cost for households with a total annual income of less than 80% of the area median income. With the help of these federal rebates, TCLP stands to help families make significant strides toward meeting TCLPs goals for all resident classes.

Provide incentives to multi-unit affordable housing that provides owner-paid utilities, to enable an all-electric building with onsite generation and storage and participates in Demand Response programs.

17.8 Multifamily Program

Recommendation: Create a standalone Multifamily program to provide energy efficiency and carbon reducing incentives to property owners and their tenants (commercial and residential). Participating property owners and management companies would work closely with an energy coach to identify potential upgrades and incentive opportunities that cut across TCLPs residential and commercial offerings. Engaging with a dedicated Energy Coach will assist the property owner/management company in streamlining the rebate application, multi-measure incentives, financing options and potentially direct installations of energy efficiency measures. Importantly, the utility's attention of this sector (rents, not homeowners) addresses the affordable housing issue facing the Traverse City region. There is frequent overlap between Income-Qualified and Multifamily programs, allowing for synergies between them.

17.9 Preferred Contractor Program

A common theme of utility-led rebate programs across the state is the importance of customer-contractor collaboration in effectively implementing program energy measures. While some measures can be accomplished through do-it-yourself methods, many others require specialized knowledge, licensing, and expertise that only contractors can provide. However, it is crucial to acknowledge that not all contractors may fully support or believe in the measures offered for rebates, leading to potential discrepancies in recommendations. For instance, a contractor might argue against the suitability of a measure like a cold weather heat pump for the TCLP region. Additionally, contractors may have limited familiarity with certain measures such as heat pumps, energy recovery ventilators (ERVs), and heat recovery ventilators (HRVs), or they may not possess models that align with TCLP's energy and decarbonization goals. To address these challenges and ensure consistent quality, it may be beneficial to establish a Preferred Contractor Program for trade allies.

A proposed Preferred Contractor Trade Ally program would serve as a partnership initiative between TCLP and selected contractors who meet specific criteria and demonstrate their commitment to promoting energy measures and supporting TCLP's savings and decarbonization goals.

TCLP Preferred Contractor Trade Ally Program: A program established by TCLP to collaborate with contractors who align with TCLP's objectives, actively promote energy measures, and support TCLP's 100% decarbonization goals. Contractors may be grouped in categories such as a “heat pump networks” or “building envelope networks.”

- Eligibility Criteria: TCLP would establish specific eligibility criteria that contractors must meet to be considered for the Preferred Contractor Program. This can include factors such as relevant licenses, certifications, industry experience, and adherence to ethical business practices.
- Product Alignment: Contractors seeking to join the program would need to demonstrate that they carry and install products included in TCLP's rebate program. This ensures that they are equipped to offer the eligible energy-efficient measures to customers and facilitate the rebate process.
- TCLP Vetting Process may include the following:
- Application and Documentation: Contractors interested in becoming a Preferred Contractor would complete an application, providing information about their business, qualifications, experience, and references. They would also provide documentation to verify their licenses, certifications, and insurance coverage.
- Evaluation and Screening: TCLP would conduct a thorough evaluation of the applications, reviewing the contractor's qualifications, experience, reputation, and previous project performance. This evaluation would include an assessment of the contractor's alignment with TCLP's program offerings, decarbonization goals and commitment to energy efficiency.
- Interview and Site Visit: Shortlisted contractors may be interviewed to further assess their understanding of energy efficiency practices, familiarity with TCLP's rebate program, and commitment to supporting TCLP's decarbonization goals. A site visit may also be conducted to verify the contractor's operations and capabilities if questions arise among TCLP staff of capability.
- Memorandum of Understanding (MOU): Once a contractor successfully completes the vetting process, TCLP would enter into a MOU with the contractor, outlining the terms and conditions of their participation as a Preferred Contractor. This agreement would include provisions related to the promotion of energy efficiency, adherence to program guidelines, and support for TCLP's decarbonization goals.

Trade Ally Benefits: Upon becoming a TCLP Preferred Contractor, trade allies would gain access to a range of benefits, such as:

- Marketing Support: TCLP would provide marketing materials, co-branding opportunities, and inclusion in the program's promotional efforts to help contractors attract additional customers.
- Training and Education: Preferred Contractors would receive specialized training and education on energy-efficient products, installation best practices, and updates on TCLP's rebate program. This ensures they stay informed and can provide quality service to customers.
- Recognition and Awards: TCLP can publicly recognize contractors through awards, certificates, or inclusion in promotional materials. This acknowledges their contribution to community goals and can enhance their reputation within the community.

- Program Updates and Collaboration: TCLP would regularly communicate with Preferred Contractors, providing updates on program changes, new measures, and sharing insights to foster collaboration and improve the overall program.

To encourage additional participation in the Preferred Contractor Program, TCLP could consider offering contractor financial incentives and midstream rebates in addition to the non-financial benefits listed above. Contractor incentives are designed to motivate contractors to actively promote and install eligible measures for residential and commercial customers, effectively becoming an active member of the TCLP team. Options include:

- Rebate Bonuses: Contractors can receive additional financial incentives for each successful rebate application they submit on behalf of their customers. The bonus amount can be based on a percentage of the rebate value or a fixed amount per eligible measure installed.
- Volume Incentives: Contractors can earn higher incentives as they achieve predetermined installation targets or milestones. This encourages contractors to actively promote and install energy-efficient measures, driving higher participation rates.
- Performance-Based Incentives: Contractors can be rewarded based on the energy savings achieved through their installations. TCLP may set energy-saving targets, and contractors who exceed these targets can receive higher incentives as a recognition of their exemplary performance.
- Midstream Rebates: Consider implementing a midstream rebate program that offers direct payment of rebates to contractors, enabling them to markdown or discount eligible products for customers. This approach not only provides customers with immediate savings but also equips contractors with a sales discount tool to promote energy-efficient measures. By incentivizing contractors to offer reduced prices on eligible products, we can enhance customer affordability and encourage widespread adoption of TCLP promoted technologies.

17.10 Heating and Cooling District

A heating and cooling district is a centralized infrastructure that provides heating and cooling services to multiple buildings within a specific area or district. It involves the generation, distribution, and delivery of thermal energy through a network of pipes to meet the heating and cooling needs of buildings.

A district energy system provides a more efficient and sustainable alternative to individual building heating and cooling systems. It offers several advantages, including reduced energy consumption, lower greenhouse gas emissions, increased reliability, and improved operational efficiency. It can be particularly beneficial for densely populated areas, commercial complexes, educational institutions, and other large-scale developments. As this is a complex project, TCLP should consider the evaluation of creating a ground-source or water-source heating and cooling district in denser commercial or industrial portions of the TCLP service territory.

Recommendation: Consider contracting in-depth evaluation of creating a ground-source or water-source district heating and cooling utility in denser portions of the TCLP service territory.

Contract with specialized experts in district heating and cooling systems to conduct a comprehensive analysis, considering factors such as geothermal resources, infrastructure requirements, economic viability, potential energy savings, environmental impact, and stakeholder engagement.

Evaluate the availability and suitability of geothermal resources in the identified areas, including geothermal wells or water bodies that can be utilized for efficient heating and cooling.

Assess the infrastructure requirements for implementing a district heating and cooling system, including the installation of distribution networks, heat exchangers, and control systems to deliver heating and cooling to connected buildings.

Analyze the economic viability of the proposed district system, considering factors such as initial capital investment, operational costs, potential revenue streams, and long-term financial sustainability.

Estimate the potential energy savings and carbon emissions reduction that can be achieved through the implementation of a district heating and cooling utility.

Evaluate the environmental impact of the district system, considering factors such as reduced reliance on fossil fuel-based heating and cooling, greenhouse gas emissions reduction, and potential benefits for local air quality.

Engage stakeholders, including property owners, developers and TC planning and zoning departments to gather input, address concerns, and foster support for the proposed district heating and cooling initiative.

Review successful case studies from other Michigan locations that have implemented district heating and cooling systems such as University of Michigan, Michigan State University, and City of Wyandotte.

17.11 Demand Response Program Recommendations

Provide a financial offer for customers to enroll in an automated demand management program for vehicle charging, space conditioning, water heating, pumping, electricity storage, that will:

- Inform equipment operations about time-of-use rate schedules.
- Allow real-time management of demand within customer-friendly limits.
- Allow (at customer option) emergency management of demand as needed to qualify as MISO capacity resources.

17.11.1Increase Marketing of DR Programs

With increased use of IoT, the potential for DR should increase in the future. There should be an expectation for increased adoption of smart technologies from controls, software, hardware, and end use equipment. The chief way to increase DR participation will be through educating customers of the simplicity and financial benefits of DR participation.

Advanced end use equipment such as battery energy storage systems, battery, and EV charging management systems, etc. should be selected by TCLP to meet Open ADR protocol and BACnet protocols for building systems. When including end use equipment for DR program acceptance, should consult:

- IEEE 2030
- ASHRAE 135
- ASHRAE 201
- UL 9741
- ISO 15118-20

17.11.2Residential Customers

Gain interest by residential customers in Bring Your Own Thermostat (BYOT)

- Increase awareness that homes are already fitted with advanced metering infrastructure.
- Provide a fixed bill credit for summer months for customers with air conditioning but fossil-fueled space heat, but a bill credit for both summer and winter for customers with electric space heat. In

the alternative, TCLP could offer rebates for reduced usage during announced demand response events.
- Make sure that signup is easy.

17.11.3 C&I Customers

Gain interest by customers in BYOT

- Increase awareness that buildings are already fitted with advanced metering infrastructure.
- Make sure that signup is easy, and provide signup incentive payments based on customer using equipment that includes automated control protocols such as Open ADR protocol, BACnet protocol, DALI protocol, OCPP protocol, and OICP protocol.
- Because the potential demand response of commercial and industrial customers is highly varied, the most appropriate strategy for C&I demand response is to either (1) offer a discount on regular bills in return for being subject to a high price for all electricity used during called demand response events or (2) provide rebates for demand reduction below "ordinary" levels for a customer whenever a demand response event is called.
- As TCLP acquires demand response management software to signal customer participation, TCLP should consider integrated software that also supports battery management and EV charging management.

17.11.4 Solar and Storage Program Recommendations

TCLP has offered a rooftop solar program for approximately a decade and in that period, uptake for residential customers has averaged three to five installations per annum. Commercial has been less that. As of the end of 2022, 36 residential and 10 commercial customers are participating in the utility's net metering solar program. Previous recommendations in this document suggest moving away from a net metering program to a distributed resource policy (Section 14).

Recommendation: As part of the customer energy optimization program, reduce the "soft costs" of behind-the-meter solar and storage by providing each customer an annual report of the expected costs and bill savings for solar at their premises, referral to qualified vendors or automated solicitation of proposals from qualified vendors, streamlined permitting and inspections, and on-bill repayment and other attractive financing for system costs.

Meet with the permitting agencies (e.g., building, electrical) in the City of Traverse City to understand and potentially improve upon the education of residents/businesses interest in distributed solar. The utility could provide a Fact Sheet for the City to disseminate, and also work to ensure the process for getting solar includes City requirements (building and electrical permits) and utility requirements (interconnection agreement). Similarly, the utility could make usability improvements on its website so customers can quickly access relevant information, such a FAQ.

Most residential solar installers will scope a potential DG project for free. That said, TCLP could provide a free "first blush" assessment for customers interested in getting solar. TCLP or its vendor could do a desktop analysis (PV Watts, SAM) of an address and easily determine if it has enough of a solar resource to justify a customer exploring an installation. Google Sunroof also could provide TCLP (or for the customer referred directly) as to the prospects of a solar project working, yea of nay.

Allow customers to install as much onsite solar as they desire with a contractual agreement with TCLP that the utility will buy the excess at LMP + capacity + optional sREC (but not at full retail). An interconnection grid study might be necessary for installs larger than 20kW.

Promote solar for itself as a utility priority and also as a key component of DER. Solar is often the attraction for a customer, which allows to have a further conversation about energy efficiency—the first step in decarbonizing a household or business.

Similarly, interest in solar storage (batteries) is increasing among customers, driven in part by the penetration of EVs into our consumer economy. However, storage is ill-understood by most people. The utility might consider including fact sheets about solar, storage and solar plus storage on the website, and perhaps host a couple informational webinars on these topics.

Provide potential financing resources to customers who are moving forward on solar projects: IRA, USDA, State of Michigan, Michigan Saves, etc. Also, some financing might require a building energy audit, which should be made clear as part of customer education.

18 Integrated Customer Energy Optimization Program Delivery

Broadly, community outreach entails a combination of marketing/advertising, customer education, a user-friendly, frequently updated website; social media presence; earned media coverage; events; and "ambassador spokespeople" for TCLP's ambitions—nonprofit and business leaders, elected and appointed officials. While there are many modalities available to get the word out, nothing replaces building the networks and rapport with your customers, which TCLP has been doing for years.

Importantly, however, you are about to launch and "new and improved" utility with a visionary goal and suite of actions to meet that goal. Decarbonization is not intuitively understood by everyone and there will even be indifference among some customers. This means that TCLP at the outset of the program should consider frontloading with enough people, community outreach, cadence of messages, market penetration and sales follow-up so this effort starts strong out of the gates. In short, TCLP should consider the first 12 months to be a period of a "campaign" in which this is not merely a tweak to what you've been doing already with customers. Instead, you want to motivate people to "vote for your cause" in the sense of taking action through the utility's new program offerings. The Energy Coach could potentially be the keystone to all of this, dovetailing with TCLP leadership, marketing and customer service departments and with your variety of customers.

18.1 Integrating Federal and State Tax Funding and Other Financing Options

Recommendation: Through the integrated customer energy optimization program, provide maximum feasible assistance for customer access to federal and state tax credits and rebates. To maximize the benefits for customers and further enhance the attractiveness of the TCLP Energy Savers program, we recommend integrating and promoting federal and state tax incentives, rebates, and, potentially, grant opportunities. Marketing efforts should be put here in the foreseeable future since IIJA and IRA funds and incentives are finite. That said, some incentives such as the Investment Tax Credit has a 10-year window, starting in 2022. For TCLP to signal to its customers that you are a resource to help them save money and do important energy upgrades will do much in having the utility become identified as a decarbonization leader.

Inflation Reduction Act			
Energy Measure	Type	Max (in addition to TCLP incentives)	Timing
Rooftop Solar	Tax Credit	30%	Available now
Battery Storage	Tax Credit	30%	Available now
Heat Pump (Air Source)	Tax Credit	$2,000	Available now
Heat Pump Water Heater	Tax Credit	$2,000	Available now
Electric Panel Upgrades	Tax Credit	$600	Available now
Weatherization {energy efficiency)	Tax Credit	$1,200	Available now
Heat Pump (Air Source)	Rebate	Up to $8,000	TBD by Income and Adopted State Rules
Heat Pump Water Heater	Rebate	Up to $1,750	TBD by Income and Adopted State Rules
Electric Panel Upgrades	Rebate	Up to $4,000	TBD by Income and Adopted State Rules
Electric Wiring	Rebate	Up to $2,500	TBD by Income and Adopted State Rules
Induction Stove	Rebate	Up to $840	TBD by Income and Adopted State Rules
Weatherization (energy efficiency)	Rebate	Up to $1,600	TBD by Income and Adopted State Rules
See what you may qualify for: https://www.rewiringamerica.org/app/ira-calculator			

Table 18-1 TCLP customer tax incentives available from the Inflation Reduction Act.

Related Recommendations: Create a dedicated section on the TCLP Energy Savers website that provides, at a minimum, information about federal and state tax incentives and rebates relevant to energy-saving measures. This section could also include more in-depth details on eligibility criteria, application processes, and any specific requirements. For example, TCLPs website and application materials could reference the current Inflation Reduction Act tax offerings.

Additionally, listing opportunities such as Federal Rural Energy for America Program (REAP) grants, or State Energy office grants may also be desirable for commercial customers.

Incorporate information about tax incentives and rebates into marketing materials, such as brochures, flyers, and online campaigns. Highlight the potential savings and financial advantages of participating in the Energy Savers program alongside these additional incentives.
Financing Options should be included and highlighted in all marketing materials: on-bill financing, TCLP Commercial Loan, PACE (Property Assessed Clean Energy) and Michigan Saves. These low or no-interest

debt products are already in place and have been utilized by TCLP customers in the past. Renewed attention to these as opportunities to braid more resources into a capital stack for a customer energy upgrade—especially those that are holistic and multifaceted—again follow the precept of making energy decisions and action *easy* for TCLP customers.

The Energy Coach(es) must have expertise in the funding and financing that is available, when it is available and how a customer may access it, such as through a TCLP-certified contractor, through an online application process and so forth. A goal for customer service from an Energy Coach should be that the many sources of funding currently available—specifically on-bill financing and Michigan Saves—is explored with the customer.

18.2 TCLP Website

Recommendation: To enhance customer experience and streamline access to information and resources, TCLP should establish its Energy Savers webpages as a comprehensive and integrated program hub. This program hub will serve as a centralized repository, bringing together the various energy efficiency initiatives, beneficial electrification efforts, demand response programs, solar programs, financing options, and online applications.

Education plays a vital role in helping customers navigate complex topics such as heat pumps, financing, and utility Demand Response programming. Within the Energy Savers program hub, TCLP should provide comprehensive educational materials and resources to guide customers through each stage of their energy journey. This includes information on identifying potential energy upgrades, selecting qualified contractors, seeking assistance from Energy Coaches, choosing the most suitable equipment for their specific needs, accessing additional incentive offerings, exploring financing options, and seamlessly submitting rebate applications.

The education component should focus on simplifying complex concepts and explaining them in a clear and accessible manner. For instance, for customers interested in heat pumps, TCLP can provide detailed guides, FAQs, and potentially interactive tools that explain how heat pumps work, their benefits, installation considerations, and cost savings potential. This option could be extended to a variety of measure categories, helping customers understand both measures and potential incentive options like tiers or multipliers.

Furthermore, the program hub could include engaging and interactive elements such as videos, infographics, and case studies to enhance understanding and illustrate real-life examples of energy optimization success stories. These resources can help customers visualize the benefits of energy efficiency initiatives, beneficial electrification, and demand response programs, making them more likely to participate and take advantage of the available opportunities. The city of Burlington's Electric Department rebate program[31] is an example of many aspects of a centralized hub.

18.3 Customer Journey

Create an integrated customer energy optimization program covering energy efficiency, building electrification, vehicle electrification, on-site solar, on-site storage, and demand response. The customer journey (or roadmap) will provide to customers the actions they should take to fully decarbonize their personal life or business with triggering events for or sequence of actions. Customers' interests in decarbonization, climate change and clean energy solutions will vary. Some may be only interested in upgrades if these are free or low-cost. Others may be motivated to make maximal energy improvements because of their desire to reduce carbon in their lives.

[31] https://www.burlingtonelectric.com/rebates

The art and science of TCLP's Customer Energy Optimization Program will be designing offerings that will appeal to both types—and other types—of customers that you serve. Asking for feedback and input at the point of, or, after an interaction can provide you important insights that you can then use to sharpen your marketing of program offerings as programs continue. Related, tracking rebates and incentives in real-time will let you understand what is popular and what is not and allow you to make adjustments accordingly.

The Customer Journey and community outreach are entwined. Both require attentiveness—especially in the first year—by the utility, which, in turn, is likely to require investment of people and expertise. The ambitions of the climate action plan are of the scale and consequence never before tackled by the Traverse City community, and by very few others anywhere. TCLP will need to be alongside that customer as they decarbonize their lives.

18.3.1 Process Flow for Customer Journey

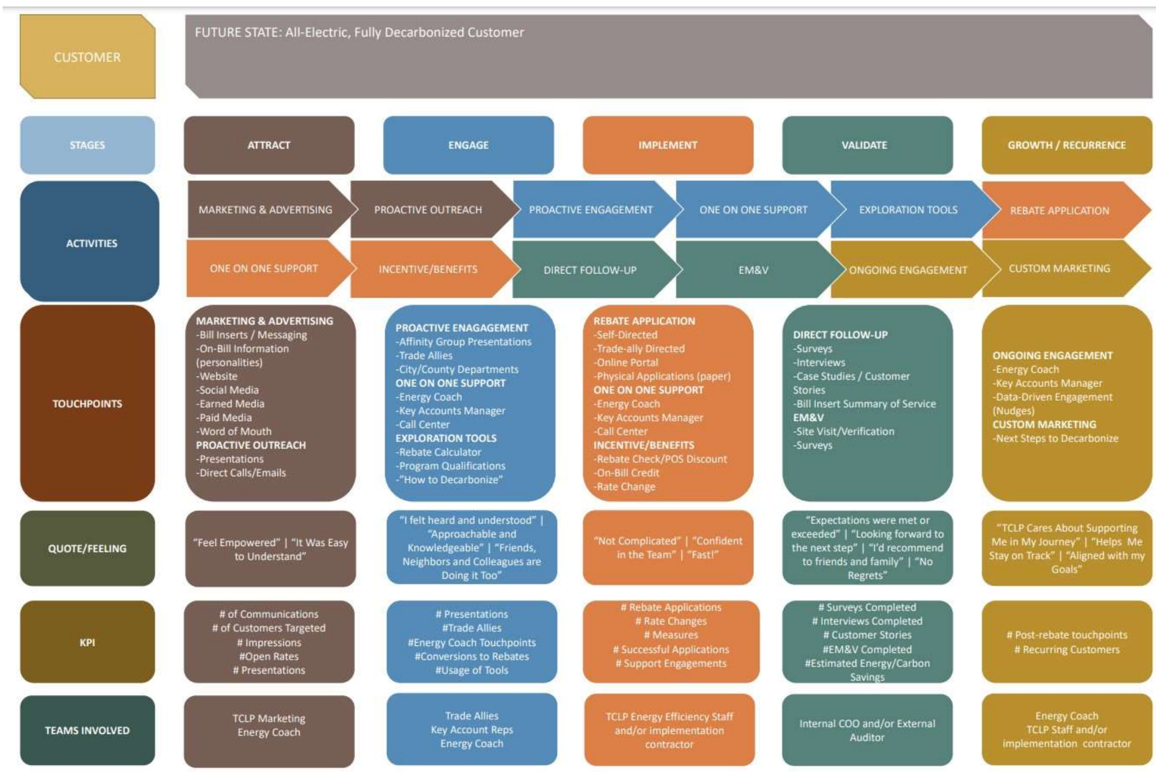

Figure 18-1 Process flow for Customer Journey

19 Budgeting for Potential Integrated Customer Program

Energy Waste Reduction kWh savings potentials were derived from the comprehensive 2021 Michigan Energy Waste Reduction Statewide Potential Study conducted by Guidehouse for the Michigan Public Service Commission. This study served as the foundation for assessing energy usage and determining the maximum potential for energy savings across the lower peninsula of Michigan. By analyzing the Guidehouse-selected end-use categories, Michigan Energy Options (MEO) calculated the maximum savings percentage achievable for each end-use category by dividing the total savings potential by the total energy usage.

In collaboration with 5LE, MEO aligned the Guidehouse end-use categories with the ResStock and ComStock end-use categories developed by the NREL. The ResStock and ComStock end-use profiles for Traverse City were scaled accordingly to accurately represent TCLP's energy consumption across residential, commercial, and commercial demand customer classes.

Using the total sales and savings potential data from the Guidehouse Study, MEO calculated savings percentages for each specific ResStock and ComStock end-use category. These savings percentages were then applied to the respective end-use profiles for residential, commercial, and commercial demand customer classes. To estimate annual savings potential, the savings percentages were divided by the average life expectancy of measures within each end-use category, assuming that all customers would adopt energy-efficient equipment when their current inefficient equipment is due for replacement. The resulting figures represent the annual savings potential and can be found in the Cumulative Savings Potential Tables for residential, commercial, and commercial demand customers.
To determine the annual kWh savings potential, the ResStock and ComStock kWh usage data from the base year were multiplied by the first-year potential savings percentage for each specific end-use category. This calculation yielded the first-year kWh savings figure for each end-use. These individual end-use kWh savings values were then aggregated to establish a single-year kWh savings goal for each customer class.

To estimate the budgets needed to achieve these kWh savings goals, the single-year kWh savings goals for each customer class were multiplied by a series of Net Present Value (NPV) scenarios. The resulting figures provide estimated budgets required to accomplish the kWh savings goals. These potential budgets, broken down by end-use category, can be found in the first-year budget tables for each customer class, providing valuable insights into the financial requirements of achieving the targeted kWh savings.

Fuel switching program budgets were developed separately for the Residential, Commercial, and Commercial Demand classes using a common methodology. These budgets are based on average NPV societal net benefits from building electrification offset by reduced natural gas consumption. Given our recommendation to implement comprehensive building envelope retrofits using the building electrification deployment schedule, a separate budget line item was computed for this program element reflecting its relative contribution to net benefits. Also, while we had no solid basis for estimating electrical panel upgrades, the fuel switching budget tables (below) include this as a program element to signal its importance in overall program strategy.

19.1 Integrated Residential Customer Program 2025 Budget Estimates

Program	NPV Avoided Utility MC Factor	NPV Total Avoided Societal Costs with TCLP 100% Marginal RE	NPV Total Avoided Societal Cost with Generic Grid Power
HVAC Space Heating & Cooling	$ 33,307.52	$ 41,765.12	$ 90,763.45
Ventilation	$ 1,047.63	$ 1,313.65	$ 2,871.19
Domestic Water	$ 123,709.85	$ 155,122.83	$ 358,560.65
Clothes Washing & Drying	$ 53,614.93	$ 67,229.08	$ 153,774.81
ENERGY STAR® Home Appliances	$ 244,471.01	$ 306,548.23	$ 674,707.81
Refrigerator & Freezers	$ 94,129.45	$ 118,031.24	$ 262,117.83
Exterior & Interior Lighting	$ 170,529.37	$ 213,830.97	$ 478,649.43
	$ 720,809.77	**$ 903,841.13**	**$ 2,021,445.17**

Table 19-1 Residential Energy Waste Reduction budget for targeted adoption rates

Residential Fuel Switching Program	Initial Annual Budget ($)	Accounts/Year	Per Unit Budget ($/Account)
Building Electrification	650,793	206	3,155
Building Envelope Retrofit	78,473	206	380
Electrical Panel Upgrade	*Not Specified*		
Residential	**729,266**	**206**	**3,535**

Table 19-2 Residential electrification and building envelope budget for targeted adoption rates.

