“Cooperative is an Oxymoron”: The Polycentric Energy Transition of Midwestern Electric Cooperatives to Load Management Technologies, 1940s to Present

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This project's leaves trace to roots in the woods, rivers, farms, and towns here in the Midwest. Returning to these places and ideas, I learn they are fractal and prairie-like and are strings in a loom. So it was talking with the interviewees (from one of whom the "oxymoron" phrase came about) that allowed me to explore the ways in which the fractured and whole possibilities of the future, of my home, outgain the doomy, unlaughing probabilities of the past.

Thank you to my interviewees who warmly shared so much of their lives with me. I tried my best to represent the impressive and real work you do every day.

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ABSTRACT

Since the 1940s, Minnkota Power Cooperative, Great River Energy (then United Power Association and Cooperative Power), Dairyland Power Cooperative, and East River Electric Power Cooperative in the Midwestern United States have deployed nearly 600,000 load management devices with their more-than 1.2 million member-owners. Building upon technological innovation systems theory and using case studies of the co-ops, I show the importance of intermediaries such as contractors and distribution cooperative managers in facilitating the deployment of these distributed energy resources for the co-ops. I then use common pool resource rules to highlight the intermediary functions that helped drive the common pool resource of the co-ops' innovations. This research has implications for future decarbonized distributed energy resource deployments and the electrification of formerly fossil-fueled technologies. More widely, this study shows the potential need for appropriate levels, connectedness, and locations of polycentric governance within a far-reaching, deep, and distributed energy resource transition.

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LIST OF ABBREVIATIONS AND ACRONYMS

CIP	Conservation Improvement Program
Co-op	Electric Cooperative Utility
CPA	Cooperative Power Association
CPR	Common Pool Resource
DERs	Distributed Energy Resources
DSM	Demand-side Management
EIA	U.S. Energy Information Administration
IPCC	Intergovernmental Panel on Climate Change
G&T	Generation and Transmission Cooperative
GRE	Great River Energy
kW, kWh	Kilowatt, Kilowatt-hour
MISO	Midcontinent Independent System Operator
MW, MWh	Megawatt, Megawatt-hour
NRECA	National Rural Electric Cooperative Association
PUC	Public Utilities Commission
REA	Rural Energy Administration
RUS	Rural Utilities Service
UPA	United Power Association
USDA	U.S. Department of Agriculture
WAPA	Western Area Power Administration

1. INTRODUCTION

Energy transitions can depend on cooperation and competition within layers of polycentric governance (Cole, 2015; Köhler et al., 2019; Nowak, 2006; Ostrom, 2010). Cooperation and competition occur through implicit and explicit terms, through inactions such as technological lock-in and incumbent non-participation, and through actions such as supply- and demand-side norms and policies. These multiple layers and centers of institutions and actors are important in the face of climate change, which as a problem of the global commons, will use any number of nested combinations of cooperation and competition to reduce greenhouse gas emissions.

At the macro-level, currently there is little progress on limiting climate change-causing emissions. The United States' carbon emissions rose from 2017 to 2018 by 3.4% (Plumer, 2019). Global carbon emission matched that trajectory, growing by an estimated 2.7% in 2018 alone (Hausfather, 2018). Some sectors are more responsible for these increases, yet all play a role in the continued growth of carbon-emitting resources. The Intergovernmental Panel on Climate Change (IPCC) wrote in 2018 that "pathways limiting global warming to 1.5°C with no or limited overshoot would require rapid and far-reaching transitions in energy, land, urban and infrastructure... and industrial buildings" (Intergovernmental Panel on Climate Change, 2018). To achieve no or limited overshoot of keeping global temperature rise under 1.5 degrees-Celsius, the IPCC says that carbon emissions must decline by 45% from 2010 levels by 2030, reaching net zero by 2050.

From country to country, these sectors' contributions to climate change vary. For example, Figure 1.1 below shows greenhouse gas emissions in different sectors over a 26-year time period in the United States (U.S. Environmental Protection Agency, 2017). Electricity generation has shown downward emission trends in recent years, and other sectors have remained relatively flat. After years of electricity generation producing the most greenhouse gas emissions, electricity generation is now second to transportation (U.S. Energy Information Administration, 2017).

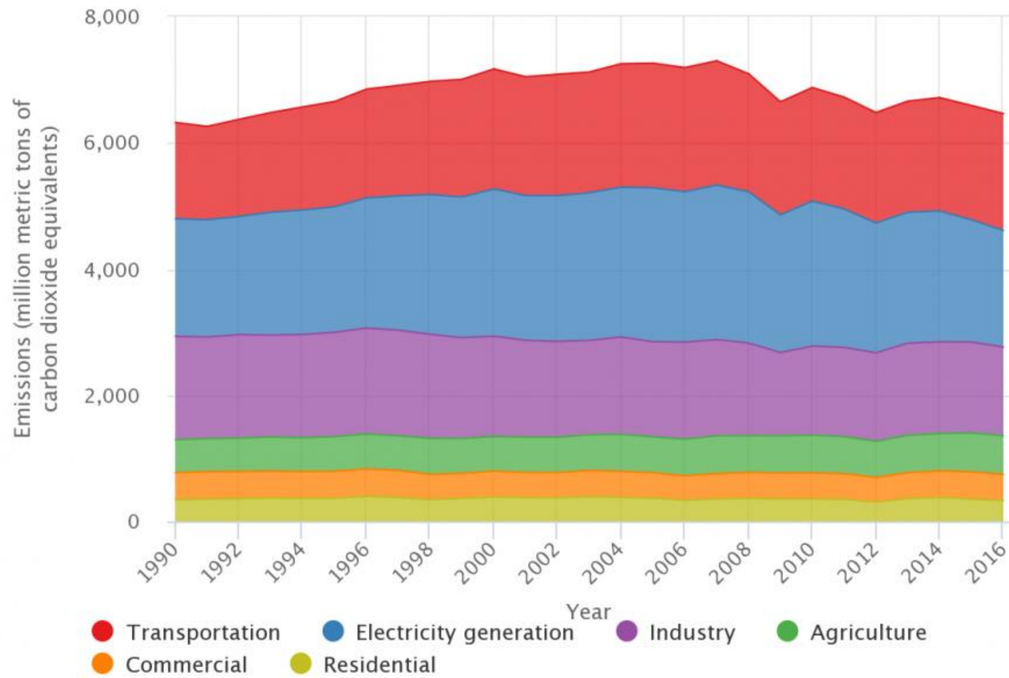


Figure 1.1: U.S. Greenhouse Gas Emissions by Economic Sector, 1990-2016.

The switch-off between transportation and electric generation highlights that decarbonization will demand a multi-sector mobilization of approaches and policies (Harvey, Orvis, & Rissman, 2018). Yet within each sector, there are multitudes of dynamic, complex greenhouse gas emitters, and there can be considerable differences among them in governance models, business models, or infrastructure choices. Perhaps for these differences between and within sectors, or nations, the IPCC authors say there are no global precedents for large-scale energy transitions.

The IPCC nonetheless says small-scale, fast-paced energy transitions around the world have continuously occurred within specific sectors, technologies, and spatial contexts. These energy transitions are the subject of repeated research and inquiry, each showing in their own way how a future sustainable and decarbonized energy system should or could occur (Köhler et al., 2019; Loorbach, Frantzeskaki, & Avelino, 2017). While past and more contemporary processes do not necessarily indicate future potential, they can show unseen connections and possibilities for creating a more equitable, faster, and efficient transition to decarbonization or sustainability in general (R. F. Hirsh & Jones, 2014)

Through this paper, I intend to show possible transition paths and policies for an energy transition involving the mass mobilization of more distributed energy resources (DERs), which include energy efficiency, demand response, load management, distributed generation, and even the electrification of end-use technologies. DERs tend to play an important role in many climate change mitigation strategies. In modelled scenarios with no or limited overshoot of 1.5 degrees-Celsius, the IPCC shows lower energy usage and faster electrification of fossil fueled end-uses is necessary to remain under the 2 degrees-Celsius warming scenarios. While there are other IPCC paths assuming a greater expansion of centralized carbon capture and storage plants, the International Energy Agency notes that more energy efficiency – from mitigating power plant conversion losses, to storing or shifting energy or actively reducing demand – is widely expected to be essential to meeting global carbon reduction goals in the coming decades (Geels, Schwanen, Sorrell, Jenkins, & Sovacool, 2018; International Energy Agency, 2017). Because distributed energy resources play roles regardless of a preferred national or global path to decarbonization, and because they impact many types of localities and regions, it's necessary to understand how institutional and actor roles impact distributed energy deployment.

For my study on actors and institutions, I use an often-overlooked geography of the energy transitions research. I look to the Midwestern United States and focus on electric cooperatives, whose history is specific to the United States, and their load management systems, whose controls allow them to turn on and off or modulate hundreds of thousands of water heaters, irrigators, air conditioners, and other technologies in their member-owners' homes and businesses. Specifically, I look at four electric cooperative load management systems and their programs' deployments in the 1940s onward: Minnkota Power Cooperative, East River Electric Power Cooperative, Great River Energy (a merger of Cooperative Power Association and United Power Association in 1999), and Dairyland Power (Figure 1.2). Collectively, these co-ops deployed nearly 600,000 load management devices for their more-than 1.2 million member-owners between the 1940s and today.

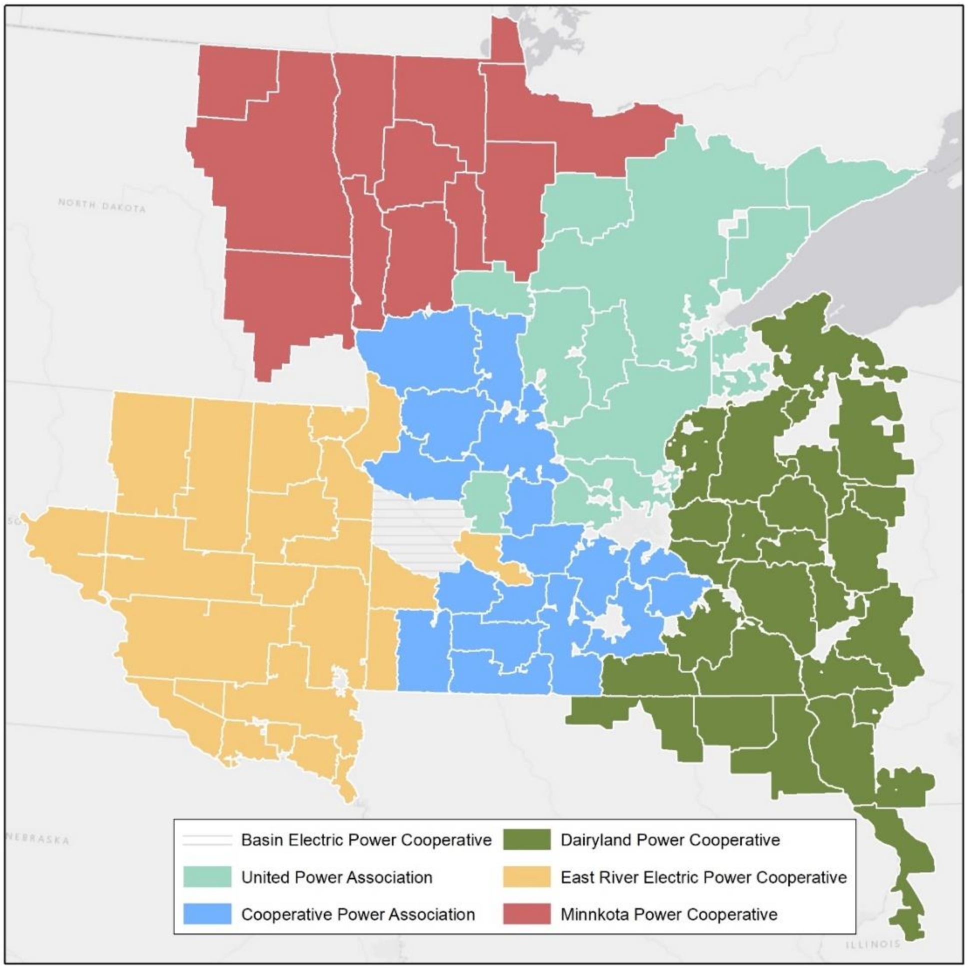


Figure 1.2: Service Areas of Five Generation and/or Transmission Cooperatives in the Upper Midwestern United States, Pre-1999. Every system except for Basin Electric Power Cooperative (delivering power to Minnesota Valley Cooperative Light and Power in western Minnesota) developed its own load management programs from the 1970s onward. Largely unregulated by national and state authorities, the generation and transmission cooperatives of the United States often span multiple states with member distribution cooperatives. The member distribution cooperatives share resources through these G&Ts: efficiency programs, billing systems, outreach efforts, and policy planning are just a few shared functions. While the service areas demarcated above represent present ties, they are the cumulation of years and decades of mergers, additions, and subtractions from each G&T service area. East River, for instance, was formerly all centered in South Dakota. Same with Dairyland and Wisconsin.

This research fills important research gaps that have potential policy and research impacts. In the energy transition literature, sub-national contexts are understudied, and localized niches are ignored both by research and many policy efforts (Graff, Carley, & Konisky, 2018; Mattes, Huber, & Koehrsen, 2015). In the academic literature, or policymaking more broadly, electric cooperatives in the United States are also not often the subject of focus (Lenhart, Chan, Forsberg, Grimley, & Wilson, Forthcoming). Moreover, these electric cooperatives' history is often contained within self-published or affiliate-published histories, leaving much shrouded about their structure, motives, and place within the energy landscape and general history of the United States.

To inform my study of these electric cooperatives' distributed energy resource-based transitions, I use current literature and theory on energy transitions, specifically the multi-level perspective and technological innovation systems. I examine the rate, means, and type of transition that allowed these electric cooperatives to deploy tens of thousands of distributed controls, communications, and devices in just a few years' time, and sustain them for the decades thereafter as policies, personnel, and technology shifted. Finding that the cooperatives' intermediary innovation functions help form polycentric governance models, I show that the creation of long-lived and potentially-rapid deployments of distributed energy resources may be understood as management schemes for common pool resources (CPR). As energy transitions spanning multiple sectors or regions are often overlooked, and the important boundary-spanning and actor-connecting roles of innovation intermediaries are often misunderstood, this research fills an important current need to understand how innovation is cultured and constructed (Kivimaa, Boon, Hyysalo, & Klerkx, 2019; Köhler et al., 2019).

The electric cooperatives' polycentric governance structures in deploying their load management programs allows for an examination of the promise and pitfalls of self-governance within energy transitions. In policy and politics, American electric cooperatives are often lightly-regulated at the state and federal levels, instead governed mostly by democratically-elected boards of directors at the distribution level. Because the distribution utilities are provided power by generation and transmission cooperatives (G&Ts), on whose boards their board members vote, they must represent their interests within vertical and horizontal governances that can seem complicated to outside observers. For example, East River Electric Power Cooperative in South Dakota buys power from Basin Electric Power Cooperative and the Western Area Power Administration; in turn, it provisions electricity and infrastructure to 24 distribution cooperatives and 1 municipal utility (Figure 1.3). Between these layers, some duties such as government affairs, marketing, and load management control are centralized at East River's level, while others such as wholesale market activities or billing may be decentralized or shared at the power supplier or distribution utility. Each G&T/distribution utility system's governance is independently determined by the member utilities of that system. These arrangements remain unique and negotiated throughout time, representing a polycentric tradition worthy of further study beyond this thesis.

Figure 1.3: Power Supply Network of East River Electric Power Cooperative. East River is unique among G&Ts in that in only supplies "T," or transmission, to its member utilities, whereas many others provide both power and transmission. Additionally, several of its member utilities buy electricity from it only for peak power conditions, with the remainder buying all power from East River. These individual differences speak to the polycentricity of their and other G&T networks. Adopted from East River's website.

Load management, also known today as “demand response,” also provides a useful framing lens to the polycentric transition: in shifting load, and determining how to appropriate costs and benefits, these cooperatives are necessarily negotiating the pace and legitimacy of their transition. Their transition does not directly involve clean energy or decarbonization; instead, it can allow for greater system flexibility with the control of customer-sited devices. Overall within the literature, load management’s development might be categorized around diffusion of end-use devices such as lighting or air conditioning (Sovacool, 2016). It might also fall under a subset of technologies today known broadly as “energy efficiency,” and be examined closely in conjunction with distributed generation and energy conservation (Geels et al., 2018; Kuzemko, Mitchell, Lockwood, & Hoggett, 2017). As Kuzemko et al. (2017) notes, “Demand reduction and energy efficiency, together with active demand side response, can also ensure the most *efficient* use of decarbonized generation capacity thereby also bringing down the overall costs of energy systems.” Therefore, load management, while not a complete energy transition to a new fuel or technological choice, is instead an intermediating transition that allows for new choices and potentials to be explored within the electric grid.

Load management today is one of several ways to create a more efficient supply-demand relationship in the energy sector (Figure 1.4). While its usage in the past was constrained to devices like residential appliances and interruptible industrial demand, today loads such as electric vehicles, distributed energy storage, and microgrids can all participate in a more-distributed electric grid under demand response programs (Potter, Stuart, & Cappers, 2018). Even water heaters, some of the first load management devices to be used in the world in the early 20th century, are now considered by some to be the nation’s biggest battery, sitting idle in more than 50 million homes across the United States. These and other managed and electrified loads will have a heavy impact in any future state or national decarbonization efforts (Clark W. Gellings, 2017; Vibrant Clean Energy, LLC, 2018).

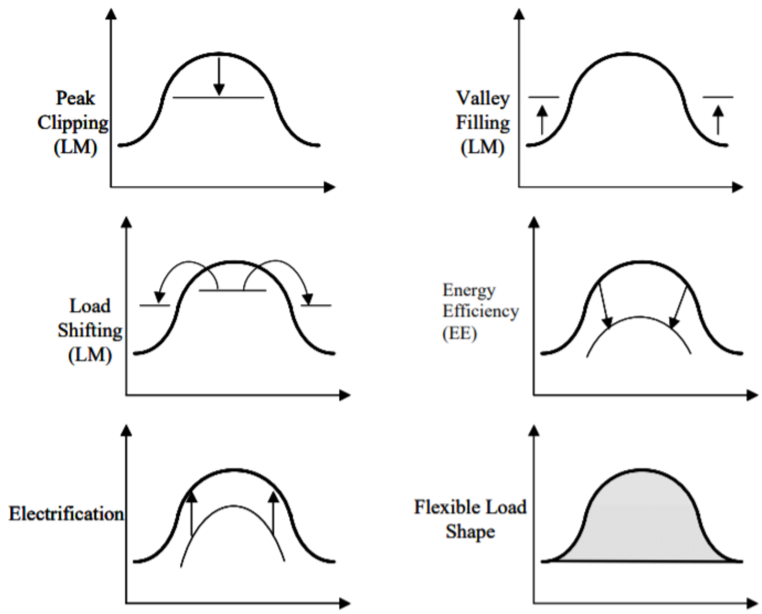


Figure 1.4: Comparisons of Load Curves and Impacts from Load Management, Conservation, and Electrification. These generalized load curves show the relative impact of each type of "load management" practice. These load curves should not be taken as scripture, however: different conservation measures will have different time impacts. For instance, a more efficient A/C unit will impact late afternoon loads the most. Likewise, controllable water heaters, depending on their control system, could shed peaks, valley fill, or even perform flexible load shapes in response to intermittent renewable generation or wholesale market fluctuations. Adopted from (World Bank, 2005).

With one-way communication systems built in the 1970s and '80s, these cooperative load management systems remain alive today. They are in various levels of participation with wholesale markets, and in varying levels of repair or re-creation to two-way communication. Their grid impact is in megawatts and electrified, off-peak energy sales, but their full value may be in the unveiling of social infrastructure, governance models, and deployment efforts that allowed co-ops to deploy hundreds of thousands of load management receivers and end-use devices around a six-state region for more than four decades.

My theoretical framework centers on maintaining that these electric-cooperative are polycentric actors who, to deploy and sustain the distributed energy resource of load management devices, created and managed a common pool resource through intermediary innovation functions.

The remainder of this thesis is focused on examining how and why those functions and common pool rules came into play and, more generally, answering the question, **"How did these cooperatives create and sustain their load management programs?"**

2. BACKGROUND

Electric cooperatives, load management, and polycentricity and energy transitions are covered in the sections below with a brief history of their origins, their organizations and people, and their practices and theories. Some gaps in the knowledge base presented below are expected, especially with electric cooperatives, whose histories remain somewhat hidden.

2.1. Electric Cooperatives in the United States

In the United States, 834 electric cooperatives provide only 12 percent of all electricity sales, but stretch across 56 percent of the nation's land (EIA, 2018; National Rural Electric Cooperative Association, 2017). They serve an estimated 42 million people in 47 states and source power, in part, through 63 generation and transmission cooperatives (G&Ts), which are cooperatives of the distribution cooperatives. The G&Ts often have requirements contracts with their member cooperatives, stipulating how much power the distribution cooperatives can self-supply, if any. All-requirements contracts, which say that distribution cooperatives must purchase all power from the G&T, exist for many distribution cooperatives.

These electric cooperatives exist alongside investor-owned and municipal utilities, who provide more than 51 and 11 percent of electric sales, respectively, in the United States today. Other forms of electric utility ownership include retail power marketers, behind-the-meter third parties, political subdivisions, federal and state governments, and community choice aggregators, who collectively provide the remaining 26 percent of sales in the United States, according to the U.S. Energy Information Administration.