19.2 Integrated Commercial Customer Program 2025 Budget Estimates

Program	NPV Avoided Utility MC Factor	NPV Total Avoided Societal Costs with TCLP 100% Marginal RE	NPV Total Avoided Societal Cost with Generic Grid Power
Ventilation	$ 553,746.92	$ 694,356.92	$ 1,597,787.72
Water Heating and Pumping	$ 220,664.19	$ 276,696.27	$ 637,369.66
Refrigeration	$ 2,270.62	$ 2,847.19	$ 6,209.72
Exterior & Interior Lighting	$ 553,216.01	$ 693,691.19	$ 1,553,829.00
Pumps	$ 2,041.40	$ 2,559.76	$ 6,030.63
Interior Equipment	$ 451,581.84	$ 412,060.65	$ 897,675.60
	$ 1,783,520.99	**$ 2,082,211.98**	**$ 4,698,902.33**

Table 19-3 Commercial Energy Waste Reduction budget for targeted adoption rates.

Commercial Fuel Switching Program	Initial Annual Budget ($)	Average Accounts/Year	Average Program Budget per Account
Building Electrification	138,921	28	5,041
Building Envelope Retrofit	17,777	28	645
Electrical Panel Upgrade	*Not Specified*		
Commercial	**156,698**	**28**	**5,686**

Table 19-4 Small commercial customer electrification and building envelope budget for targeted adoption rates.

Commercial Demand Fuel Switching Program	Initial Annual Budget ($)	Average Accounts/Year	Average Program Budget per Account
Building Electrification	479,717	13	37,654
Building Envelope Retrofit	61,387	13	4,818
Electrical Panel Upgrade	*Not Specified*		
Commercial Demand	**541,103**	**13**	**42,473**

Table 19-5 Commercial demand customer electrification and building envelope budget for targeted adoption rates.

20 Integrated Impact Assessment

One common concern utilities have about transportation electrification, building electrification, and distributed generation is that these may drive changes in power flows that will affect the distribution system and add unexpected costs.

Detailed geographic analysis of distribution system loading is beyond the scope of this project and likely irrelevant in that the evolution of load profiles will occur at unpredictable times in specific locations. To assess how likely it is that TCLP will face distribution system challenges, we assessed the integrated impact of the full set of recommended programs on the distribution system at an aggregated level.

In general, changes in load can cause two type of problems in a distribution system. Elevated loads can cause voltage to drop too much at the "end of the wire" in the distribution system, such that customer equipment does not operate correctly or efficiently. This can usually be addressed at modest cost with line voltage regulators.

Elevated loads can also stress transformers. Broadly, transformers do not have a capacity limit in the sense that they cannot handle more than a certain current. Rather, if frequently overloaded, they age more quickly and must be replaced more often. A utility usually recognizes these overloads and upgrades an overloaded transformer to a higher rating or splits a group of customers to serve them with multiple transformers in place of one. When performed on an as-needed basis, this will not be costly.

To determine whether the projected load profile changes in TCLP's system would be consequential, we modeled the hourly loss of life of representative line transformers in residential and commercial neighborhoods and at the substation level. The following graphs show the percentage loss of life in each hour of 2025 and 2040 for such a representative residential neighborhood line transformer, assuming the same weather in both years. Our key conclusion is simple: the recommended programs appear unlikely to have much effect on the distribution system. The principal reason that we do not see much effect is that transformers age due to high internal temperatures. In winter, cold ambient temperatures keep transformers from heating up even though load is comparatively higher due to heating electrification and vehicle electrification. In summer, load increases due to vehicle electrification are largely offset by efficiency and distributed generation.

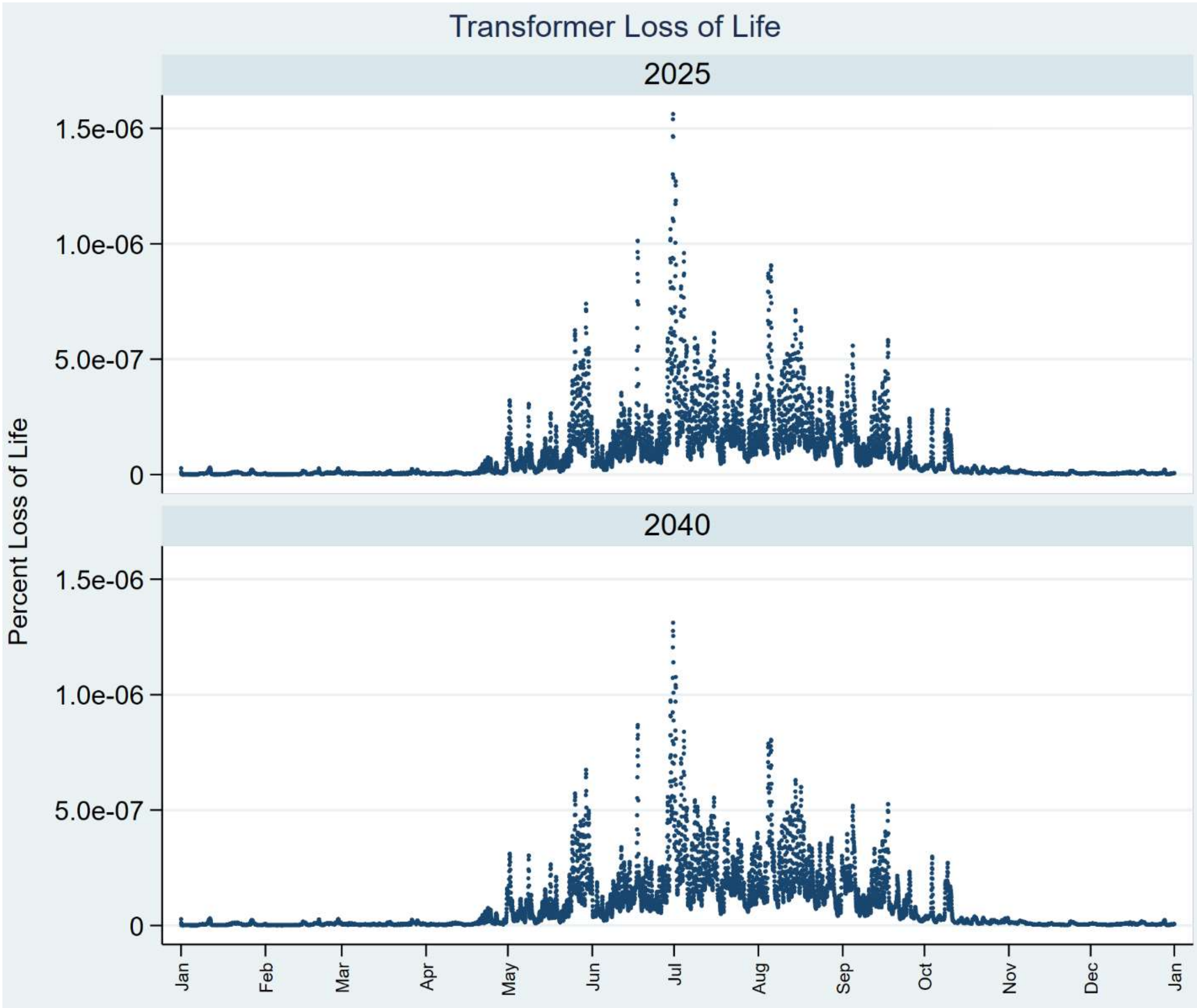

Figure 20-1 Transformer loss of life comparison between 2025 and 2040

21 Integrated Resource Plan

21.1 Introduction to IRP Modeling and Analysis

5 Lakes Energy's IRP analysis for TCLP is rooted in two related models developed by 5 Lakes Energy which were used sequentially to produce the recommendations that follow. The first is STEP8760 which was calibrated to model the grid price and periods of tight supply for resource adequacy requirements in the whole of MISO Zone 7, from which TCLP buys wholesale power. The second is STEP Forward TCLP, which is a model built entirely custom for this IRP. STEP Forward TCLP uses data from, and load projections for, TCLP, and models optimal new generation procurement in the context of wholesale power supply costs modeled in STEP8760 for MISO Zone 7. As part of running STEP8760, we necessarily model the hourly deployment of every thermal generator in MISO Zone 7, which includes Kalkaska, and Belle River, generators from which TCLP contracts directly for power supply. The hourly generation results from these two plants are also incorporated into our STEP Forward TCLP model.

21.2 Qualitative Overview of IRP Findings

What follows is a conceptual overview of our findings followed by specific recommendations for a portfolio of new generation resources that can be procured to allow TCLP to achieve its goal of serving its entire load using renewable energy sources while still meeting its capacity obligations to MISO.

Renewables can be used to supply the electricity required by TCLP on a yearly basis with relative economic efficiency. Depending on the price of development, new renewable energy projects may be immediately profitable given the comparatively low LCOE of renewables when compared to other sources of power. However, given MISO's capacity construct for renewables, the capacity value of those renewables would not be sufficient to meet its capacity obligations to MISO. To meet its capacity obligations using only renewable sources would require TCLP to contract for far more generation than it would need to meet local demand. Furthermore, we expect the capacity value of renewable generation to decrease as more renewables come online in MISO Zone 7. Unsurprisingly, we find the economic potential of any given renewable asset is highly dependent on what else is built in MISO Zone 7, this applies both to its energy value and its capacity value. This volatility and decline in capacity value of TCLP's renewables portfolio is something that TCLP will need to contend with as it makes decisions around the development of new generation resources.

In all our models, we maintain TCLP's ownership stake in Belle River gas (after its conversion from coal) until the project's expected retirement in 2039. However, we modeled retirement dates of 2030, 2035, and 2040 for TCLP's stake in the Kalkaska Combustion Turbine project which is currently TCLP's single largest source of capacity credits.

Every portfolio STEP Forward generated requires substantial deployment of battery to ensure TCLP's ability to meet its capacity obligations. MISO values battery capacity as the lesser of a battery's power rating or one quarter of its energy rating. This is, by current rules, a stable valuation of battery capacity. It should also be noted that this current valuation of battery capacity incents the development of four-hour batteries (those with energy exactly 4x the power rating of the battery. For instance, a battery with 20MWhs of storage and a 5MW power rating).

Consequently, the trend we see is that the model finds the optimal amount of renewables for TCLP to develop to serve its load, and then backfills any remaining capacity obligation with battery. As modeled, battery's primary economic value is its capacity value. Although, as noted in Section 22.7.1 it is likely our modeling undervalues somewhat the potential revenue from battery operation. Furthermore, as discussed in Section 15.3**,** TCLP's grid-scale battery could be used to provide backup power to key facilities in its service territory, a potentially beneficial service to which we have not attempted to ascribe an economic value in our IRP modeling.

Electrification of heating builds demand in the winter months, even when using high-efficiency cold-weather heat pump technology accompanied by building envelope improvements. This is exacerbated by electric vehicle charging which adds load in all seasons but adds additional load in winter resulting from meaningfully lower EV mileage and charging efficiencies under colder conditions. At a high enough penetration of electrified heating and EV deployment both TCLP's and MISO Zone 7's grid peaks shift into the winter season.

This shift in load from summer to winter and from daytime to nighttime, on top of wind's and solar's relative capacity factors in Michigan (wind performing better than solar), causes our model to prefer the development of TCLP's wind portfolio over solar in most STEP8760 scenarios, as wind is not only a better suited resource to the region, it also performs better during tight hours in a winter peaking grid.

However, wind is increasingly difficult to site in MISO Zone 7 due to localized political difficulties in obtaining siting permits, furthermore, there is a limited maximum technical potential for wind development in the region as wind siting is constrained by the availability of high-quality wind resource. To contend with this reality, we have modeled scenarios where TCLP is unable to contract for new wind, or only able to contract for a small amount of new wind. These scenarios force TCLP to rely heavily or entirely on solar and battery to meet its goals.

Figure 21-1 below shows a heatmap TCLP's projected load in 2040 alongside heatmaps of available capacity in MISO Zone 7 (under one of our STEP8760 scenarios[32]), and the production of an average MW of solar and wind capacity in Michigan. Solar production clearly matches a large portion of the high-demand hours in summer, but it falls off rapidly in summer evenings, and produces almost no power in the winter, when heating demand is high in an electrified future. In contrast, wind's production profile has a less load shape, but does produce during evenings and sees some of its highest production in the most demanding winter hours.

[32] See table 1 in the "STEP8760 Tables" Excel file - scenario abbreviation "bau_ev_conservative_6_6kcons"

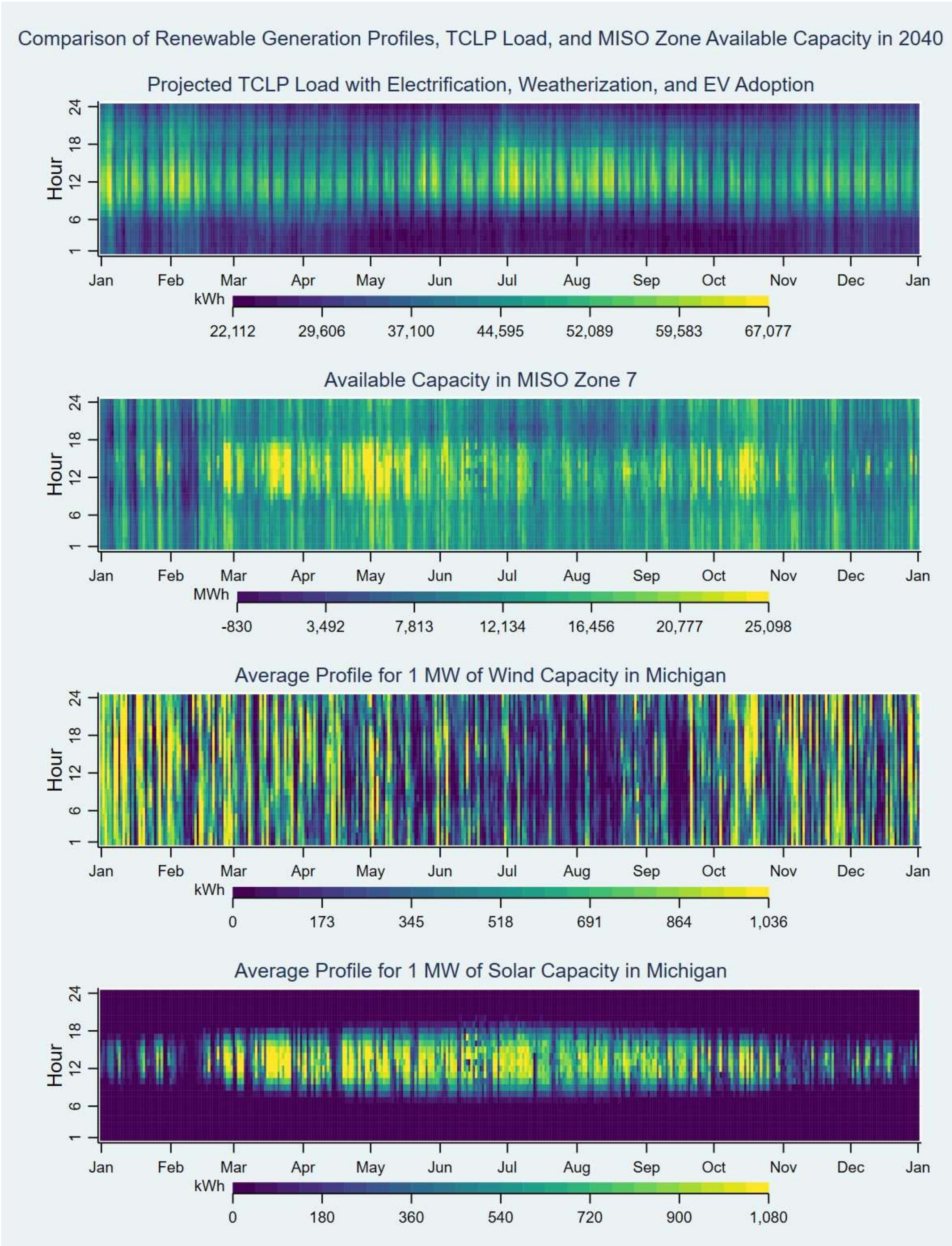

Figure 21-1 Comparison of TCLP load, Zone 7 capacity, and Michigan renewable generation profiles

21.3 Quantitative Overview of IRP Findings

In the process of developing this IRP we performed a wide range of model runs producing varying results in terms of how much generation TCLP will need to procure in each model year to achieve its goal of serving its generation with 100% renewables by 2040, and how much that procurement will cost. In our initial evaluation, we looked at four different electrification pathways for TCLP across four different macro scenarios for MISO zone 7 across four different potential sets of constraints. This produced 64 different model pathways. These scenarios are described briefly below in Section 21.5 and in more detail in Section 22.7.1. These 64 models all produced different results, but some of them are quite similar and in aggregate the give a good sense of the range of resources TCLP likely need.

The figures below represent one hybrid electrification pathway where we assume that in 2025 TCLP's load will look like its 2021 load with the addition of a small amount of vehicle electrification, and in model years 2030, 2035, and 2040 TCLP's load will look like our projected electrification pathway which incorporates building electrification and deep energy efficiency improvements as well as vehicle electrification. We chose this as our preferred pathway because it produced, in our eyes, the results that seemed most realistic given our understanding of TCLP's current trajectory towards achieving its goals. These figures show results from the full array of constraints, as these constraints produced the most variation across models. Finally, the figures show one or more MISO Zone 7 pathways. When only one MISO Zone 7 pathways is shown, it is the most constrained MISO pathway, wherein wind buildout in MISO is limited to 6.6GW by 2040. [33] This is well under the technical potential for wind in Michigan, and well under what unconstrained modeling of the region would expect to see, but this is still more than we would expect if the recent slow pace of Michigan wind development continues.

In Figure 21-2 below the column colors represent different MISO Zone 7 scenarios and each subgraph is a different set of constraints on what resources TCLP can purchase (given the difficulty of siting wind in Michigan), or whether TCLP leaves its stake in the Kalkaska combustion turbine project. Across the scenarios pictured, TCLP enters contracts for 0-150MW of total solar development by 2040 and 0-60 MW of total wind development by 2040. In most cases wind is preferred by the model if its development is not constrained.

In the zone 7 scenario shown by green bars, in the wind constrained cases, the model chose not to build any solar after 2025. This is a high renewables zone 7 scenario in which there is a massive deployment of solar in the rest of zone 7. This makes each marginal MW of solar uneconomic and would require TCLP to expect a loss on solar development to reach its renewable goals. While this is a possible future market environment, the profitability of TCLP's resources will also be subject to the individual contracts for solar that TCLP enters.

As discussed above in the *Qualitative Overview of IRP Findings*, in all scenarios where TCLP succeeds in meeting its new generation and its capacity obligations with non-fossil resources, TCLP must develop substantial energy storage capacity. In most scenarios, this is about 25MW of storage power with 100 or more MWhs of storage energy by 2040. In the scenario where Kalkaska is retired (or contract exited), an additional 30 or more MW of storage capacity are necessary at the time of Kalkaska's retirement.

[33] See table 1 in the "STEP8760 Tables" Excel file - scenario abbreviation "bau_ev_conservative_6_6kcons"

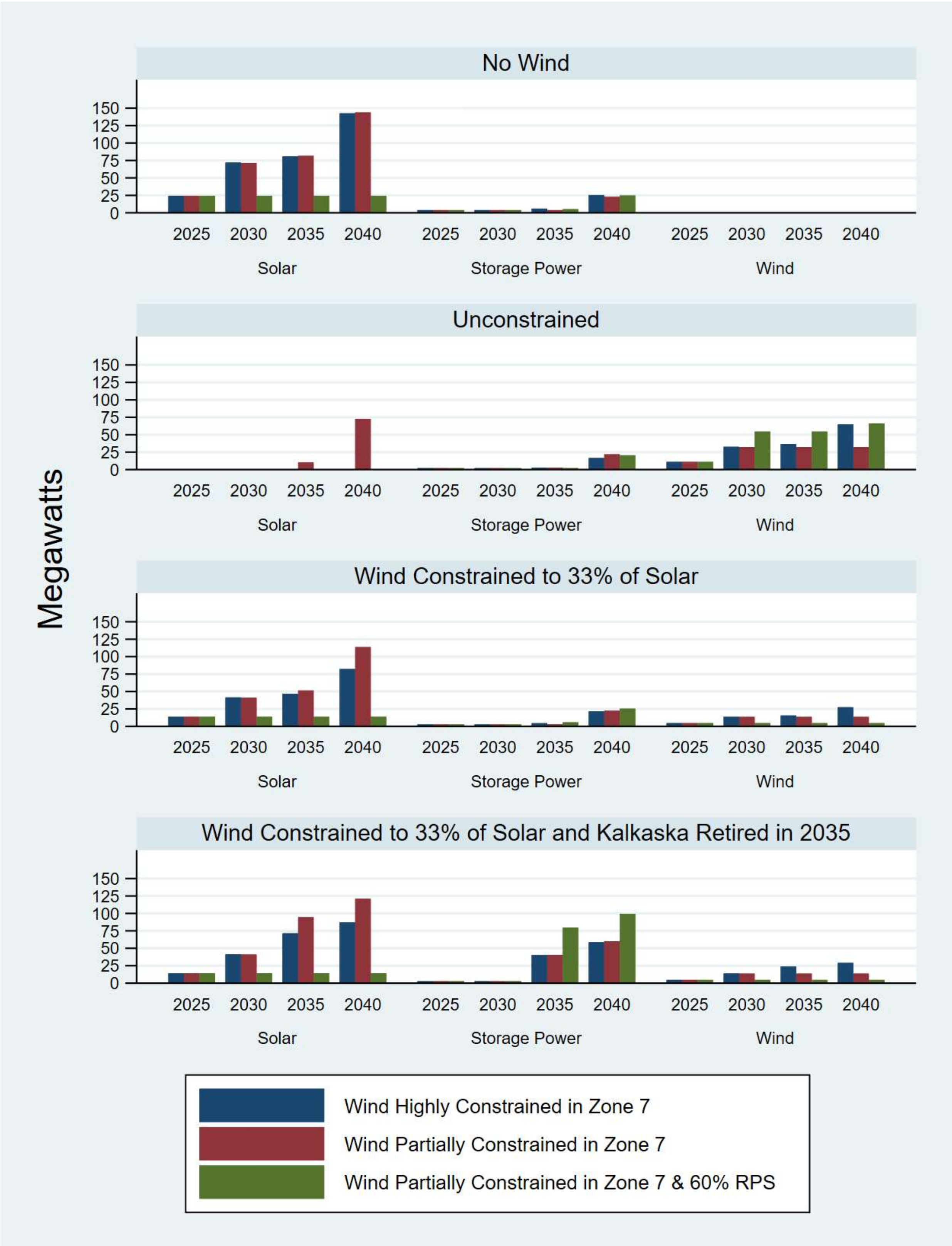

Figure 21-2 Comparison of TCLP optimized new-build portfolios across years, build constraints, and Zone 7 scenarios

In Figure 21-3 and Figure 21-4 below, we see TCLP's generation mix and capacity mix under a single MISO Zone 7 scenario (Wind Highly Constrained in Zone 7). Each subgraph is a different set of constraints on what resources TCLP can purchase, or whether TCLP leaves its stake in the Kalkaska combustion turbine project. These constraints scenarios are described below in Section 22.7.2

What is most notable is the comparison between these two figures. In Figure 21-3, we see the volume of generation from combustion sources is relatively small compared with renewable generation. This results from both Kalkaska and the Belle River natural gas conversion being peakers that provide mostly backup capacity – neither is designed to run all the time. In 2040, even when Kalkaska is still online, its output drops almost to zero. In our modeling, this results from more efficient peaking capacity being brought online between now and then, which is a plausible albeit uncertain scenario.

In Figure 21-4 we see the outsized portion of TCLP's capacity that is provided by thermal generators, namely Kalkaska, and how little capacity solar and wind provide, even when they are most of the generation. This comparison, especially the case showing TCLP's capacity mix without Kalkaska, highlights the difficulty and potential expense of fulfilling TCLP's capacity obligation with renewables and battery, unless the economics of large-scale battery improve dramatically.

Figure 21-5 shows the seasonality of capacity. The detail worth emphasizing here is how little capacity solar provides in the winter. This is unsurprising, given solar's production profile, but it shows the difficulty of meeting winter capacity obligations with a solar dominated generation portfolio in a future with winter peaks resulting from electrified heating.

Figure 21-4 and Figure 21-5 both show solar's capacity dropping off rapidly between 2025 and 2030. This results from our Zone 7 model building out large amounts of solar during this period. There is a chance that Michigan will be unable to build solar as quickly as we have modeled it. Slower deployment of solar across Zone 7 would maintain the accredited capacity of TCLP's solar resources longer than is pictured in these figures.

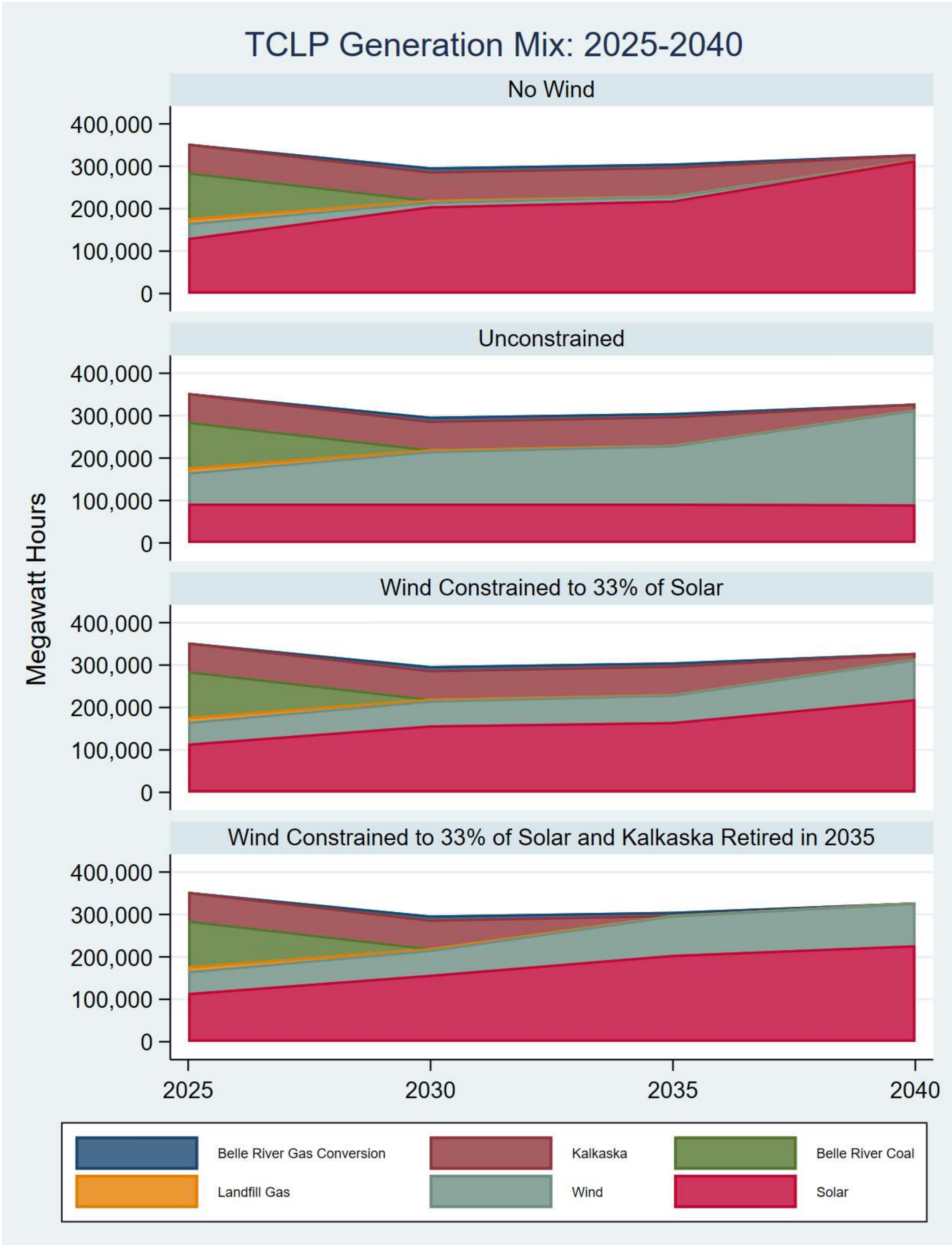

Figure 21-3 Stacked area comparison of TCLP generation mix across years and build constraints

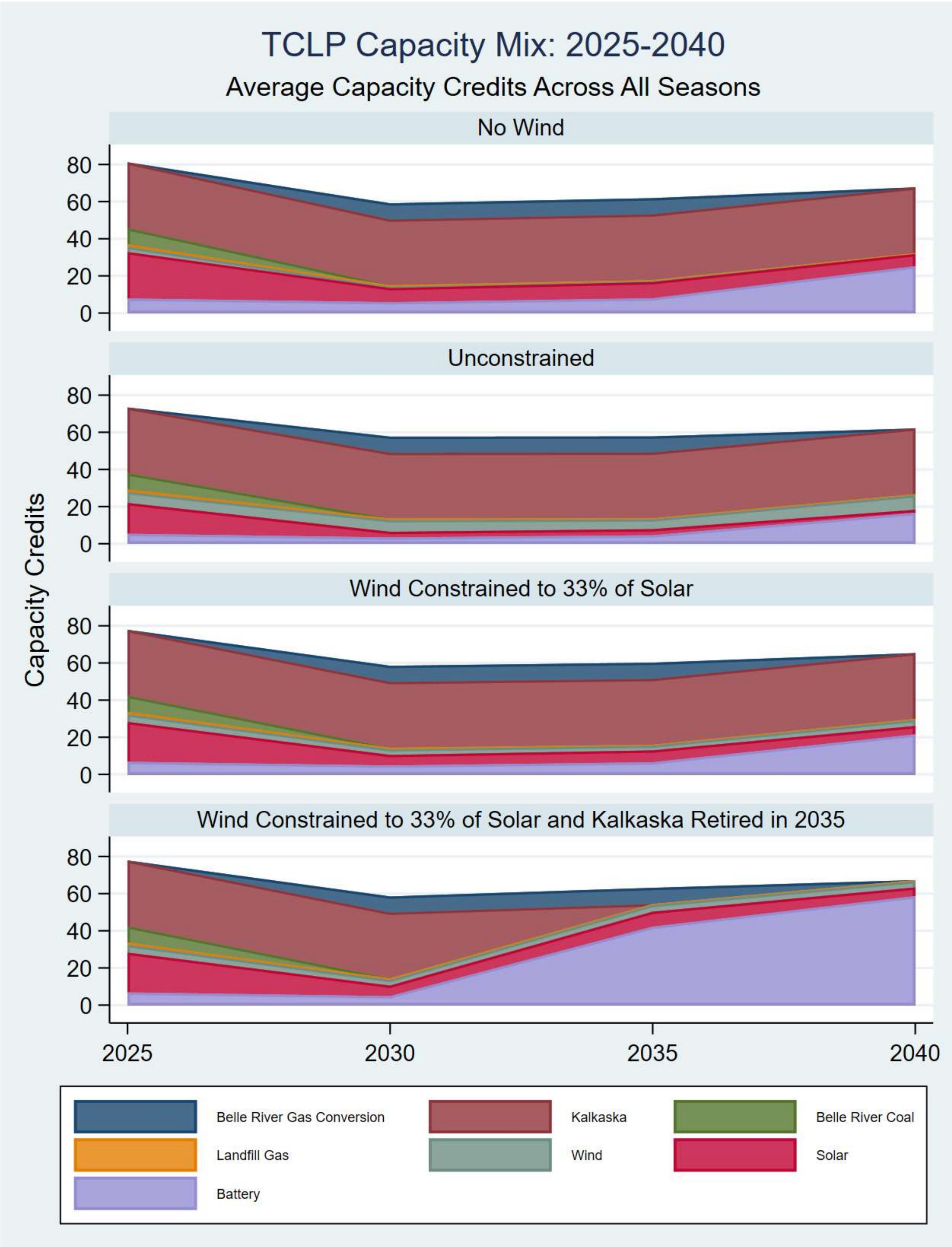

Figure 21-4 Stacked area comparison of TCLP capacity source mix across years and build constraints

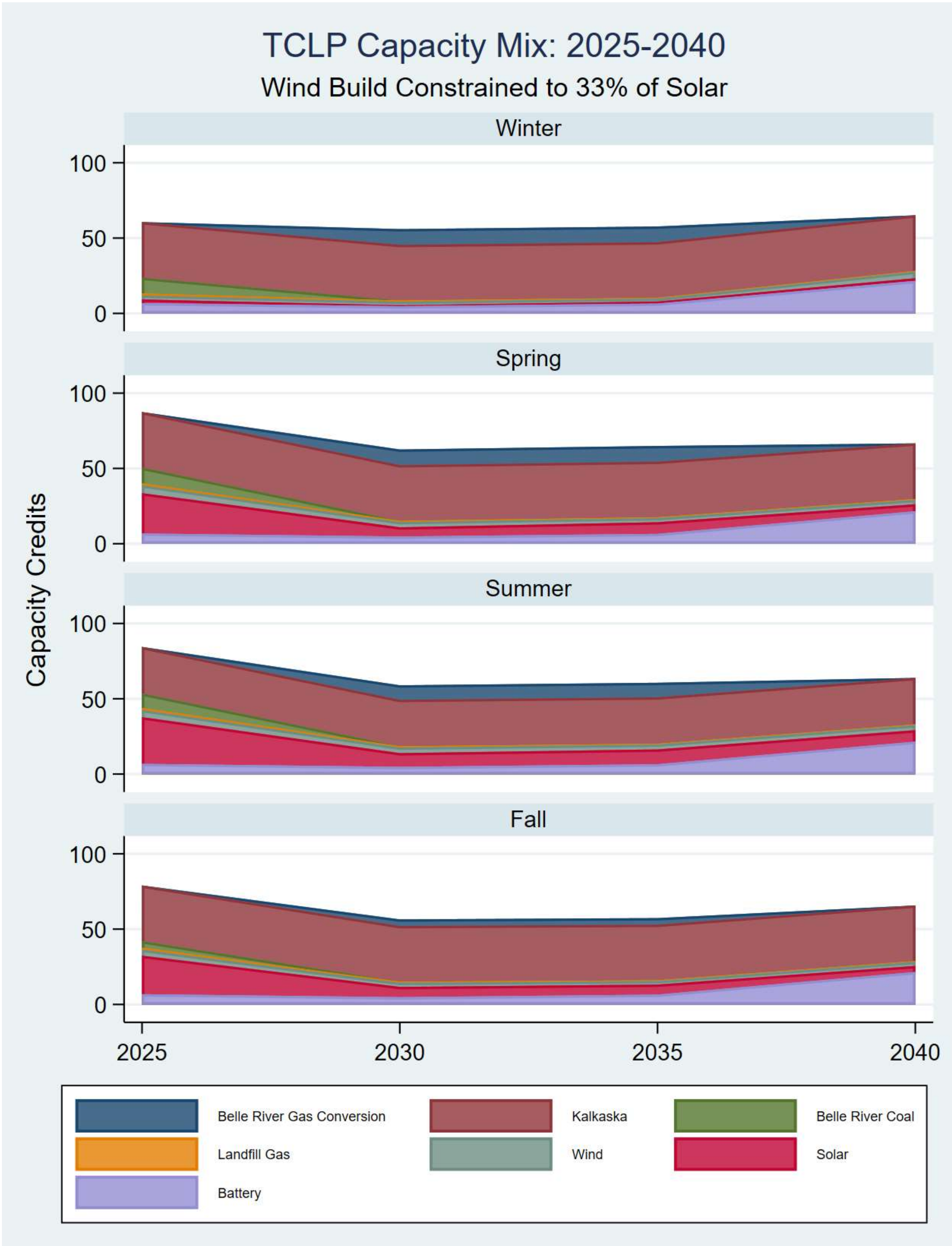

Figure 21-5 Stacked area comparison of TCLP capacity source mix across years and seasons

21.4 IRP Recommendations

21.4.1 Approach

A small utility like TCLP should take advantage of its ability to develop its power supply reactively, in a way that larger utilities may be unable. In an environment where storage and demand-side management is expensive and limited, renewable generation sources have the unfortunate property of devaluing the marginal unit of same resource. That is, each MW of solar competes with all other solar in the region and drives down both its capacity value and the wholesale value of its production. The same is true of wind, but to a lesser extent, as the times at which wind produces are less uniform across space.

This implies that TCLP should work to acquire the less-developed resource. We expect that this will be wind. With the understanding that new wind generation projects in MISO Zone 7 are hard to come by, we still encourage TCLP to explore what options are available. Specifically, TCLP should attempt to maintain a stake in the Stoney Corners Wind Farm if it is repowered.

Inevitably, TCLP will need to serve a portion of its demand with new solar projects. Given the assumption that more solar will be developed in Zone 7, devaluing existing solar, sales contracts structured like TCLP's contract with M-72 Solar III, wherein TCLP purchases power at the price of LMP should be preferred over riskier fixed-price or accelerating-price contracts that often, in later years in our modeling, lose money.

In every modeling scenario, if TCLP wants to meet its capacity obligations with clean resources, it will need to acquire some storage assets. Battery storage is still an expensive source of capacity. To the extent that it is possible, TCLP should maximize the value of storage by siting it locally and taking advantage of all possible revenue streams from storage, including use of battery in a future potential microgrid services programs.[34]

21.4.2 Build Quantities

As will be evident in the recommended build quantities for wind and solar, the two resources are not one-to-one tradeoffs, even at the level of energy production. This is due to their different capacity factors. In our model, a standardized MW of wind produces 3448.6 MWh of energy a year (a capacity factor of .393), and a standardized MW of solar produces only 1565.3 MWh (a capacity factor of .179). That is, a MW of wind produces about 2.2 more energy than a MW of solar in MISO Zone 7. When considering the build values below, and how a mix of renewable resources might be deployed to serve TCLP's demand, this ratio can be used to weigh tradeoffs in value.

- Wind – As discussed above and elsewhere in this report it is unlikely TCLP will be able to enter contracts for enough wind to supply all its new demand. However, our unconstrained models (those allowing for as much wind as the model wants) find TCLP is able to fulfill all of its needs in 2040 with 60-80 MW of new wind contracts with up 30-40MW of those necessary by 2030.
- Solar – If TCLP is unable to contract for any wind, it will require 140-200MW of new solar contracts by 2040 with 70-115MW necessary by 2030.
- Battery Storage – Across all scenarios, those with all wind, all solar, or a mix of generation. 25-50 MW of battery storage power by 2040, with 5-15MW deployed by 2030. In our modeling, batteries stored 2-6 MWhs of energy per MW of power output.

[34] See Section 15.3

21.4.3 Exiting All Fossil Contracts

In the short to medium term, we do not recommend TCLP prematurely exit its contracts with Kalkaska or Belle River. As discussed above, Kalkaska especially provides a large portion of TCLP's capacity. In the current storage market, replacing that capacity with standalone lithium battery storage would be economically untenable. However, we recommend TCLP reevaluate this option in future IRPs as storage technologies and supply chains develop. It is possible that this option will be more feasible in the future.

We recommend first acquiring sufficient renewable resources to meet TCLP's energy requirements in excess of current resources, on an annual basis, then considering the potential resources to replace either Belle River or Kalkaska.

21.5 Technical Overview of IRP Modeling

21.5.1 STEP8760

21.5.1.1Model Summary

STEP8760 is a model developed by 5 Lakes Energy which can be calibrated to different wholesale markets to estimate the price of power in each hour of the year as well as project the lowest-cost resource mix for the region given a future load, expected resource prices, and user-defined constraints.

As a MISO market participant TCLP is affected by MISO's power pool prices. Power imports from the rest of MISO to the Lower Peninsula of Michigan (MISO Zone 7) are limited by transmission capacity so power prices in MISO Zone 7 are largely determined by the resources within Zone 7. Given TCLP's small size, load and generation resources are unlikely to materially affect power prices in MISO Zone 7. For this reason, 5 Lakes Energy has performed TCL&P transmission and resource modeling with TCLP as a "price taker" in Zone 7.

In its calibration for this IRP, STEP8760 uses existing Zone 7 resources and the resources to be added in the 2020s in Consumers Energy's and DTE Electric's most recent IRPs. Likewise, it factors in any retirements projected in those same IRPs. From this generator mix STEP8760 calculates the least-cost resource portfolio that meets requirements in a selected future year in MISO Zone 7. We model an 8760-hour year with a system-wide hourly load profile and hourly generation from existing and potential new non-dispatchable resources, schedule dispatchable resources in merit order and compute the resulting power pool energy price, then optimally schedule available storage and redispatch other resources considering load shifts resulting from storage operations. Existing resources in a projected year include both those that currently exist and not scheduled for retirement by the model year and those considered in the modeling scenario as planned to become operational before the model year. STEP8760 then calculates the optimal (least-cost) mix of new generation and storage resources to be added by the model year through a numerical search for the least-cost solution subject to specified constraints.

In our IRP modeling for TCLP, 5 lakes energy modeled 11 different Zone 7 scenarios in 4 model years (2025, 2030, 2035, 2040) using a range of assumptions about the following variables:

- new generation resources costs
- fuel costs
- politically defined renewable energy targets
- demand growth resulting from vehicle and building electrification
- retirement dates for thermal generators
- constraints on the development of new wind in Michigan

A more comprehensive description of the STEP8760 model including input values and constraints for each scenario are available in Section 22.7.1.

21.5.2 STEP Forward TCLP

21.5.2.1STEP Forward TCLP Model Summary

We modeled eleven distinct scenarios in STEP8760 resulting in four MISO Zone 7 hourly price and demand profiles for each scenario - one for each year modeled (2025, 2030, 2035, and 2040).[35]

Of these eleven STEP8760 scenarios, we selected four to move forward into our STEP Forward TCLP model.[36] The selected scenarios and their parameters can be seen in Table 1 in the "STEP8760 Tables" Excel file. The STEP Forward TCLP model estimates TCLP's generation, transmission, and capacity portfolio costs including the least-cost optimized set of additional generation and capacity resources given the 8760 demand and market price profiles produced by STEP8760. STEP Forward TCLP also models emissions and their social costs to the climate and health. Although, we do not account for these costs in our optimization functions, these values help illuminate the benefits of TCLP reducing its reliance on fossil fuels.

21.5.2.2 STEP Forward Dollar Values

The results from STEP Forward modeling are given in nominal dollars. Many of TCLP's existing generation contracts include future nominal dollar costs or specific price accelerators. Rather than convert these contract values into real dollars, we found the future value of all modeled costs (being originally in real dollars), using an inflation rate of 2.2%.

21.5.2.3 STEP Forward TCLP Electrification Pathways

STEP Forward TCLP evaluates four different electrification pathways across the four different model years (2025, 2030, 2035, 2040) optimized in the STEP8760 model. Thus, we evaluate 16 unique projected TCLP hourly load profiles under four different MISO Zone 7 scenarios and four different sets of external constraints on what generation TCLP might reasonably be able to acquire (see following section).

The four electrification pathways are:

- Business as Usual (BAU)—The hourly demand profile in the BAU pathway is TCLP's actual 2018 hourly demand profile scaled to TCLP's total 2021 demand with additional demand applied based on our projected vehicle charging demand outlined in Section 11.2. This pathway makes no assumptions about building electrification or additional energy efficiency measures.
- Projected Electrification Pathway (PEP)—The PEP pathway uses modeled load profiles based on local ResStock and ComStock data which incorporates our expected electrification and energy efficiency measures for each model year. This pathway also includes identical vehicle electrification assumptions as those included in the BAU pathway.
- Net Zero Electrification Pathway (NZEP)—The NZEP pathway uses modeled load profiles based on local ResStock and ComStock data similar to the PEP pathway, but the NZEP pathway assumes total electrification of the TCLP service territory by 2050. This pathway also includes identical vehicle electrification assumptions as those included in the BAU pathway.
- Combined BAU and PEP—After looking at the results from modeling the three pathways above, we determined that the PEP pathway assumed an unrealistic amount of energy efficiency

[35] Detailed in Section 22.7.1.

[36] Detailed in Section 22.7.2.

deployment by 2025, given when we can reasonably expect TCLP to adopt and deploy aggressive efficiency programs. As a result, we created a combined pathway that uses the BAU TCLP demand profile for model year 2025 and the PEP demand profile for the following model years. This assumes a rapid, but plausible ramp-up of efficiency programs around the year 2025 and into the following years.

21.5.2.4STEP Forward TCLP Constraint Scenarios

When we ran STEP Forward TCLP without any constraints on what types of renewable generation TCLP could reasonably source, under most circumstances the model had TCLP buying predominantly new wind. Recognizing that this might be difficult, given how difficult wind siting has become in Michigan, we modeled two scenarios constraining TCLP's access to new wind development.

In one scenario we assume TCLP will have no access to wind development deals and will need to serve its load with solar alone. In the other, we hold wind development to a maximum of one third of solar development by nameplate value of build.

Finally, we modeled the retirement of Kalkaska, or TCLP's withdrawal from its contract with the generator. This allowed us to see the cost of replacing Kalkaska's capacity and generation with renewables and battery.

22 Appendices

22.1 Load Profile Input Data

22.1.1 TCLP Customer Classes

In 2021 TCLP used 45 unique rates with 65 unique rate descriptors. Many of these rates share a base tariff but include different riders for different degrees of commitment by the utility to serve the ratepayer's load with green power. For instance, rates R1, R2, R3, and R4 are residential rates with riders for 100%, 75%, 50%, and 25% green power respectively. To aggregate customers by use-pattern for more substantive analysis, these rates were bucketed into eight distinct rate classes as shown in the figure below. Notably, public authority loads, apart from pumping load which have been separated into their own categories, were bucketed into the commercial rate class, consistent with how TCLP reports these loads to the EIA.

Residential		Commercial		Primary	
Description	Rate	Description	Rate	Description	Rate
Garage - Residential	R	Amplifier Rate	AM	Industrial - No Intermediate Read	I1
Garage - Residential Green 100%	R1	Commercial - Elec Heat & A/C	C1	Industrial Green 100%	I0
Garage - Residential Time of Use	T-Gar	Commercial - GS	C		
Garage - Senior Citizen	SR	Commercial - SPCR	CE	Pumping Primary	
Garage - Senior Space Heat	SS	Commercial - Water Heater	CH	Description	Rate
Garage-Water Heater	RH	Commercial Green 100%	M1	MP - 2 SPCR	PE
Res. Senior Life Support	91	Garage - Commercial	C	Public Authority MP - 2	P2
Residential	R	Public Authority Green 100%	PO		
Residential - Time of Use	T	Street Lighting	GV	Commercial Demand Primary	
Residential Green	RG	Temporary - Commercial	C	Description	Rate
Residential Green 100%	R1	VGP Flat Rate St Light	VS	Commercial Demand Primary	D3
Residential Green 100%	T1	Yd Lights - Commercial	C		
Residential Green 25%	R4	Yd Lights - Commercial EH & A/C	C1	Metal Melting	
Residential Green 50%	R3			Description	Rate
Residential Green 75%	R2	Commercial Demand		Metal Melting	MM
Residential Life Support	90	Description	Rate		
Residential Space Green 100%	T1	Commercial - GSO	CD		
Residential Space Heat	RS	Commercial Demand - City Solar	DE		
Residential Water Heat	RH	Commercial Demand - SPCR	DE		
Senior Citizen	SR	Commercial Demand Green	G1		
Senior Green 100%	O1	Commercial Demand Green 100%	G1		
Senior Green 25%	O4	Commercial Demand Green 25%	G3		
Senior Green Rate 75%	O2	Garage - Commercial Demand	CD		
Senior Space Heat	SS	Yd Lights - Commercial Demand	CD		
Senior Space Rider 100%	U1				
Senior Space Rider 50%	U3	Pumping			
Senior Water Heat 100%	W1	Description	Rate		
Senior Water Heater	SH	MP-1 SPCR	ME		
Temporary - Residential	R	Public Authority Green 100%	P0		
Time of Use - VGP 100%	1T	Public Authority MP - 1	P1		
Water Heat Green 100%	H1				
Yd Lights - Residential	R				
Yd Lights - Residential Water Heat	RH				
Yd Lights - Senior Water Heat	SH				
Yd Lights-Senior Citizen	SR				

Table 22-1 Rate to modeled rate class crosswalk

22.1.2 TCLP Billing Data

Data from TCLP's billing system was used for three primary purposes in this analysis:

Rate schedules and AMI system multipliers were contained in the billing system but not in the AMI system. Unique account, location, and meter numbers are shared between the TCLP's billing and AMI systems such that AMI data can be joined with billing data using these unique identifiers, alone or in conjunction.

Summary data from the billing system allowed us to produce scaling factors for the aggregated rate class load profiles where accounts were missing from the AMI dataset used. These scaling factors are presented in the following appendix *TCLP AMI Data.*

Address data from TCLP's billing system was used to determine the ComStock building type mix for TCLP's commercial and commercial demand customers. Discerning the ComStock building type of any given address required the address be searched on Google Maps and viewed using street view, then judged using subjective visual criteria as well as knowledge of the business's activities. In some instances, business activities are obvious, in others, they were discovered using further web-based research.

Due to the time-intensive nature of this identification process it was not practical to characterize each building on a commercial or commercial demand rate. Therefore, we characterized a sample of TCLP's customers through the following process: for each class, a list of customers was identified and sorted randomly using a randomization function in the statistical analysis software Stata. Once randomized, the buildings at the customers' billing addresses were characterized in order. This process was performed in samples of 25 customer increments. After each 25 customers were characterized, the load for sample buildings in each building type was summed and compared to the sum of load for each building type from the accumulated previous increments. Sampling was concluded when the relative load of each building type was similar that of the prior accumulated sample. For both classes sampled, we concluded sampling after characterizing 300 accounts in that class.

Not all sampled accounts were associated with buildings fitting neatly into a ComStock category. Some accounts were tied to parks and parking garages, and presumably only metered lighting and plug loads; other accounts were apparently tied to outdoor equipment, such as one account owned by AT&T. These accounts were classified as "other." A different set of issues arose accounts associated with building form factors not covered by ComStock models. These building types were categorized into descriptive categories, the largest of which were "midrise apartment" and "retirement community." How "other" and non-conforming building types were treated for modeling purposes is described in Section 22.1.5.5.