Electric cooperatives trace back to the Rochdale Equitable Pioneers Society, an English mutual self-help organization formed in 1844. It sold products such as butter and sugar and returned surplus profits to its member-owners (Boland, 2017). The Rochdale model spawned principles that became the International Cooperative Alliance's seven principles in 1995. Today, there are many kinds of cooperatives – from farm supply to homecare providers – with varying structures, roles, and purposes. Importantly, cooperatives can span many types of ownership and subsidiary models that respond to member-owners' shifting needs, showing organizational characteristics that reduce risk (e.g. by over-accumulating stock and prioritizing equity over efficiency more than in investor-owned utilities) (Chaddad & Cook, 2004; Sexton, 1986).

Electric co-ops in the U.S. are a type of consumer cooperative. Legally, they are considered nonprofit corporations so long as 85 percent or more of their annual income comes from member-owners (University of Wisconsin Center for Cooperatives, n.d.). Each electricity consumer within an electric cooperative service area currently are de facto member-owners (though not historically, given state-to-state variation on exclusive service area laws). Each member-owner has one vote for the utility's board of directors, who come from the community and help make decisions regarding the co-op's policy, finance, and operations. Excess margin is allocated to membership on varying cycles, sometimes at spans of more than twenty years, due to the long-lived nature of electric utility operational costs. These capital credits or patronage are based on the amount of electricity that member-owner has consumed and returned proportionate to usage.

Cooperatively-owned electric utilities in the U.S. emerged at-scale out of the New Deal legislations of the Great Depression-era, but their early forms were numerous across the world, including the U.S. (Doyle, 1979):

> Farmers and rural communities were organizing for electric service on their own behalf in several regions of the country at least a decade or more before 1930. Early advocates of rural electrification in the United States pointed to the success of rural electric cooperatives serving farms in Germany, Sweden, Denmark, and Ontario during the early 1900s. In 1920… a group of farmers in southwest Idaho formed a non-profit mutual company and built 256 miles of electric lines to obtain power from a U.S. Bureau of Reclamation hydro facility. At about the same time,

> a group of Minnesota farmers near Granite Falls also formed a cooperative, buying power at three cents per kilowatt hour (kwh) from a municipal system… By 1923, thirty-one electric cooperatives had been incorporated in nine states. By 1930, 46 co-ops were operating in 13 states.

Despite early progress in rural electrification in the United States, aided in large part by local universities and electric utility trade organizations, incentives to spread electric lines to the countryside were not enough for investor-owned utilities to act quickly enough (R. Hirsh, 2018). In the 1930s, more than 90 percent of the electricity sales came from private utilities, 70 percent of which were controlled by just eight companies (Cebul, 2018; Spinak, 2014). Some historians felt it was a matter of time before these investor-owned utilities would find profit in their uneconomic power lines to build out completely to farms (Cebul, 2018). Yet private electricity companies were facing their own troubles, too, with the Public Utility Holding Company Act of 1935, which enabled the U.S. Securities and Exchange Commission to break up their many-tiered, monopolistic holding companies (Ellis, 1966).

In 1935, the federally-created Rural Electrification Administration (REA) emerged by Executive Order. It first gave support to for-profit utilities in electrifying the countryside, as many in society at the time bemoaned any government involvement in the environs of private electric business. Yet early successes with the Tennessee Valley Authority's sponsored creation of electric cooperatives were beginning to gain acceptance within various state agencies. These nascent cooperatives often fell short of complete "area coverage," which meant that only through economies-of-scale, or complete electrification of the countryside, could rural electric grids be built economically.

In 1936, with the passage of the Rural Electrification Act, the REA was directed to give low-cost loan preference to non-profit entities. Newly-formed federal power agencies such as the Tennessee Valley Authority and the Bonneville Power Administration were directed to provide low-cost hydro power to the cooperatives as "preference" customers. The first administrator of the REA, Morris Cooke, decided that his agency would not only provide loans to cooperatives, they would also help organize them with their own personnel (Ellis, 1966). Against other forms of ownership, cooperatives won out as a political compromise because there was no other utility ownership form available that could legally or politically complete the job (Spinak, 2014). At the least, lest there be more government involvement in private business, promoting cooperatives was a tool to help coerce the IOUs into providing cheaper electricity rates.

In 1937 the REA drafted model electric cooperative laws for states to follow (National Rural Electric Cooperative Association, 2016). As massive organizing efforts followed, rumors of the government condemning farms for the potential insolvency of the cooperative at first stunted the growth of electric cooperatives in places such as Minnesota (Severson, 1962). Hard-fought volunteers walked up and down roads for $2 to $5 in per-person equity contributions. Skeptical farmers often stood still, waiting for others to purchase a lightbulb or get pestered by extension agents for utility pole easements before they could commit to joining in the new infrastructure.

Beyond politicking, new member-owners of the cooperative faced additional hurdles: the REA required fair wholesale power prices and minimum numbers of member-owners per mile of line before it would approve loans. Once the cooperative lines were energized and rates were established, new consumers often faced high bills. In this way, the early cooperatives depended on economies-of-scale in member-owners and sales, self-determined governance, and federal loans.

Electric cooperatives, for their reliance on federal debt, drew criticism from others like Cooperative League, who represented cooperatives made more from member-owner equity, less on debt. They and other groups eventually settled their grudges as these consumer-owned utilities grew in numbers: by 1939, the REA helped establish 417 new cooperative and just a year later that number increased by more than two hundred (New Deal Network, 2013; Reynolds, 2014). Where in 1935 only 10 percent of farms had electricity, by 1953 more than 90 percent had the lights on (National Rural Electric Cooperative Association, 2016). With electricity also came access to new appliances, overall consumption growth, and parts of “modern” life that were heavily marked by co-ops (Spinak, 2014). Rural America was beginning to change.

The electric cooperatives began scaling. Starting in the ‘30s, they co-created under joint ownership schemes generation and transmission facilities across the United States. The earliest “G&T” formed was the Wisconsin Power Cooperative in 1938, which later merged with another like-organization to become Dairyland Power Cooperative. (Ellis, 1966). Other cooperatives banded with each other to form transmission cooperatives, buying energy from G&Ts and forming a three-tier structure between generation, transmission, and distribution cooperatives. Data gathered in the 1970s reveals that nearly 30 percent of cooperative power in that time was sourced by G&Ts, up from less than 10% in 1940; federal and investor-owned utilities provided the remaining 70 to 75 percent, having alternated in greater shares of sales to cooperatives since 1940 (Doyle, 1979).

From the 1950s on, state agencies for cooperatives that performed legislative and educational duties remained important, but largely were shunned from the REA’s financing process. The agency instead took a larger role in the day-to-day scruples of its co-ops, directing them on rate-setting norms, providing education to board members, and many other activities (Spinak, 2014). Despite the direct federal support, shifting federal politics often interfered with the programs as presidencies and legislatures seemed to alternate over the next decades in their helpfulness and obstruction, raising interest rates on loans and delaying action on others, creating uncertainty for new power projects. In the 1970s, REA loans and loan guarantees increased greatly: for generation plants alone, for whom cost overruns were becoming the norm, the increase was more than 900 percent over a few years. To cope with political instability, the co-ops also grew their own financing sources: the REA provided 100 percent of all cooperative funding as late as 1970, the National Rural Utilities Cooperative Finance Corporation (CFC) and other financiers stepped in to fill as much as 25 percent of funding in 1974 (Doyle, 1979). These financing shifts coincided with the fortification of requirements contracts between G&Ts and member utilities, foretelling the growing self-sufficiency of the electric cooperatives in building centralized generation.

Hundreds of thousands of rural customers were coming online every year in the ‘60s and ‘70s, and with the growth of G&T systems, more money was directed toward larger-scale, centralized coal- and nuclear-generating stations. Historically, co-ops were un- or little-regulated at the local, state, or federal level: in 1970s, public utilities commissions oversaw their rates in some form in only 21 states (Doyle, 1979). A portion of their external regulations came from the REA itself in the form of rate and infrastructure planning approvals. These approvals were necessary for any rate changes by REA borrowers up until the late 1990s, at which point the REA had merged with other departments to become the Rural Utilities Service (RUS) (National Rural Utilities Cooperative Finance Corporation, 2008; U.S. Department of Agriculture, Rural Utilities Service, 2013).

The 1970s saw large disruption for electric utilities that forever changed their outlook. Electric cooperatives were not spared: their costs began to rise, and customer demand began to plummet (Figure 2.1). These consumer-owned utilities, who served mostly residential farm or non-farm member-owners, began to shift from pseudo-government agencies, based on large amounts of debt and increasingly centralized supply, to other business models (J. Cooper, 2008).

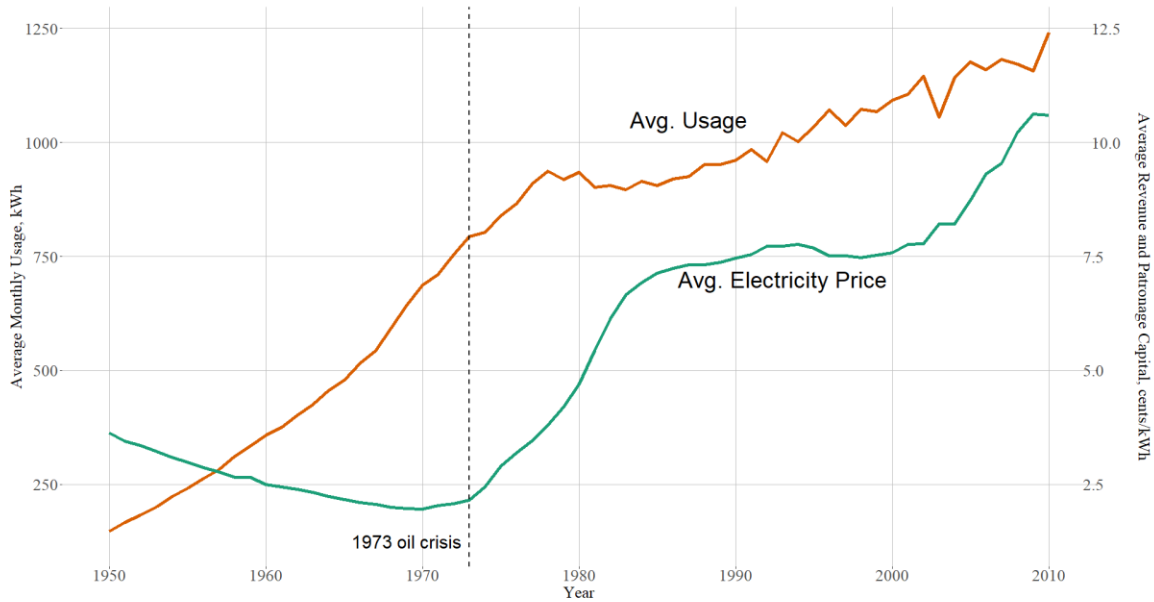


Figure 2.1: Average Usage and Revenue from Residential Member-Owners of REA/RUS-funded Electric Cooperatives, 1950-2010. Prior to 1970, electricity prices fell and consumption rose rapidly. However, the 1970s saw increasing inflation, escalating fuel prices from the 1973 oil crisis, and larger, centralized power stations that became stranded as customer usage began to peter out in the late 1970s. Source: (Richard. F. Hirsh, 1999; U.S. Department of Agriculture, Rural Utilities Service, 2013).

The generation and transmission cooperatives based in and around Minnesota that are the focus of this study weren't that different from other generation and transmission cooperatives of the time in the United States. While their member cooperatives had merged up, even these G&Ts began to merge together, creating a network of co-ops that continues to span six states and supports more than 1.2 million member-owners, as of 2017 (Table 2.1).

Co-op Summary	Date Founded	Organizational Statistics (2017)
Minnkota Power Cooperative *Generation and Transmission Cooperative* All-requirements contracts with member utilities, with 5% self-supply limit	1940	**Revenue:** $375,500,000 **Energy Sales for Resale (MWh):** 7,283,628 **Member-owners Served:** 136,447 members at 11 co-ops and 12 munis at Northern Municipal Power Agency
Great River Energy *Generation and Transmission Cooperative* All-requirements contracts with member utilities with 5% self-supply limit; some member utilities on fixed power contracts	1999, a merger of Cooperative Power Association (1956) and United Power Association (1963)	**Revenue:** $720,195,300 **Energy Sales for Resale (MWh):** 13,339,075 **Member-owners Served:** 695,000 members at 28 co-ops
East River Electric Power Cooperative *Transmission Cooperative, buying power from Basin Power Cooperative and Western Area Power Administration* All-requirements contracts with member utilities	1950	**Revenue:** $257,803,600 **Energy Sales for Resale (MWh):** 3,997,139 **Member-owners Served:** 126,517 members at 24 co-ops and 1 municipal
Dairyland Power Cooperative *Generation and Transmission Cooperative* All-requirements contracts with member utilities, 250 kW self-supply limit	1938	**Revenue:** $414,194,000 **Energy Sales for Resale (MWh):** 5,891,455 **Member-owners Served:** 262,542 members at 24 co-ops and 17 municipals

Table 2.1: Summaries of Examined Cooperative Utility Subjects, as of 2017. Basin Electric Power Cooperative, serving Minnesota Valley Cooperative Light and Power, is not listed here as a study subject, although it serves as a power provider to East River Electric Power Cooperative, alongside the Western Area Power Administration. Minnesota Valley has no load management program, and therefore Basin was not a study subject. Sources: EIA Form 861, 2018, utility websites or annual reports, and (Chan, Lenhart, Forsberg, Grimley, & Wilson, 2019).

2.2. Load Management, Energy Policy, and the 1973 Oil Crisis

"Load management" is the practice of a utility deliberately controlling electric customers' load curves. This is different from "demand response," which encompasses both customer- and utility-controlled loads. These terms are again different from "demand-side management," which encompasses both demand response and efficiency and conservation measures (Figure 2.2). While these terms have all been used interchangeably, especially in the beginning of the mainstreaming of the technologies in the 1970s on, I use "load management" as a technological subset of DERs, and a specific term to denote utility control and facilitation of demand-side technologies.

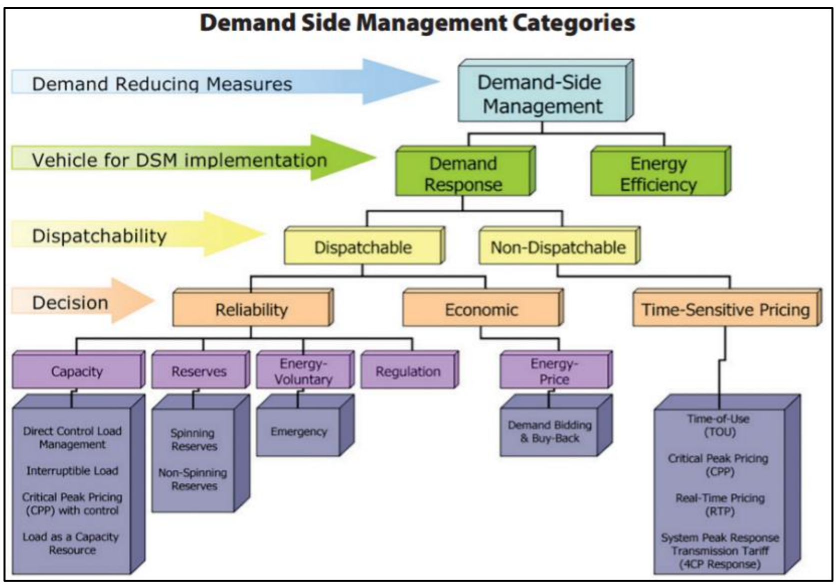


Figure 2.2: Nested Definitions of Demand-side Management, Demand Response, and Load Management. While the diagram above classifies load management as a capacity service for reliability, the studied electric cooperatives here also used it for strategic load-building of energy sales. In other words, not all load management acts as capacity reduction or peak shaving and can perform many other grid services such as emergency shut-off or frequency control that are not reflected here. Source: (North American Electric Reliability Corporation, 2011).

The concept of “load management” dates to the growth of the electric grid in the early 20th century at utilities across the United States and Europe (Richard. F. Hirsh, 1999; Mitchell, Manning, Jr., & Acton, 1978). From the beginning, the goal of load management was to use the electric grid and its power plants more efficiently by spreading loads evenly throughout the day. Samuel Insull, an early assistant of Thomas Edison, and later monopolist of electric utilities across the U.S., first used the term to describe enticing diverse loads such as appliances and industrial loads to his various electric utilities’ grids. As he discovered, because electricity depends on instantaneous balancing of supply and demand of power, the less “peaky” a grid’s power was over a certain timespan, the more efficiently the fixed costs of power plant and power lines could be sized and run. Therefore, a win-win could be made: Insull could get more sales and revenue from the system, and cheaper power and energy was provided for all users (Cudahy & Henderson, 2005; Yakubovich, Granovetter, & Mcguire, 2005).

The concept of “load factor,” which is *a ratio of average load to peak load within a certain time span*, served as a metaphor for a grid’s efficiency and a rationale for later definitions of load management. The closer to 100 percent a load factor gets, the idea was and is, the more economically a grid is thought to run. For example, balancing a morning-peaking electric cooperative with an evening-peaking electric cooperative means that the system, perhaps under one G&T, has higher load factor and better utilization of fixed costs overall (Figure 2.3).

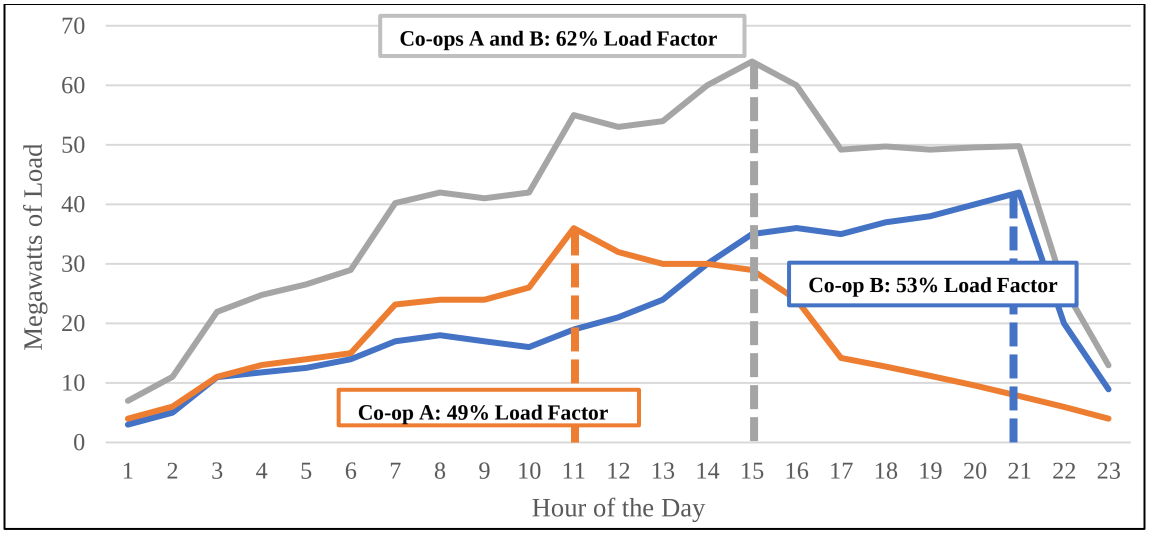


Figure 2.3: Load Factors of Hypothetical Electric Co-ops. Cooperative A has a noncoincident or individual peak at 11 a.m. with relatively low load through the night and early morning, giving it an average load of 17.7 MW compared to a maximum load of 36 MW (17.7/36=Load Factor of 49%). Adding to Cooperative A the load of Cooperative B, which peaks later in the night, makes their coincident or system peak occur at 3 p.m. (in gray). Because the two cooperatives peak at completely different times of the day, their system's coincident peak falls on neither of the individual peaks and their coincident load factor (62%) is higher than either's individually.

These competing and cooperating peaks and system priorities help frame the electric grid as a set of resource decisions and compromises, to build and/or not build supply and demand. The decisions have nested, polycentric relationships as to how utilities collect costs from customers and their various classes. Cost attribution remains a political and social process. Allocating fixed costs proportionate to customer class usage – known as cost-of-service or average-cost pricing – became in these early days a mainstay of American electric utility practice and regulation. This was due to Insull's "growth dynamic" strategy of intense monopoly utility and revenue building (Yakubovich et al., 2005). Marginal pricing methods – which reflect the cost of each additional kilowatt or kilowatt-hour sold often according to the time-of-day or level of the electric grid – emerged too. But at least in the United States, these marginal pricing methods existed only on a niche level for many utilities, serving as discounted pricing to attract new loads or in rare spots, to create price signals for customers (Mitchell et al., 1978).

The differences between average- and marginal-cost pricing reflected some amount of decisions in risk mitigation. Typically, cost-of-service pricing relies on the assumption that a utility is expected to receive a reasonable rate-of-return on its historic investments, which are collected through an averaging out of expected revenues from each customer. Average-cost pricing produces more certainty on revenue for utilities than marginal cost pricing, which are constructed by utilities or regulators to recover anticipated future short- and long-run costs (Pikk & Viiding, 2013). As these short- and long-run revenues may fail sometimes to recover the short-run fixed costs of the system, marginal prices may have to be periodically adjusted to maintain fiscal sense.

In the early 20th century, while utilities were building out supply and demand, and recovering their costs through average and marginal cost pricing, some utilities across the globe began experimenting in controlling loads, the latest definition of "load management" (Bonneville Power Administration, 1977). In the early days, the need for load management was often to avoid building under-utilized infrastructure. In Switzerland, where large-scale hydroelectric dams powered a remote grid, controllable water heaters were a popular form of energy storage since at least the 1920s. By the mid-1970s, the city of Basel, Switzerland, reported an 80 percent adoption rate of utility-controlled residential water heaters, and Hamburg, Germany, apparently had 50 percent of its total load under control, according to the Bonneville Power Administration.