22.1.3 TCLP AMI Data

At the start of 5LE's engagement with TCLP we received 15-minute AMI demand data for most (missing data explained below) TCLP customers for the test year 2021. Most analyses in this report were performed at the hourly level. The 15-minute data were transformed into hourly load profiles for each customer by averaging the data points within each hour.

TCLP had substantially, but not entirely, rolled out AMI meters for its service territory by the beginning of 2021. This caused most of the gaps in our data, but some unrelated issues are also noteworthy. The gaps in 2021 AMI data are as follows:

Of TCLP's over 13,000 customers, around 1,600 meters were entirely missing from the AMI data analyzed. Most of these were residential accounts.

December 31st was missing for all customers.

Most customers on primary rates (receiving power at the distribution voltage), including TCLP's single largest customer, did not have AMI meters set up until dates between mid-February and late April. Consequently, their load profiles were substantially incomplete.

Most customers show no AMI data for 8-12 hours over the night between September 13th and 14th, and again for a shorter period in the early morning of September 27th. We assume these missing data are a product of maintenance or an accidental outage of TCLP's AMI system, as a system-wide power outage would be evident at the same hours in MISO's settled load data, and it is not.

Around 80 data points had negative load values of nearly 10,000 kW. These values were discarded as AMI errors.

To deal with data gaps, 5LE employed several techniques. These techniques were employed in the following order:

To replace missing data for the partial-year accounts on primary rates, we used AMI load data for these customers from the same period in 2022, adjusted to align the day of the week correctly. No adjustment was made for air temperature, but we assume that the space heating load for these primary customers is largely served with natural gas, and the window of days we applied this technique to replace was primarily during the heating season. It is also possible that this technique overestimated the amount of business being done by primary customers, as COVID-19 may have been negatively affecting some businesses.

In each hour of the year, for each rate class, we recorded the number of accounts that were included in the aggregate load for that rate class. This allowed us to know if every account was accounted for in each hour. If a given hour had fewer than the total number of customers in the AMI dataset for that class, the value in that hour was scaled up by the appropriate fraction of a modeled load profile using the following equation:

$$Load_{filled} = Load + Load_{predicted} * (Accounts_{missing} / Accounts_{total})$$

Where an hour had no load data, that data point was filled using our modeled ($Load_{predicted}$). The modeled load was generated using the predicted values from the following multiple-regression equation:

$$Load_{predicted} = Intercept + \beta_0 * temperature + \beta_1 * weekend + \beta_{2\text{-}25} * hour_i + \varepsilon$$

In this equation, "*i*" is the values 1-24 with each hour constructed as a dummy variable, *weekend* is a dummy variable for whether it is a weekday or weekend, and *temperature* is the air temperature.

After all missing data were filled, the residential, commercial, commercial demand, primary, and pumping rate classes were scaled to the stated sales for that class as calculated from the billing data. Monthly billing for power does not correspond to calendar months. As a result, some accounts have eleven months billed in 2021, and others have thirteen. For rate classes containing a high volume of accounts, we assume that these discrepancies average out across the class and thus represent a nearly accurate accounting. For the metal melting, commercial demand primary, and pumping primary rate classes, we know that we have accurate AMI data for all accounts in the non-missing periods. Thus, for metal melting and commercial demand primary, we scaled the periods prior to having accurate data to the mean load during the periods where we do have accurate data. This was an unserviceable technique for pumping primary, as this rate class is highly seasonal. This rate class was left unscaled.

	Scaling Factor	Hours Scaled
Commercial	1.063	All
Commercial Demand	1.014	All
Primary	0.985	All
Pumping	0.952	All
Residential	1.163	All
Commercial Demand Primary	0.955	<2004
Metal Melting	1.018	<1334
Pumping Primary	1	<2773

Table 22-2 Rate class scaling factors

22.1.4 TCLP Distribution Losses / Unaccounted-for Load

We initially attempted to use data from the combined loads at different distribution levels to calculate loss coefficients based on energy use using standard methodologies. However, because our data set was incomplete, and we were forced to scale our loads based on load totals from billing data, we were never able to come up with technically plausible loss coefficients using mathematical methods. Consequently, we applied losses, which we termed "unaccounted-for load," evenly across all hours. This constant value was calculated as: *(EnergyPurchasedFromMISO - EnergySoldToCustomers) / 8760*.

22.1.5 Hourly End Use Load Profile Development

22.1.5.1 ResStock and ComStock End Use Load Profile (EULP) Datasets

For this project, 5LE relied on a national database of end-use load profiles (EULP) representing multiple building types, end uses, and fuel types in the U.S. commercial and residential building stock. Developed by the National Renewable Energy Laboratory (NREL), this publicly available database incorporates profiles which were simulated using physics-based "ResStock" and "ComStock" building energy models. These building models have been calibrated and validated against an array of empirical datasets. In all, this database reflects the output of nearly 550,000 residential building models and 350,000 commercial building models. ResStock and ComStock reflect a full calendar year of times series energy consumption reported in 15-minute increments for multiple end use categories and building types.

ResStock and ComStock building types align with definitions found in the U.S. EIA Residential Energy Consumption Survey and Commercial Building Energy Consumption Survey. ComStock types include all but two of U.S. DOE's sixteen commercial reference buildings which represent approximately 70 percent of commercial buildings in the United States (Source: Technical Report NREL/TP-5500-46861, "U.S. Department of Energy Commercial Reference Building Models of the National Building Stock," February 2011). Table 22-3 lists the five residential and fourteen commercial building types reflected in the ResStock and ComStock datasets.

ResStock Building Types	ComStock Building Types	
Mobile Home	Full Service Restaurant	Medium Office
Multi-Family 2-4 units	Quick Service Restaurant	Small Office
Multi-Family 5+ units	Large Hotel	Primary School
Single Family Attached	Small Hotel	Secondary School
Single Family Detached	Hospital	Retail Standalone
	Outpatient	Retail Strip Mall
	Large Office	Warehouse

Table 22-3 Building Types Represented in the ResStock and ComStock Datasets

General information and technical details about the ResStock and ComStock EULP datasets is available at https://www.nrel.gov/buildings/end-use-load-profiles.html. Details on the methodology behind the datasets are in the NREL Technical Report: Wilson et al. 2021. End-Use Load Profiles for the U.S. Building Stock: Methodology and Results of Model Calibration, Validation, and Uncertainty Quantification. NREL/TP-5500-80889. https://www.nrel.gov/docs/fy22osti/80889.pdf.

22.1.5.2 ResStock and ComStock Dataset Retrieval

ResStock and ComStock data are available as pre-aggregated load profiles in comma-separated variable files which are easily converted to Microsoft Excel. Separate files are generated for each residential and commercial building type. Within these spreadsheet files, end-use categories and fuel types are reported in separate columns while 35,040 rows represent all 15-minute time periods during the year. These pre-aggregated files are available at various geographic resolutions including county-level for 3,000+ U.S.

counties. ResStock and ComStock hourly profiles for Grand Traverse County, Michigan (county code G2600550) provided the foundation for 5LE's analytical work in support of the team's recommendations for TCLP programming. An exception is that statewide data were used to represent three of the ComStock building types. Two of these (Hospital, Large Office) do not available in the Grand Traverse County dataset, and county-level data for a third (Outpatient Clinic) were found to be incomplete.

Two different years of ResStock and ComStock data are available: one with 2018 weather and one with typical meteorological weather. Building stock characteristics for both data years represent the U.S. building stock in 2018. 5LE opted to use the 2018 weather year as a more realistic representation of outdoor air temperature variability in any given 12-month period.

Electricity and heating fuel consumption in ResStock and ComStock are reported in the common unit kilowatt-hour (kWh) thus making direct comparison of different energy options straightforward.

22.1.5.3 Time Series Adjustment

5LE determined that modeling with hourly time series data (8,760 periods/year) was suitable to inform program recommendations and would be less cumbersome than working with NREL's 15-minute data (35,040 periods/year). Therefore, we created a spreadsheet tool to convert 15-minute data to hourly data and saved separate versions of this tool for each ResStock and ComStock building type with the following filenames:

- ResStock conversion_g2600550_mobile_home
- ResStock conversion_g2600550_multi-family_with_2-4_units
- ResStock conversion_g2600550_multi-family_with_5plus_units
- ResStock conversion_g2600550_single-family_attached
- ResStock conversion_g2600550_single-family_detached
- EULP time series conversion_g2600550_fullservicerestaurant
- EULP time series conversion_g2600550_largehotel
- EULP time series conversion_g2600550_mediumoffice
- EULP time series conversion_g2600550_primaryschool
- EULP time series conversion_g2600550_quickservicerestaurant
- EULP time series conversion_g2600550_retailstandalone
- EULP time series conversion_g2600550_retailstripmall
- EULP time series conversion_g2600550_secondaryschool
- EULP time series conversion_g2600550_smallhotel
- EULP time series conversion_g2600550_smalloffice
- EULP time series conversion_g2600550_warehouse
- EULP time series conversion_mi-hospital
- EULP time series conversion_mi-largeoffice
- EULP time series conversion_mi-outpatient

22.1.5.4 End Use and Fuel Type Categories

5LE further adjusted the NREL datasets by eliminating end use and fuel type categories that we concluded were not meaningful in representing the TCLP customer base. We also assumed natural gas to be the only heating fuel consumed in ResStock and ComStock building types within TCLP service territory. Table 22-4 and Table 22-4 show the resulting lists of ResStock and ComStock end use and fuel type categories.

Residential End Use Categorization		
End Use Function	**End Use Service**	**End Use Category**
HVAC	Space Cooling	out.electricity.cooling.energy_consumption
		out.electricity.fans_cooling.energy_consumption
		out.electricity.pumps_cooling.energy_consumption
		out.electricity.ceiling_fan.energy_consumption
	Space Heating	out.electricity.heating.energy_consumption
		out.electricity.heating_supplement.energy_consumption
		out.natural_gas.heating.energy_consumption
		out.natural_gas.fireplace.energy_consumption
		out.electricity.fans_heating.energy_consumption
		out.electricity.pumps_heating.energy_consumption
	Ventilation	out.electricity.range_fan.energy_consumption
		out.electricity.bath_fan.energy_consumption
		out.electricity.house_fan.energy_consumption
Water Heating and Pumping	Domestic Water	out.electricity.water_systems.energy_consumption
		out.natural_gas.water_systems.energy_consumption
	Hot Tub	out.electricity.hot_tub_heater.energy_consumption
		out.natural_gas.hot_tub_heater.energy_consumption
		out.electricity.hot_tub_pump.energy_consumption
	Pool	out.electricity.pool_heater.energy_consumption
		out.natural_gas.pool_heater.energy_consumption
		out.electricity.pool_pump.energy_consumption
	Other Water	out.electricity.recirc_pump.energy_consumption
		out.electricity.well_pump.energy_consumption
Cooking	Range Cooking	out.electricity.cooking_range.energy_consumption
		out.natural_gas.cooking_range.energy_consumption
	Gas Grill	out.natural_gas.grill.energy_consumption
Appliances: Laundry	Clothes Dryer	out.electricity.clothes_dryer.energy_consumption
		out.natural_gas.clothes_dryer.energy_consumption
	Clothes Washer	out.electricity.clothes_washer.energy_consumption
Appliances: Kitchen	Dishwasher	out.electricity.dishwasher.energy_consumption
	Freezer	out.electricity.freezer.energy_consumption
	Refrigerator	out.electricity.refrigerator.energy_consumption
		out.electricity.extra_refrigerator.energy_consumption
Lighting	Exterior	out.electricity.ext_holiday_light.energy_consumption
		out.electricity.exterior_lighting.energy_consumption
		out.electricity.garage_lighting.energy_consumption
		out.natural_gas.lighting.energy_consumption
	Interior	out.electricity.interior_lighting.energy_consumption
Plug Loads	Plug Loads	out.electricity.plug_loads.energy_consumption

Table 22-4 Revised End Use Categorization for ResStock Building Types

Commercial and Commercial Demand End Use Categorization		
End Use Function	**End Use Service**	**End Use Category**
HVAC	Space Cooling	out.electricity.cooling.energy_consumption
		out.electricity.heat_rejection.energy_consumption
	Space Heating	out.electricity.heating.energy_consumption
		out.natural_gas.heating.energy_consumption
		out.electricity.heat_recovery.energy_consumption
	Ventilation	out.electricity.fans.energy_consumption
Water Heating and Pumping	Water Heating and Pumping	out.electricity.water_systems.energy_consumption
		out.natural_gas.water_systems.energy_consumption
Kitchen Systems	Cooking	out.natural_gas.interior_equipment.energy_consumption
	Refrigeration	out.electricity.refrigeration.energy_consumption
Lighting	Exterior	out.electricity.exterior_lighting.energy_consumption
	Interior	out.electricity.interior_lighting.energy_consumption
Other	Other	out.electricity.pumps.energy_consumption
		out.electricity.interior_equipment.energy_consumption

Table 22-5 Revised End Use Categorization for ComStock Building Types

22.1.5.5TCLP Building Activity Type Composition

5LE concluded that the TCLP Residential customer class could be effectively represented by the five ResStock building types. Therefore, we combined end use profiles from each of the five ResStock pre-aggregated time series files into a single composite file to treat all residential customers together. See spreadsheet file "Scaled ResStock_Total" for these results.

By comparison, ComStock building types, which do not reflect all commercial types in TCLP service territory, were handled separately. To establish how much TCLP load could be represented by ComStock data, 5LE first identified which TCLP customer classes were suitable—these being Commercial and Commercial Demand. We then sampled TCLP accounts from both classes and assigned them to one of the ComStock building types or one of several non-ComStock types. Based on the sampling results presented in Table 22-6 and Table 22-7, 5LE concluded that ComStock data could be applied directly to 90.6 percent of TCLP Commercial load and 68.9 percent of Commercial Demand load. Both tables are adapted from the "Scaling Factors" tab in spreadsheet "TCLP STEP8760 Hourly Load Data_v7".

Building Type		Commercial Customer Class: Sample Total Electricity Use (kWh)	Sample Load Mix		Scaled to 2021 TCLP Class Load (kWh)	2021 TCLP Sample Average (kWh/Account)	Sample Accounts Per Class
ComStock	Primary School	9,230	0.2%	90.6%	59,978	4,615	13.0
	Secondary School	0	0.0%		0	0	NA
	Quick Service Restaurant	43,640	0.9%		283,571	14,547	19.5
	Full Service Restaurant	152,827	3.3%		993,068	30,565	32.5
	Hospital	0	0.0%		0	0	NA
	Outpatient	158,212	3.4%		1,028,062	11,301	91.0
	Small Hotel	326,383	7.1%		2,120,833	13,055	162.4
	Large Hotel	418,514	9.1%		2,719,496	69,752	39.0
	Retail Standalone	326,899	7.1%		2,124,183	17,205	123.5
	Retail Strip Mall	722,237	15.7%		4,693,082	11,111	422.4
	Small Office	356,510	7.7%		2,316,593	8,291	279.4
	Medium Office	911,040	19.8%		5,919,924	56,940	104.0
	Large Office	0	0.0%		0	0	NA
	Warehouse	744,099	16.2%		4,835,145	24,003	201.4
Non-ComStock	Midrise Apartment	171,877	3.7%	9.4%	1,116,851	10,742	104.0
	Religious Worship	23,991	0.5%		155,894	7,997	19.5
	Retirement Community	152,963	3.3%		993,954	50,988	19.5
	Service	0	0.0%		0	0	NA
	Supermarket	28,051	0.6%		182,273	28,051	6.5
	Other	57,655	1.3%		374,641	4,435	84.5
		4,604,129		**100.0%**	**29,917,546**		

Table 22-6 Building Type Sampling Results: TCLP Commercial Class

Building Type		Commercial Demand Customer Class					
		Sample Total Electricity Use (kWh)	Sample Load Mix		Scaled to 2021 TCLP Class Load (kWh)	2021 TCLP Sample Average (kWh/Account)	Sample Accounts Per Class
ComStock	Primary School	129,544	0.3%	68.9%	327,629	129,544	2.5
	Secondary School	2,560,695	6.3%		6,476,214	640,174	10.1
	Quick Service Restaurant	496,383	1.2%		1,255,393	70,912	17.7
	Full Service Restaurant	2,884,654	7.2%		7,295,532	115,386	63.2
	Hospital	43,888	0.1%		110,995	43,888	2.5
	Outpatient	564,964	1.4%		1,428,841	62,774	22.8
	Small Hotel	2,219,246	5.5%		5,612,661	317,035	17.7
	Large Hotel	0	0.0%		0	0	NA
	Retail Standalone	3,600,243	8.9%		9,105,317	102,864	88.5
	Retail Strip Mall	1,626,543	4.0%		4,113,665	52,469	78.4
	Small Office	1,803,818	4.5%		4,562,007	75,159	60.7
	Medium Office	5,658,545	14.0%		14,310,938	131,594	108.8
	Large Office	302,555	0.8%		765,187	100,852	7.6
	Warehouse	5,910,558	14.7%		14,948,299	151,553	98.6
Non-ComStock	Midrise Apartment	1,346,115	3.3%	31.1%	3,404,438	112,176	30.3
	Religious Worship	369,622	0.9%		934,806	123,207	7.6
	Retirement Community	879,490	2.2%		2,224,304	109,936	20.2
	Service	735,291	1.8%		1,859,613	122,549	15.2
	Supermarket	3,225,105	8.0%		8,156,563	645,021	12.6
	Other	5,969,179	14.8%		15,096,557	351,128	43.0
		40,326,439		**100.0%**	**101,988,961**		

Table 22-7 Building Type Sampling Results: TCLP Commercial Demand Class

Table 22-8 reports how much TCLP customer load can be directly represented by the adjusted ResStock and ComStock datasets. Residential, Commercial, and Commercial Demand classes together were 62.1 percent of 2021 TCLP system load. By applying the respective sampling portions of these three classes (100.0 percent, 90.6 percent, and 68.9 percent), we see that 50.9 percent of 2021 TCLP system load are directly represented by ResStock and ComStock building types. And because these three classes comprise the great majority of TCLP customer accounts, they reflect a substantial market for TCLP programming discussed elsewhere in this report.

	TCLP Customer Class		
	Residential	Commercial	Commercial Demand
Class Portion of 2021 TCLP System Load	19.2%	9.7%	33.2%
		62.1%	
NREL EULP portion of sampled accounts	100.0%	90.6%	68.9%
Portion of 2021 TCLP System Load represented by NREL EULP building types	19.2%	8.8%	22.9%
		50.9%	

Table 22-8 Portion of 2021 TCLP System Load Represented by ResStock and ComStock Building Types

22.1.5.6 Representative Account Definition

The next step in 5LE's analytical work was to define a convenient modeling unit of analysis, the "representative account," as the total energy consumed in the service territory by a unique customer class, for all end uses and fuel types, divided by the number of customers in that class. To be clear, this normalized unit of energy usage does not reflect a typical or average customer in an actual setting, but rather an account-level composite of customer class equipment and energy consumption behavior.

For the residential sector, ResStock reports total electricity usage in Grand Traverse County as 7,980 kWh/household. By comparison, 2021 TCLP electricity usage is reported as 6,310 kWh per residential account. Therefore, as shown in Table 22-9 5LE scaled county-level ResStock hourly profiles by a factor of 0.791 (or the ratio 6,310/7,980) to yield a residential representative account with annual total electricity load of 6,310 kWh/year.

ResStock Dataset (Grand Traverse County)			2021 TCLP Residential Use (kWh/Account)	Ratio: ResStock to 2021 TCLP	2021 TCLP Residential Electricity (kWh)	Number of 2021 TCLP Average Accounts
Total Annual Electricty (kWh)	Number of Units (All Building Types)	Average Annual Use (kWh/Unit)				
338,132,163	42,373	7,980	6,310	0.791	59,159,821	9,376.0

Table 22-9 Residential Representative Account Derivation

Representative accounts for the Commercial and Commercial Demand classes were constructed for each ComStock building type by dividing sampled electricity load by the corresponding number of accounts in the sample. Table 22-6 and Table 22-7 report these results under the column heading "2021 TCLP Sample Average (kWh/Account)," which, to be clear, are equivalent to the representative accounts for these two customer classes.

22.1.5.7 Representative Account End Use Load Profiles

The reformatted ResStock and ComStock hourly end use load profiles for electricity and natural usage, resized to the representative accounts by annual electricity consumption, became input data for the TCLP Electrification and Measures Model described in Section 22.2. The following subsections present typical load profile results in visual format.

22.1.5.7.1 Residential End Use Load Profiles for Electricity

To illustrate load profile results, Figure 22-1 8760-hour electricity load profiles for a representative account using natural gas for space and water heatingFigure 22-1 and Figure 22-2 present ResStock electricity load profiles, adjusted and scaled to the representative account level, and modified to compare two different equipment setups: (1) Space and water heating using natural gas; and (2) Space and water heating using electric resistance. Using a common scale for the y-axis makes the dominant effect of electric resistance heating on total electricity consumption obvious.

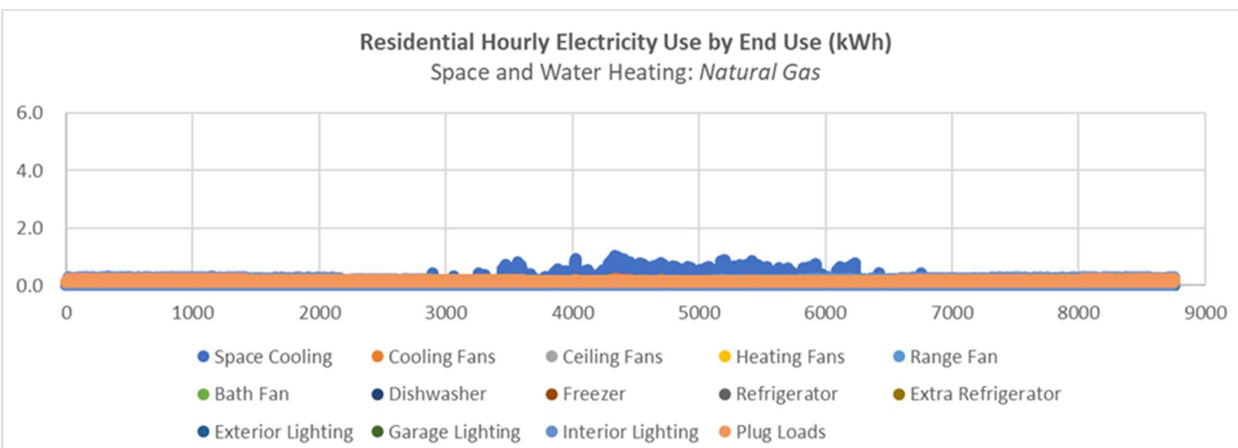

Figure 22-1 8760-hour electricity load profiles for a representative account using natural gas for space and water heating

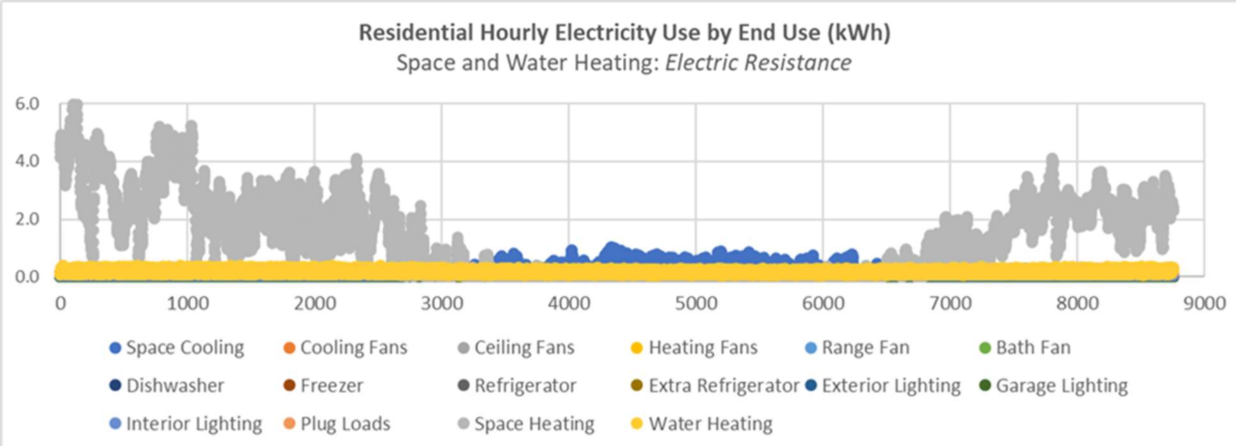

Figure 22-2 8760-hour electricity load profiles for a representative account using electric resistance for space and water heating

Figure 22-3repeats Figure 22-1 using a different y-axis scale so that non-heating end use load profiles are more discernable. From this, the sizeable effect of summertime air conditioning electricity load is clear (but still dwarfed by electric resistance heating when that is used). Although the ResStock data used in our analyses include some electricity consumption for range cooking and clothes drying, the results presented in this section assume, for simplification, that natural gas is used for these end uses.

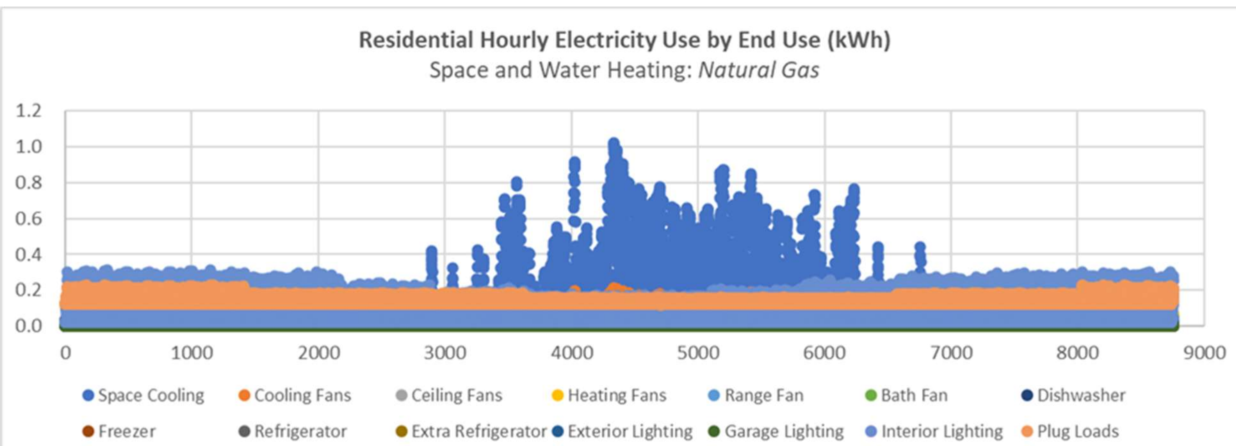

Figure 22-3 Presentation of data shown in Figure 4 using a different y-axis scale.

22.1.5.7.2 Residential End Use Load Profiles for Natural Gas

Similarly for natural gas, Figure 22-4 and Figure 22-5present ResStock natural gas load profiles, adjusted and scaled to the representative account level, and modified to compare two different equipment setups: (1) Space and water heating using natural gas; and (2) Space and water heating using electric resistance. Again, using a common scale for the y-axis shows the dominance of natural gas consumption for space and water heating.

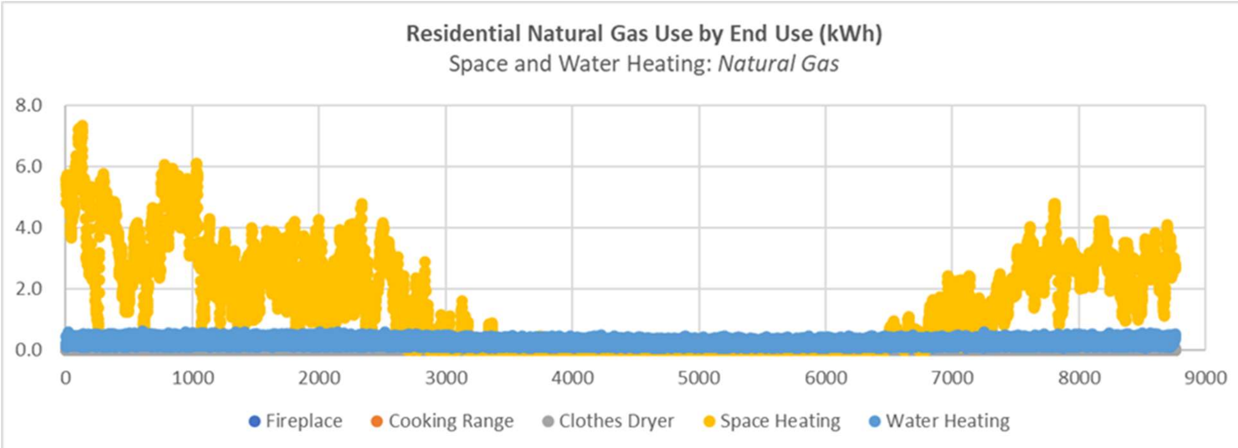

Figure 22-4 8760-hour natural gas load profiles for a representative account using natural gas for space and water heating

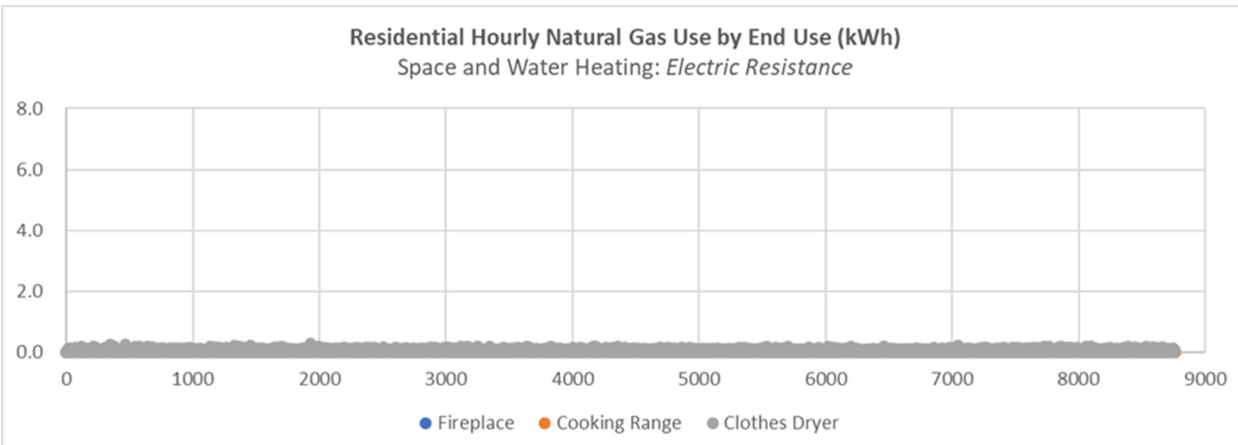

Figure 22-5 8760-hour natural gas load profiles for a representative account using electric resistance for space and water heating

Figure 22-6 repeats Figure 22-5 using a different y-axis scale so that non-dominant end use load profiles are more visible.

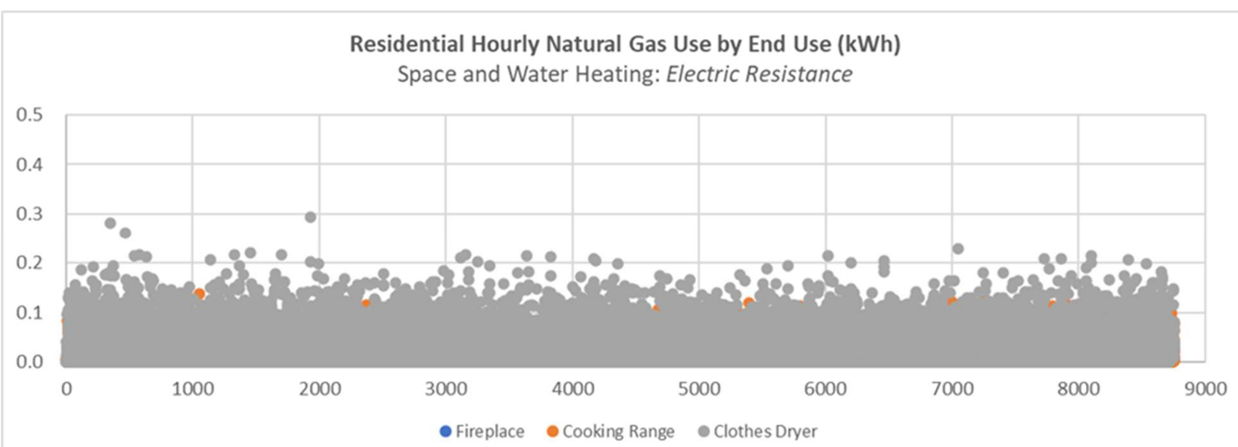

Figure 22-6 8760-hour natural gas load profiles for a representative account using electric resistance for space and water heating

A key observation is that fuel switching from natural gas space heating would have the greatest impact by far on reducing on-site fuel combustion, followed by fuel switching from natural gas water heating. Electrifying any remaining natural gas end uses such as range cooking and clothes drying would have a less significant effect on reducing on-site fuel combustion.

22.1.5.7.3 Commercial and Commercial Demand End Use Load Profiles for Electricity

This section presents 8760-hour load profile results for the Full-Service Restaurant ComStock building type in the Commercial Demand customer class. Figure 22-7 and Figure 22-8 show electricity load profiles for two different equipment setups: (1) Space and water heating using natural gas; and (2) Space and water heating using electric resistance. Using a common scale for the y-axis makes the dominant effect of electric space heating. In this case, the electric water heating load appears similar in size to interior equipment.

Commercial and Commercial Demand Load profiles for the other ComStock-based building types are qualitatively similar to those for the Commercial Demand Full-Service Restaurant. Therefore, for brevity, the corresponding graphs for the other building types are not repeated here.

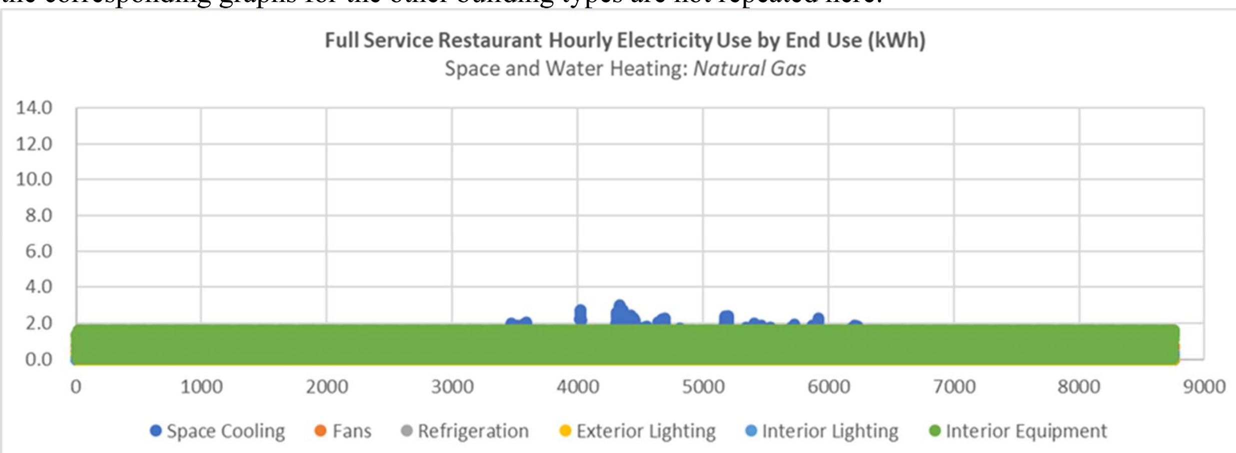

Figure 22-7 8760-hour electricity load profiles for a representative account using natural gas for space and water heating

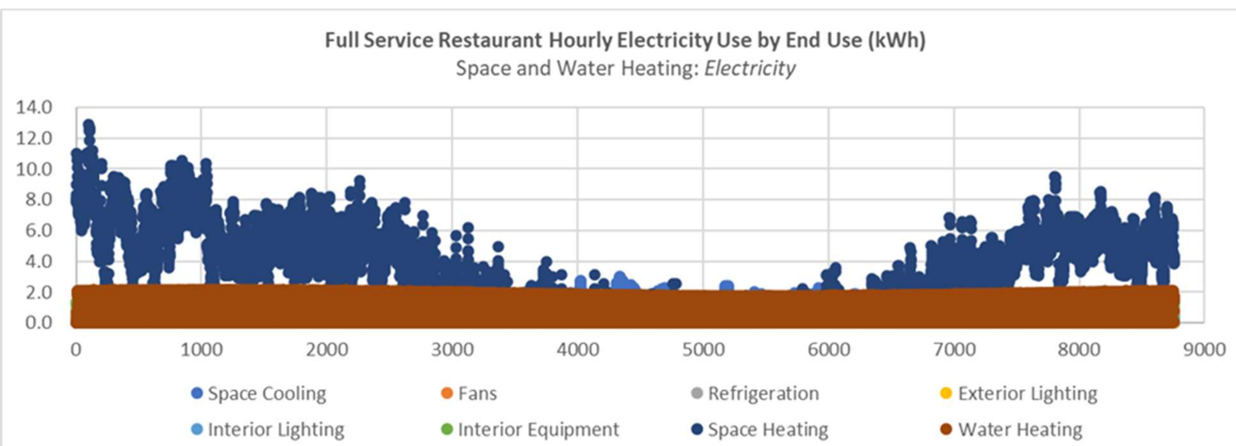

Figure 22-8 8760-hour electricity load profiles for a representative account using electric resistance for space and water heating

22.1.5.7.4 Commercial and Commercial Demand End Use Load Profiles for Natural Gas

Similarly for natural gas, Figure 22-9 and Figure 22-10 present the Full-Service Restaurant natural gas load profiles, adjusted and scaled to the Commercial Demand representative account level, and modified to compare two different equipment setups: (1) Space and water heating using natural gas; and (2) Space and water heating using electric resistance. Again, using a common scale for the y-axis is useful for showing the significant effect of natural gas consumption for space heating. In this case, natural gas consumption for kitchen equipment is actually greater than what is needed for water heating. As a result, electrifying kitchen equipment can have a meaningful impact on reducing on-site fuel combustion in this building type.

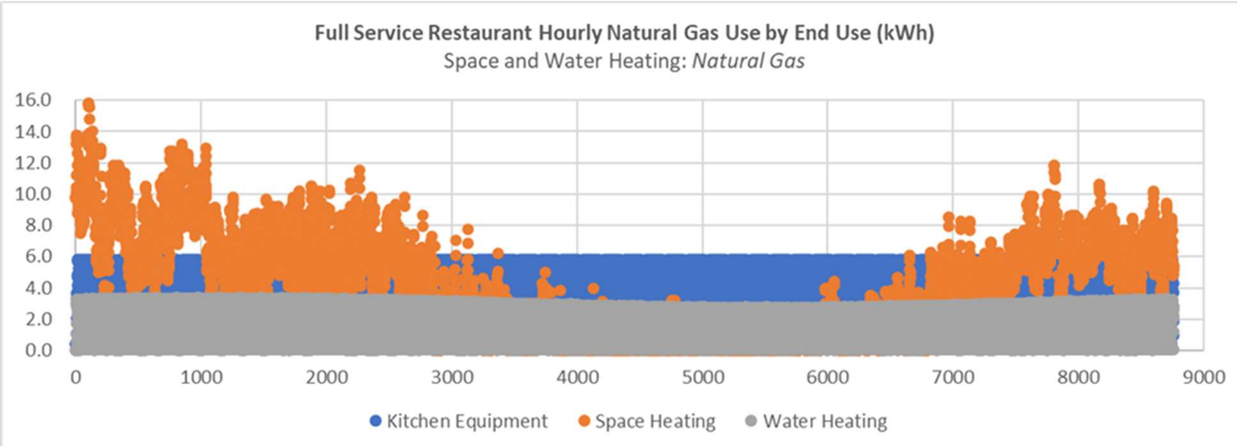

Figure 22-9 8760-hour natural gas load profiles for a representative account using natural gas for space and water heating

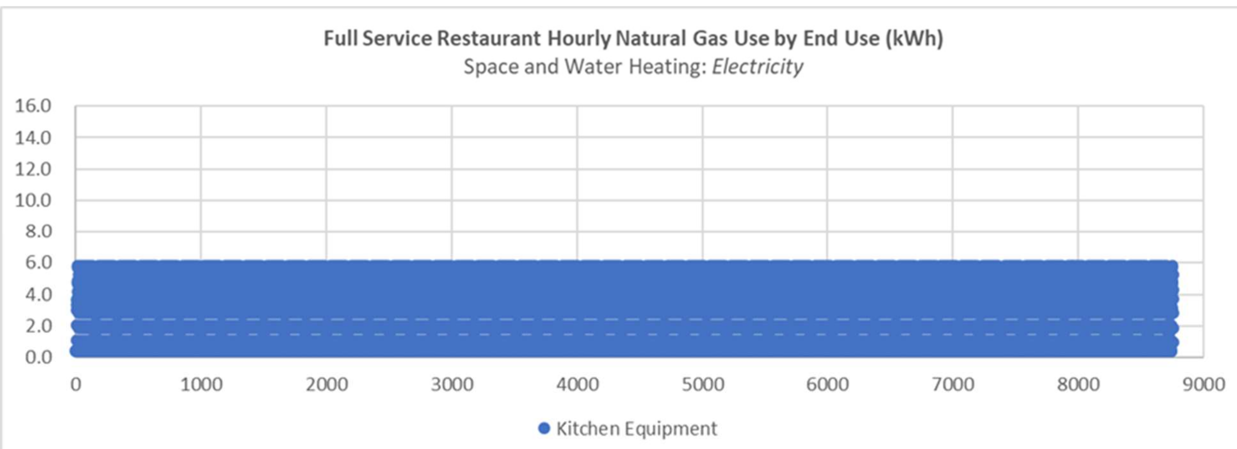

Figure 22-10 8760-hour natural gas load profiles for a representative account using electric resistance for space and water heating

Because some end uses in commercial and institutional buildings are quite regular and repetitive, their energy load profiles can appear as solid bars in 8760-hour graphs as in the four figures above. To better understand the underlying time series data, Figure 22-11repeats Figure 22-10 using a different y-axis scale at which individual data points start to become more apparent. To gain even more clarity, Figure 22-12 restricts Figure 22-11 to the first two weeks of the year. This more granular view makes evident the effect of cyclical building activities on daily and weekly energy consumption patterns common in much of the ComStock data.

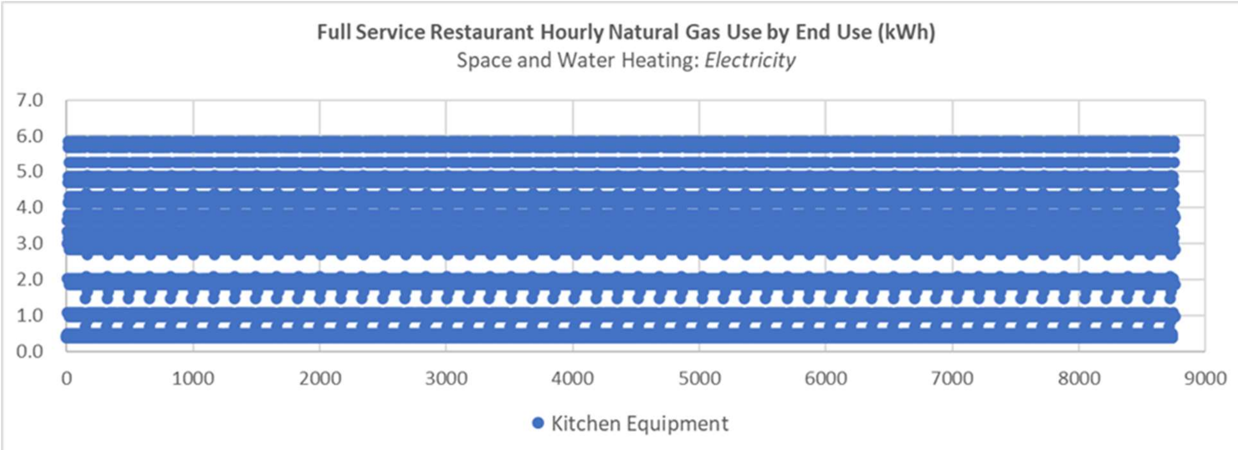

Figure 22-11 Same as Figure 22-10 using a different y-axis scale.

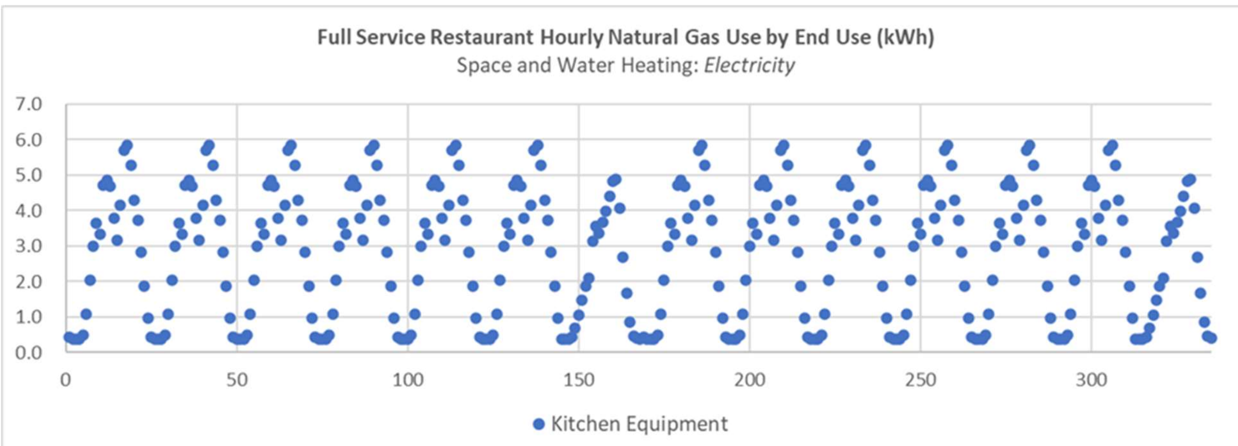

Figure 22-12 Same as Figure 22-11 restricted to the first two weeks of the 8760-hour year.

22.1.5.8 Representative Account Profiles Scaled to 2021 TCLP System Load

To represent a significant portion of 2021 TCLP system load with hourly load profiles generated from ResStock and ComStock data, 5LE computed scaling factors to adjust representative account profiles to the 2021 Residential, Commercial, and Commercial Demand class loads. Conceptually, these scaling factors are equivalent to the number of representative accounts in each customer class. Table 4 reports this figure for the Residential class as 9,376. Tables 1 and 2 report these scaling factors for Commercial and Commercial Demand under the column heading "Sample Accounts Per Class." Results of this scaling exercise by building type appear in the "Load Profiles_2018" tab in spreadsheet file "TCLP STEP8760 Hourly Load Data_v7".

22.2 TCLP Electrification and Measure Model

22.2.1 Purpose and Objectives of the Model

5LE developed an integrated spreadsheet tool, formally called the TCLP Electrification and Measure Model ("the model"), to perform multiple quantitative analyses in support of the team's final recommendations for TCLP programming. This section of the report describes the development and application of the model.

22.2.2 General Architecture and Inputs

The model—of which similar separate versions were developed for the Residential, Commercial, and Commercial Demand customer classes—is a Microsoft Excel spreadsheet built around the imported hourly end use load profiles for each representative account. In the Residential version, all hourly end use load profiles are situated in a single tab. In the Commercial and Commercial Demand versions, load profiles are imported into separate tabs for each ComStock building type. Note that the Commercial and Commercial Demand versions have eleven and thirteen such tabs, respectively, because neither customer class sample included all fourteen ComStock building types. Ultimately, these twelve final versions of the model were used and are available:

- TCLP Measure Tool_Residential_2025 EWR SHELL_v2
- TCLP Measure Tool_Residential_2030 EWR SHELL_v2
- TCLP Measure Tool_Residential_2035 EWR SHELL_v2
- TCLP Measure Tool_Residential_2040 EWR SHELL_v2
- TCLP Measure Tool_Commercial_2025 EWR SHELL_v2
- TCLP Measure Tool_Commercial_2030 EWR SHELL_v2
- TCLP Measure Tool_Commercial_2035 EWR SHELL_v2
- TCLP Measure Tool_Commercial_2040 EWR SHELL_v2
- TCLP Measure Tool_CD_2025 EWR SHELL_v2
- TCLP Measure Tool_CD_2030 EWR SHELL_v2
- TCLP Measure Tool_CD_2035 EWR SHELL_v2
- TCLP Measure Tool_CD_2040 EWR SHELL_v3
-

Note the four year-specific versions for each of the three customer classes.

Beyond the imported hourly end use load profiles, there are key parameters which users can set. Most are located in the "User Inputs" tab. Key parameters relate to equipment selection and performance, economic and financial assumptions, emissions-related health and social costs, and a few other important model settings.

In addition to enabling the numerous user-defined input parameters, 5LE developed several function-specific modules to enable the model to perform various analyses in support of the team's TCLP program recommendations. These capabilities are further explained in the following sections.

22.2.3 Economic and Societal Benefit/Cost Module

A primary objective of our modeling was to establish the potential scope for customer program rebates and offers for various measures that TCLP could make available. This required the computation normalized ratio factors (in the unit $/kWh) by which program alternatives could be assessed and compared. The subsections immediately below describe the modeling elements behind these computations, while later sections discuss the factor computations themselves within the context of specific program areas.

22.2.3.1 Tariff Representation and Selection

The model computes time-sensitive electricity and natural gas variable revenues for each end use load profile and combines these with fixed and demand charges to yield the annual total utility revenue for each representative account. (Or, from the customer perspective, the annual total energy bill is simply the negative of total utility revenue.)

Up to fifteen actual or conceptual electricity tariff designs can be pre-loaded in the model and users select from these using a drop-down menu. In addition to including TCLP's current Residential (R), Commercial

(C), and Commercial Demand (CD) tariffs in various versions of the model (see PDF file "09062022 #1 07.28.2022 Rate Tariff Sheets - Final Revised Karla Myers-Beman"), 5LE loaded three proposed tariff designs provided by Utility Financial Solutions: (1) Residential time of use (TOU) with Critical Peak (2) Small Commercial TOU; (3) Small Commercial TOU with Critical Peak; and (4) Commercial Demand TOU with Critical Peak (Phase 5 only). Of these, Proposed Tariff (1) was used to generate results for the Residential class, Proposed Tariff (3) for Commercial, and Proposed Tariff (4) for Commercial Demand. Details of these proposed tariff designs are in the spreadsheet file "TCLP TOU Outputs for 5 Lakes" [and in personal correspondence from Karla Myers-Beman to Douglas Jester, June 2, 2023].

To represent the natural gas tariff, 5LE used DTE Energy's current residential and commercial variable and fixed charges for its gas customers in Northwest Michigan (see PDF files "dtegas1curd1throughend" and "gasrates"). The model's electricity and natural gas tariff features can be found in the model in tabs "TCLP Tariff Options", "TCLP Tariff Profiles", and "DTE Gas Tariffs".