In the mid-20th century, following World War II, there was a surplus of demand and a deficit of generating capacity across the world. In response, load management policies and utility practices in Europe co-evolved with still-nascent marginal pricing theory and practices (McKay, 1979). In 1950s France, industrial time-of-day rates shifted load to off-peak times to defer large generation and transmission buildouts, and with aggressive marketing in the late 1960s, 600,000 controllable water heaters were deployed across the country in just a few years' time. Other countries such as Germany and Finland used centralized control of water heaters and space heating to stave off the need for peaking gas and oil plant additions. South Africa and New Zealand also experienced large buildouts of their controllable loads by the 1970s.

These lessons were slow to the United States. One executive with the Central Vermont Public Service Corporation felt the United States' case for load management was quite different from Europe's, as the United States as still focused more on meeting demand with peaking power plants, while Europe was more focused from the beginning (after World War II) on shifting load to under-utilized parts of the day with lower peaks (Bonneville Power Administration, 1977). America still built power plants, Europe deferred power plants, in other words. The executive also suggested that European utilities, with heavy state investment if not ownership, were more likely to be less sensitive to a potential loss of revenue from marginal pricing, with the state serving as backstop to potentially bad investments.

When the Organization of Arab Petroleum Exporting Countries decided to halt U.S. oil exports in '73, it was a shock to American electric utilities. Electricity prices began to climb, and in general, customer demand began to flatten. Stranded power plants and transmission emerged from a failure to collect on these massive capital investments (Richard. F. Hirsh, 1999).

With an allowed rate-of-return for shareholder equity invested in new capital projects, investor-owned utilities experienced a widening gap between what costs were allowed by their regulators and what was actually recovered (Corey, 1979). Fighting for advance recovery and other mechanisms to reduce their uncertainties, many of these private utilities were beginning to experience revenue loss. Their ground was getting shaky in other places, too: credit rating agencies downgraded many utilities' debt, growing inflation devalued the utility investments, and regulatory uncertainty and delay grew as oil prices soared.

Simply, electric utilities' investments in supply couldn't run in pace with unpredictable demand (thus revenues). Meanwhile, the oil crisis spurred a series of legislative wins for demand-side practices. Energy Policy and Conservation Act of 1975, the Energy Conservation and Production Act of 1976, and the National Energy Conservation Policy Act of 1978 provided the policy basis for load management and energy conservation at the federal and state levels (Gillingham, Newell, & Palmer, 2004). As energy prices continued to rise through the 1970s, the

Public Utilities Regulatory Policy Act of 1978 (PURPA) was enacted to compel state regulatory authorities and utilities to take into account marginal capacity and energy prices as they offered contracts to independent power producers or built their own cost-of-service ratemaking processes (Mahoney Jr., 1979). PURPA also recommended various load management practices to be investigated alongside other generation and non-generation in the burgeoning field of demand-side management. Notably for this study, these regulations pertained to utilities under state regulatory authorities, and only to nonregulated electric utilities (such as co-ops) if they chose to adhere to them.

These motions toward load management followed a general trend that pushed U.S. utilities to notice customer preferences. While some electric utility managers had grown distant from their customers' needs, according to Hirsh (1999), other utilities had already been practicing load management and demand-side management for years. One utility in the Pacific Northwest reported using time-controlled water heaters since the 1940s (Puget Sound Energy, 2016). The practice of time-switching load appears to have been widespread in niche experiments among other utilities, as well. Other programs were robust: Detroit Edison Electric's 200,000 water-heater program began in the 1930s as a promotional effort to outcompete natural gas companies, later turning to time- and radio-control in the '60s (Special Committee On Aging, United States Senate, 1979).

Load management popped up elsewhere. In the 1950s, under pressure from G&Ts that priced their power supply based on noncoincident peak demand (the demand of the individual distribution electric cooperative), or from their own physical constraints, some electric cooperatives were said to begin to install their first load management programs (Clark W. Gellings, 2017). In the 1970s, Wisconsin Electric Co. purchased 150,000 controlled water heater units for its customers, following approval from the Wisconsin Public Service Commission. Elsewhere, from the early '70s on, with dozens of studies and pilots into marginal pricing, load management permeated the nations' utilities' planning processes. Many appeared from partnerships with the U.S. Department of Energy or its forerunner, the Federal Energy Administration (Morgan & Talukdar, 1979).

The 1970s saw a dual-pronged approach emerge to handle unpredictable demand patterns: load management focused on the *utility controlling demand-side systems*, while pricing or customer-based load management focused on *customers responding to price signals with their own systems* (Table 2.2). The two approaches achieve close to the same result in theory, but with different probabilities of success: load management granted more certainty of load management deployment and control for the utility, while customer-controlled load management relied on customer-borne costs and achieved more uncertain results from unpredictable customer behavior.

Table 2.2: Comparison of Utility- and Customer-controlled Demand Response Strategies

	Utility-controlled	**Customer-controlled**
Strategy	More command-and-control	More market-based
Objective	Load is directly controlled, curtailed, interrupted, or scheduled	Customer responds to price signals with load-shifting practices/technologies
Who bears most of the cost	Utility	Customer
Who controls	Utility	Customer
Customer Rates	Reimbursed for load management device usage; marginal or time-of-use rates	Time-of-use rates, demand charges, or other marginal price signals
Technology options	Control receivers on load management devices with communication system backbone	Load management devices, time-of-use or demand meters

Adapted from (Rocky Mountain Institute, 2006).

Many early load management programs centered on water heaters, a kind of thermal energy storage, but many different types of end-use controllable technologies were available in the 1970s (Table 2.3). To facilitate these technologies, communication systems allowed the utility to remotely control a load management receiver from their headquarters (Table 2.4). One- or two-way communication equipment allowed the utilities, customers, and their devices some customizability in how they distributed control over their devices. Control strategies began to include explicit and implicit combinations of utility and customer negotiations including direct customer requests to switch control of the device; scheduling the devices' usage in aggregate with other devices; and price response to arbitrage real-time or time-of-use prices at the utility level (Rabl, 1988).

Table 2.3: Survey of Load Management Technologies.

Load Control Type	Description
Heat storage	Water, in-ground, ceramic, wall, and other systems allowed the utility to charge reservoirs on off-peak periods, allowing the medium to slowly release heat throughout the day or night. Sized from residential to industrial.
Cool storage	Water, ice, ceramic, and other systems are cooled during off-peak periods to provide air conditioning or cooling services.
Customer-owned generation	Back-up generation, often in the form of small diesel gensets, is controlled by the utility in times of high energy costs.
Air conditioning and water heating	A/C and water heating units are controlled to minimize peak power times.
Interruptible	Includes controlling when factory service, irrigation, and grain dryers, and other loads can run.
Dual-fuel	Electric heat is switched to wood, natural gas, propane, or another fuel during peak energy periods. Also used as valley-filling technology.
Self-contained	Interlocks (which prohibit the use of simultaneous loads), demand limiters (which disconnect load if too much power is drawn), time switches, and temperature-controlled switches are automatically manage customers' loads.
Utility-actuated	Substation cutoff from the grid and utility warning signals (in the form of phone calls, TV or radio ads)

Sources: (Argonne National Laboratory, Systems Control, Inc., Gordian Associates, Inc., & Temple, Barker and Sloane, Ince, 1980; Donovan, Hamester, & Rattien, Inc., 1979; Morgan & Talukdar, 1979; Rabl, 1988)

Table 2.4: Survey of Load Management Communication System Types

Communication System Type	Description, Examples
Ripple	Signals between 140 and 750 hertz are injected into power lines by a utility. They're interpreted by a decoder at an endpoint. Signals are transmitted and read and any time and point in the network. Most popular network worldwide. Can be one- or two-way.
Radio	Receivers and transmitters use radio waves to communicate. Can be directed toward specific devices. Popular in U.S.. Can be one- or two-way.
Power line carrier	Signals between 5 and 300 kilohertz are injected into power lines by a utility. Popular alongside radio and ripple. Two-way.
Pilot wire	Independent communication wire strung to customer's premise. Two-way, no examples of use found.
CATV	Existing cable TV systems are used for communication. Two-way.
Telephone	Existing telephone lines are used without interference to customers' regular telephone service. Two-way.

Sources: (Donovan, Hamester, & Rattien, Inc., 1979; Morgan & Talukdar, 1979)

From these beginnings in the early 1970s and ‘80s, load management coalesced into an overall portfolio-based approach known as demand-side load management, or DSM (Gillingham et al., 2004; Richard. F. Hirsh, 1999)(Gillingham et al., 2004; Richard. F. Hirsh, 1999). In 1985, 259 utilities were reported to be involved in the control of more than 2.5 million loads, the majority being water heaters (Rabl, 1988). Tens or hundreds of thousands more devices were also under customer-control or by time switch, which automatically turned on and off certain devices without utility or customer intervention.

Over the next thirty years, coinciding with the advent of federal wholesale energy markets in the mid-2000s – which with PURPA effectively softened utility control of electricity supply in the United States – utilities and other third parties expanded control of customer retail devices. This included more two-way, real-time communications networks. While utilities had experience with wholesale electricity practices through power pools such as the Mid-continent Area Power Pool in the past, the pooling of electricity across states through wholesale markets such as the Midcontinent Independent System Operator (MISO) was a new economic and political frontier.

By 2017, 247 utilities were reported to have more than 5 million customers in direct load control programs (EIA, 2018). In that same year, the EIA reported more than 9 million consumers were a part of a demand response program, which included customer-controlled devices. In all, a 2018 survey of nearly 160 utilities found that 40 percent of demand response capacity was customer-controlled (Chew, Feldman, Ghosh, & Surampudy, 2018). From air conditioning to water heaters, while also including newer technologies in electric vehicles and energy storage, the survey found more than 18 gigawatts of enrolled demand response in total, representing 2.8 percent of peak demand across the utilities surveyed.

A count of 160 utilities did not comprise the total of more than 3,000 electric utilities, however, seeming to leave out the nation’s many electric co-ops. As mentioned previously, starting in the 1950s, many cooperatives began a long history with load management. They shifted into “once-forbidden territory,” as load management forerunner Clark W. Gellings wrote: “the customer’s side of the meter" (C. W. Gellings, 1981). According to a 1978 survey of its nearly 1,000 member utilities, the National Rural Electric Cooperative Association found that 330 of about 360 responding cooperatives were "involved in varying degrees in load management, conservation, weatherization, and research projects" (Doyle, 1979). Of the 330, only 42 had load management programs in place.

Those programs blossomed in the 1980s (Shah, Sanger, & Mashaw, 1984). 1982 reported 92 cooperatives with load management programs, with an additional 79 implementing "indirect" load management such as voluntary commercial and industrial curtailment. Minnesota had the most cooperative load management programs of any state with 25.

Today, all but one of the 45 cooperatives in Minnesota has a load management program, and load management programs stretch across all states in the Midwest in general. Those cooperatives' programs, which are the focus of this study and are aggregated by their generation and/or transmission cooperatives, are summarized below (Table 2.5). The composition of those totals by megawatt impact is further summarized (Figure 2.4).

		Minnkota Power Cooperative	Great River Energy (CPA and UPA)	Dairyland Power Cooperative	East River Electric Power Cooperative
Load Management Program Years in Formation		1973-1976	Mid-1970s-1980 for both CPA and UPA	Early 1970s to 1980	1981-1984
Years of Deployment		1976-Present	1980-Present	1982-Present	1984-Present
Communication/Control System Type		Ripple	Radio	Radio	Power Line Carrier
First Year's (F) and Subsequent Years' (S) Additions to Technology Deployed/ Retrofitted	**Water heater**	S	**F**	**F**	**F**
	Dual fuel	**F**	**F**	**F**	**F**
	Heat storage	**F**	**F**	S	**F**
	Air conditioner		S	S	S
	Interruptible irrigation		S	S	S
	Interruptible commercial and industrial	S	S	S	S
	Customer-owned generation	S	S	S	S
	More	S	S	S	S
Number of Devices Deployed or Participating Member-owners (Reporting Year)		>94,500 devices (2008)	>239,950 devices (2013)	184,271 devices (2010)	78,337 devices (2018)
Megawatts of Devices Deployed (Reporting Year)		477 (2018)	493 (2013)	199 (2010)	235 (2018)

Table 2.5: Summary of Historical and Current Deployments of Load Management Technologies at Minnkota, Great River Energy, Dairyland, and East River electric cooperatives. Across all 4 G&T systems, according to available data sources, there are nearly 600,000 load management receivers for more than 1.2 million member-owners, representing a nearly 50% penetration rate, although some member-owners are known to have more than one managed device. Due to data limitations from state, federal, and utility sources, some kilowatt and number totals are mismatched by year. Sources: Survey responses, interviews, utility integrated resource plan filings with the Minnesota Public Utilities Commission, and (Dairyland Power Cooperative, 1985; EcoMotion, 1993; EIA, 2018; Nelson, 1981b; Federal Energy Regulatory Commission, 2008)

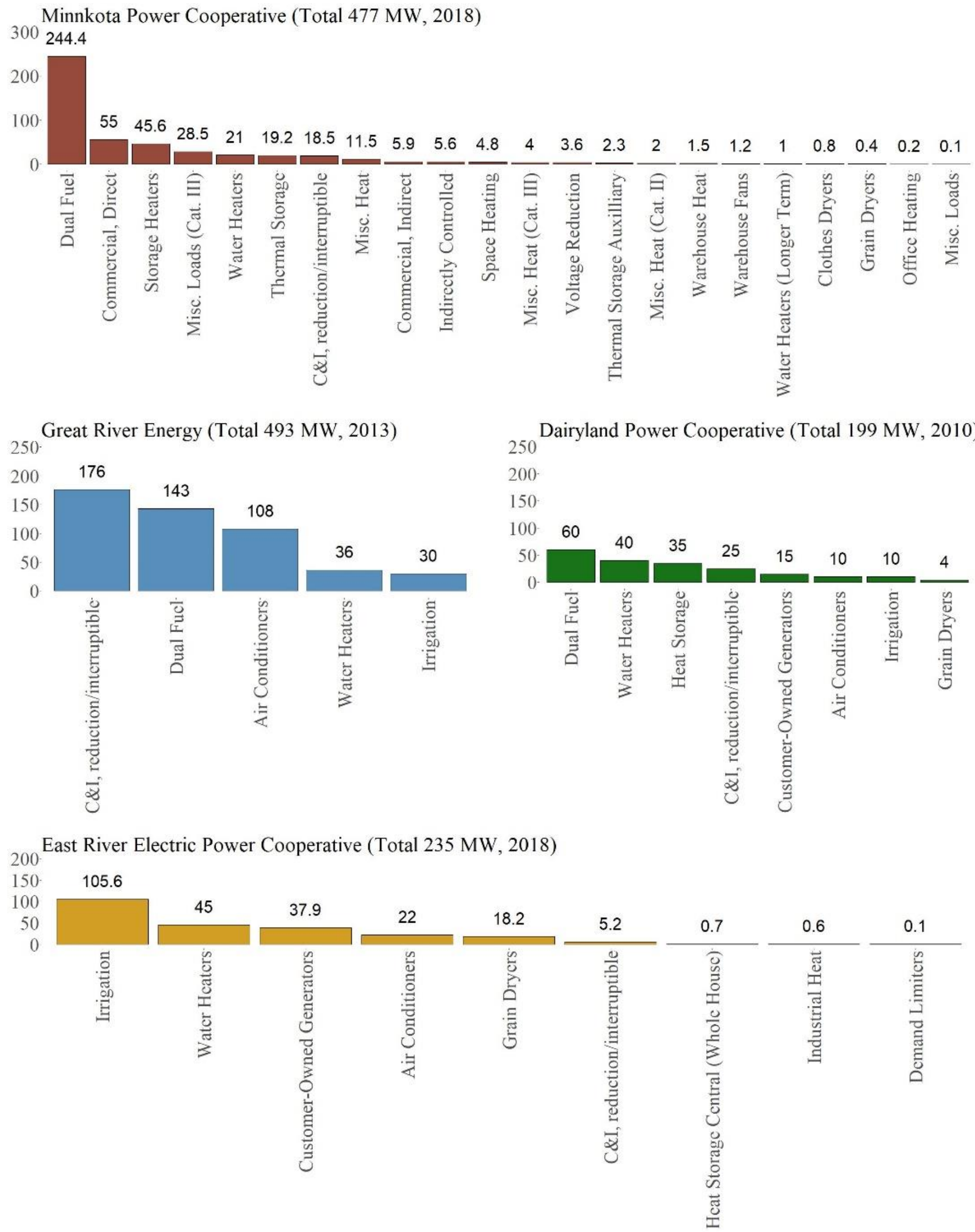


Figure 2.4: Recent and Current Megawatt Deployment of Different Load Management Device Types at Minnkota, Great River, Dairyland, and East River. Minnkota, like many of the co-ops, segments their load management devices into qualitative- and time-based categories (e.g. "Cat. II") for temporal and geographic diversity. Other cooperatives' load management totals contain many more types and sub-types of devices than reported here. Great River Energy's water heaters, for instance, include both peak-shaving and thermal storage water heaters. Data sourced from electric cooperative staff or utility integrated resource plans with the Minnesota Public Utilities Commission. Megawatt totals represent estimates that vary based on the temperature and load diversity due to cycling or other control techniques.

2.3. Energy Transitions, Intermediaries, and Polycentric Governance

My theoretical framework centers on polycentric electric-cooperative actors who, to deploy and sustain the distributed energy resource of load management devices, manage a common pool resource of the electric grid. They do so through intermediary innovation functions, or those actions and roles that act as facilitator between two or more parties in the innovation process. To show how these functions change and are negotiated through time, I follow research that hypothesizes phases of technological innovation systems (TIS) have formation, stabilization, and decline periods, arguing that decline can instead involve re-creation (Markard, 2018a). Below I will summarize current energy transition and common pool resource theories that lead to this general framework.

The field of energy transition research is relatively new, dating to the 1990s. Generally, the energy transition field means to study the shift of a nation or economic sector from one energy system to another through the diffusion of energy sources of technologies (Graff et al., 2018). It is a subsect of the larger sustainability transition field, which is more broadly related to “grand societal challenges” in domains such as water, resources, food, mobility, education, and other goods geared toward preservation and conservation (Loorbach et al., 2017).

Broadly, two major theories inform current energy transition literature: the multi-level perspective (MLP) and TIS (Table 2.6). Within the MLP, innovation occurs within niches, which can diffuse and co-evolve into existing socio-technical regimes amid broader, slow-moving landscape changes (Geels, 2014; Geels, Sovacool, Schwanen, & Sorrell, 2017). Change in the MLP is produced by realigning trajectories between levels, increasing momentum of niche innovations, weakening path-dependent existing systems, and making opportunity through landscape level changes (Figure 2.5).

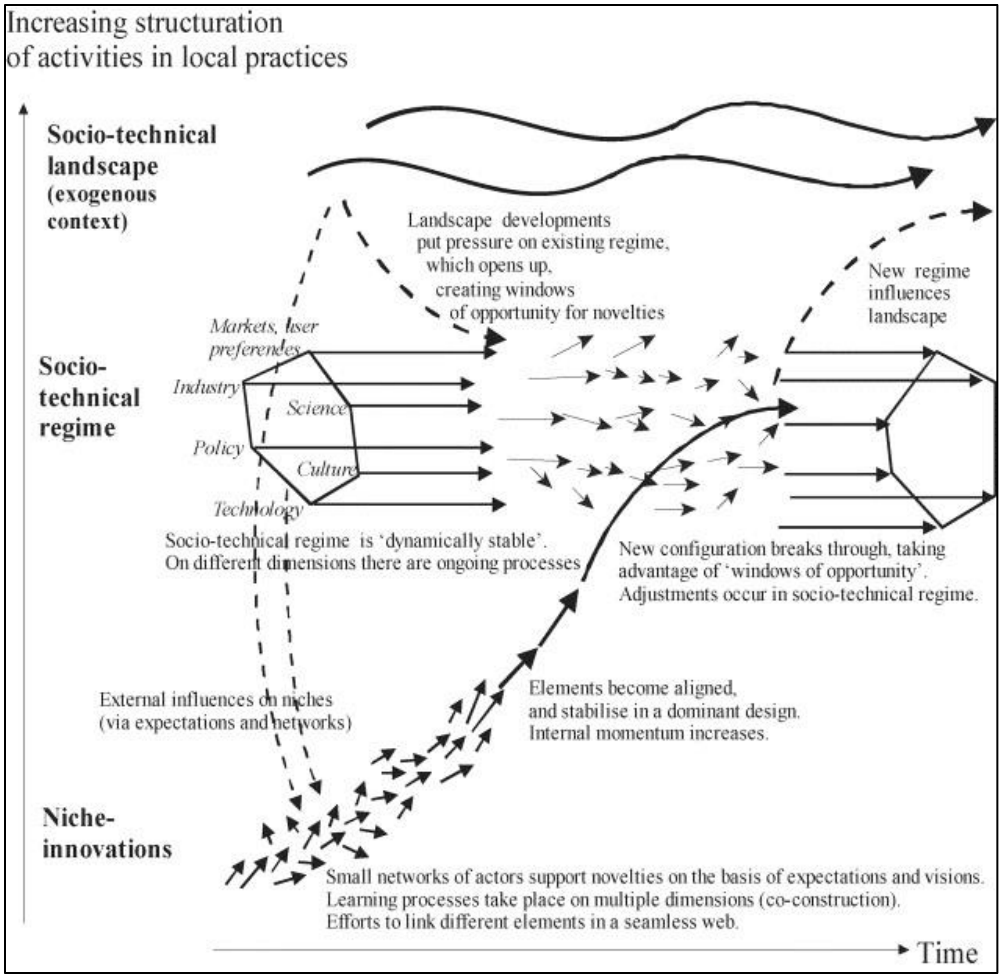


Figure 2.5: The Multi-level Perspective. Source:(Geels & Schot, 2007)

Adjacent to the MLP, the TIS consists of "networks of actors and institutions that jointly interact in a specific technological field and contribute to the generation, diffusion and utilization of variants of a new technology and/or a new product" (Markard & Truffer, 2008). In order to produce and diffuse an innovation, a number of subfunctions must be performed, including market formation, entrepreneurial experimentation, influence on the direction of the search, resource mobilization, knowledge development and legitimation (Bergek, Jacobsson, Carlsson, Lindmark, & Rickne, 2008).