22.2.3.2 Utility Cost of Service (COS) and Marginal Cost (MC)

Using information provided by Utility Financial Solutions, the model calculates annual electric utility cost of service (COS) and marginal cost (MC) for each electricity end use profile and each representative account profile (see the spreadsheet file "8A Allocators Tab - 5 Lakes Energy" and model tab "TCLP COS and MC Metrics" for details). It also calculates annual natural gas utility marginal cost for each natural gas end use profile and each representative account profile (see model tab "DTE Gas Tariffs" for details).

22.2.3.3 Emissions-Related Societal Costs

Societal benefits and costs serve to determine whether aggregate benefits exceed aggregate costs for a particular program offering. For both electricity (existing grid) and natural gas, the model computes the avoided costs related to emissions. Table 22-10 summarizes the relevant $/kWh emissions cost factors for human health and greenhouse gas impacts which are applied in the model. Information behind their development can be found in the in the model (see the tab "Emissions Factors") and in the spreadsheet file "Externality Costs."

Electricity Emission Cost Factors		
Health cost (PM2.5, SO2, NOX, VOC)	0.022541	$/kWh
GHG societal cost (CO2)	0.062765	$/kWh
GHG societal cost (CH4)	0.000060	$/kWh
GHG societal cost (N2O)	0.000222	$/kWh
Natural Gas Health Emission Cost Factors		
Residential, PM2.5	0.001981	$/kWh
Residential, SO2	0.000053	$/kWh
Residential, NOX	0.001853	$/kWh
Residential, VOC	0.000001	$/kWh
Commercial, PM2.5	0.001977	$/kWh
Commercial, SO2	0.000052	$/kWh
Commercial, NOX	0.001971	$/kWh
Commercial, VOC	0.000001	$/kWh
Natural Gas GHG Emission Cost Factors		
GHG societal cost (CO2)	0.021850	$/kWh
GHG societal cost (CH4)	0.000005	$/kWh
GHG societal cost (N2O)	0.000117	$/kWh

Source: TCLP Electrification/Measure Model, "Emissions Factors" tab

Table 22-10 Emission Cost Factors for Calculating Health and Social Costs

22.2.3.4 Net Present Value (NPV) of Annual Results

After computing utility revenue, COS, MC, and avoided emissions costs in annual terms, the model converts these to net present values to better inform customer and utility decision-making over a relevant investment horizon—assumed to be 16 years for all results shared in this report. The two perspectives of the utility company and society are seen in the different assumptions for their discount rates of 5.84 percent and 2.50 percent, respectively. The lower societal discount rate reflects that benefits to society normally accrue over timeframes which are longer than typical financial investment windows. 5LE also computed the NPV of certain figures using a utility customer discount rate of 4.00 percent.

22.2.4 Building Energy Efficiency Module

22.2.4.1 Unit Energy Savings Factor

For electricity end uses, the model computes direct energy savings profiles due to energy efficiency measures by multiplying a user-selected percent savings factor by the energy consumed in each hour. The resulting 8760-hour sum is the annual energy saved for the end use. This assumes that measure savings are proportional to hourly energy use regardless of time and season. A further assumption is that measure-driven savings increase linearly with percentage savings factors; therefore, an arbitrary energy savings factor can be constructed such that predicting energy efficiency performance is simply a matter scaling the savings factor. 5LE applied this concept by defining a unit scaling factor of 1.0 percent and using it to calculate the corresponding avoided utility revenue, COS, MC, and emissions costs for each electricity end use.

The model also estimates indirect effects on internal space heating and cooling loads from energy efficiency measures. All energy consumed by electric equipment and appliances is eventually converted to waste heat. For measures installed on devices within conditioned spaces, 5LE assumed that reduced waste heat must be made up by the heating system during wintertime. This acts as a penalty which reduces the measure's performance. The opposite effect during summertime—a decrease in waste heat serving to reduce cooling load—boosts the measure's performance. The interaction of these indirect effects with direct energy savings determines the measure's net overall performance.

Net performance of internal measures also depends on whether the building's heating system is natural gas or electric resistance. If natural gas, then the model assigns to the electricity measure the additional revenue and costs for makeup heat in terms of the additional natural gas consumed. If electric resistance, this is done in terms of the additional electricity consumed using a coefficient of performance of unity.

22.2.4.2 Energy Efficiency Savings Projections

The team's analysis and design of TCLP programs required the projection of energy efficiency measure savings over time. First, MEO provided 5LE with tables of annual and total savings estimates for each electricity end use by building type out to 2040 (See spreadsheet files "Residential End Use Potential Summary FINAL" and "Commercial End Use Summary FINAL"). Next, 5LE created a separate spreadsheet tool for applying these aggressive but achievable savings levels to the corresponding end use load profiles in each representative account for the years 2025, 2030, 2035, and 2040. Three class-specific versions of this tool exist (See spreadsheet files "TCLP EWR Tool_Residential_v2," "TCLP EWR Tool_Commercial_v2," and "TCLP EWR Tool_CD_v2"). These adjusted end use load profiles were imported into the twelve iterations of the model.

22.2.5 Building Electrification Module

To examine the energy and benefit/cost effects of fuel switching on TCLP and its customers, 5LE programmed the model to compute electricity load profiles for various scenarios before and after installing electrification technologies. Table 22-11 shows which NREL end use categories in the model are eligible for conversion from natural gas or electric resistance to heat pump and other technologies. It also reports a high percentage of total natural gas consumption from these end uses for both ResStock and ComStock building types. In other words, the model effectively simulates conversion to all-electric buildings.

End Use Categories for Fuel Switching	
ResStock	**ComStock**
Space heating	Space heating
Water heating	Water heating
Range cooking	Interior/kitchen
Clothes drying	
Pool heating	
Percentage of Total Natural Gas Usage in NREL EULP	
99.5%	100.0%

Table 22-11 End Use Categories Eligible for Fuel Switching

To model realistic equipment arrangements from the composite representative accounts, the actual hourly heating demand for each end use to be converted is found by applying equipment efficiencies to each fuel type load profile and summing the results. Using space heating as an example, the model multiplies the hourly profile for natural gas space heating by a furnace efficiency of 86 percent (residential buildings) or 80 percent (commercial buildings). If any electric heating is reported, it applies a coefficient of performance of 1.0 and adds the result to the adjusted natural gas profile. This becomes the actual space heating demand profile eligible for fuel switching. The model repeats this process for each end use shown in Table 6.

To illustrate how the model performs fuel switching, consider space heating again. First, the user selects either the air-source heat pump (ASHP) or ground-source heat pump (GSHP) option to replace natural gas and electric resistance space heating and electric air conditioning. The model also has data fields to represent the water-source heat pump (WSHP) option, but these are not populated with technology-specific data yet. If ASHP is selected, the model assigns and applies hourly coefficients of performance (COP) based on hourly outdoor air temperature data for Grand Traverse County in 2018. The algorithm for this temperature-dependent COP selection is based on manufacturer technical performance data located in the model tabs "ASHP_Residential" and "ASHP_HPWH_Commercial".

Additional energy is computed for the ASHP defrost cycle, which is assumed to operate in each hour when outdoor air temperature is at or below 32 degrees Fahrenheit. Given the manufacturer's rating of cold climate ASHP equipment down to negative 13 degrees Fahrenheit, and the lowest hourly temperature of negative 2.92 in the 2018 dataset, 5LE concluded that ignoring the energy and cost effects of a backup heating system was justified in this analysis. For space cooling, the model calculates existing hourly air conditioning demand and replaces it with ASHP operation dictated by the same temperature-dependent COP algorithm. If the user selects the GSHP option, similar computations are made except that COP is based on a seasonal algorithm and no defrost cycle is needed.

With hourly electrification profiles computed for each eligible end use, the model compiles the pre-conversion natural gas and electricity profiles and post-conversion electricity profiles into a limited number of scenarios for comparative analysis. While the model permits the user to select which end uses to fuel switch, 5LE's core analysis assumed conversion to all-electric buildings. Given that space heating and water heating dominate natural gas usage in all ResStock and ComStock building types, 5LE constructed four pre-conversion electrification scenarios reflecting all possible arrangements of natural gas (NG) and electric resistance (ER) for space heating (SH) and water heating (WH). The three post-conversion electrification scenarios reflect the available space heating and space cooling options of ASHP, GSHP, and WSHP—although we note that the WSHP data field remains unpopulated until better performance data become available for this technology. Table 22-12 shows the model's column layout of four pre-conversion and three post-conversion electrification scenarios. In addition to heat pumps for space heating, the post-conversion scenarios include heat pump water heaters and all other natural gas end uses switched to electricity.

Pre-Conversion Scenarios				Post-Converstion Scenarios		
Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH	Post-Conversion with ASHP	Post-Conversion with GSHP	Post-Conversion with WSHP

Table 22-12 Fuel Switching Scenario Framework in the Model

Changes in electricity consumption due to fuel switching are easily computed as the difference between the total hourly profile of any post-conversion scenario (future state) and any pre-conversion scenario (present state). In similar fashion, the model computes benefit/cost impacts of fuel switching by subtracting present state economic and societal costs from future state costs.

To illustrate these modeling results, the six following figures show annual total electricity profiles in the base year for the four pre-conversion scenarios and the ASHP and GSHP all-electric post-conversion scenarios. All six profiles use the same y-axis scale for direct comparison. The dominant effect of space heating can be seen in the two pre-conversion electric resistance cases (Scenarios 3 and 4) and both post-conversion scenarios. The greater efficiency of GSHP equipment compared to ASHP equipment is also evident. Similar results occur for many of the Commercial and Commercial Demand ComStock building types; therefore, for brevity, the numerous graphs for these are not repeated here.

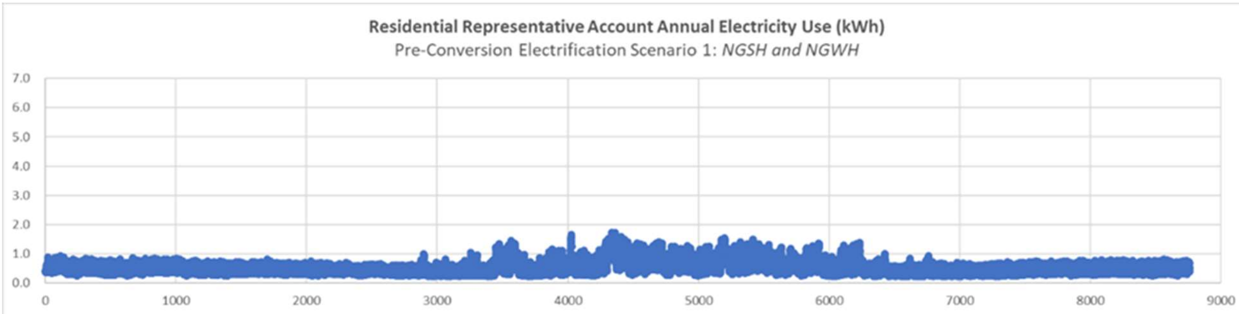

Figure 22-13 Residential Pre-Conversion Electrification Scenario 1

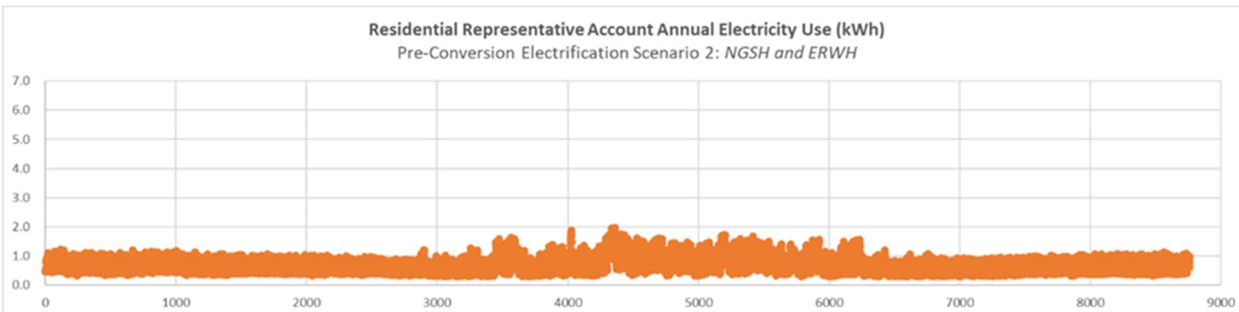

Figure 22-14 Residential Pre-Conversion Electrification Scenario 2

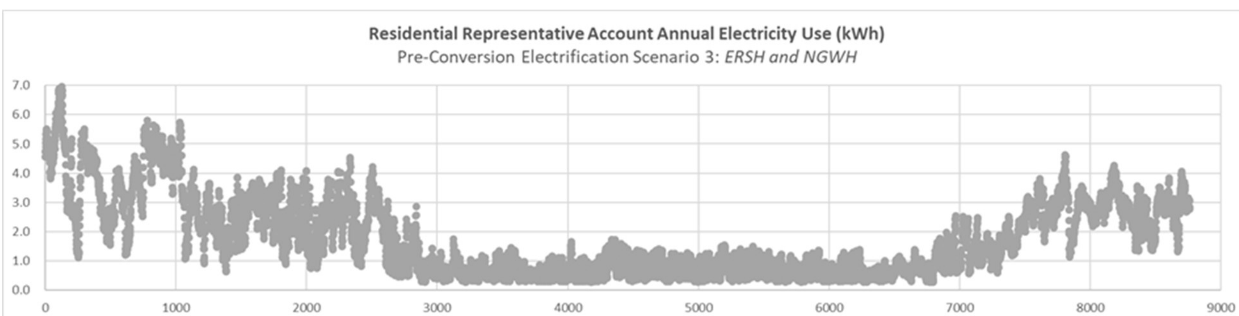

Figure 22-15 Residential Pre-Conversion Electrification Scenario 3

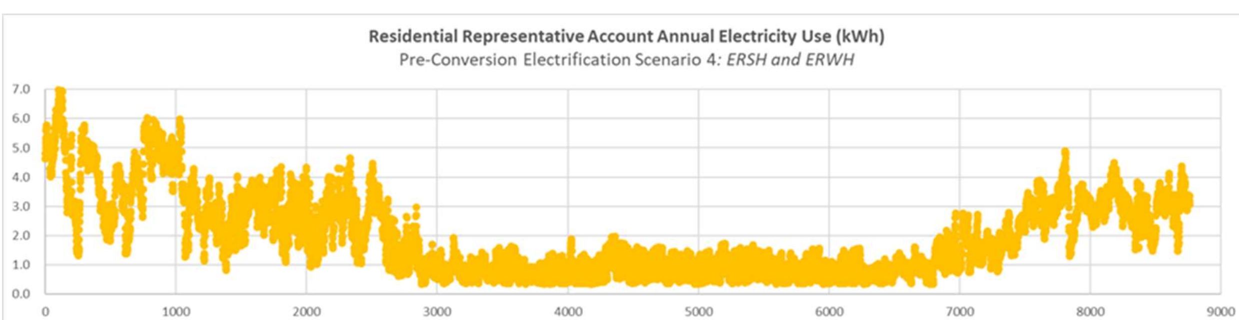

Figure 22-16 Residential Pre-Conversion Electrification Scenario 4

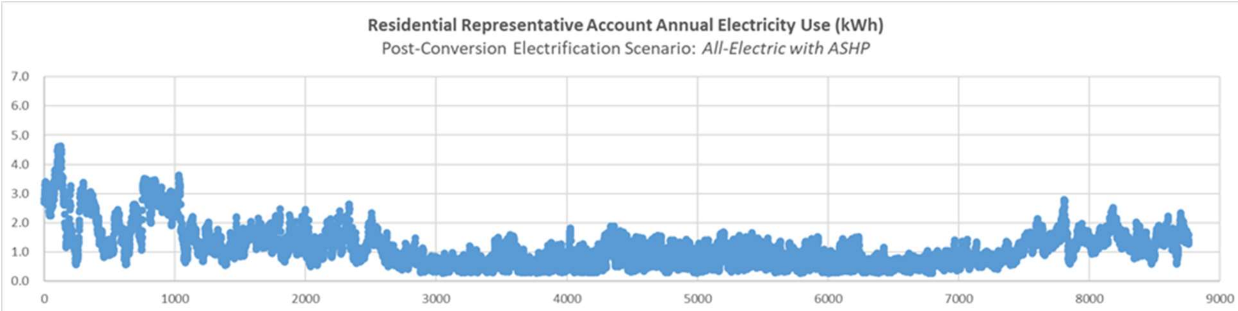

Figure 22-17 Residential Post-Conversion Electrification Scenario (ASHP)

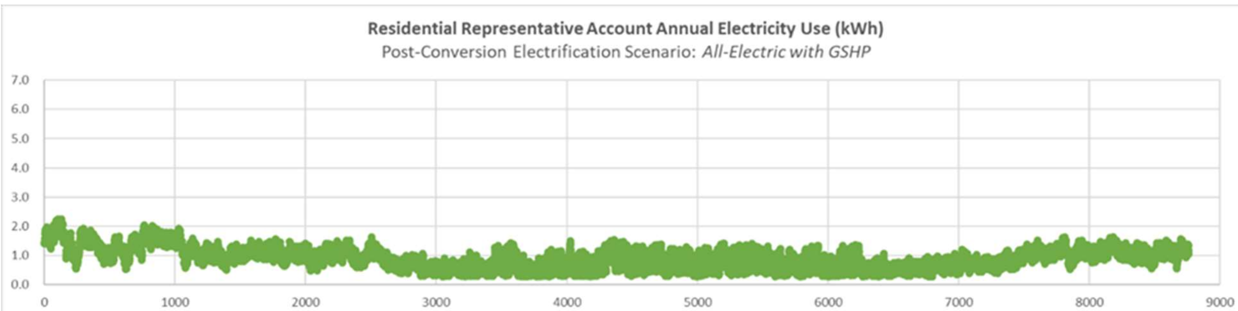

Figure 22-18 Residential Post-Conversion Electrification Scenario (GSHP)

22.2.6 Building Envelope Improvement Module

Building envelope measures can drive significant energy savings for residential and commercial customers. The model investigates this opportunity by computing the four pre-conversion and three post-conversion fuel switching scenarios with and without building envelope improvements, which 5LE defined as air sealing and insulation measures modeled together. To operationalize this concept, we created a savings percentage and used it to modify the space heating and space cooling profiles. For the results presented in this report, we assumed a measure savings figure of 25 percent to be a reasonable proxy for a comprehensive building envelope retrofit. To apply it, we adjusted for the effect of building envelope measures on the dissipation of internal heat load (*InternalHeat*) generated by electric equipment within the conditioned space. The model computes adjusted space heating and cooling loads (*SpaceHeatingAdjusted* and *SpaceCoolingAdjusted*) from initial loads (*SpaceHeating* and *SpaceCooling*) using the following relationships:

$$SpaceHeatingAdjusted = [(1.00 - 0.25) \times (SpaceHeating + InternalHeat)] - InternalHeat$$

$$SpaceCoolingAdjusted = [(1.00 - 0.25) \times (SpaceCooling - InternalHeat)] + InternalHeat$$

To apply the adjusted space heating and cooling loads, 5LE created a parallel data field for the seven fuel switching scenarios shown in Table 22-12 to compare electrification profiles with and without building envelope improvements. Table 22-13 shows this arrangement of the two data fields in the model.

TOTAL ELECTRICITY USE WITH BUILDING ENVELOPE IMPROVEMENTS						
Pre-Conv. Rep. Account Electridty Use (kWh)				Post-Conv. Electricity Use (kWh)		
Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH	Post-Conversion with ASHP	Post-Conversion with GSHP	Post-Conversion with WSHP

TOTAL ELECTRICITY USE WITHOUT BUILDING ENVELOPE IMPROVEMENTS						
Pre-Conv. Rep. Account Electricity Use (kWh)				Post-Conv. Electricity Use (kWh)		
Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH	Post-Conversion with ASHP	Post-Conversion with GSHP	Post-Conversion with WSHP

Table 22-13 Parallel Data Fields to Compare Electrification With (Left) and Without (Right) Building Envelope Improvements

The change in electricity usage due to building envelope measures is derived as the difference between the hourly profiles in the righthand data field in Table 22-13 (present state) and those in the lefthand data field (future state). Similarly, the benefit/cost effects of building envelope measures are computed as the difference in $/kWh electrification factors before and after conversion.

22.2.7 TCLP System Hourly Load Projections

The first step in developing system load projections using ResStock and ComStock end use load profiles was to predict Commercial and Commercial Demand customer adoption rates of building electrification technologies in 2025, 2030, 2035, and 2040. Elevate provided this information for two different fuel switching pathways for each ComStock building type: (1) a realistically ambitious path ("Proposed"), and (2) the more aspirational full building electrification by 2050 ("Net Zero"). See spreadsheet file "TCLP Measure and Equip Uptake_Electrification_v1" for these projections. 5LE reconciled Elevate's implementation pathways to the four pre-conversion and three post-conversion electrification scenarios identified in Figure 22-13(see the tab "Electrification Paths2" in spreadsheet file "Commercial Integration_v1"). We then developed similar fuel switching projections for the Residential customer class in 2025, 2030, 2035, and 2040.

Next, 5LE created an aggregation spreadsheet tool and imported the reconciled "Proposed" and "Net Zero" electrification pathways into the tab "Weighting Factors." A dropdown menu was added for users to select either of the two pathways for analysis. Three separate class-specific versions of the aggregation tool were used and are available as these spreadsheet files:

- "TCLP Aggregation_Residential_WITH AND WITHOUT EWR_SHELL_v2"
- "TCLP Aggregation_Commercial_WITH EWR_SHELL_v2"
- "TCLP Aggregation_CD_WITH EWR_SHELL_v2"

The aggregation tool imported data from the twelve year-based iterations of the model described in Section 22.2.2; specifically, the 8760-hour electricity profiles from the fuel switching tables depicted in Table 22-11 Based on the electrification pathway selected, the tool combines the various pre- and post-conversion profiles into composite profiles in 2025, 2030, 2035, and 2040 to reflect the pace of fuel switching. For each year, the tool builds a single profile by scaling each building type profile by the number of representative accounts in the customer class. The resulting sum is the portion of total class load directly represented by ResStock and ComStock building types.

To incorporate building envelope measures, 5LE assumed that customers will adopt these at roughly the same rate they fuel switch. Therefore, the aggregation tool pulls pre-conversion electricity profiles from the "Without Building Envelope Improvements" scenario tables and pulls post-conversion profiles from the "With Building Envelope Improvements" scenario tables to construct the composite profiles in each year.

5LE created a final spreadsheet tool to construct TCLP system load projections (See file "TCLP System Results Tool_v3") by first importing twenty-four hourly load profiles from the three versions of the aggregation tool (twenty-four being the number of combinations of two electrification pathways

(“Proposed” and “Net Zero”), four years (2025, 2030, 2035, 2040), and three customer classes (Residential, Commercial, Commercial Demand).

Because the resulting residential profiles encompass the entire Residential class, they were applied directly for the total system load. For Commercial and Commercial Demand, 5LE assumed that ComStock profile shapes serve as a reasonable approximation for these entire class loads, and the imported Commercial and Commercial Demand profiles were scaled up accordingly. We made a similar judgement to model the Primary and Primary Commercial Demand classes using the Commercial Demand profile shape, which was scaled to the annual loads of these two classes. For the three remaining classes—Metal Melting, Pumping, and Primary Pumping—5LE applied their 2021 TCLP load profiles directly for the total system load.

The tab “Total System Projections” in spreadsheet file “TCLP System Results Tool_v3” compiles our final projections of TCLP system load in the form of eight total system hourly profiles: “Proposed” electrification in 2025, 2030, 2035, and 2040; and “Net Zero” electrification in 2025, 2030, 2035, and 2040. Figure 22-19 shows these eight results as a bar graph for easy comparison. It is important to note that all eight of these system load projections reflect aggressive implementation of energy efficiency programming as projected by MEO out to 2040.

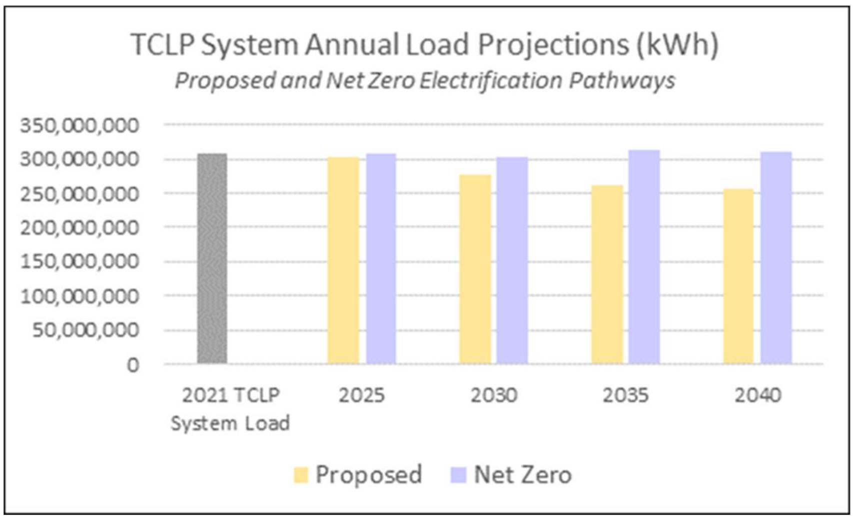

Figure 22-19 Final Results of TCLP Load Projections Using ResStock and ComStock End Use Load Profiles

5LE subsequently applied these electricity profile projections in STEP8760 modeling.