Table 2.6: Theories of Energy Transition. Sources: (Araújo, 2014, 2017).

Theory	Some Main Contributors	Summary
Multilevel perspective or middle-range theory	*Frank Geels, Johan Schot*	Between a nested niches, regimes, and landscape levels, co-evolving practices emerge among technology, users, policy, and cultural meaning, among other facets. Change is produced by the realignment of trajectories between levels.
Technology innovation systems	*Anna Bergek, Marko Hekkert, Jochen Markard*	Innovations are generated, diffused, and used through a series of subfunctions from a series of actors and institutions. The strength and scale of the subfunctions, along with the relationships between them, determine whether change occurs.

In the energy transition literature, among the MLP and TIS, most studies tend to focus on the macro-level, within single sectors, usually at the national or international levels. As a result, sub-national contexts are understudied, leaving gaps in the understanding of polycentric transition actors at the local or regional levels (Graff et al., 2018; Mattes et al., 2015). This trend toward the macro- has been criticized because it “implicitly ignores the uneven implications for specific communities that are affected differentially, both positively and negatively,” says Graff et al. (2018). Mattes et al., using Regional Innovation Systems to identify distinct cognitive, organization, social, and geographic subsystems of small-scale socio-technical configurations within the MLP, added further clarification that subsystems of polycentric or centralized actors can coevolve with an energy transition in highly different ways.

It’s important now to recognize the inherent polycentricity of the electric grid today. The grid, as it exists in many parts around the world, contains layers of generation, transmission, and distribution, each with their own geographic or temporal institutions to manage electricity services. Cooperatives embody these layers, being separated into G&Ts and distribution cooperatives. Often, the distribution cooperatives will contract with other wholesale, federal, or private power sources for electricity services, while maintaining electricity provision at the distribution level within their internal and external networks of member-owners, contractors, outreach associates, and associated community organizations. Just as G&Ts and distribution utility members perform distinct, adjacent duties, their coordinated and uncoordinated actions symbolize that change, occurring through innovation processes as the MLP and TIS state, is always a function of institutions that manage the grid in all its socio-technical politics.

Across the grid, then, small-scale changes at locations such as distribution utilities can be as patchwork and localized as other technological adoptions and diffusions. These differences relate to larger energy transitions and institutions across the grid, as relationships and power dynamics unfold in important ways in energy transitions. In the MLP, these dynamics relate to incumbents, who are mostly thought to resist change. This is important for electric cooperatives, as they represent regimes whose interests in deploying load management must co-evolve with their incumbent technological power supply preferences of centralized power (Geels, 2014). Some research has suggested that incumbents are not static or locked-in monoliths; rather they exist within historically unstable or stable environments and adapt within disparate levels of internal resources and business models (van Mossel, van Rijnsoever, & Hekkert, 2018). Over time, it seems, incumbents do not disappear with new, competitive technology or ways – they reorganize, learning through trial-and-error to change, to survive.

Incumbents can change, and small-scale and collective actors known as "intermediaries" throughout the niches and regimes can help them and other small-scale actors and innovation processes to co-evolve (Kivimaa et al., 2019). As defined by Kivimaa et al. (2019), and as followed for this research, intermediaries are:

> …actors and platforms that positively influence sustainability transition processes by linking actors and activities, and their related skills and resources, or by connecting transition visions and demands of networks of actors with existing regimes in order to create momentum for socio-technical system change, to create new collaborations within and across niche technologies, ideas and markets, and to disrupt dominant unsustainable socio-technical configurations.

More simple a definition, intermediaries act as "an agent or broker in any aspect of the innovation process between two or more parties" (Howells, 2006). Intermediary actors have been found in practice, and are discussed in theory, to help speed up energy transitions from the local to international levels (Gliedt, Hoicka, & Jackson, 2018; Schot & Kanger, 2018). They lie within research that seeks to distinguish actors from the governance, innovation, and sectors they operate in, seeking to find how these actors mediate decision-making in networks of actors (Fischer & Newig, 2016; Michael Hodson, Marvin, & Bulkeley, 2013; Mike Hodson & Marvin, 2010).

At any point in time, there is an overall ecology of intermediaries with different competencies responding to and shaping innovation systems (Kivimaa et al., 2019). Actors that take on intermediary functions have been found to shift functions as the innovation system matures and declines, acquiring and losing different roles as new technologies or institutions come into view. As other studies have found that supportive structures for technological innovation systems are deliberately created and maintained through formal and informal networks and collectives, these intermediary functions can also serve as examples of mutually agreed-upon roles and contributions to the common good (Musiolik & Markard, 2011; Skjølsvold, Throndsen, Ryghaug, Fjellså, & Koksvik, 2018). Because the MLP pertains to broader system level changes, and the TIS diffuses into segmented functions and actors, fitting the nested institutionalism of the electric cooperatives, I choose to focus my study on the TIS intermediary functions (Table 2.7) while maintaining aspects of the MLP.

TIS Function	Description	Intermediary Function	Policy Related to TIS
Knowledge development and diffusion	How knowledge is developed, combined, exchanged and diffused in the system.	Knowledge gathering, processing, generation; communication and dissemination of knowledge; education and training; provision of advice and training.	R&D funding schemes, educational policies, informational instruments.
Directionality	Selecting a direction to allocate resources to; incentives to develop/ adopt certain technologies or practices; visions of the future.	Articulation of needs, expectations and requirements; strategy development; advancement of sustainability aims; policy implementation.	Targets set in strategies, regulations, tax incentives, foresight exercises.
Entrepreneurial experimentation	Testing of new technologies, applications and markets; opportunities for learning and reduced uncertainty.	Creating conditions for learning by doing and using.	Policies stimulating new entrepreneurship and diversification of existing firms, e.g. funding for demonstration projects.
Market formation	Influencing demand; market creation for novel solutions throughout development stages and establishment of innovation.	Acceleration of the application and commercialization of new technologies; prototyping and piloting; investment in new businesses.	Regulation-induced niche markets, tax exemptions, market-based policy instruments, public procurement, demand-side management.
Legitimation	Counteracting resistance to change; social acceptance and compliance with institutions.	Gatekeeping; configuring and aligning interests; technology assessment; arbitration based on neutrality and trust; accreditation and standard setting.	Problem and justification framing in policies creating legitimacy, public participation.
Resource mobilization	Financial and human resources; other complementary assets (networks and infrastructure).	Creation and facilitation of new networks; managing financial resources; identification and management of human resource needs (skills); project design and management.	Subsidies, educational policies, secondment of expertise.
Development of positive externalities	Entry of new actors into the TIS; benefits to other actors or sectors.	Creating new jobs.	Policies promoting more responsible corporate practices.

Table 2.7: Technological Innovation System Functions, Intermediary Functions, and Related Policies. Sources: Adapted from (Bergek et al., 2008; Kivimaa et al., 2019; Kivimaa & Virkamäki, 2014; Lukkarinen et al., 2018)

Importantly, these ecologies of intermediary innovation functions are carried out by actors and institutions that closely resemble polycentric governance schemes. Polycentricity, as Elinor Ostrom wrote, is a system characterized by the multiple opportunities by multiple actors to both compete and cooperate at different scales (Cole, 2015; Ostrom, 1990, 2010). The Paris Agreement was built upon many of Ostrom's precepts, challenging participants to build networks of trust for voluntary carbon reductions (M. Cooper, 2016). Against top-down regulation or privatization, which are theorized by some to be the only ways of managing a common pool resource (CPR), polycentric modes of governance are based on coordination, trust, transparency, and legitimacy between many actors and institutions to manage a resource. They can blend in market rules and mandates into their structure, but the resource management remains largely self-negotiated. Their nodes are often nested within a hierarchy of constitutional, collective choice, and operational rules that determine eligibility, provisioning, and appropriation activities at different levels of resource production and consumption.

First developed by Ostrom, basic rules to govern common pool resources are encapsulated in a set of eight design principles, which help indicate the longevity and success of managing a resource (Cox, Arnold, & Villamayor Tomás, 2010). Below, I match these rules with conditions present for the cooperatives and their load management programs (Table 2.8).

Common Pool Resource Design Principles	Applicability to American Electric Cooperatives
1A. Clearly defined user boundaries	Each distribution cooperative, and each member-owner has a right to use and receive electricity sales. There are also some rights to self-generate or to not receive sales.
1B. Clear boundaries of resource system	American electric cooperatives often have exclusive service areas. Between G&T and distribution cooperatives and member-owners, there are boundaries between responsibilities.
2A. Congruence with local conditions	Distribution cooperatives set tariffs and choose to apply programs according to local conditions.
2B. Benefits of appropriation and provision inputs are proportionate	All demand and energy sales are billed according to principles of cost causation, likewise rewarding load management participation proportionately to member-owners and distribution co-ops.
3. Collective-choice arrangements	Within a representative form of government, member-owners can vote for board members of the distribution cooperative and advocate for changes locally with co-op staff. Distribution co-ops can advocate and vote for changes at the G&T or larger wholesale levels.
4A. Monitoring users	Meters tell demand and energy sales for distribution cooperatives and their member-owners.
4B. Monitoring the resource	Cooperatives monitor both member demand and supply of their own power systems through substation and individual member meters. Load management receivers, though, can be faulty in readings.
5. Graduated sanctions	Electricity, generally, can be disconnected for non-payment, though graduated sanctions remain difficult overall. Failure to respond to load management events sometimes resulted in financial penalties, as negotiated through contract.
6. Conflict-resolution mechanisms	Board policies and cooperative bylaws regulate conflict resolution mechanisms. State regulatory agencies can provide other avenues for resolution.
7. Minimal recognition of rights to organize	Distribution electric cooperatives are largely unregulated by states, although there are challenges with wholesale market integration and occasional state and federal policy mandates.
8. Nested enterprises	Member-owners own distribution cooperatives; distribution cooperatives own generation and transmission cooperatives; between member-owners and between the distribution cooperatives, there can be additional nested enterprises.

Table 2.8: Design Principles for Successful Common Pool Resource Management Groups as Applied to Electric Cooperatives and Their Load Management Programs. Rules are sourced from (Cox et al., 2010), developed from those originally published in (Ostrom, 1990).

Other authors have provided ways to think about electricity and its infrastructure as a common pool resource (Goldthau, 2014; Pless & Fell, 2017). According to Pless and Fell (2017), the capacity and energy components of electricity make it subtractable (one's consumption, in real time, subtracts from the quantity available to others and affects their usage), while the voltage, frequency, and reliability components make it non-excludable (it's close to impossible to exclude consumers from consuming voltage, frequency, and overall reliability on a given network). Electricity, in this way, exists as a bundle of inseparable services with which private interests can subvert the collective good. A "tragedy of the commons" for the cooperatives, specifically, exists in the danger of too much demand or too little at any given time by private interests, or too much or too little infrastructure in the long-run. This gives way to an inefficiently run and planned grid in the long-run, or blackouts and high costs in the short-run.

Some research has tried to draw out these common pool resource design principles into empirical case studies on smart grids and demand response (Melville, Christie, Burningham, Way, & Hampshire, 2017). Few papers, it seems, connect energy transitions and innovation to polycentric actors and institutions, even as some like Goldthau (2014) argue that polycentricity can be a lens to analyze increasing numbers of actors, distributed energy resources, and tailored and working solutions for an increasingly decarbonized grid. This research gap is important because, in recent years, other scholars have introduced concepts of power dynamics, institutional mediation, and polycentric governance to energy transition research to help understand why climate change mitigation efforts appear to have stalled (Breetz, Mildenberger, & Stokes, 2018; Geels, 2014; Goldthau, 2014; Kuzemko, Lockwood, Mitchell, & Hoggett, 2016). This suggests that political durability and institutional understandings can be just as important to fighting climate change as economic and technological deployments.

Despite these learnings, the field (and public discourse more broadly) has been criticized for its lack of attention on the political creation of technology deployments and transitions (Stokes & Breetz, 2018). It may be within that frame that polycentricity is most important for examining distributed energy deployments: it allows the somewhat-apolitical TIS and MLP to better encapsulate the constant self-negotiations and intermediations that belong to American electric cooperatives in deploying and sustaining their distributed energy resources of load management devices. In creating shared, rivalrous resources of peak power demand and supply, the co-ops generated a sub-infrastructure and commons to the already-present infrastructure and commons of wires and centralized generation. G&Ts and distribution cooperatives and their member-owners, in this way, employed systemic and niche intermediary innovation functions, navigating between local projects, higher and nested levels of aggregation, and overseeing large-scale transition activities.

3. METHODOLOGY

To better understand the histories of electric cooperatives managing their common pool resources of load management, I apply TIS intermediary functions to three distinct phases of their programs, formation (1940s to 1970s/'80s), stabilization (1980s to 2000s), and re-creation (2000 to present), to see how the commons was maintained over time. While drawing out intermediary functions, I incorporate aspects of common pool resource design principles into the TIS intermediary functions and into the results' narratives to help identify the polycentric regimes in which they exist.

Given my focus on deployment and negotiation between actors and institutions, and not necessarily early stage research and development of the technologies themselves (as had already happened with load management technology in the mid-20th century), I apply only TIS intermediary functions of market formation, resource mobilization, and legitimation to the time periods. Here I imagine that resource mobilization is defined by more education and training resources, roles that the TIS function of "Knowledge Development and Diffusion" has usually absorbed into mostly early-stage research and development work. I also allow for co-determined policies to be included in market formation.

To incorporate polycentric themes, I amend the TIS intermediary functions as follows. I imagine the legitimation function of the TIS to share the second and third design principles of common pool resources, as updated by Cox et. al (2009): congruence with local conditions, appropriation and provision, and collective choice arrangements. This creates a new definition that follows others' conceptualization of legitimation as "created in a collective, social process involving organizations such as technology developers, experts, associations or interest groups" (Markard, Wirth, & Truffer, 2016). For market formation and resource mobilization, with which many specific common pool resource design principles could apply, I name basic definitions of the functions that denote polycentricity (Table 3.1).

Table 3.1: Summary of Study's Dimensions

TIS/CPR Design Principle	Description Followed for Intermediary Roles.
Market Formation	Demand and demonstration for new or existing technologies are co-created by TIS users using various CPR design principles. Functions include influencing demand with co-determined policies; acceleration of the application and commercialization of new technologies; prototyping and piloting; investment in new businesses.
Resource Mobilization	Organizational growth and emergence are facilitated through co-creation by TIS user. Functions include creation and facilitation of new networks; managing financial resources; identification and management of human resource needs (skills); project design, management and evaluation; education and training.
Legitimation with Local Provisioning and Collective Choice	Local conditions and proportionate or fair benefits and costs are negotiated between individuals within the TIS system and its other functions. Functions include gatekeeping and brokering; configuring and aligning interests; technology assessment and evaluation; arbitration based on neutrality and trust; accreditation and standard setting.

Choosing to study particular electric cooperatives – Minnkota Power Cooperative, Cooperative Power Association, United Power Association, Dairyland Power Cooperative, and East River Electric Power Cooperative – I used a "most similar systems" study design, allowing me to compare load management programs with their cumulative bundles of successes and failures of deployment (Levy, 2008). I selected the cases following the report that Minnesota had the most cooperative load management programs of any state in the nation as of the early 1980s (Shah et al., 1984). This state-based selection also helps to isolate the effect of any Minnesota state policy on cooperative action during the period studied. To study the development of deployment and polycentric decision-making, I also took a longitudinal perspective to help trace the process of each program and further isolate clarifying variables.

Data for this study came from primary and secondary data on utility load management deployment and adoption, as well as semi-structured interviews that I performed with current and former cooperative employees. Given that this is in part an exploratory study, cooperative employees were given priority for interviews, although some affiliates in industry or associated organizations were consulted as part of background interviews. I also conducted background interviews with some of the eventual on-record interviewees, who provided useful framing and background information for the interview protocols and documentary research. As on-record interviews do not total a saturation of information, I used primary and secondary historical documents to fill in information gaps.

With the background interviewees' referrals and subsequent purposive sampling, I recorded on-record interviews through the months of February and March 2019. A total of 10 interviews were conducted with 5 distribution cooperative employees and 8 generation and/or transmission cooperative employees, resulting in more than 822 minutes of interviews, with many more minutes spent in background interviews with current and former cooperative employees. I conducted most interviews over the phone, except for two, which occurred at G&T headquarters.

A semi-structured interview protocol was used to find out how the cooperatives deployed and created opportunities for adoption of load management technologies (Appendix A). I coded interviews for intermediary functions and common pool resource design principles, then processed them through case study comparisons, review with primary and secondary data, and process mapping with available historical documents. In interviews, I also allowed interviewees to review and co-create questions and brainstorm conclusions of the research, following aspects of participatory action research.

Historical load management deployment data was requested from each electric cooperative, both at the G&T and distribution levels. Due to the scarcity of publicly available or compiled historical information at the utility, load management rollout data was also collected from academic papers, historical articles, the U.S. Energy Information Administration, or presentations available online. All data sources are cited in-text.

Anonymity was offered to individuals and distribution cooperatives and not to the generation and transmission cooperatives. The choice was grounded in a debate over the naming of organizations (Guenther, 2009) and is described more fully in Appendix B.

4. RESULTS

The results follow Table 4.1 below. Placing results into narratives, I synthesize interview results with cited documentary evidence. I use the term “G&T” here to mean Minnkota, Cooperative Power, United Power, Great River Energy, East River, or Dairyland generally, even though East River owns only transmission.

In both the table and subsequent narratives, I seek to name either the G&T or distribution cooperative as providing TIS intermediary services, which serve to help manage the common pool resources of load management devices and the grid more generally. I apply these functions over semi-distinct formation, stabilization, and re-creation time periods, labeled below. While I expect there to be some overlap between TIS intermediary functions (i.e. what’s marked as “Legitimation” could apply to “Market Formation”), I use the definitions in Table 3.1 in the “Methodology” section to help demarcate these functions. Overlapping boundaries are not a bad thing in this context: it helps clarify the amorphous roles that transition intermediaries take to support the overall system of innovation and diffusion.

In each period, following the MLP, I also describe other competing or cooperating regimes and broader landscape dynamics. This helps to explain and explore the external pressures the cooperatives saw in deploying their load management programs in their niches. For the purposes of my description, regimes are understood as distinct socio-technical groups relating to a technology, while landscape changes are broader trends (i.e. flattening energy usage rates) that impact the cooperatives and other electric utilities in their day-to-day operations and collective choice efforts.

Where neither a G&T or member cooperative is mentioned in the table below, it should be assumed that both helped provide this function. This doesn't mean to say that each of the studied G&T systems performed these functions, but it does mean that at least one G&T or distribution cooperative was represented in these functions. Combining summary and specifics across and within cases allows my case study approach, with its small sample size and tendency to focus on the past more than present, to begin to generalize conclusions.

Table 4.1: Summary of Results

<table>
<tr><th></th><th>Formation:
1940s to 1970s/’80s</th><th>Stabilization:
1980s to 2000s</th><th>Re-creation:
2000s to Present</th></tr>
<tr><td>Landscape Interactions</td><td>• Rapid growth post-WWII
• Industrialization of farming
• Power plant industry cost overruns
• Sudden flattening of growth in 1970s and early 1980s with spiking interest rates, farm crisis</td><td>• Stabilization of farm economy leads to more growth
• Policy pushes for deregulation
• Increased suburban growth
• Increased C&I presence</td><td>• Recession dampens growth
• Policy push for decarbonization
• Digitalization and data intensive industries emerge
• Wholesale power market creation</td></tr>
<tr><td>Regime Interactions</td><td colspan="3">Fossil-fuel heating regimes in rural areas with increasing presence
Agriculture consolidates, remains cornerstone of co-op service areas, despite losses in total farms
Growth of commercial and industrial loads, digital third-party vendors and aggregators of distributed energy resources</td></tr>
<tr><td>Market Formation</td><td>- Member cooperatives move to coincident peak of all cooperatives, rather than individual peaks
- Member cooperatives’ monthly demand charges become annual or seasonal
- G&T and distribution cooperatives pilot new load management technologies</td><td>- G&T create off-peak electricity rates to member cooperatives
- Creation, at member cooperatives, of varied marginal rates and incentives
- G&T create of end-use device distribution businesses
- Distribution cooperatives and G&Ts create businesses to service non-members</td><td>- Member cooperatives aggregate multiple power suppliers and even wholesale market signals
- G&Ts and member cooperatives begin to pilot grid-interactive water heaters, among other techs</td></tr>
</table>

	Formation: 1940s to 1970s/'80s	Stabilization: 1980s to 2000s	Re-creation: 2000s to Present
Resource Mobilization	- G&Ts aggregate cooperatives into Department of Energy grant and other funding - G&Ts provide funds for early explorations of load management technologies - G&Ts and power suppliers manage balancing of supply- and demand-side decision-making	- G&T and distribution cooperatives provide mass education and coordination with local contractors - Distribution cooperatives integrate load management with new homes developers and other contractors' businesses - G&Ts negotiate manufacturer deals on behalf of member cooperatives	- Third-party communication techs become integrated and marketed by G&Ts and member cooperatives - G&Ts aggregate funds to replace or re-create their communication systems
Legitimation with Local Provisioning and Collective Choice	- Generational and cultural issues, barriers to initial adoptions, are jointly overcome - Mediated opposition to rate impacts through rate studies and committees through direction of G&T - Control strategies are debated, leaving G&Ts with centralized control and member cooperatives, in some instances, with backstop control centers - G&Ts mediate actual cost impacts of system implementation through cost-sharing mechanisms	- Negotiation of deployment strategies and informal standards with local contractors and consumers - Iterative operational design forms based on feedback with contractors, member-owners - Cooperatives balance needs of in-house expertise and external contractors - G&T organize utility partners to shift wholesale power rates and defend contract provisions - Integration of member co-op programs into state policymaking and decision-making	- As member co-ops integrate into wholesale power markets and with third-party vendors, G&Ts begin to lose centralized control - Unevenly, G&Ts and member cooperatives work with external partners to re-legitimate and politick the technology for wholesale and renewable energy integration

4.1. 1940s to 1970s and Early 1980s: Formation

4.1.1. Regime and Landscape Interactions with the Niche

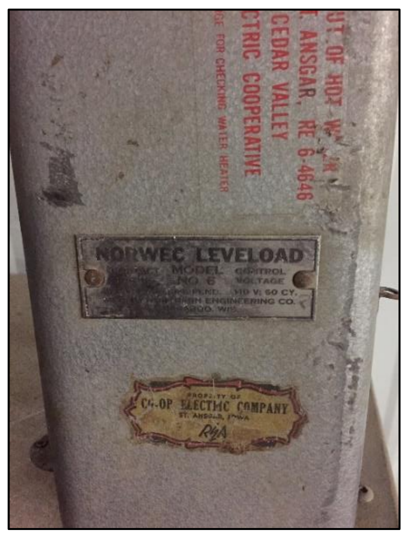
By the 1970s, a series of global, national, and regional events brought load management into focus for the cooperatives (Table 4.2). In this decade, each cooperatives' rationale for load management drew on a central theme, where electricity consumption and supply had begun a volatile period of mismatched resources. Massive 5-or-more percent growth in sales year-over-year were driven by electrified industrial, residential, and agricultural practices, such as automatic irrigation systems, dairy coolers, electric home heating, and air conditioning. As the 1970s wore on, interest rates rose, and by 1980, recession had begun to strike after repeated oil embargos. East River had their rates from Basin Electric Power cooperative nearly triple from 1970 to 1980, and one interviewee reported UPA rates doubling in just a few years' time (Holt, 2007). The cooperatives, either in forecast or in real-time, had economic throes, and past large capital investments in large power plants had to be paid for, somehow.

Table 4.2: Summary of G&Ts' Reasons for Initializing Each Program. Sources: Interviews and (Northern Municipal Power Agency, 1981).

Utility	Year Program Formed	External Shock/Need	Cooperative Rationale for Load Management
Minnkota Power Cooperative	1976	1973 oil crisis and need to defer costly baseload generation additions	Winter peaking, the cooperative would save member-owners money on fuel costs through dual fuel, contribute to national energy independence, and avoid future generation costs
Great River Energy (CPA and UPA)	1980	Coal Creek generating station cost overruns by late 1970s create great debt	With hundreds of millions of dollars to pay on Coal Creek, off-peak load management program would help pay off the power plant through increased electrification of end-uses
Dairyland Power Cooperative	1982	Projected cost increases at peaking power plants create uncertainty, and two-hour "needle peaks" from concentrated "chore time" energy usage on system in early 1970s create a poor load factor	Load management, a non-generation alternative, avoided expensive generation and helped shave the largely-residential peak
East River Electric Power Cooperative	1984	Farm crisis with Antelope Valley generating station debt service from Basin Electric Power Cooperative create great member-owner costs	Confronted with increasing demand charges from Basin, and lowered allocations of cheap hydro from Western Area Power Administration, East River sought load management to decrease wholesale billing costs and help defer member utility costs

Large power plants were increasingly contentious at a societal level as well as in Minnesota. Ongoing opposition to CP and UPA's Coal Creek power plant in North Dakota and its high voltage transmission line filled the state regulatory agencies with siting and public participation issues. By the late 1970s, increasingly militant farmer-protestors were responded to by the governor calling on the National Guard (Reagan, 1979; Wellstone & Casper, 2003). But even before, Northern States Power Company's nuclear power plants were built under heavy opposition, and their Sherco and Minnesota Power's Floodwood-Fine generation projects saw large public disputes. Combined with industry issues and new environmental regulations, building large facilities on time was just becoming less likely.

In public hearings for siting Coal Creek's power lines in Minnesota in 1975, the advocacy group Minnesota Public Interest Research Group (MPIRG) identified "load management" as a possible alternative to the power plant and its lines. MPIRG said Cooperative Power and United Power Association's application contained no discussion whatsoever of the possibilities for shifting demand, conservation, or renewable energy (Wellstone & Casper, 2003). It may have been that at the time, no one thought any of those alternatives were possible compared with large-scale power generation. In granting the eventual certificate of need to the program, the Minnesota Energy Agency director at the time wrote, "Existing state and federal conservation programs and any possible new programs are not likely to have a significant impact on the Applicants' energy and demand projections for the short term" (Wellstone & Casper, 2003). Yet these ideas, from as far away as Europe, or from other American utilities or these G&Ts' own member cooperatives, had already began to percolate in time clocks and early communication systems (Figures 4.1 and 4.2).

Figures 4.1 and 4.2: Time Clock (Left) and Powerline Carrier Receiver (Right) from an Iowan Electric Cooperative. Early permutations of load management were relatively plug-and-play, such as time clocks, which with a simple turn of the hand, allowed for customized control of on-farm electricity demand. Powerline carrier receivers, requiring more advanced communication over power lines, were more advanced, requiring communication networks to be set up. Source: Dairyland Power Cooperative personal communication.

4.1.2. Market Formation

The market for electric cooperative load management had to be made internally. Prior to the 1970s and '80s, each distribution cooperative was billed by the G&T for their own individual peak, noncoincident with other cooperatives. This aligned costs with individual needs, as each member co-op ultimately had to build out distribution systems to accept their own peak power. By voting to move to a coincident peak, however, each cooperative would be incentivized by a demand charge to avoid power usage during a collective peak of all the member cooperatives within a G&T system. While individual cooperatives might have to build out their distribution grids to handle their noncoincident peak, they now had to worry about a coincident peak demand charge as well, one that was often scores higher in aggregate than the old noncoincident demand charges.

Choosing to constrain themselves to a coincident peak of all member cooperatives – which in almost every case was an annualizing or seasonalizing of a demand charge alongside smaller, monthly demand charges – the member co-ops chose what was necessary to translate system needs into individual market signals for the good of load management. The change was accepted, grudgingly, it seems. It meant a loss of control from the distribution cooperatives, no longer having to worry solely about building their own system and demand. They now had to worry about building for the collective peak (and common good of the G&T system), as well.

The dual considerations were challenging for balancing the priorities of the individual co-ops within the infrastructure. "It's like having 27 kids", says Larry Thorson, former Director of Energy Management for Dairyland Power says. Allowing distribution cooperatives to build and maintain their own load management systems was considered, but ultimately dismissed by all this study's G&T systems as being too disorganized for greater load management deployment and efficiency. "Some of you can go your own way," says Thorson, "[but] you just know there's going to be some headaches going down the road when somebody says, 'I didn't get the signal.'"

It was better, everyone decided in the end, to have these rates centralized, an imposition mutually agreed-upon by the board members of the distribution cooperatives. Common, centralized rates had the side-effect of snapping different distribution co-op approaches to retail rate setting into focus, says Jeff Nelson, former manager of East River's load management program, and general manager of East River in later years. Prior to the program, each cooperative had their own rate philosophy: different levels of fixed charges, meter charges, and energy charges began to be harmonized as cooperatives experienced a common cost and rate structure. As Ostrom (1990) relates in her hierarchy of rules, from the highest G&T and their constitutional rules of rate structures, down to the distribution cooperative and their collective choice structure, member-owners using the common pool resource in operational or day-to-day rules began to see system transformation through their retail rates and load management programs offered to them.

Pilot projects were an essential part of testing the effectiveness and monitoring of each of the end-use devices and the communication products in the G&T-sponsored load management programs. But that didn't prevent member cooperatives from using the technology. Thorson recounts that even as the G&T was exploring load management, Cedar Valley – a forerunner to Iowa-based Heartland Electric – acquired their own radio control system to get ahead of the game. Other co-ops had been ahead for some time. Going into the 1950s, a couple interviewees estimated that at least a dozen or so cooperatives in the G&T systems also had invested in early power line carrier and radio technologies to help stem the peaky loads from on-farm welders and newly electrified dairy operations. These technologies rose during the 1950s and '60s, but ultimately died off as the grid became more interconnected with other utilities, more dependent on centralized supply, and less constrained on their own individual physical capacities of distribution wires and poles.

The cooperatives that engaged in early forays into load management had a jumpstart on the market when G&Ts began to push their programs. More widely, many distribution cooperatives also had their own electrification programs from years past, formed to indiscriminately build load with electric heating, stoves, water heaters, and other types of appliances. These homespun shops of marketing and decision-making (which still exist today as electric cooperatives offer electric grills and other electric home products to consumers) allowed cooperatives to tailor offerings to their service areas. By the 1970s, the co-ops' early electrification and load management efforts had instilled confidence in the distribution cooperatives' communal abilities to sell products to member-owners, allowing for some additional ease in retrofitting appliances with load management communication receivers.

Individual abilities and opportunities of the member co-ops and G&Ts also helped inform and create later common pool uses. For Minnkota, a large regional shopping center in Fargo, North Dakota, symbolized this collective learning process. The mall was facing budget shortfalls from the impending oil costs in 1973. The mall's electric cooperative, Cass County Electric Cooperative, offered to electrify its heating arrangements for off-peak times, leaving its oil as the peaking energy solution (Gustafson, 1981). This unique partnership helped fortify the dual fuel solution as the primary load management solution that Minnkota wanted to pursue, allowing the G&T system to fill in valleys with off-peak electricity, while clipping peaks by interrupting electricity with fossil fuels, thus ensuring its overall load factor never lessened (see Figure 1.4 for a basic illustration of competing, cooperating peaks).

4.1.3. Resource Mobilization

G&Ts often aggregated their member utilities' equity, used their own, or sought external funding to help identify and promote the load management programs. One notable example of seeking funding for a common purpose was United Power Association. In the middle of heated dispute over the Coal Creek generating station and resulting powerline, and fresh off suggestions from advocates to implement load management and conservation instead of building a power plant, by 1976, UPA had decided to apply to the Rural Electrification Administration for a load management study. The G&T wrote, "This will cost money but in the long run it will be more economical than building new plants and lines if we can reduce demand" (United Power Association, 1976).

That REA grant shifted into a project with the newly-formed U.S. Department of Energy, with facilitating help from the National Rural Electric Cooperative Association (Minnesota Historical Society, 1978). Test load management projects were rolled out in partnership with member cooperatives such as Crow Wing Power, tracking metering and performance data from electric thermal room storage demonstrations or electric water heater aggregations. “It was after the [Department of Energy] project that proved some of those things out,” says Gary Connett, a former manager of demand-side management with Great River Energy.

Often, multiple options were consulted adjacent to or in place of load management, a process often intermediated by the G&T and assisted by input from individual member utilities. This optionality was emphasized by the systems approach that East River took on behalf of its member cooperatives to better their collective load factor. With an external consultant, Burns & McDonnell, the cooperative assessed conservation, improving transmission and distribution equipment to prevent losses, simple load management like time clocks, and even renegotiating wholesale power costs. East River, however, was unique: unlike other G&Ts, they were tied to Basin Electric Power Cooperative and the Western Area Power Administration for power needs and faced distinct demand and energy charges that other G&Ts only saw in their own power plants or marketplaces.

The end costs of deployment and the communication systems were not trivial for any G&T system. East River’s alone was close to 20 percent of their total asset base. But the G&T, as an aggregator of interests and resources, alone had the finances and human resources to coordinate the discovery and rollout of the projects and alternatives. Negotiations without side vendors for communication techs was likewise investigated by G&Ts: in the case of Minnkota, they traveled to Switzerland for product demonstrations, while other cooperatives such as Dairyland chose to survey and tour with other utilities like Oglethorpe Power Corporation in Georgia or Buckeye Power in Ohio.

What these G&Ts were doing at the time was relatively unprecedented for these communication systems, it seems. Covering sometimes an area the size of the state of Indiana with radio control towers or ripple injection sites at substations, they didn't have full certainty that the technology could even work fully for their use. As one manager said, there were no guideposts or manuals to read. Indicative of this pioneering activity, by 1980, Mel Nelson, the lead on Minnkota's load management program, reported that only seven large-scale load management programs existed at the time; and of them, only Minnkota's was aimed at annual load factor changes, not just daily or weekly (Nelson, 1981a).

G&Ts, as intermediaries of individual utility interests, leveraged economies of scope and scale that individual cooperatives never could, at least in the initial phases of the TIS. Devoting themselves to exploration, the G&Ts aggregated risk and made it palatable for the group, even as individual co-ops explored and deployed their own load management systems.

4.1.4. Legitimation with Local Provisioning and Collective Choice

Each load management program, as it was sold to member cooperatives and their member-owners by the G&Ts and some advocate member systems, was controversial, even among staff. Having returned from World War II deployment to electrify the countryside, many of the older generations of staff in each cooperative felt the load management programs were empty promises. After all, these staffers had seen what reliable, cost-effective electricity did for their peers and their families. "No longer were people that lived out in the country second class citizens," says Jeff Nelson.

Now in the 1980s, coming out of the oil crisis and the farm crisis, was a "tough philosophical change to ask guys" to now turn off lights, says Nelson. "Guys who lived through [World War II] … it wasn't just a casual meal… they were committed."

The older generation viewed it as a breach of their social contract to offer interruptible, controlled electricity. Even though it was a voluntary program for both distribution co-ops and member-owners, negotiated down in East River and other G&Ts from a mandatory program, it was still a breach that needed mending. At Dairyland, Thorson said it was often the younger managers at cooperatives that embraced the change and deployment strategies before their older counterparts, indicating a social solution that was co-created by the cooperatives' own internal diversity of resources.

There were other shifts that happened. The shift to a coincident peak had to lead to a shift in mindset: "Share the pain, share the gain," says Jeff Nelson. East River had to find a "sweet spot" among the 25 individual cooperatives, balancing costs and benefits and perceptions of them. Using their rate studies and consulting reports as authoritative boundary objects, the G&Ts could then better pitch the load management systems to member cooperatives. For East River, that meant politicking at least 13 out of 25 member utilities to agree to a "Yes." Nelson remembers it was the only closed-box ballot vote he'd ever seen, after many arguments and anger against it, including a study funded by a member cooperative to debunk Burns & McDonnell's initial feasibility study.

But for the most part, Nelson said of the 12 opposing votes, some weren't "all in" on opposing it. "They were just worried," he says. "I guess a lot of us were." At Dairyland, that same vociferous opposition to load management, even on the day of the board vote, died down. Thorson remembers one board member pounding his fist on the table one moment, and then just before the vote settling down. That board member said, "I don't like it, but it's the right thing to do." Dairyland's vote was almost unanimous in favor.

After the votes to commit to load management, the heart-strain was not over. Some managers now felt the pinch of having to hire new member services personnel. For them, too, it was anxiety-provoking to think of an irate customer calling after a cold shower from an empty water heater. Yet the other situation, where the co-op didn't deploy load management, was ruined by the threat of heaping demand charges.

Those demand charges, which were being avoided in the present by other member cooperatives with load management deployments, would increase in future years for all co-ops in the G&T system. The G&T had to, no matter what, collect demand charges for its fixed costs of the grid's debt. Therefore, in the future, the non-deploying co-op would see increasing demand charge-related pains. Only off-peak sales and peak-shaving from controlling electrified loads could help ease present costs, and ease the uncertainty of the future costs for an individual co-op. As a common incentive, if load management was deployed collectively among all co-ops, costs could be deferred and evened-out for everyone in the G&T system, despite however unevenly those demand charges might affect individuals in the present.

Faced with these certain present costs and uncertain future costs, the co-op managers were “between a rock and a hard spot,” as Thorson says. A “friendly competition” ensued between the co-ops to sell more off-peak power and cut more peak demand, according to Thorson.

Sometimes the competition was one that individual distribution co-ops wanted to avoid. To win these laggards over, sometimes that competition’s impact on nonparticipants would be lessened initially through the pooling of rebates or accounting practices that would effectively delay the impact of costs or revenues associated with a new power plant or rate structure. Cross-subsidization worked both ways here, balancing perceptions of future and present costs, signaling fairness to non-adopters and adopters alike, showing that the appropriators of this common pool resource would engage all perspectives and local conditions to deploy load management.

It was necessary, then, to engage each cooperative on its own terms, fitting the technology to individual and communal preference all at once. Minnkota’s system, winter-peaking for the unrestrained electric heating growth of prior years, still had many rural customers relying on fuel oil or wood for heat during the winter – dual fuel technology, in that case, was a specific fit to the northwest corner of Minnesota that hadn’t the fossil fuel penetration of other regions. For East River customers, concerned as they were about the farm crisis, and with heavy on- or off-farm residential usage, water heaters were a natural initial fit for the program, though the programs would later turn to other technologies in accordance with local conditions at each member cooperative (Figure 4.3).

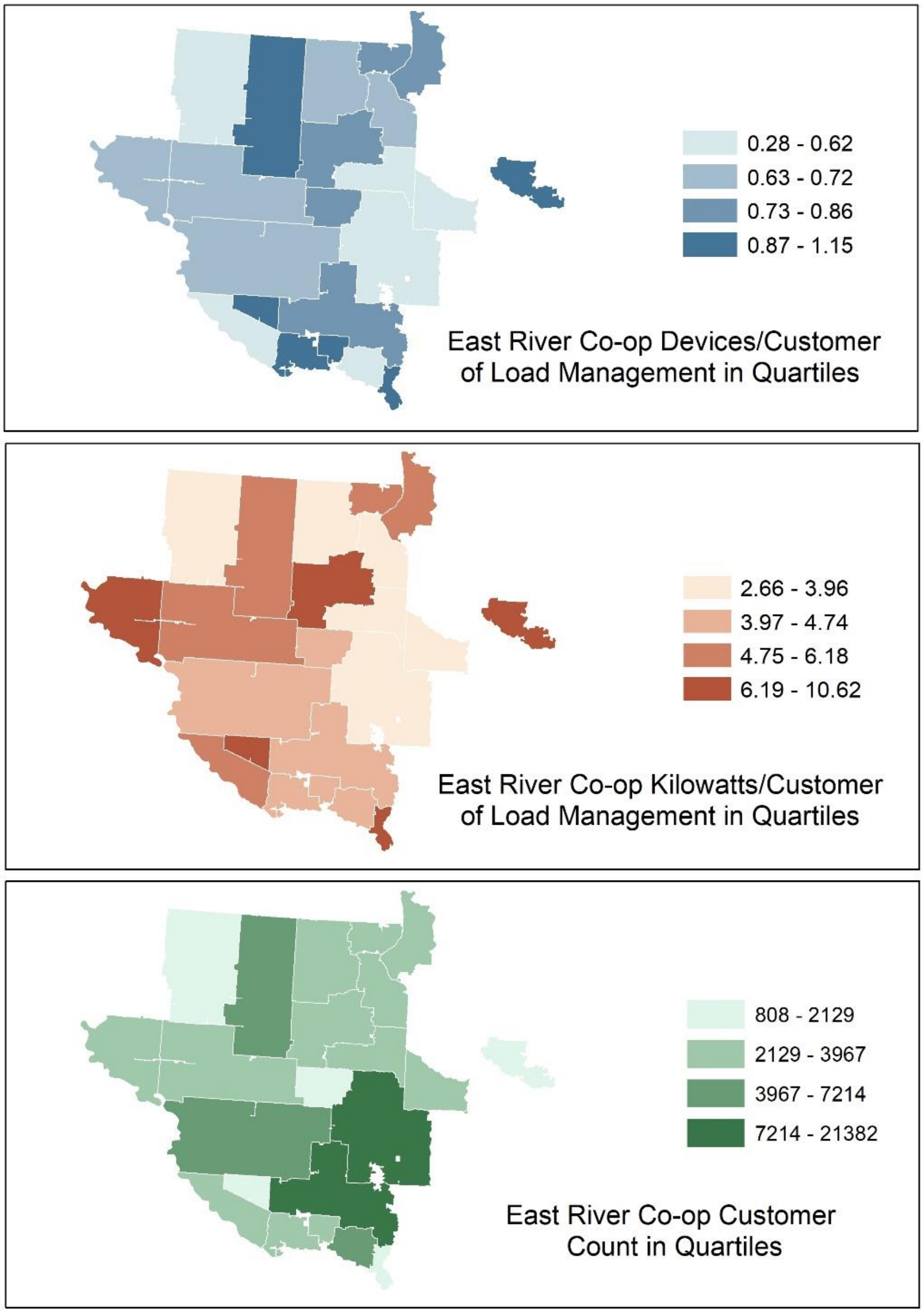


Figure 4.3: East River Device and Kilowatt Penetrations of Load Management, as Compared to Customer Totals, in 2010. Those cooperatives with the most customers didn't necessarily achieve the highest penetrations of load management receivers, and it was those with special resources (such as grain dryers or commercial and industrial accounts) that often achieved the greatest kilowatt penetrations of load management. Data source: Jeff Rud, East River Electric Power Cooperative.

The load management programs also acted as a pressure valve for the co-ops and G&Ts, offering some consciously-provided financial relief to customers where agricultural commodity prices plummeted, interest rates rose up to 20 percent, and farmers were losing land to banks. Though interviewees from other G&T systems didn't bring up impacts of the farm crisis, its presence is known to have loomed over their programs, being one component of rapidly rising electricity rates. For a G&T like Dairyland and its member co-ops, load management was a solution for an angry customer, welfare that once again signaled fairness and agency. In this way, the legitimacy of load management was determined throughout the nested, polycentric levels of G&T, co-op, and customer, tracking price signals through the chain of power supply and demand, creating social and institutional solutions to match at each juncture of the provisioning.