22.3 Building Energy Efficiency Analysis

22.3.1 Energy Efficiency Benefit/Cost Factors

5LE used the Building Electrification and Measure Tool described in Section 22.2 to compute $/kWh benefit/cost factors with which to evaluate energy efficiency measure options. The first step was applying a unit savings factor of 1.0 percent to measure-eligible electricity end use profiles to generate annual energy savings in kWh and annual avoided utility revenue, cost of service (COS), marginal cost (MC), and emissions costs related to health and greenhouse gas impacts in dollars. The model then derived NPV figures for each dollar amount and divided each of these results by the annual kWh savings to yield $/kWh for each end use category.

To illustrate typical results, Table 22-14 presents these for a single ResStock end use, an electric cooling fan. Note that various NPV figures are calculated from the three perspectives of customer, utility, and society by using discount rates of 4.00 percent, 5.84 percent, and 2.50 percent, respectively. The bottom two rows in the table report different societal avoided cost results—one assuming that any marginal electricity acquired by TCLP is 100 percent renewable energy, and the other assuming zero percent renewable energy. The lower result for the former case reflects that TCLP does not receive credit for avoided emissions impacts by adding all renewable energy to replace what has been saved through energy efficiency. Instead, it only receives credit for the MC discounted at the societal rate.

	Internal Heating & Cooling Impact			
Performance Metric	Electric Cooling Fan (ERSH)	Electric Cooling Fan (NGSH): Electricity	Electric Cooling Fan (NGSH): Nat Gas	Electric Cooling Fan (NGSH): Total
Direct Annual Savings from EWR Measure (kWh)	2.031	2.031		
Ratio: (Direct Annual Savings + Internal Effects) / (Direct Annual Savings)	0.7623	1.2555	(0.3635)	
Annual Avoided Revenue Factor ($/kWh)	0.0713	0.1174	(0.0108)	0.1066
Annual Avoided COS Factor ($/kWh)	0.1280	0.1816		
Annual Avoided MC Factor ($/kWh)	0.0612	0.1012	(0.0046)	0.0965
2023 Avoided Health Cost Factor ($/kWh)	0.0182	0.0300	(0.0087)	0.0213
2023 Avoided GHG CO2 Cost Factor ($/kWh)	0.0504	0.0830	(0.0240)	0.0590
2023 Avoided GHG CH4 Cost Factor ($/kWh)	0.0001	0.0001	(0.0000)	0.0001
2023 Avoided GHG N2O Cost Factor ($/kWh)	0.0002	0.0003	(0.0001)	0.0002
Net Present Value Results (Customer)				
NPV Avoided Customer Charges Factor ($/kWh)	0.9898	1.6302	(0.1496)	1.4806
Net Present Value Results (Electric Utility)				
NPV Avoided Utility Revenue Factor ($/kWh)	0.8769	1.4444		
NPV Avoided Utility COS Factor ($/kWh)	1.5745	2.2342		
NPV Avoided Utility MC Factor ($/kWh)	0.7524	1.2446		
NPV Utility Revenue minus Utility COS Factor ($/kWh)	(0.6976)	(0.7899)		
NPV Utility Revenue minus Utility MC Factor ($/kWh)	0.1245	0.1998		
Net Present Value Results (Society)				
NPV Avoided Societal MC Factor ($/kWh)	0.9435	1.5606	(0.0716)	1.489
NPV Avoided Societal Health Cost Factor ($/kWh)	0.2813	0.4634	(0.1342)	0.329
NPV Avoided Societal GHG CO2 Cost Factor ($/kWh)	0.7644	1.2590	(0.3646)	0.894
NPV Avoided Societal GHG CH4 Cost Factor ($/kWh)	0.0009	0.0015	(0.0004)	0.001
NPV Avoided Societal GHG N2O Cost Factor ($/kWh)	0.0029	0.0047	(0.0014)	0.003
NPV Total Avoided Societal Costs with TCLP RE Goal Factor ($/kWh)	0.9435	1.5606	(0.5721)	0.989
NPV Total Avoided Societal Cost with TCLP 0% RE Factor ($/kWh)	1.9930	3.2891	(0.5721)	2.717

Table 22-14 EWR Factors Computed for a Residential End Use

The example shown in Table 22-14 also demonstrates how the model addresses energy savings from internal end uses, i.e., appliances and equipment located within the conditioned space. As discussed previously, energy efficiency measures reduce waste heat which either increases space heating load or decreases space cooling load depending on the season. If the heating system is electric resistance (represented in the first column of Table 22-14), then these net effects are all reported in terms of electricity. If natural gas is used (represented in the righthand three columns in Table 22-14), then the heating system effects must be tallied separately and then combined with the direct savings and indirect cooling effects for electricity. To be clear, avoided costs due to energy efficiency in Table 22-14 are positive while additional costs are negative.

5LE organized the energy efficiency benefit/cost factors generated this way for each building type and end use for the Residential, Commercial, and Commercial Demand classes. These results were compiled and reported to MEO for further program analysis (See the spreadsheet files "TCLP NPV EWR Measures_Residential_v1" and "TCLP NPV EWR Measures_Comm and CD_v3").

Conceptually, TCLP could set the total program budget for an energy efficiency measure using one of three benefit/cost factors: (1) avoided utility MC; (2) avoided societal MC (assuming additional electricity is 100 percent renewable); or (3) avoided societal MC plus avoided emissions costs (assuming additional electricity is zero percent renewable). For example, if annual measure savings of 10 kWh is applied to Table 22-14, then TCLP could set the maximum program budget (including any rebate) as one of these three options: (1) $7.524 based on avoided utility MC; (2) $9.435 based on avoided societal MC; or (3) $19.93 based on avoided societal MC and emissions costs.

22.4 Building Electrification Analysis

22.4.1 Building Electrification Benefit/Cost Factors

5LE used the Building Electrification and Measure Tool described in Section 22.2 to compute $/kWh benefit/cost factors with which to evaluate building electrification options. For each electrification scenario depicted in Figure 22-15, NPV figures were generated for utility revenue, COS and MC, and societal health and greenhouse gas costs. To evaluate the impact of fuel switching, the difference between these factors in going from the four pre-conversion scenarios to the ASHP and GSHP post-conversion scenarios were calculated and then divided by the net change in electricity kWh consumed. 5LE compiled these results from all twelve model iterations (reflecting the combinations of three customer classes and four energy efficiency projection years). Table 22-15 and Table 22-16 present results for one of these twelve cases, Residential in 2025. The difference between pre-conversion and post-conversion NPV figures are shown in Table 22-15 while Table 22-16 shows figures divided by net change in electricity consumption to get benefit/cost factors.

Positive ratios in Table 22-16 reflect one of two cases; either additional revenue or cost (positive) divided by additional electricity (positive) or avoided revenue or cost (negative) divided by a decrease in electricity consumption (negative).

	2025			
	NPV Deltas			
	Pre-Conversion Rep. Account Scenarios			
Note: These results are computed as Post-Conversion figures minus Pre-Conversion figures.	Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH
Parameter	Post-Conversion Scenario: ASHP			
Annual Electricity Use (kWh)	**3,957**	**2,243**	**(3,624)**	**(5,338)**
Annual Natural Gas Use (kWh)	**(11,822)**	**(9,101)**	**(3,007)**	**(286)**
NPV Total Electricity Revenue ($)	4,551.82	2,579.91	(4,168.90)	(6,140.81)
NPV Electric Utility COS ($)	3,208.21	1,588.00	(2,550.13)	(4,170.34)
NPV Electric Utility MC ($)	3,074.73	1,639.67	(2,683.61)	(4,118.67)
NPV Societal Electricity MC ($)	3,855.48	2,056.03	(3,365.05)	(5,164.50)
NPV Societal Natural Gas MC ($)	(2,327.50)	(1,791.81)	(592.02)	(56.34)
NPV NG Health, CO2, CH4, N20 Cost @ 100% RE ($)	(4,903.57)	(3,774.99)	(1,247.27)	(118.69)
NPV Total Societal Cost @ 100% RE ($)	(3,375.59)	(3,510.77)	(5,204.34)	(5,339.53)
NPV Total Electricity Revenue Minus NPV Utility COS ($)	1,343.61	991.90	(1,618.76)	(1,970.47)
NPV Total Electricity Revenue Minus NPV Utility MC ($)	1,477.09	940.24	(1,485.28)	(2,022.14)
Parameter	Post-Conversion Scenario: GSHP			
Annual Electricity Use (kWh)	**2,424.16**	**710.03**	**(5,156.54)**	**(6,870.67)**
Annual Natural Gas Use (kWh)	**(11,822)**	**(9,101)**	**(3,007)**	**(286)**
NPV Total Electricity Revenue ($)	2,788.72	816.81	(5,932.00)	(7,903.91)
NPV Electric Utility COS ($)	1,880.53	260.32	(3,877.82)	(5,498.02)
NPV Electric Utility MC ($)	1,876.73	441.67	(3,881.61)	(5,316.67)
NPV Societal Electricity MC ($)	2,353.28	553.82	(4,867.25)	(6,666.70)
NPV Societal Natural Gas MC ($)	(2,327.50)	(1,791.81)	(592.02)	(56.34)
NPV NG Health, CO2, CH4, N20 Cost @ 100% RE ($)	(4,903.57)	(3,774.99)	(1,247.27)	(118.69)
NPV Total Societal Cost @ 100% RE ($)	(4,877.79)	(5,012.97)	(6,706.55)	(6,841.73)
NPV Total Electricity Revenue Minus NPV Utility COS ($)	908.19	556.49	(2,054.18)	(2,405.88)
NPV Total Electricity Revenue Minus NPV Utility MC ($)	911.99	375.14	(2,050.38)	(2,587.24)

Table 22-15 Residential Post-Conversion NPV Figures minus Pre-Conversion NPV Figures Projected in 2025

	2025			
	$/kWh Factors (Denominator is Electricity)			
	Pre-Conversion Rep. Account Scenarios			
Note: These results are computed as Post-Conversion figures minus Pre-Conversion figures.	Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH
Parameter	**Post-Conversion Scenario: ASHP**			
NPV Total Electricity Revenue ($/kWh)	1.15	1.15	1.15	1.15
NPV Electric Utility COS ($/kWh)	0.81	0.71	0.70	0.78
NPV Electric Utility MC ($/kWh)	0.78	0.73	0.74	0.77
NPV Societal Electricity MC ($/kWh)	0.97	0.92	0.93	0.97
NPV Societal Natural Gas MC ($/kWh)	(0.59)	(0.80)	0.16	0.01
NPV NG Health, CO2, CH4, N20 Cost @ 100% RE ($/kWh)	(1.24)	(1.68)	0.34	0.02
NPV Total Societal Cost @ 100% RE ($/kWh)	(0.85)	(1.57)	1.44	1.00
NPV Total Electricity Revenue Minus NPV Utility COS ($/kWh)	0.34	0.44	0.45	0.37
NPV Total Electricity Revenue Minus NPV Utility MC ($/kWh)	0.37	0.42	0.41	0.38
Parameter	**Post-Conversion Scenario: GSHP**			
NPV Total Electricity Revenue ($/kWh)	1.15	1.15	1.15	1.15
NPV Electric Utility COS ($/kWh)	0.78	0.37	0.75	0.80
NPV Electric Utility MC ($/kWh)	0.77	0.62	0.75	0.77
NPV Societal Electricity MC ($/kWh)	0.97	0.78	0.94	0.97
NPV Societal Natural Gas MC ($/kWh)	(0.96)	(2.52)	0.11	0.01
NPV NG Health, CO2, CH4, N20 Cost @ 100% RE ($/kWh)	(2.02)	(5.32)	0.24	0.02
NPV Total Societal Cost @ 100% RE ($/kWh)	(2.01)	(7.06)	1.30	1.00
NPV Total Electricity Revenue Minus NPV Utility COS ($/kWh)	0.37	0.78	0.40	0.35
NPV Total Electricity Revenue Minus NPV Utility MC ($/kWh)	0.38	0.53	0.40	0.38

Table 22-16 Residential Cost-Benefit Electrification Factors Projected in 2025

When adding electric load through fuel switching, TCLP could consider returning to the customer the NPV of gross margin; i.e., NPV of revenue minus NPV of utility MC. This is calculated by multiplying the appropriate $/kWh benefit/cost factors (such as in Table 22-16) by the additional electricity in kWh consumed after fuel switching. Alternatively, TCLP could return to the customer NPV of revenue minus NPV of societal MC.

22.4.2 Building Envelope Measure Benefit/Cost Factors

5LE used the Building Electrification and Measure Tool described in Section 22.2 to compute $/kWh benefit/cost factors with which to evaluate building envelope improvement options. While envelope measures are usually managed within energy efficiency programming, we discuss their benefit/cost factors here because they were derived with the model's building electrification functionality. Specifically, NPV figures were generated for utility revenue, COS and MC, and societal health and greenhouse gas costs for the various electrification scenarios with and without building envelope improvements. Then factors without improvements (present state) were subtracted from factors with improvements (future state). Table 22-17 shows typical NPV results from installing a comprehensive envelope retrofit for a residential representative account in 2025.

	"WITH BUILDING ENVELOPE IMPROVEMENTS" MINUS "WITHOUT IMPROVEMENTS"					
	2025 Residential Representative Account NPV Results ($)					
	Pre-Conversion Scenarios				Post-Conversion Scenarios	
	Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH	Post-Conversion with ASHP	Post-Conversion with GSHP
Annual Electricity Use Delta (kWh)	**(26.6)**	**(26.6)**	**(3,277.2)**	**(3,277.2)**	**(1,332.1)**	**(767.9)**
NPV Total Electricity Revenue ($)	(59.8)	(59.8)	(4,984.7)	(4,984.7)	(2,029.4)	(1,179.6)
NPV Electric Utility COS ($)	(187.0)	(187.0)	(2,665.7)	(2,665.7)	(1,191.5)	(724.0)
NPV Electric Utility MC ($)	(50.0)	(50.0)	(2,528.7)	(2,528.7)	(1,044.7)	(610.1)
NPV Societal Electricity MC ($)	(62.8)	(62.8)	(3,170.8)	(3,170.8)	(1,310.0)	(765.0)
NPV Societal Natural Gas MC ($)	(744.2)	(744.2)	0.0	0.0	0.0	0.0
NPV NG Health, CO2, CH4, N20 Cost @ 100% RE ($)	(1,567.8)	(1,567.8)	0.0	0.0	0.0	0.0
NPV Total Societal Cost @ 100% RE ($)	(2,374.8)	(2,374.8)	(3,170.8)	(3,170.8)	(1,310.0)	(765.0)
NPV Total Electricity Revenue Minus NPV Utility COS ($)	127.2	127.2	(2,319.0)	(2,319.0)	(837.8)	(455.5)
NPV Total Electricity Revenue Minus NPV Utility MC ($)	(9.8)	(9.8)	(2,455.9)	(2,455.9)	(984.7)	(569.5)

Table 22-17 Residential NPV Figures With Envelope Improvements minus NPV Figures Without Improvements Projected in 2025

The net NPV results were divided by "Annual Electricity Use Delta (kWh)" in Table 10 to yield the building envelope measure benefit/cost factors shown in Table 22-18.

	"WITH BUILDING ENVELOPE IMPROVEMENTS" MINUS "WITHOUT IMPROVEMENTS"					
	2025 Residential Representative Account NPV Factors ($/kWh)					
	Pre-Conversion Scenarios				Post-Conversion Scenarios	
	Scenario 1: NGSH and NGWH	Scenario 2: NGSH and ERWH	Scenario 3: ERSH and NGWH	Scenario 4: ERSH and ERWH	Post-Conversion with ASHP	Post-Conversion with GSHP
NPV Total Electricity Revenue ($/kWh)	2.25	2.25	1.52	1.52	1.52	1.54
NPV Electric Utility COS ($/kWh)	7.03	7.03	0.81	0.81	0.89	0.94
NPV Electric Utility MC ($/kWh)	1.88	1.88	0.77	0.77	0.78	0.79
NPV Societal Electricity MC ($/kWh)	2.36	2.36	0.97	0.97	0.98	1.00
NPV Societal Natural Gas MC ($/kWh)	27.95	27.95	0.00	0.00	0.00	0.00
NPV NG Health, CO2, CH4, N20 Cost @ 100% RE ($/kWh)	58.89	58.89	0.00	0.00	0.00	0.00
NPV Total Societal Cost @ 100% RE ($/kWh)	89.21	89.21	0.97	0.97	0.98	1.00
NPV Total Electricity Revenue Minus NPV Utility COS ($/kWh)	(4.78)	(4.78)	0.71	0.71	0.63	0.59
NPV Total Electricity Revenue Minus NPV Utility MC ($/kWh)	0.37	0.37	0.75	0.75	0.74	0.74

Table 22-18 Residential Building Envelope Benefit/Cost Factors Projected in 2025

TCLP has the option to compute the total program budget for a building envelope measure using one of three benefit/cost factors: (1) avoided utility MC; (2) avoided societal MC (assuming additional electricity is 100 percent renewable); or (3) avoided societal MC plus avoided emissions costs (assuming additional electricity is zero percent renewable).

22.5 Transportation Electrification Requirements

22.5.1 Passenger Vehicle Electrification Analysis

5LE developed a passenger vehicle electrification model using local data shared by the Michigan Department of State (MDOS), the Michigan Department of Transportation (MDOT), and public data from the U.S. Census other sources. The core of 5LE's model is the EVI-Pro Lite vehicle electrification load model developed by U.S. Department of Energy (DOE).

The EVI-Pro Lite model takes a limited set of inputs and provides average 15-minute weekday and weekend load profiles for six different charging types:

a. DC Fast (150 kW)
b. Public Level 2
c. Work Level 2
d. Work Level 1
e. Home Level 2
f. Home Level 1

Table 22-19 below shows the different variables available in the EVI-Pro Lite model.

Average Daily Miles Traveled per Vehicle	Plug-in Vehicles that are All-Electric	Plug-in Vehicles that are Sedans %	Mix of Workplace Charging lvl1/lvl2	Access to Home Charging %	Mix of Home Charging lvl1/lvl2	Preference for Home Charging %	Home Charging Strategy (see strategy list)	Workplace Charging Strategy (see strategy list)	Average Ambient Temperature (F)
25	25%	20%	20%/80%	50%	20%/80%	60%	I-F	I-F	-4
35	50%	50%	50%/50%	75%	50%/50%	80%	I-S	I-S	14
45	75%	80%	80%/20%	100%	80%/20%	100%	D-FBD	D-FBD	32
								D-SAM	50
									68
									86
									104

Table 22-19 EVI-Pro Lite input options

Charging Strategies:

- (I-F) Immediate – as fast as possible: vehicles charge as soon as they are plugged in at the maximum charge rate until the vehicle is finished charging.
- (I-S) Immediate - as slow as possible (even spread): vehicles charge as slowly as possible given the window of time the vehicle is expected to be charging with the assumption that the vehicle will be at full charge at the end of the charging period.
- (D-FBD) Delayed - finish by departure: vehicles charge at the maximum charge rate but do not begin charging until the start of the period that would be necessary for the vehicle to achieve full charge at the time of departure. For instance, a vehicle that arrives home at 6 PM and leaves the home at 7 AM which only takes 4 hours to charge would begin charging at 3 AM. The same vehicle, under the I-F strategy, would begin charging at 6 PM, and be finished by 10 PM.
- (D-SAM) Delayed – start at midnight: vehicles charge, beginning at midnight, at the maximum charge rate, until the vehicle is finished charging.

Because of the limitations of the input variables, we determined a need to develop multiple charging profiles representing different potential outcomes of future EV charging that we could assess individually or blended. We also assumed fundamental differences in driving and charging habits for drivers commuting into the TCLP service territory for work, and drivers living and working in TCLP. Consequently, we came up with six unique charging profiles based on EVI-Pro Lite inputs. For each of the strategies, we exported a version of that strategy for each available temperature.

	Average Daily Miles Traveled per Vehicle	Plug-in Vehicles that are All-Electric	Plug-in Vehicles that are Sedans %	Mix of Workplace Charging lvl1/lvl2	Access to Home Charging %	Mix of Home Charging lvl1/lvl2	Preference for Home Charging %	Home Charging Strategy (see strategy list)	Workplace Charging Strategy (see strategy list)
Resident - Slow Charging, Daytime	35	80%	50%	20%/80%	75%	80%/20%	60%	I-S	I-S
Resident - Medium Charging, Evening	35	80%	50%	20%/80%	75%	50%/50%	100%	I-S	I-F
Resident - Aggressive Charing, Midnight	35	80%	50%	20%/80%	75%	20%/80%	100%	D-SAM	I-F
Commuter - Slow Charging, Daytime	45	80%	50%	20%/80%	100%	80%/20%	60%	I-S	I-S
Commuter - Medium Charging, Evening	45	80%	50%	20%/80%	100%	50%/50%	100%	I-S	I-F
Commuter - Aggressive Charging, Midnight	45	80%	50%	20%/80%	100%	20%/80%	100%	D-SAM	I-F

Table 22-20 Six unique charging profiles exported from EVI-Pro Lite

Average day profiles were then knit together using a Stata script that selected the correct profile to use for each day of the 2018 test year, based on the average daily temperature and the day of the week. These profiles were further modified using daily scaling factors we calculated based on MDOT traffic data. These scaling factors help account for the seasonality of traffic in Traverse City and Grand Traverse County (see below). Finally, we used registration data from MDOS, commuting data from the American Community Survey in conjunction with TCLP's own account data by township to determine an estimate of the number of vehicles charging the TCLP service territory on an average day[37].

22.5.1.1 Generating Seasonal Scaling Factors from MDOT Traffic Data

We received a large amount of traffic data MDOT that included short count data (48-hour vehicle count data aggregated at the 15-minute and hourly levels) for over 100 road segments in Grand Traverse County, and long count data (8760-hour vehicle count data aggregated at the hourly level) for seven road segments in and around Grand Traverse County.

To generate the hourly scaling factors incorporated into the vehicle electrification model, we isolated two road segments for which we had long count data that we deemed to be major thoroughfares into and out of the Traverse City, which we determined could stand in for overall city traffic circulation. Using the sum of daily traffic counts on these two roads, we produced daily traffic factors which account for both seasonal variation and daily variation throughout each week. These factors range from .515 to 1.448, or a nearly

[37] These values are calculated in the workbook "Passenger Model Inputs.xlsx"

three-fold increase in traffic from the highest traffic summer day to the lowest traffic winter day. However, when accounting for day of week, which better represents seasonality, the difference between maximum and minimum traffic factors is substantial, but under two-fold. For example, the range of traffic factors on Fridays is .821 to 1.448.

22.5.2 Commercial Vehicle Electrification Analysis

Due to lack of data, we took a simplified approach to commercial vehicle electrification. Rather than determine separate charging profiles for commercial vehicles, we took the published number of vehicle miles traveled in Grand Traverse County and scaled it down to what we determined was the portion of passanger vehicles based in TCLP's service territory—22.4%. We then approximated an average vehicle efficiency for commercial vehicles of 2.25kWh/mi. This value is higher than that of a large pickup truck or delivery van, but lower than that of published values for long-haul trucks. We converted this to passanger vehicle equivalents using the vehicle efficiencies from the EVI-Pro Lite documentation. These equivalents were added to the total number of passanger vehicles and used to produce our EV charging profile. However, the number of equivalents electrified in each model year was determined by the predicted pace of commercial vehicle electrification rather than that of passenger vehicle electrification.

22.6 Transportation Charging Infrastructure Requirements

22.6.1 Blink Charging Network Data

Blink data summarizes each 'charging event' on the network—when a driver plugged into the charger and when they disconnected. Variables of interest for each event were the location, charge start time, energy end time, and cumulative energy provided. The data delineated between the connect and disconnect times of the plug itself and the start and stop times of energy being supplied to the vehicle. While connection times and energy start times were identical in nearly every event, disconnect times and energy end times differed as some drivers left their vehicles plugged in after reaching a full state of charge. To define the start and end of every event, the connection time and energy end time were used. Connection time was used in favor of energy start time as Blink's data architecture stored connection time in 24-hour format, and energy start time in 12-hr format.

To create the load profiles used in this analysis, the data was initially cleaned for errors, filtering by energy supplied. Observations between 0kW and 120kW were accepted in order to filter out errors where either no load was reported, or a technically impossible load was reported. This filtering removed 22% of charging events from the data. Most of the observations removed were invalidated due to not having any load reported and were not connected to the charger for more than a couple of minutes.

Once the data was cleaned, load rates to be assigned to the time of day in the profiles were created. The process for this was to first find the total period of time, as defined by the time the vehicle was plugged in until energy was not being supplied to it and convert the time period into seconds. From there, the total energy that was supplied was divided by this period to create the most accurate charging rate possible, before it was scaled back up to the hour-level for the load profile.

A note to be made here is the assumption of a constant, linear charging rate. While this is not how electric vehicle chargers behave, it is the most accurate rate calculable from the data provided by Blink. In reality, factors such as temperature and vehicle state of charge (battery level) can affect the rate at which a vehicle is charged, with this rate varying throughout a charging session. However, the variance in charging rate is rarely significant in loading calculations such as this one. The length of a charging event determines how impactful this may be, as longer charging events present a wider range of time for allotted energy to be unevenly allocated to an hour in the profile, while shorter charging events do not.

Equations for the load rate calculations:

$$load.period = energy.end.time - plugin.time$$
$$load.rate = \frac{cumulative.energy}{load.period}$$

After determining the load rate, each rate value was assigned to an hour from the range it was calculated. These were then sorted into a format resembling an 8760-hour load profile, though it does not extend from January to December, but rather the timeline that these data were collected. This profile can then be sorted into weeks and months to analyze seasonal patterns. To calculate daily load shapes, each day was stacked on top of each other, then averaged out to reveal a typical load shape of electric vehicle charging.

22.7 IRP Modeling

22.7.1 STEP8760

22.7.1.1 Model Parameters

While STEP8760 is fully manipulable by anyone with time and strong knowledge of both Excel and grid operations, the primary variation modeled to develop an appropriate range of MISO LRZ7 grid pricing is based on a limited number of variables that could be easily adjusted prior to running Excel's built-in optimization algorithm (Solver) to determine the least-cost generation mix expected to be built in LRZ7. These variables and their options are as follows:

Tech Scenario (NREL ATB)
- Advanced
- Moderate
- Conservative

Accelerated Generator Retirements
- Yes
- No

Portfolio Standard
- Business as Usual
- MI Healthy Climate Plan
- Success of Biden Goals

Electrification Pathway
- Slow
- Fast
- Updated Emissions Standard

Wind Build Constraint (applied manually in Solver setup)
- 2200MW/5-Years
- 6500MW/5-Years

Table 1 in the "STEP8760 Tables" Excel file shows the inputs into the 11 scenarios run in STEP8760. Each scenario, unless otherwise marked, was run four times. Once for each model year 2025, 2030, 2035 and 2040. Each model year is run with the optimized build portfolios from prior model years maintained.

Some scenarios were also run from the later years to the earlier years with the results of later years becoming model constraints for the next year's run. For instance, a 2040 optimization run finds an LRZ7 portfolio including 10 GW of solar, 8GW of wind, 8GW of combustion turbines, and 5GW of 4-hour battery storage. Each of these values then becomes a constraint on the build limits of these resources in the 2035 optimization of the same scenario, preventing the model from building more of these resources in early years than will exist in later years. Theoretically, this approach mimics more closely the conventional modeling techniques used by industry which look at the desired end state first and then find the optimal path. However, when we took stock of the final results from both approaches, we deemed the results from forward optimization to be preferable for final analysis.

22.7.1.2 Variable Descriptions

Tech Scenario (NREL ATB)

Projected costs of fuel and new generation or storage resources can be specified as user assumptions in a modeling scenario. We use the 2023 US Energy Information Administration's (EIA) Annual Energy Outlook (AEO) and the 2022 National Renewable Energy Laboratories (NREL) Annual Technology Baseline (ATB). We have modified the 2022 NREL ATB for the effects of Inflation Reduction Act modifying tax credits for various technologies.

To reduce input variables and avoid conflicting modeling assumptions we tied the fuel price scenario to the input for the ATB technology cost scenario. Specifically, the ATB and AEO tables were linked as represented below:

NREL Annual Technology Baseline Scenario	**EIA Annual Energy Outlook Fuel Cost Scenario**
Advanced	Low Zero-Carbon Technology Cost
Moderate	Reference
Conservative	High Zero-Carbon Technology Cost

Table 22-21 NREL ATB and EIA AEO technology price and fuel price crosswalk

The values for both the AEO fuel cost assumptions and the ATB technology cost assumptions can be seen in Table 2 in the "STEP8760 Tables" Excel file. However, it is important to note that the fuel cost construct used to determine merit order in the in the STEP8760 model does not use values directly from the AEO. Instead, it uses a monthly fuel price construct based on local historical data for natural gas, and an actual value for coal used at the Monroe coal generation plant, pulled from a recent public rate case, for the starting value of coal. We then use the relative cost pathways mapped out in AEO scenarios to extrapolate future prices for fuels based on our localized starting prices.

Accelerated Generator Retirements

Although some generators in MISO Zone 7 have stated retirement dates, many do not, others do have stated dates, but they are currently contested. Where possible, we use stated generator retirement dates. However, if "Yes" is selected for this parameter, we set earlier retirement dates for contested generators, and we determine a set of retirement dates for another set of generators based on our understanding of the economic and political trajectories of some types of generation. The full list of generators included in the model and the standard and accelerated retirement dates can be seen in Table 3 in the "STEP8760 Tables" Excel file.

Portfolio Standard

STEP8760 calculates the percentage of MWh generated by renewable energy and the percentage of MWh generated by clean energy. Clean energy includes nuclear generation, while renewable energy does not. The portfolio standard is set as a constraint on one of these two metrics, depending on the selected standard.

The Business as Usual option maintains a 15% renewable energy goal for all model years. The MI Healthy Climate Plan option assumes adoption of a 60% renewable energy goal in all model years from 2030 onward. The Success of Biden Goals option adopts the Biden administration's stated goal of 100% clean energy by 2035.

Electrification Pathway

Both vehicle and building electrification will play an important role in Michigan's load growth over the coming decades. However, it is difficult to determine at what pace new technologies will be adopted. We setup three potential electrification pathways that incorporate different scenarios for vehicle and building electrification. The details of these electrification pathways can be seen in Table 4 in the "STEP8760 Tables" Excel file.

Wind Build Constraint

Our initial runs of STEP8760 did not include binding constraints on renewable energy generation build-out. This resulted in the model preferring massive build out of wind energy to meet increasing electricity demand in winter months as winter heating load and winter EV charging were projected in later model years. Wind build-out was also driven by the wind's relatively low LCOE due to the production tax credit, especially when compared, in Michigan, to solar which has a low capacity factor in Northern states.

While we find these STEP8760 results interesting, we recognized that the model was exceeding both the technical potential and the political realities of wind siting in Michigan. Consequently, we set constraints on wind development on some model runs. We tested two constraints:

The first constraint approximated Michigan's technical potential for on-shore wind development, which we set at an additional 19.5GW or 6.5GW per model year from 2030-2040.

The second constraint was even tighter, and we determined it to be the limit of politically feasible siting potential. This constraint was 6.6GW or 2.2GW per model year from 2030-2040. Even this constraint we believe is ambitious without substantial political reforms to siting and/or property tax policy.

22.7.1.3 Model Simplifying Assumptions

Because we have built an Excel-based model with the express purpose of it being more accessible and manipulable than a proprietary black-box model, we have had to make some simplifying assumptions to keep it within the capabilities of Excel, which make it less computationally intensive than commercial IRP models.

We assume that transmission within the modeled area is unconstrained and that transmission between the modeled area and the rest of the world has a single capacity limit. Given that the TCL&P service area is small and compact, we assess that the assumption that transmission within the modeled area is unconstrained is reasonable. Any transmission capacity limitation between TCL&P and the rest of MISO Zone 7 will be dealt with as a cost that may affect tradeoffs between generation within and outside of TCL&P's service area. We have done multiple comparisons of our modeled MISO Zone 7 pool locational marginal prices to actual MISO Zone 7 day-ahead prices and found good correspondence, so we do not assess that the assumption that transmission within MISO Zone 7 is unconstrained is important to the accuracy of STEP8760 in this context.

We do not formally impose a full set of start-up, ramp-rate, and shut-down constraints on each generator as is done in a typical production scheduling and costing model through unit commitment logic. Thus far in our use of STEP8760 we have not observed problematic results. Start-up, ramp rate, and shut-down constraints are important characteristics of nuclear, coal, and other steam plants and are less significant for wind, solar, batteries, combustion turbines, and even combined cycle plants. In STEP8760, we have chosen to model nuclear plants as largely non-dispatchable since they essentially always operate in existing markets, if available. As the generation mix in MISO Zone 7 exits coal and adds renewables, gas, and storage, this simplification will become increasingly less relevant.

Portfolio optimization is done year-by-year and not over the full-time horizon of the analysis. The commonly used mathematical techniques for cross-year optimization are mixed integer programming in which resource options are identified by year of initial operation as well as their other characteristics, and dynamic programming in which the value of an option in any given year is assessed by looking at the options it forecloses going forward or backward in time. The computational burden of these methods is very high. These methods are most important when resources are very "lumpy," such as building a very large generation plant, or when costs are very dynamic so that building a resource at a particular time forecloses a real option to build a similar resource sooner or later. 5 Lakes Energy has developed practices in performing scenario analysis using STEP8760 that emulate the logic of dynamic programming and will address the optimal timing of resource acquisition. We assess that this simplification must be understood but will not materially affect the development of TCL&P's integrated resource plan.

STEP8760 is deterministic in a single run. We therefore use the common practice of performing stochastic analyses through iterative runs with varying assumptions; many tools that provide stochastic analysis simply apply this method through automated iterative runs. Iterative model runs require some effort, so this simplification in STEP8760 creates a tradeoff between user effort and the scope of stochastic analyses. We address this simplification in our proposal by proposing a structured approach to discovery of the uncertain factors that matter in the integrated resource plan, development of an uncertainty analysis through iterative runs, and building a risk analysis on that basis. Our experience is that in a typical integrated resource planning effort, only a few factors materially affect the resource decisions to be made and that optimal resource decisions are changed only at a few key threshold values of the uncertain decision factors. Our approach therefore tends to clarify the factors about which judgements, or bets, must be made to manage risks as contrasted with brute force methods that use a large number of iterations and present statistical distributions of outcomes but often fail to elucidate what causes risks.

STEP8760 models battery operation using a modified version of a VBA algorithm developed by K.R. Ward and Iain Staffell and published in the Journal of Energy Storage in 2018[38]. This algorithm efficiently simulates price-aware storage without time-consuming linear optimization. It is a perfect-foresight model meaning that the determination of when to charge or discharge is not limited by a receding window of knowledge. For example, a good deal of variation in electricity use is determined by weather. A real-world battery operator will have to determine when to charge and discharge their battery without perfect knowledge of future electricity prices, and in practice, would attempt to algorithmically guess future electricity prices based on weather predictions, historical pricing, and experience. A perfect-foresight model operates battery with full knowledge of future electricity prices, and thus may operate unrealistically optimally. However, in our modeling, battery cannot operate at the sub-hourly level, and thus cannot benefit from short-duration price arbitrage and the sale of other grid-services the way a real battery operator might.

[38]https://www.academia.edu/38055623/Simulating_price_aware_electricity_storage_without_linear_optimisation?email_work_card=view-paper

In total, we expect that the latter benefit of sub-hourly battery operation and grid services would provide more benefit to the operator than perfect foresight. Thus, we expect STEP8760 undervalues, rather than over-values battery operations.

22.7.2 STEP Forward TCLP

22.7.2.1 File Layout

Delivered with this report are a set of files named "STEP_Forward_Optimized_v7" with an additional suffix describing the optimization constraints or electrification pathway applied in that version of the file. These suffixes are:

- NoWind – wind was constrained to zero in the optimization such that only new solar and battery could be built by the model
- PartialWind – wind was constrained to one third of solar by MW nameplate capacity, such that only a portion of new build could be wind
- K35 – the Kalkaska plant is dropped from the model starting in year 2035, this forces the optimization to replace Kalkaska's capacity and generation starting that year
- PEPBAU – after running our planned three electrification pathways—a business as usual pathway, our projected efficiency and electrification pathway, and a net zero pathway—we opted to add a fourth pathway that uses the business as usual pathway for 2025 and the projected electrification pathway for all subsequent years. Files with this suffix contain only that pathway, where as other files contain the other three.
- No Suffix – the file with no suffix has no constraints applied to the optimizations

The first four sheets of each Excel file are the only sheets with immediately interesting data. They are the results of the modeling in their complete form. Each of these four sheets is identical in appearance, but uses a different MISO Zone 7 scenario for its inputs. Every other sheet contains necessary background data but can be ignored unless viewers are interested in directing the model's inputs and structures. Figure 22-20 below shows the layout of the STEP Forward files.

Figure 22-20 Layout of STEP Forward TCLP files

22.7.2.2 STEP Forward Model Reporting Metrics

Each model contains *Electricity Sales* as its first row, which is all negative values and shows the total need or use of/by TCLP in that model year. At the bottom of each model are rows for *Total TCLP Resources* and *Net Portfolio;* these rows show the sum of all TCLP resources, and their net portfolio of resource—*Electricity Sales* + *Total TCLP Resources* respectively. All other rows are either existing or new (projected) generation resources.

For the total system and each generation resource in the modeled portfolio, both existing and future, we report the below set of data:

- Nominal Capacity—The nominal capacity of the generation resource. For existing generation sources like Belle River Coal, or the Pegasus/Huron Wind farm the value here is the MW portion of the project that TCLP has contracted for. For new generation resources, those that the model suggests TCLP build or contract for, this is the nominal capacity value of those new resources.
- Levelized Cost of Nominal Capacity—The yearly fixed costs of the ownership stake TCLP has or could have in a resource. In the case of Belle River, Kalkaska, and the Transmission Project, these costs are based on real values supplied by TCLP. For new solar, wind, battery, these costs come from NREL's ATB report, and represent either the moderate or conservative technology cost pathways and are the same as those used in the associated STEP8760 model scenario. Detailed information can be found in tables 1 & 2 of the "STEP8760 Tables" Excel file.
- Annual Energy [production]—The projected MWh production of each resource in the portfolio. For existing contracted wind and solar projects this is the estimated production of each resource as forecast in TCLP's PPA for each project. In some cases, these values are less or more than the actual production of those projects. The deployment shape of TCLP's existing wind and solar resources are determined by using indexed wind and solar profiles generated from the average 2018 wind and solar profiles for all Consumers and DTE wind and solar projects across the state of

Michigan. New wind and solar generation resources are also ascribed to these average generation profiles as scaled to the amount deployed by the model. Thermal generation profiles (Belle River and Kalkaska) are produced using the STEP8760 model output in the modeled scenario but are scaled to the proportion of those generators' production contracted for by TCLP. In some scenarios, STEP8760 has modeled Kalkaska as running more than it is legally allowed to, we do not see this as an issue for the validity of the results of STEP8760, as it is small and one of many similar generators in the model. However, in the STEP Forward TCLP model, the over-running of Kalkaska would produce problematic results. Consequently, we added a parameter that allows Kalkaska's generation profile to be throttled to a specific capacity factor. We maintained this capacity factor as 20% in all of our modeling as this value aligns with what is currently permitted by the EPA for Kalkaska.

- Annual RECs [produced by the resource]—RECs are calculated as the energy value of each renewable generation source less its portion or curtailed energy in the year. We simplify our calculation of curtailment such that we do not consider the hourly profile of generation resources, or their geographic proximity to load, only their respective share of total curtailed energy in the model year. This simplification may overvalue or undervalue the number of RECs from a given resource, depending on the generation mix in the underlying STEP8760 scenario. However, given how small a portion of total generation curtailment is, we do not think this simplification causes problems for our overall system model.
- Annual Variable Energy Cost—Energy Costs for Belle River and Kalkaska are pulled directly from STEP8760's calculation of hourly production costs which includes both fuel costs and variable operation and maintenance costs. For Kalkaska, this is scaled appropriately, as described above. For new, model determined, renewable generation energy costs are zero. For existing renewable generation resources contracted for by TCLP, variable energy costs are the actual expected cost of the PPA in the model year based on TCLP's contracted price.
- Annual Wholesale Energy Revenue—Energy costs/revenue is calculated as the sum of the price of power in each hour, as calculated in STEP8760 for each scenario, multiplied by the hourly generation of each renewable energy resource.
- Annual Transmission Costs/Revenues—TCLP's annual transmission cost is calculated by finding the sum of TCLP's load during the system peak hour (for all of MISO Zone 7) in each month and multiplying it by the estimated value of transmission. Transmission value comes from TCLP's actual data, and is trended forward in time to estimate future transmission costs.
- Capacity Credits [seasonal]—We calculate the capacity value of each generation resource for each season. By MISO's capacity accreditation rules, seasons are each three months long with winter being the months of December, January, and February, the rest of the seasons following this pattern accordingly. Capacity credits for new resources are calculated as the average production of the resource in the tightest 65 hours of the season—the hours with the lowest reserve dispatchable capacity. Capacity credits for Kalkaska and Belle River are these plants' actual capacity accreditation in 2021. Capacity credits for TCLP's existing contracts for renewable resources are calculated as a fraction of their total capacity accreditation in 2021 based on the resources' MW shares of that total. This approach was used because we did not receive capacity accreditation data for individual renewable generation resources. It should be noted that these values are substantially less than what would be calculated by tight-65 methodology described above. We believe what accounts for this is a shift in how MISO accredits renewables--in previous years, accreditation was based on the single tightest hour in the season, rather than an average of the 65 tightest.
- Capacity Value [dollar value/expense of capacity credits]—Capacity value/cost is calculated as the produced or required capacity credits multiplied by three-quarters of CONE(Cost of New Entry), as calculated by MISO for the 23/24 year.[39]

[39] https://cdn.misoenergy.org/20221012%20RASC%20Item%2004c%20CONE%20Update626542.pdf

- Annual Net Revenue—The sum of *Annual LCONC, Annual Variable Energy Cost, Annual Wholesale Energy Revenue, Annual Transmission Costs / Revenues,* and *Capacity Value*.
- Annual GHG Emissions (mmt CO2 eq)—The annual direct CO2 emissions of each resource in millions of metric tons based on the plant's emissions rate per MWh as calculated in STEP8760 from EPA data.
- Annual Social Cost to Climate [of emissions]—The calculated cost of the climate harms attributed to each plant's direct GHG emissions based on a 2022 EPA report: Estimates Incorporating Recent Scientific Advances. External Review Draft in Docket No. EPA-HQ-OAR-2021-0317.
- Annual Social Cost of Pollution [of emissions]—The calculated cost of the societal harms (health costs) attributed to each plant's direct GHG emissions based on values documented at https://www.epa.gov/cobra.

22.7.2.3 STEP Forward Optimization

In each model year there are three rows with new resources that are optimized using Excel's solver function to find the best resource mix for that model year, given all other model parameters and resources. Although New Storage Power and New Storage Energy are shown separately, only power is a variable in the optimization. Storage energy is a function of power and is based on the optimization of storage energy in the underlying STEP8760 model, where energy and storage were optimized separately.

The optimization function is designed to meet the following criteria:

- *Net Portfolio* Annual Energy <= 0, such that TCLP's generation portfolio will meet but not exceed the energy demanded in that model year. In some cases, TCLP's net annual energy is greater than 0. This results from either a reduction of load between model years, or an increase in generation by one of the fossil generators in TCLP's portfolio which results from that generator running more in the STEP8760 model for that year than it did in the prior model year.
- *Net Portfolio* for each seasonal capacity credit >= 0.
- Additional constraints as described in *File Layout* above may also be applied during optimization.

Acknowledgements

Work done pursuant to contract with TCLP

This report was prepared by 5 Lakes Energy and its partners Elevate Energy, Michigan Energy Options, and NextEnergy pursuant to contracts between Traverse City Light and Power and 5 Lakes Energy. 5 Lakes Energy's obligations under these contracts are to provide analyses and recommendations upon which Traverse City Light and Power can adopt a Climate Action Plan. These analyses and recommendations cover climate neutrality policy, energy efficiency, building electrification, transportation electrification, demand response, distributed generation, electricity storage, and an integrated resource plan that will guide TCLP's future portfolio of resources and programs.

5 Lakes Energy (5LE)

5 Lakes Energy, a Michigan-based limited liability corporation founded in 2010, is a policy consulting firm dedicated to mitigating climate change by advancing the deployment of clean energy. For more than a decade, they have built a solid reputation for expertise in energy systems and utility regulation, unbiased quantitative analysis, sophisticated modeling capability, and effective public policy advocacy. Clients have included businesses, industry associations, public interest groups, philanthropic foundations, environmental nonprofits, attorneys, and state and local governments.

Elevate Energy (Elevate)

Elevate is a 501c3 nonprofit working at the nexus of energy efficiency, sustainability, and affordable housing for over 20 years. Elevate seeks to create a world in which everyone has clean and affordable heat, power, and water in their homes and communities – no matter who they are or where they live. Making the benefits and services of the clean energy economy accessible to everyone is how we fight climate change while supporting equity.

Elevate is based in Chicago and works nationally, with offices in Michigan, Wisconsin, Missouri, Oregon, Washington, and California. We have Michigan-based employees in Grand Rapids, East Lansing, Ann Arbor, Detroit, and Marquette. With a team of nearly 170, Elevate delivers high-quality programs, services, and research that contribute to healthy, thriving communities both locally and nationally. Elevate have extensive experience in energy efficiency and smart grid program management, most recently serving as implementer for joint utility income-eligible multifamily, public housing, and nonprofit energy efficiency programs as well as low-income solar programs in Illinois and Michigan. In addition to efficiency and solar, their expertise includes supporting local government agencies with climate action plans and comprehensive state energy plans including the State of Iowa, State of Missouri, Iowa City, Washtenaw County, City of Detroit, City of Ann Arbor etc. Elevate's clients range from utilities, municipalities, and federal agencies to real estate portfolio managers, building owners, and residents.

Michigan Energy Options (MEO)

Michigan Energy Options (MEO) is a nonprofit that has been in business since 1978. From its offices in East Lansing and Marquette, MEO pursues daily its mission of guiding communities toward being more sustainable and resilient through the adoption of energy efficiency and renewable energy. MEO does this by providing unbiased expertise, research and results-driven programs, all the while working collaboratively with local governments, businesses, utilities and community leaders.

NextEnergy (NextEnergy)

NextEnergy works with a variety of industry partners to transform innovative technologies into solutions that will create a better quality of life for all. Based in the center of Detroit's growing innovation district with access to a microgrid, smart home, electric vehicle charging infrastructure and an alternative fuels platform, NextEnergy demonstrates and pilots technologies in real-world environments to gather data and diverse user-experiences. This process helps to quickly scale and deploy solutions by accelerating commercialization in two key areas:

- Smartt Mobility: Connected, automated, shared and electrified (CASE) mobility solutions and how they interact with the surrounding infrastructure and systems.
- Smart Grid: Smart, energy-efficient solutions for buildings and homes, and how they interact with the surrounding infrastructure and systems.

NextEnergy's depth of experience, technical knowledge and established network of partners allow them develop effective programs and pilots and facilitate new relationships to help clients achieve their commercialization goals.

Authors and Roles

Work embodied in this report and the report itself were authored by the people listed below.

David Gard (5LE)

David performed most of the buildings load profile analysis, building efficiency and electrification benefit-cost analysis, and coordinated the integration of these analyses with related program recommendations.

Eli Gold (5LE)

Eli processed and managed TCLP's AMI data, performed the transportation electrification requirements analysis and the integrated resource plan analysis.

Douglas Jester (5LE)

Douglas guided the analyses behind and the writing of the report and represented the team throughout the stakeholder engagement process.

Brandon Kawalec (MEO)

Brandon focused on TCLP's energy waste reduction efforts relying upon his extensive experience managing other municipal utility programs.

John Kinch (MEO)

John and MEO Team analyzed utility program offerings and recommended future options to deepen customer engagement in existing and emerging efficiency and distributed energy resources.

Michael Larson (MEO)

Michael and Brandon analyzed the cost-benefits of existing TCLP EWR programs and what new offerings could potentially achieve in terms of energy and cost savings.

Jamie Leonard (NextEnergy)

Jamie analyzed current vehicle charging using TCLP's public charging network and worked on demand response analysis.

Henry Love (Elevate)

Henry worked with the 5LE team to develop the electrification methodology and led Elevate's efforts for program design recommendations.

Eric McDonald (NextEnergy)

Eric led development of the demand response analysis.

Rob Ozar (5LE)

Rob developed the analysis of behind-the-meter solar and storage resources.

Jamie Scripps (Hunterston Consulting)

Jamie coordinated project activities for the team and assisted in the development of materials used in stakeholder engagement.

Tim Skrotski (Elevate)

Tim participated in public engagement events, provided educational materials on electrification, and worked with the Elevate team on developing electrification program design recommendations.

Graham Woolley (5LE)

Graham provided analyses of transmission basis and modeled transformer aging in relation to load and ambient temperature in support of the integrated impact assessment in this report.

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Glossary

AMI – Advanced Metering Infrastructure
ASHP – air-source heat pump
ATB – Annual Technology Baseline
BAU – business as usual
BTM – behind the meter
BYOD – bring your own device
BYOT – bring your own thermostat
CBECS – Commercial Buildings Energy Consumption Survey
CO2 – carbon dioxide

COBRA – Co-benefits Risk Assessment
CONE – cost of new entry
COP – coefficient of performance
COP27 – Conference of the Parties of the UNFCCC 27
COS – cost of service
CPP – critical peak pricing
DOE – Department of Energy
DR – Demand Response
EGLE – Michigan department of Energy Great Lakes and Environment
EMS – energy management system
EPA – Environmental Protection Agency
ERV – energy recovery ventilator
EULP – end use load profile
EV – Electric Vehicle
FERC – Federal Energy Regulatory Commission
GSHP – ground-source heat pump
HOMER – Hybrid Optimization of Multiple Energy Resources
HRV – heat recovery ventilator
HVAC – heating, ventilating, air conditioning
IPCC – Intergovernmental Panel on Climate Change
ISO – Independent System Operator
kWh – kilowatt hour
LRZ7 – MISO local resource zone 7
MC – marginal cost
MDOS – Michigan Department of State
MDOT – Michigan Department of Transportation
MEMD – Michigan Energy Measurements Database
MIHCP – Michigan Healthy Climate Plan
MISO – Midcontinent Independent System Operator
MMP – Modeled market price
mmt – million metric tons
MOU – Memorandum of Understanding
MPPA – Michigan Public Power Agency
MVA – mega volt-amps
mWh – megawatt hour
NDC – nationally determined contribution
NOx – nitrogen oxides
NPV – net present value
NREL – National Renewable Energy Laboratory
NZEP – net zero energy pathway
PACE – Property Assessed Clean Energy
PEP – projected energy pathway
PM2.5 – particulate matter 2.5 micrometers and smaller
PV – photovoltaic
REAP – Rural Energy for America Program
REC – renewable energy credit
RTO – Regional Transmission Organization
SO2 – sulfur dioxide
SRE – sensible recovery efficiency
sREC – solar renewable energy credit
TEDB – Transportation Energy Data Book

TOU – time of use
UFS – Utility Financial Solutions
VFD – variable frequency drives
VSD – variable speed drives
WSHP – water-source heat pump