4.2. 1980s to 2000s: Stabilization

4.2.1. Regime and Landscape Interactions

The load management boom times started with rural areas, often at the behest of the more suburban cooperatives. The reason was simple: lack of competition from fossil fuel. "Rural areas…that's where the opportunities were," says Connett. "The metro co-ops just sort of shrugged their shoulders and said, 'Everybody here has natural gas. I just can't make it happen.'"

While natural gas and other fossil fuels continued their expensive presence in the country, in Minnesota and elsewhere there were cries for deregulation. Following larger energy industry and national general trends toward merger and diversification through economies-of-scope, the electric cooperatives began to experiment in product offerings, side-businesses, partially to stave off the uncertainty of retail choice in the electricity industry in general. Cooperative Power Association and Dairyland, for instance, formed a joint energy marketing venture called GENSYS, joining their supply-side activities together and even filing a joint-integrated resource plan with the Minnesota Public Utilities Commission in 1998. CPA pulled away from GENSYS, though, when the G&T

merged with UPA, forming Great River Energy in 1999, effectively doubling their utility and load management program size and, according to one interviewee, increasing their load factor (Figure 4.4).

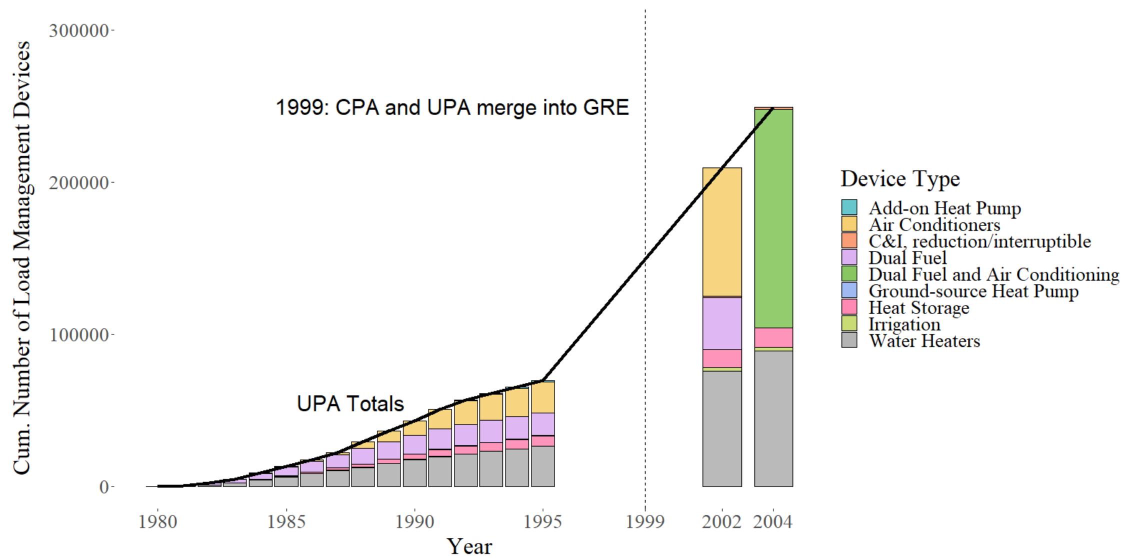


Figure 4.4: UPA's Load Management Device Totals, Before and After the Merger with CPA. UPA's program focused in the early years on water heaters and dual fuel systems but grew a formidable cycling air conditioner program as the utility turned summer peaking in the 1980s. After joining CPA in merger in 1999, the utility's customer base and load management program doubled. Note that dual fuel and air conditioning are grouped together in 2004, an anomaly of the utility's own filing method. Source: Great River Energy integrated resource plan filings with the Minnesota Public Utilities Commission and (Connett, 1996; EcoMotion, 1993).

Economy-wide, coming into the 1990s was a more stable time than what the electric cooperatives saw in the '70s, although rural areas still saw less productivity growth in general as compared to metro areas (Federal Reserve Bank of Chicago, 1997). Commercial and industrial loads were coming to these mostly residential cooperatives, especially within the smaller counties, who finally saw some diversification of their loads, but for the most part, growth was fell short of the productivity, wages, and population growth of cities.

It was also becoming clear by the '90s, and even by the '80s, that electric utilities were only one set of players in the new utility industry. Independent power producers, retail marketers, distributed generators, third-party aggregators disrupted a dominant utility consensus about how best to run the industry (Richard. F. Hirsh, 1999). Additional shifts in economics forced distribution and G&T cooperatives (such as UPA and CPA) to merge (Hexom, 2000). Competition ruled some of the thought around load management, too, as one interviewee described it as “customer choice” before customer choice had arrived.

4.2.2. Market Formation

The Mid-Continent Area Power Pool (MAPP) – or in the case of East River, its power providers of Basin and the Western Area Power Administration – created the overarching market policies for three out of the four load management programs. These entities’ constitutional or meta-constitutional market rules, as Ostrom (1990) writes, often set the tone for what cooperatives could do after they supplied their primary demand. In Minnkota, reduced capacity requirements from dual fuel usage during peak times meant they could sell their capacity surplus at a profit – in a single winter in 1978, this amounted to $600,000 for 30 megawatts, or $20 per kilowatt, when they had only spent the equivalent of $55 per kilowatt of dual fuel control at the outset. (Capehart, n.d.). Aggregating its member cooperatives’ interest, Minnkota aligned the MAPP market partners to make these off-peak electricity sales possible between wholesale market members. This change thereby allowed G&Ts like Minnkota to fully pass through off-peak rates to member co-ops, who then could pass-through rates to their member-owners (Minnkota Power Cooperative, Inc., 1995). As MAPP also required a reserve margin, it is within the ‘80s that cooperatives began to focus on clipping their peak in order to reduce that reserve capacity needed to operate and market within MAPP (Connett, 1996).

Within G&T systems, member cooperatives formed rate and marketing committees to help hash out details on specific offerings or rate designs. Most G&Ts also hired rate consultants to be used by member cooperatives. While some systems, such as UPA’s or Dairyland’s, allowed their member utilities to offer whatever rates for off-peak or peak shaving programs they wanted, East River had focused on offering and encouraging uniformity across rates and exerted stronger top-down pressure on member utilities. This was an intentional scheme on East River's part: it hinged on farmers' social networks, their appreciation of transparency, and their innate ability to compare deals with each other. The most notable uniform rate of East River's was their $6-per-month rebate on the electric water heater, which was adopted by two-thirds of the East River membership. Some offered more than $6, some less, says Jeff Nelson, and some didn't offer it at all. These differences allowed the rates to be locally tailored and appropriated, and while the G&T could coordinate prices and rates to the extent allowed by federal antitrust rules, they seldom interfered with the distribution utility and their member-owners, showing distinct boundaries in common pool duties and responsibilities.

In developing rates, the distribution cooperatives also were piloting new programs, making some mistakes and improvements with each other. Minnkota tested out control of stoves, and East River did the same to worse ends, recalling a fatefully cold holiday season when turkeys emerged from stoves uncooked. Televisions were also tested as managed devices. From these and other demand-side applications, the cooperatives generally found pairings with other conservation offerings such as compact-fluorescent light bulbs and insulation. Pairing conservation and load management improvements together, the co-ops found they could ease strain on installation practices for member-owners and increase acceptance and adoption among member-owners.

Amid increasing natural gas penetration in rural areas, and fossil fuel usage in general, it became necessary to retain current electric customers while also encouraging new electrification projects. Older electrified loads were being abandoned, literally cobwebbed in houses, while new heating units were installed. To that end, East River first rolled out dual fuel and all-home heat storage systems in the late '80s, investing more than $10 million in rolling out the programs.

Other cooperatives formed side ventures to help smooth out business prospects for project partners. For UPA, the partner was Steffes – prior a North Dakotan manufacturer of oaken church pews – who joined UPA on its Department of Energy grant. That opportunity allowed Steffes to shift their operations to room heat storage products, which it provided to nearly all Minnesotan electric cooperatives. Yet these products were composed of heavy, dense materials such as bricks, and with no market yet for it on a regional or national scale, there was no distributor who would handle it. UPA filled the gap, warehousing the products and delivering them to member cooperatives on a biweekly basis. Filling a similar gap in the workforce, a South Dakotan electric cooperative reported hiring their own HVAC staff to help serve the western portion of their service area, where there were no qualified contractors. These HVAC personnel even worked with non-cooperative members, a sign of the co-op intermediating in larger economic needs in the area. Dairyland undertook the contract for managing Northern States Power – Wisconsin's load management program through its own radio system.

Pilot projects like the above were common in other utilities, as well. Cass County Electric Cooperative reported on-going tests of equipment that might be compatible with the load management receiver, including "dual heating options for mobile homes, liquid and solids material storage devices, outdoor fuel-fired heating systems for secondary peaking energy, computerized load control equipment without a back-up energy source and alternative energy options that may include wind and solar mixed with off-peak energy" (Gustafson, 1981). Operational characteristics were also continually tested in home subdivisions. While consumer acceptance overall increased over time, even some market saturation points were beginning to be felt: not even within a decade of its program beginning, Minnkota's daily load factor on a January day in the early 1980s was above 90 percent thanks to prodigious levels of dual fuel and electric heating. That left a lacking annual load factor, as summer days' peak load was much less than winter days' (Nelson, 1981a). This helps clarify the multiple goals of load factor management, which remained (and remains) a temporal consideration, a balancing of daily, seasonal, and yearly needs as much as individual and groups needs, showing again the role for nested rules in managing this common pool resource.

4.2.3. Resource Mobilization

Education and coordination were absolute necessities for the programs. They were also albeit marked shifts in utility activities. “Utilities traditionally haven't had to network with HVAC contractors or electricians,” says Connett. “For years at UPA, [we would] build power plants or transmission lines to handle whatever's out there.” The shift moved them to interact with their customers and contractor base in a way that allowed the users of the common pool resource to become producers, either of valuable off-peak sales or peak-shaving capacity at the member-owner level, or of the installation and product provisioning services at the contractor and co-op levels, so necessary to maintain growth and the usefulness of the load management system overall.

Perhaps the first hurdle was understanding the real costs of education. One explicit case paints the picture: of the \$80 it took to install each receiver switch, \$55 was used to account for promotion and making customer contracts. While a seemingly large amount, \$55 was little compared to the value of the dual fuel loads. These costs would decrease, too, as penetration levels increased, following earlier REA notions of “area coverage” (Energy Utilization Systems, Inc., 1982).

Distribution cooperatives, in general throughout the interviewees and public documents, reported spending much of their outreach efforts on annual meetings, monthly board member district meetings, monthly member-owner newsletters, radio, TV, and newspaper advertising. While some interviewees stressed the importance of pooling these activities through funds or money at the G&T, it’s also clear that each distribution cooperative ran an adjacent education and marketing campaign, showing important polycentricity that allowed them to deploy in the fashion most preferred to them. One electric cooperative, one of the tiniest in the nation at the time with under 1,000 member-owners, even went door-to-door to persuade customers to take up the program. Its former manager estimates that more than two-thirds of its member-owners took up a controllable water heater, suggesting (as with Figure 4.3) that the size and institutional connectedness of a member co-op’s service area had correlation to deployment success.

Because the G&Ts often had no direct contact with customers, they often interacted with third parties such as electricians and plumbers to sell and pitch load management, while distribution cooperatives performed more localized intermediary functions. Cass County Electric Cooperative wrote in 1980 that the response to the new program was terrible, that "many contractors responded by indicating that it simply would not work" (Gustafson, 1981). The cooperative pressed on with Minnkota and the North Dakota Continuing Education Department, making a series of classes highlighting the technology and its vagaries and proper installation techniques.

Eventually, following some reports of poor installations, Minnkota's program would grow in 1987 into the Guaranteed Heating Program. Here Minnkota certified installers and guaranteed certain manufacturers' products, a rarity for electric utilities on behalf of manufacturers. Shortly after, the program morphed into the Professional Contractors' Program, providing educational tracks and certification programs to electrical, HVAC, and building contractors to more than 300 contractors, students, product distributors, and cooperative personnel on an annual basis (Northern Municipal Power Agency, 2002). These trainings would give vendors a chance to sell products while simultaneously accrediting contractors with classes necessary for state licensure and putting them on Minnkota's list of preferred contractors. Minnkota also apparently coordinated with manufacturers such as Steffes and Electro Industries to set up product trainings and schools for regional contractors.

At UPA, the education process meant two-and-a-half-day contractor training sessions every year in the Twin Cities, paying the contractors for room and board to come and hear manufacturers talk about their products and listen to the cooperatives as they troubleshooted technological and installation issues. In their polycentric schemes, other UPA and CPA member cooperatives followed the G&Ts with coordination efforts of their own with more locally focused efforts, often making referral lists of contractors. These distribution cooperative contractor offerings often formed along the distinct boundary that they placed between their and the G&T services. For instance, Great River Energy would participate, only if asked, in member cooperative trainings.

GRE would even provide their own staff to help train cooperative workers and contractors, but they had to be asked, signaling the voluntary nature of contributions within this common pool resource.

There was plenty of work for other types of contractors and business, too. UPA, in the early days, had to retrofit smaller 40-gallon water heaters with a second tank, such that the load management program could better bank kilowatt-hours for off-peak usage and leave the bathwater warm and plentiful. They engaged plumbers for years on this duplicative task, until manufacturers saw the promise of the water heating market and manufactured oversized residential water heaters between 80 to 120 gallons. With a location in the Twin Cities, Marathon provided a plastic-cased water heater that never rusted, serving the cooperatives well until the company was bought out. It moved south, and from that manufacturing facility many shipments of leaky, faulty water heaters came for the co-ops. This supply chain issue was largely handled by UPA as it sought other manufacturer partners, a common supply chain intermediary function for the G&T in the early days of the CPR.

Other issues with manufacturers were negotiated in the early days mostly by G&Ts. One of the first was that other manufacturers had to be lined up for products. The task could be daunting: European manufacturers were ahead of their American counterparts, and there was often no local or easily accessible load management product for the electric cooperatives' member-owners (Gustafson, 1981). Often it took time for the manufacturers to respond to national market conditions and pent-up demand from other utilities. This left cooperatives like Minnkota to rely on more regional manufacturers such as Minnesota-based Electro Industries, who were used for their dual fuel and heat storage systems (Electro Industries, 2014).

For individual gains and resources, the distribution cooperatives who had prior to the creation of the G&T load management programs incentivized water heaters and other electrified loads, now had a head start on the utilities in the system. The "friendly competition," as Thorson called it, began before others even knew it for Dairyland's co-ops. Between a few of Dairyland's distribution cooperatives, more than 10,000 water heaters were installed before the program was even started in 1980 (Figure 4.5).

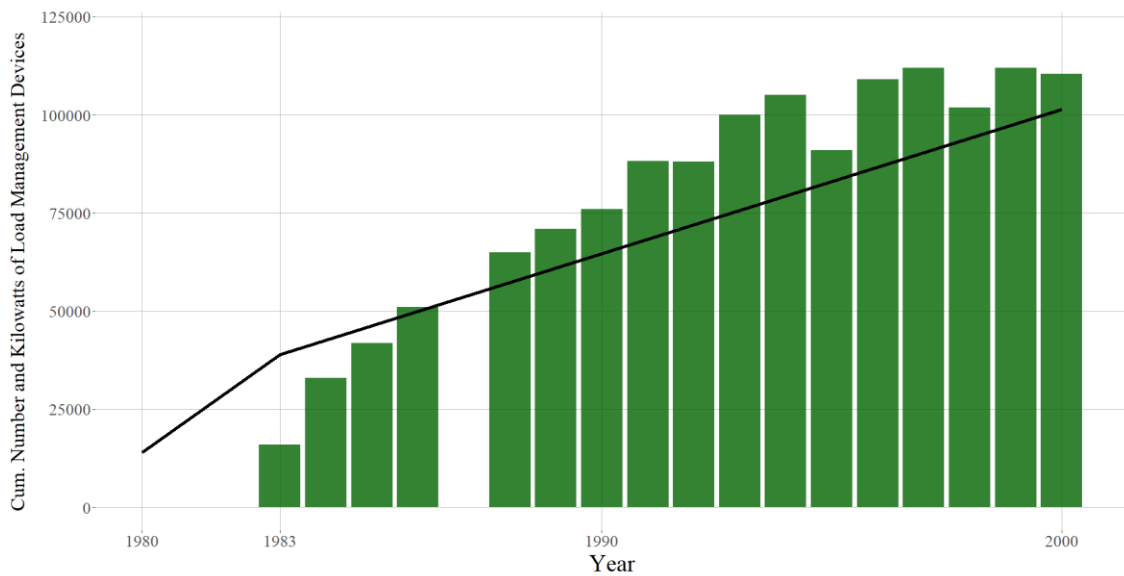


Figure 4.5: Cumulative Number (Line) and Winter Peak Reduction Kilowatts (Columns) of Load Management Devices at Dairyland Power Cooperative, 1980-2000. Dairyland's program began in 1982 with more than 10,000 devices, mostly water heaters, already equipped with receivers. These were "installed over the past 20 years," as Dairyland's REA loan application said, suggesting distribution cooperatives doing much of the work with their own communication systems beforehand. From 1980, over the next three years, the number of water heaters either installed or retrofitted increased by more than 20,000. By 2000, the amount of water heaters within Dairyland's system was at 80,000. Meanwhile, 16,000 dual fuel systems, 5,000 heat storage, and other C&I loads were also installed. Data sources: Dairyland Power Cooperative's integrated resource plan filings with the Minnesota Public Utilities Commission and (Dairyland Power Cooperative, 1985). Black line estimate gain in cumulative number of devices between 1983 and 2000.

4.2.4. Legitimation with Local Provisioning and Collective Choice

While G&Ts initiated programs, it didn't necessarily mean that their distribution cooperatives took advantage of the new platform or that G&Ts promoted it to their member cooperatives strongly. CPA cooperatives, for instance, were mentioned as not having much of a program at all until the late '80s, almost a full decade past its creation. Dakota Electric's program, for instance, wasn't made until the mid-'80s, and documents from the time show a focus mostly on irrigation and dual fuel for kilowatt impact, and a smaller year-on-year uptake of 20 new devices in other programs, all despite Dakota's presence as the largest cooperative in the CPA system (Dakota Electric Association, 1987, 2014; Doyle, 1979).

The cooperative, the only in Minnesota to be rate regulated by the state utilities commission, cited their lack of off-peak rates from the G&T as part of the problem. "[A]t 3.6 cents a kilowatt-hour," the cooperative wrote, "we cannot compete with natural gas or propane. Reduce that number by a four-mill credit to 3.2 cents, and we still cannot compete." Yet the 0.4 cent per kilowatt-hour rate was still voted- and agreed-upon at CPA in 1986, along with the allowance in the new rate of heat storage and dual fuel systems. In addition to these changes, less-than-80-gallon water heaters were now allowed in programs, or as determined by individual cooperatives.

These year-to-year, trial-and-error calculations in program design – like those reported in the common pool resource managements of Ostrom (1990) – seemed common for the cooperatives, allowing for at least some collective determination, via boards at the distribution and G&T levels, of program modifications. One interviewee said it took nearly ten years to sort through all the programmatic changes. Through committees organized at the G&T level, additional opportunities for staff to mix and exchange program designs occurred. Member services representatives across the distribution cooperatives would meet often to talk about how to handle paper work, but also to share ideas on program management. Some program shifts came from the bottom-up: some interviewees at distribution cooperatives reported holding training sessions with electricians wherein they would discuss with electrical inspectors what to present on. With electrical inspectors, they formed an informal governance of supervisors and educators to area electricians, setting best practices or informal standards for installations. But getting in the door with these and other contractors could be tricky. Outstanding commitments from contractors to certain manufacturers or distributors sometimes meant backlogs of non-utility approved load management devices stored in a garage, waiting to be unloaded on potential co-op customers.

The cooperatives had to offer a “win-win” to contractors. This became the increased business opportunity from the cooperative, since electrified loads often paid more on a job basis than any gas installation. The jobs could be at least sometimes negotiated, such that each contractor on a cooperative’s preferred list of contractors would be apportioned a slice of work from the occasional request-for-proposals. With building contractors, too, cooperatives sought to ingratiate themselves, working specifically so that new developments of hundreds of houses would all have controllable water heaters or air conditioning units. These new house builds were cited in multiple interviews as a key point in which the cooperative mediated the adoption process for consumers and contractors.

Closer to the G&T level, organizational differences between the G&Ts became more pronounced as time went on. In contrast to CPA’s deferral of an off-peak rate, UPA and Minnkota had allowed an off-peak rate from the beginning to their member cooperatives (EcoMotion, 1993; Energy Utilization Systems, Inc., 1982). UPA additionally offered loans to member cooperatives so that they could, in turn, offer loans to their member cooperatives. These types of financing decisions and optionality were important, as the G&Ts’ involvement once again didn’t mean strict implementation of load management. It meant something bigger: trust. This was a facet that Minnkota seemed prescient of when its board of directors “strongly urge[d]” member utilities to adopt policies to encourage dual fuel systems along with a “a publicity program” for those policies (Nelson, 1981b). There was no centralized control, other than in their physical communications systems: everything else was left to the distribution cooperative.

Basin Electric Power Cooperative also allowed an off-peak rate to its other G&T member cooperatives, but only after a conflict with East River, whose dual fuel and electric room heat programs were becoming too well-deployed for Basin’s other member G&Ts. Those other G&T member co-ops, whose load factor sometimes topped 70 percent due to the presence of coal mining and other heavy industries, complained that East River’s load management successes was making it in breach of its duty to buy from Basin. In other words, it was shifting fixed costs onto another member G&Ts too rapidly, cross-subsidizing too noticeably. The math came down to a demand and energy charge, where the crossover point of load factor (where East River would start shifting costs onto other member G&Ts, hypothetically) was 57 percent, according to Jeff Nelson. For years prior, East River had existed at 40 percent, but now as they neared 60 percent coming in the '90s, they were told to end their dual fuel and electric room heat programs. That decision alone stranded more than $10 million in startup costs. "I just said to them, 'So then I guess we should've been mad at the system that had 70 percent because they didn't have to do a damn thing," says Jeff Nelson.

East River acquiesced, the result a rare top-down interference with the common pool resources of these load management programs. To be on the losing end of a battle was painful for East River, because while it had the same winners-and-losers result of all load management efforts between member cooperatives of other G&T systems, this one ended explicitly-successful programs.

East River's experience with Basin was unique among this study's participants, showing a G&T that could not align with meta-constitutional rules of its power supplier with the common pool resource at the distribution level. Yet East River, and many other utilities, had other successes aligning rules with in its other power supplier, WAPA. The utility helped organize hundreds of other utilities to renegotiate their contract, which was based on a percentage of an annual peak, to a fixed, monthly allocation. Intermediating in the process, East River helped facilitate a change that was deemed better for the great majority's stake in the common pool, although a few were left with the option to retain the old contract, following a trend of voluntary contribution/non-contribution throughout the levels of the electric grid.

Like East River's power supply intermediation with WAPA, the fix to allow off-peak sales in MAPP was facilitated by Minnkota. Ultimately, the cooperative had to convince everyone in its special MAPP committee that it "may not be the best individually, but good for the pool," says Mel Nelson, supervisor of the load management program for Minnkota at the time. Eventually, Mel

Nelson and the others on the committee were successful in passing a rule that Northern States Power, owner of the most votes in MAPP, could agree to.

The constitutional and meta-constitutional rules of the commons' power supply thus had to be changed to legitimate the load management technology innovation at the bottom. G&Ts aggregated the interests of their member utilities to help work out supply-side incongruencies, while at the bottom, distribution cooperatives tried to fairly align prices and consumers' perceptions of them. It was important once again to the distribution co-ops and the G&Ts administering off-peak rates or annual demand charges, to allow the distribution utilities to offer what was locally legitimate, following Ostrom's precept of local benefits being proportionate to local costs. Some of Minnkota's distribution cooperatives, for instance, chose to offer low-interest loans and a 1 cent-per-kilowatt-hour discount for dual fuel systems; some went the opposite direction, not allowing new electric heating from their member-owners unless it was controlled (Energy Utilization Systems, Inc., 1982). Over the following decades, an diverse number of financing and rate options developed across member cooperatives and between their programs, combining financing from the G&Ts, local and regional finance institutions, and the distribution cooperatives themselves (Connett, 2001).

As addressed in the formation period of these programs, G&T systems took great care to address these concerns of fairness in how they operated and marketed their programs. East River reports their control strategy is redetermined annually, and takes into account "benefit in proportion to the number of receivers installed" at the member cooperatives (Holt, 2007). One interviewee, working in the East River network, said they declined to use the uniform $6/month credit for water heaters that Jeff Nelson said was most popular. He explained their rationale:

> It didn't make sense to install it and for us to try and save on the program and then to turn around and give them 6 dollars. Because it came 6 dollars on our revenue, [and] that ends up as an expense to us. This is to help in the energy rate and everybody will benefit from it… [and] once you give the six dollars, you'll never be able to take it away.

Yet other rates were designed with the understanding there was more at play than just a cold shower. Irrigation, grain dryers, and customer-owned generators impacted livelihoods, and a slip-up meant the farmer couldn’t pay their backer, as one interviewee stated. Yet each offered a large reward in kilowatts clipped, and were highly sought-after customers in both UPA, CPA, and East River. The process to enroll these customers and control their loads was often highly negotiated. East River relied on South Dakota State University’s (SDSU) irrigation specialist to introduce them to farmers, relying on the networks of the Farm Bureau, the Farmers Union, and the Dairy Association to build trust with farmers. With SDSU, the irrigation specialists also worked with farmers simultaneously to reform their overwatering practices.

To allow for flexibility with their individual member-owner requirements with these large loads, some allowed farmers to bypass the control. For East River, auto-restart features were installed on irrigation receivers to allow a farmer the freedom to not manually restart the receiver on his irrigator at 11 at night. In all, the process of engaging with irrigators was a process that would take them from farm to farm, even working with farmers to help monitor their peers who might unfairly bypass their load management receiver to receive credits without controlling, signaling a manner of common pool resource enforcement by the users of that resource.

The commercial and industrial interruptible loads were the most negotiated, as their operations had perhaps the most to lose from a slip-up. As such, these were by-and-large bypassable controls, giving the business the option to ride out a high demand charge, often passed through straight from the G&T, or shut down parts of or all the business. The shut-downs were not trivial for Dairyland C&I loads: a chipboard production facility had time-sensitive products whose parts could start on fire if left unset, and plastics manufacturers might have to deal with hardened gunk of plastics on their machines for a day after. Considering this, commercial and industrial loads often chose to manage their own energy usage without utility involvement, though member cooperative incentives could often persuade them into common pool resource involvement.

In total, for any type of member-owner, utility-controlled load management programs were thought to be more operationally flexible to their needs, be they hot water or interruptible manufacturing, compared to a time-of-use rate, which without utility control, ran the risk of burdening consumers with too many decisions and actions (see Table 2.2 for more information on time-of-use rates). Yet shared benefits were often worth the risks of load management. For the utility, too, a portfolio of utility-controlled load management products provided a backstop to other voluntary customer load reductions. In this portfolio, the co-ops could trust the aggregate effect of certain technologies such as water heaters, which one interviewee called the "baseload" capacity for the entire peak and off-peak performance of the load management system. Baseload supply, apparently, can have baseload demand.

Because the programs were coordinated and largely created through the G&T, a sense of ownership of the program eventually came to the distribution cooperatives. This incorporated in the long-run even the laggards, who took sometimes two decades of common pool resource integration to become proponents of the G&T-led system, according to Jeff Nelson:

> Letting guys like myself and many others trying to make the system operate, to try to get customers to participate, to explain why they had to change their rates, to report on the number of end customers who complained about the system and the number of operations were just not working… [It] changed the thinking of that old social contract into a new social contract.

Interestingly, state regulations sometimes affected the co-ops, who sought to change them to help protect, in part, their load management programs. Advocacy groups and state officials began to show concern over perceived wasteful practices of electrification through load management (Engelking, 1995). Their worries would eventually become integrated into Minnesota's Conservation Improvement Program (CIP). The initial rule allowed energy efficiency, system efficiency improvements, and load management to count toward spending and efficiency mandates, creating a situation where more than 80 percent of expenditures were for load management (Minnesota Department of Public Service, 1992). The allowance of spending for load management in the program would be later renegotiated in 2001, limiting the allowances of load management practices toward CIP's mandate (Minnesota Municipal Utilities Association, 2002). In 2007, when the standard was renegotiated again, system efficiency credits, such as upgrading a power line or power plant, would be allowable as energy efficiency credits, indirectly linking to the practices and philosophies that created the load management programs in the first place (Minnesota Center for Energy and Environment, Optimal Energy, & Seventhwave, 2018).

The co-ops were mentioned in an interview as having successfully negotiated load management into the CIP over time, citing system efficiency (via load factor increases, for example) as the main goal rather than an energy conservation specifically. These changes are important because they show cooperatives effectively negotiating common pool resource constitutional rules as they pertained to state regulations. This could also be taken as an example of the electric grid's larger network of polycentric actors negotiating a rule that acknowledged individual co-op institutional agency, while combining aspects of privatization (for energy efficiency credits) and top-down management (the Conservation Improvement Program was a mandate). Here the intermediary functions that G&Ts performed on behalf of their distribution cooperatives, legitimating their programs to wider political interests, showed nested institutions changing what, on the surface, might otherwise appear to be a straightforward government mandate.

4.3. 2000s to Present: Re-creation

4.3.1. Regime and Landscape Interactions

Nascent in the 1980s, but coming into mainstream in the 1990s and 2000s, two-way, digitalized technology spread through the utility world, bringing with it advanced metering and real-time pricing opportunities, but also new system weaknesses in cybersecurity (Pérez-Arriaga & Knittel, 2016). Most interviewees reported the change as being monumental to the future of load management programs. Many interviewees held load management in question now not around its presence, but around its overall usage with wholesale markets such as the Midcontinent Independent System Operator (MISO).

With new wind and solar rapidly declining in costs, and natural gas flooding the market with low prices thanks to a national fracking boom, demand- and supply-side technological and economic changes were occurring fast for the cooperatives. Yet by the recession, which had crashed at least a few cooperatives' methods of selling load management through new home builds, energy sales again flattened. Only a decade later did they begin to rise (Gahran, 2018). In this time, too, growth in global climate change mitigation efforts and damages, along with increasing interconnectedness of electric grids with each other and cheaper renewable sources of generation, increasingly drove electric utilities and policymakers toward decarbonized energy solutions. This occurred even as locations, such as Minnesota, stalled in their emission reduction goals (Minnesota Pollution Control Agency, 2019; Pérez-Arriaga & Knittel, 2016).

In the Midwest, fossil fuel heating regimes (involving natural gas, propane, and fuel oil), combined with cheaper gas supplies, spread into the more urban and suburban centers, still not fully penetrating the rural areas. In Minnesota, for example, electricity still provided upwards of 30 percent of heat for residential units as of 2014 (Figure 4.6), while natural gas provided upward of 70 percent of heating for many counties centered around the Twin Cities and into southern Minnesota. Over the past decade, close to 100,000 residential units gained electric heat, mostly in the rural areas of the state, outpacing natural gas by more than 30,000 units.

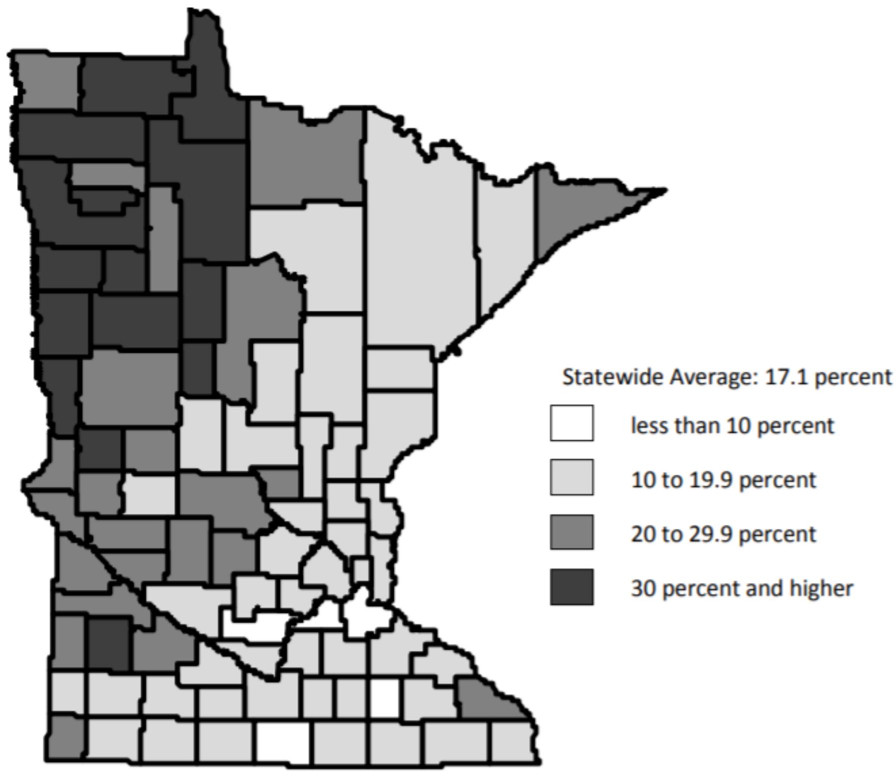


Figure 4.6: Percent of Housing Units Using Electricity as a Heating Fuel, 2010-2014. Metropolitan counties experienced much higher natural gas penetration than the rural counties, which still used high percentages of propane, fuel oil, and wood to heat their homes. The most electrified heating sources, according to the map, coincide with western and northern Minnesota, an intersection of this study's G&T subjects. The highest penetrations appear to occur within Minnkota's territory, perhaps speaking to the pervasiveness of their dual-fuel approach. Adopted from (Eleff, 2017), who used U.S. Census Bureau American Community Survey 5-year estimates.

4.3.2. Market Formation

"We have a foot in the new world and that's MISO," says Connett, "and meanwhile the way we recover our costs is old world."

In an older world, as Connett says, the distribution cooperative was tied to the G&T through an all-requirements contract. The G&T provided all energy and capacity to the co-op and hedged what they didn't need through the collective organization of MAPP. Yet the advent of MISO and other independent system operators under the regulation of the Federal Energy Regulatory Agency, along with the growing economic feasibility of distributed generation, opened new markets for the co-ops. For the first time, load management was not just avoided peak capacity or reserves but could also an energy service at the constitutional level of the commons at MISO. The load management that was above a certain capacity and met certain reliability requirements – mostly customer-owned generators and interruptible commercial and industrial accounts – was able to participate in MISO or other wholesale energy markets, with the G&T acting as aggregator for the member-owner or member cooperative. Yet for water heaters and other too-small distributed assets, load management operated behind-the-meter from MISO, meaning the market did not control or detect these assets. As such, in Dairyland, when peak conditions started to hit, that meant turning off water heaters to decrease price exposure (PLMA Thought Leadership Group, 2019). It remained apparent to G&Ts like GRE, despite this incongruency in distribution and wholesale, that the wholesale market could provide benefit: one document citing GRE said the utility could receive the same value for 12 hours of load control in MISO that it would have taken 160 hours to make without it (Power Systems Engineering, Inc., 2017)

While there were potential benefits, wholesale markets also brought new uncertainty for distribution cooperatives outside those contracts and centralized rate structures. They could recover their system costs all the same from distribution utility members, but now the peak of MISO – and not the collective peak demand of the co-ops – was the uniting system goal. G&Ts now experienced what their distribution cooperatives felt in the 1970s and '80s with the advent of their G&T-system coincident peaking rates.

Despite these top-down interferences, the old co-op system remained perpetuated in the contracts that G&Ts carried with distribution cooperatives. Member cooperatives were still rewarded proportionately for the demand charges they avoided, and G&Ts were still largely able to control member-owner loads, or at least the one-way receivers that still worked. According to one report of Arrowhead Electric Cooperative, as many as half of load management receivers had at least one failed control event during the 2016-2017 heating season (Orest & Grahl, 2018).

Without heavy market intermediation or ability to intermediate by the G&T for these distributed assets, individual utilities began in this time to exert intermediary market-shaping forces on their own with new technological vendors. Cooperatives such as Connexus Energy and Minnesota Valley Electric Cooperative began to offer voluntary demand response programs with smart thermostats outside GRE's control. Other co-op piloting of programs continued. Interviewees reported electric vehicle rates and test drives at events such as annual meetings. Grid-interactive, digital water heaters were also mentioned in multiple interviews as being tested in reaction to wholesale price signals. In unique partnerships among a few Dairyland member co-ops, behind-the-meter control of batteries were also tested, placed within member-owner homes to determine overall feasibility with a time-of-use rate (Uhlenhuth, 2019).

These pilots and individual or sub-group efforts seemed localized, however, and not the norm. It may have been that here, as in the 1970s with time clocks and power line carrier, individual cooperatives with the resources acted to experiment, while those without the internal capacity fell behind, waiting for the next wave of G&T intermediation to carry them forward in the common pool of collective goals.

4.3.3. Resource Mobilization

G&T and distribution utilities faced in the 2000s more overarching questions on where and how to redevelop their load management communication infrastructure. For example, following the merger, GRE moved to consolidate the separate load management programs of CPA and UPA. Materially, this meant investing in a master controller to control each system (Minnesota Power & Great River Energy, 2005). As a matter of governance, though, it meant signaling to member utilities when to operate their own load management systems (instead of directly controlling) and building for co-op to co-op interoperability on the grid. As some interviewed co-ops had built their own control centers for their grids in the past, load management deployment became in this era a more-pronounced dual function of individual and collective resources, with many distribution utilities and G&Ts accommodating increasing numbers of third parties into their digitalized grids. GRE, for instance, moving toward increasing amounts of two-way technologies, saw upward of a dozen of member co-op communication vendors in the system, while scores of other co-ops showed non-adoption of the same vendors and technologies (Figure 4.7).

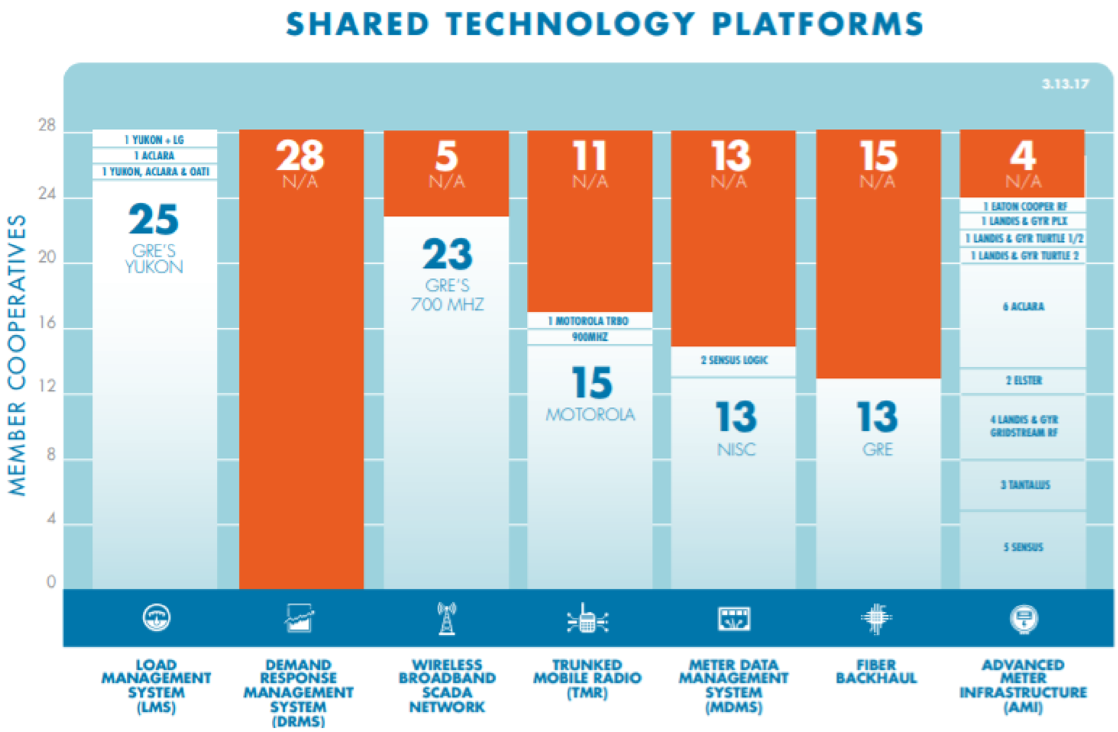


Figure 4.7: The Diversity, Type, and Ownership of Great River Energy Member Cooperative Communication System Platforms. In its 2018-2032 Integrated Resource Plan filing to the Minnesota Public Utilities Commission, Great River Energy showed the scope of their "future grid" technologies, allowing them, in part, to "control electric loads at a more granular level and interconnect with other load control technologies." Source: (Great River Energy, 2017).

While some such as GRE sought to deploy and coordinate resources for a rebuild of an interoperable communication system infrastructure for their member utilities' load management systems, other G&Ts such as Minnkota rebuilt their old, one-way ripple communications infrastructure (Minnkota Power Cooperative., 2017). Minnkota worked with Landis&Gyr and to understand the German-language blueprints of the old system and eventually replaced the ripple control injectors. “We researched the possibility of replacing everything with a whole new program,” one Minnkota employee reported in the December 2017 Minnkota Messenger, “but there was overwhelming support to keep our existing system operating… All we did was purchase new injector hardware to replicate the same signals that the co-ops were getting in the past.” As another Minnkota employee reported in the same article, “Really all we’re doing is extending the life of a legacy system,” it seemed that the collective decision to rebuild or re-create the provisioning infrastructure was on many G&T systems’ minds, even as new individual opportunities emerged.

This demand-side infrastructure decision reflected a development in the co-op world where in 2009 and the early 2010s, at least a few distribution cooperatives began to fix their all-requirements contracts to a certain level of power supply, or seek exemptions for self-supply (Chan et al., 2019). With the new entry into MISO, these cooperatives also had to seek peaking contracts from other G&Ts. Those peaking contracts, with provisions for demand and energy, often meant that cooperatives would now be controlling for three or four peaks: physical distribution grid peaks, fixed contract peaks, peaking contract peaks, and wholesale market peaks. The new contractual arrangements had the side-effect of distancing the member utility from G&T aggregation abilities in marketing, information sharing in committees, or other programs. “We’re doing our own now,” said one interviewee with a peaking contract.

The arrangements also shifted the financial fairness of the system: only 20 of the 28 GRE member cooperatives, those with all-requirements contracts, received rebates for demand-side management products from the G&T; the rest are solo (Power Systems Engineering, Inc., 2017).

Internal to the remaining common pool, the focus of the G&T remained at least somewhat on the distribution cooperatives. Education of these co-ops and their member-owners was never complete, as Thorson cited the constant turnover in member services’ personnel and the lack of experience from some board directors with the program. Other G&T interviewees talked of seeing who was gaining, and who was losing, in the blended demand-and-energy billing rates their member utilities received. They could provide more resources and incentives, collectively decided upon by different general manager-led committees, but there was also a saturation point for what any G&T could do for a distribution cooperative that had failed, after decades, to deploy measurable amounts of load management.

Looking beyond load management, the cooperatives increasingly tied their load factor to economic opportunities for businesses and community centers. Cooperatives remained overall residential-based, but their electricity became increasingly focused on commercial and industrial programs as manufacturing and large farms moved into the country. Layered benefits appeared to be on the cooperatives' minds: one interviewee reported obtaining a federal loan through the Rural Economic Development Loan & Grant Program to update a hospital wing, using it to also implement a utility-controlled diesel genset to back up the hospital during peak or emergency conditions.

To accommodate and take advantage of growing commercial and industrial loads, many programs during this time also endured a shift in focus, reflecting local preferences for load management from the distribution co-ops. For cooperatives such as East River and its member utilities, that meant shifting over time from its initial sprint of water heaters, which allowed them to remain afloat financially during the farm crisis, toward third-parties and summer-based loads like irrigation and customer-owned generators (Figure 4.8). These shifts gave them more kilowatt-bang for the device-buck, even as water heaters performed backstop "baseload" duties in the load management programs, according to one interviewee.

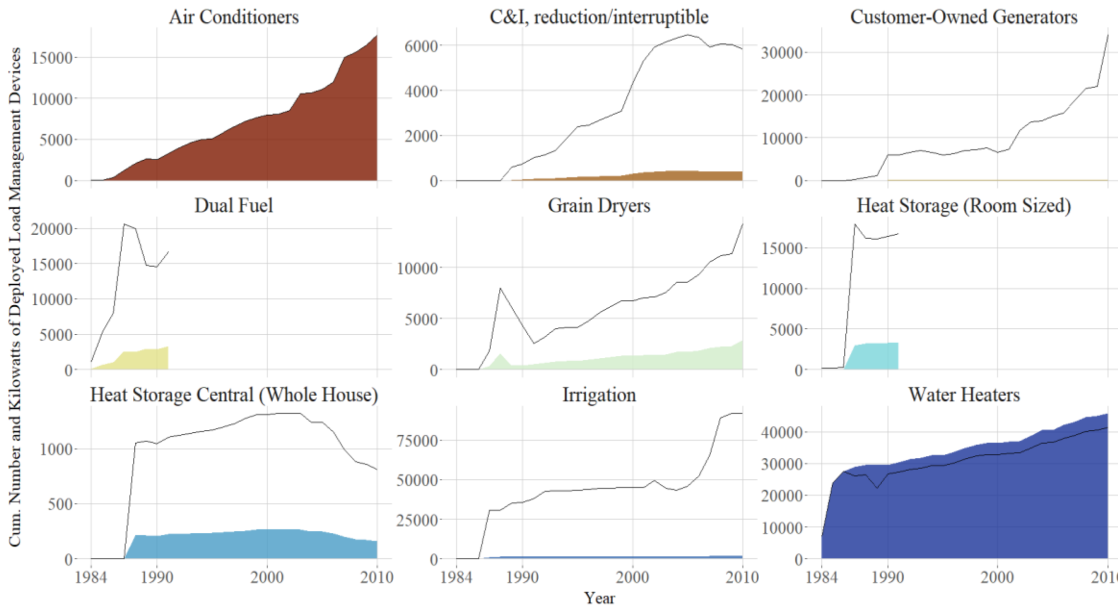


Figure 4.8: Cumulative Number (Shaded Areas) and Kilowatts (Lines) of Load Management Devices at East River Electric Power Cooperative, 1984-2018. In the first two years of East River's load management program, the collective of member cooperatives deployed more than 20,000 water heaters and/or load management receivers. Water heater adoption rates after matched the linear path of air conditioning units, while just a few irrigation and customer-owned generator units were enough to make a large kilowatt impact. Note the dual fuel and room heat storage programs which ended in 1992 after a dispute with East River's power supplier, Basin Electric Power Cooperative. Data source: Jeff Rud, East River Electric Power Cooperative.

4.3.4. Legitimation with Local Provisioning and Collective Choice

Technology and wholesale markets changed expectations for G&Ts and distribution utilities alike, along with their member-owners. "Smart thermostats were the first time we started to lose control of the control," says Connett, reflecting the growing porousness in the boundaries of this common pool resource. Customers controlled their own loads more, and distribution utilities wrangled those loads as they could. And interoperability needs with increasing numbers of third parties meant communication systems had to be integrated at the distribution and G&T levels. While increasing in the number of actors and institutions, the complexity of the system, and the resulting benefit and cost provisioning, was beginning to be sorted out.

For instance, East River had made, installed, and maintained their hand-wired irrigation load management receivers for years (East River Electric Power Cooperative, 2018). Incentivizing farmers to participate in a third-party irrigation management system, the G&T saw 161 farmers join in 2017, and more than 120 in 2018, showing a type of collective action with the facilitative intermediary of a non-cooperative unit. Echoing other interviewees, one interviewee from the East River system emphasized the growing optionality of the load management system: "We went to some load control devices that the member installs on their own system, but they can control from their iPhone. We send him a notice, and he can see if, 'Is my pivot on or is it off and do I want to ride through the demand charges and run it because it's too hot or dry?' It puts the decision in his hands rather than us deciding."

Giving up control meant more control, in a way, for the co-ops in this new age. Customer-control, through time-of-use rates or customer notifications, was enabled now through metering technology and more advanced rate structures that weren't efficient or technologically feasible in the 1970s. Unlike then, price functions with their optionality were mentioned to work just as well as load management.

Increasing individual volition at the levels of the grid led to a growing sense in interviews of a new "tragedy of the commons." While Dairyland is only a fraction of total peak in the market, if other utilities shed load or use distributed energy to offset peaks as they did, it can lead MISO's peaks to be misforecast. And because that load was taken away from the system unexpectedly, it generated new real-time locational marginal prices, arguably affecting everyone for the worse. There were signs, however, that the system's rules could be integrated top-to-bottom, as it was before: under a new docket from FERC, split off from FERC Order 841 on energy storage, new distributed energy resources aggregation rules at MISO meant the market could soon accept bids of aggregated DER from utilities like GRE (Kleckner, Kuser, Cook, Brooks, & Heidorn Jr., 2018). The order could mean bidding from third parties, too, as well as geographic constraints on aggregation, bringing again some doubt as to the old commons-based program carrying into the new market-based role.

Other impacts from MISO influenced the cooperatives' programs. Generated by influxes of geographically varied utilities and their diverse loads, longer peaks drove the cooperatives to divvy their load management assets into different geographic and temporal groupings, cycling water heaters to help hit what might be a six- or eight-hour window, a shift from the '80s and 90s when the peak only existed for a few hours. Economic growth also affected the programs: one interviewee cited the fact that peaky load growth outside the load management program almost negated the efforts of the controlled devices themselves.

Hearkening to Insull in the early days of the grid, some utilities sought to entice high-load factor loads to the grid rather than wait for them. Jeff Nelson thought the Rural Electric Economic Development (REED) Fund, a strategic pooling of participating member cooperatives' investments to loan out to attract new businesses to the area, was connected in a way to East River's load management program. The REED Fund pooled resources and abilities similarly in the management and provision of common funds, but also like load management, there was a load factor connection. Loaning out $80 million dollars over its 20-year life, the collective of East River co-ops built stable, non-peaky load for the electric cooperative (East River Electric Power Cooperative, 2018). Due to the changing nature of their customer base, and partially due to direct influence from the G&T and distribution cooperative in drawing in new load, East River's load management program didn't need to clip peaks as increasingly through the years (Figure 4.9). Interestingly, building load here was just as legitimate as the load management itself, and facilitative activities pursued by most of the member cooperatives in the REED Fund allowed the process to occur more efficiently than if they had done it co-op by co-op.

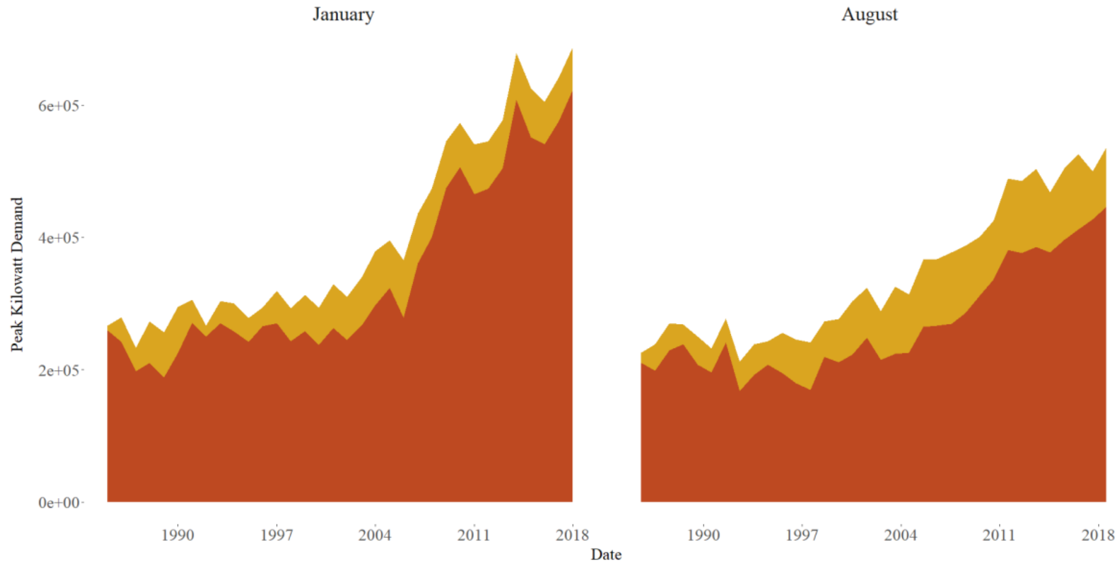


Figure 4.9: 34 Years of Peak Load (Dark Area Below) and Clipped Peaks (Light Area Above) in January and August at East River Electric Power Cooperative, 1985-2018. Above shows East River's winter peak rising faster than the summer, even as the clipped load in summer increased faster than winter. The reasons are due to commercial and industrial customers quadrupling their portion of East River's total sales, pointing to a changing customer composition that has limited the amount of necessary load clipping from load management, at least in winter. Source: Jeff Rud, East River Electric Power Cooperative.

Reflecting on the changing nature of their business, many interviewees wanted to know what to expect next. Some directly requested this study respond to that question, while other brainstormed on possible future options. One interviewee posited that the day was coming soon when the G&T didn't just sell to the distribution utility but would also buy from it. No other interviewees echoed that statement, but their individual mentions of repurposing the load management programs for new uses – incorporating intermittent renewable energy, responding to wholesale market signals, and using electric vehicles and electrified appliances to grow load and remove reliance on fossil fuels – spoke to an overarching, regenerative phase for the programs in general. This was reflected in groups such as the Beneficial Electrification League (supported jointly by the National Rural Electric Cooperative Association and the Natural Resources Defense Council) that helped to legitimate the old load management technologies. With legislation posed in the Minnesota legislature in 2019 to add electrification measures to the Conservation Improvement

Program (Office of the Revisor of Statutes, 2019), some interviewees mentioned the necessity of the law's change to include load growing activities. One interviewee mentioned their lobbying activities to legislators on behalf of the proposed legislation, signaling some of the system building activities that the G&Ts were now taking, and had always taken, on behalf of their member utilities.

5. DISCUSSION

I interpret these findings considering my theoretical framework on intermediaries, polycentricity, and energy transitions. Below I use technological innovation systems and the multi-level perspective to draw out key theoretical insights on intermediaries, showing how intermediary functions may be necessary to DER deployment in general and how they shift throughout time between decentralized partners. I then focus on polycentricity to show the importance of intermediary innovation functions in distributed energy resource deployment. Finally, I state this own study's caveats and some implications for future research ideas.

5.1. Connecting Findings to Technological Innovation Systems Theory

By highlighting the co-ops' intermediary innovation functions in managing a common pool resource of electricity infrastructure, I showed a novel connection between TIS theory and polycentricity. Innovation for these utilities and their customers was a negotiated, political process, not just technological or economic in nature. It was also never a mandated or market-driven effort. It was instead a mutual involvement of incumbent electric cooperatives facilitating early adopters and laggards alike, while encouraging new nonutility actors with their own intermediary innovation functions that changed through the phases of load management deployment. Innovation occurred here through multiple layers of competition and cooperation, showing that the TIS can be more institutionally-constructed than previously thought.

From these observations, I am led to the conclusion that the general process of a distributed energy deployment – controlling or incentivizing multiple, different loads at once with multiple, different utilities and customers – needs layers of formal and informal polycentric governance. By facilitating multiple nodes of difference and experience, the distributed energy resource deployment was able to emerge and sustain itself. Whether for a particularly quick deployment, such as East River's nearly-30,000 water heaters in three years (see Figure 4.8), or a sustained deployment (such as occurred within all the programs), intermediary innovation functions seem to have been completely necessary. This conclusion is important because while research has only begun to show the importance of politics and governance within electricity and energy, it is my hope that this study will spawn more studies and practical models on locally-relevant innovation intermediation functions in the future.

For the sake of transitions theory alone, this study shows the TIS can be a collaborative, political process between layers of cooperating and competing actors and institutions. These geographically dispersed and -dependent utilities often worked outside of strict market or top-down regulation mindsets. For instance, cross-subsidy was often accepted (against ideas of efficient markets), and local differences were often embraced (against ideas of mandates driving minimum performance), as intermediary functions of the co-ops helped to shape networks of deployment and adoption. These intermediary functions showed at all levels of the commons: through the governance and markets of MAPP or MISO (Sections 4.2.4 or 4.3.2); in the marketing committees, manufacturer networking, and co-created rate structures of the G&Ts (Sections 4.1 and 4.2); in the incentives and contractor networking of the distribution utilities, with offers of help from G&Ts (Section 4.2.3); and in the technological adoptions and utility-customer collaborations of the member-owners (Sections 4.1.2, 4.2.2, and 4.3.2). Because these functions occurred at all levels, it seems relevant that the TIS should reflect the multi-scalar nature of innovation and not contain itself within a level or sector. This is important because in the literature and in policy, there is often a heavy focus on individual customer adoption trends, and on utility-by-utility programmatic efforts, but less on the complete top-to-bottom context of these trends and cumulative efforts.

Following the results of this study, these individual adoption trends of DERs should be recognized as constructed by greater systemic institutional and social forces. These forces are not of singular actors: they flow between actors, as shown by this study's focus on intermediary innovation functions. This mirrors previous research on decentralized resource management that showed that a polycentric analyst must look "beyond the performance of a local government unit to consider the relationships among governance actors, problems, and institutional arrangements at different levels of governance" (Andersson & Ostrom, 2008). Adoption and deployment of DERs, in this case load management, were less about individual actors than the connections between them. Locally-relevant adoptions of DERs, whether they were water heaters or grain dryers, seemed to be the results of numerous ties and fostering of ties by actors and institutions. The connections between actors, problems, and institutions formed a complete DER deployment innovation system that existed through experimentation and learning, as Andersson and Ostrom (2008) similarly found.

As with the notion of "system building" in the TIS, where actors deliberately create supportive structures for innovation even if it doesn't directly benefit them, the co-ops' intermediary functions had a substantial impact on the continued deployment of distributed energy resources (Musiolik & Markard, 2011; Musiolik, Markard, Hekkert, & Furrer, 2018). Appearing to follow design principles of common pool resources, the instances in which programs failed to grow are noteworthy: they are cases of outside interference or lack of intermediation. East River's electric heat programs were ended by Basin's other member G&Ts when they became too "successful," and Minnesota Valley Cooperative Light & Power never started a program, perhaps for lack of involvement from Basin. Other programs' stunted growth often came from a mismatch with local conditions or failure to coordinate value through the chains of the system (i.e. Dakota Electric and other CPA co-ops failing to procure a low enough off-peak rate or Minnkota's lobbying to change off-peak rates in MAPP in Section 4.2.4). With the many other examples of program successes for the co-ops, the above failures demonstrate just how important cooperation and facilitative regime and system goals are to distributed energy deployments.

5.2. Connecting Findings to the Multi-level Perspective of Intermediaries

By showing the iterations of intermediary functions over phases, I also showed how polycentric decision processes overcame potential barriers through cumulative, collective action across all levels of the governance of the common pool resource. In these actions the co-ops drove niche innovations into their regimes and bridged gaps between the layers that might have hindered deployment. This provides insight into the MLP, which largely focuses on individual attainment and innovation, and shows that niche, incumbent, and systemic intermediaries may be necessary to move innovations into incumbent regimes. This follows Andersson and Ostrom (2008) who suggest "the key to effective governance arrangements lies in the relationships among actors who have a stake in the governance of the resource." Likewise, DER deployment may require strengthening of relationships to move innovations upward to different regime levels.

Importantly, the intermediary and bridging roles of the G&Ts and distribution utilities shifted throughout the time-periods, following Markard's (2018) conception of life cycles for TIS frameworks. This is important for the MLP because it shows that upward pressures for niche innovations may need to change as time goes on. For instance, in the formation stages, centralized incumbents in the G&Ts played a large role in resource deployment and market formation, giving central coordination and legitimation to what would have been too decentralized, too divisive to carry in an individual fashion. As one interviewee said:

> By East River coordinating the rebates, the incentive programs, the overall utility load management system, the economies of scale, the direction from the G&T… That was huge, really got us going in the right direction. Otherwise, we would have been 25 of us going completely different directions and we wouldn't have been as effective.

Going into the stabilization phase of the co-ops' deployment, intermediary functions expanded to include more of the distribution utilities and external program partners. Distribution cooperatives undertook intermediary functions such as warehousing, business creation, and education that were formerly taken up alone by the G&T. With heavier involvement by locally-connected utilities, important decision processes were formalized, built on the structures (both in communication networks and governance) that the G&Ts first helped establish. Electric inspectors and contractors could input and collaborate on distribution cooperative program rules and responsibilities; individual cooperatives and member-owners pursued programs and pilots in conjunction with the G&T's own programs; and constitutional, collective action, and operational rules were modified year after year in a constant muddling-through of best practices. These feedback loops developed the stability of each program's development, playing out in intermediaries such as committees, boards, and member services representatives that relayed changes throughout the course of each program between actors, institutions, and scales.

As the load management programs carried on into the re-creation phase, manufacturers and third-party vendors and contractors became more proficient in provisioning market-ready load management products. They too took on more intermediary functions such as legitimation, business creation, and customer marketing and education that were formerly taken up alone by the G&T and distribution utilities. Today many distribution utilities seem to compete and cooperate with third-party aggregators such as smart thermostat vendors, reflecting the expansion of the common pool resource on the grid.

These shifting intermediary actions recall the "friendly competition" that has existed between the distribution utilities themselves for the past four decades. In this way, it seems there are constant feedback loops that inform and are being informed by electric utilities' institutional and social innovations on the grid. Stronger feedback loops might increase the speed of a deployment, just as weaker feedback loops might hinder it, and the MLP is better thought of a joint creation between incumbent and niche actors and institutions.

5.3. Polycentricity and its Implications for Understanding DER Deployment, In and Outside of Cooperatives

Following the results of this study, and the premises accepted in the past two sections on the TIS and MLP, it seems clear that the co-ops' load management deployments were polycentric, constructed, social, and political. Always different, always the same were these programs: interviewees often cited the constancy of centralized rates – along with ever-present contractor, member-owner, and distribution cooperative education and coordination – as being keys to the programs' ongoing success. The acts of dictating and communicating the rules, then, between the meta-constitutional, constitutional, collective choice, and operational layers was key to upholding the common pool resource of the grid (Ostrom, 2008).

But currently the common pool resource, once closed to outside interference, is undergoing a period of vast technological change and external influence from wholesale markets, posing some uncertainty for the programs in general. Though the programs can continue as before between the G&T and distribution utility, new third parties offer solutions to member-owners, and the G&Ts necessarily interface with wholesale markets such as MISO. As in the 1970s and prior, when individual utilities used timer clocks and radio or ripple control receivers to perform their own load management functions, today the ever-present piloting of the distribution utilities seems more individual, and less collective.

Then as now, while distribution utilities continue to individualize, G&Ts seek to collectivize. Now to maintain the collective interests of the commons, it therefore seems necessary to centralize and coordinate greater system goals, as in the 1970s. The programs can continue to exist behind-the-meter between the G&T and distribution utility; however, full system value will not be achieved until the programs are fully integrated from the wholesale markets to the member-owner.

Yet it's also clear from these interviews and subsequent research that to even begin collective resource management in the '70s, the co-ops faced external shocks (in the form of oil and farm crises, for example) to lock in central system goals. Today, alone, the co-ops may not be able to integrate long-term system needs (such as decarbonization or DER maximization) without broader signals from a facilitative regime, as Ostrom (1990) described. In the first place, the co-ops also needed a level of supportive policies to allow their load management programs to begin and thrive; they may need such an environment to re-create again. For example, few interviewees were able to name important government policies that affected their deployment, yet there was an entire background in interviews and documentary research of cooperatively-determined and state-determined policies that affected deployment.

- Electric cooperative co-determined policies included mandates (no electric heat without dual fuel), standards and informal licensure (best practices or preferred contractor lists), goals (G&T-wide load factor improvement), financing (rebate pooling, loan funds), product guarantees (for water heaters and dual fuel systems), and education policies through a variety of means.

- Important government policies included Department of Energy grants, Rural Electrification Administration or Rural Utilities Services/Department of Agriculture grants and loans, state policies for efficiency standards, and even integrated resource planning rules, which made the cooperatives negotiate with a broader set of policy stakeholders in their demand-side management programs. Other known impactful policies include emissions standards for diesel generators, technology and communication system standards for engineering and system interoperability, and the variety of rules dictating services within the wholesale energy markets.

That the co-ops sought to integrate their programs with government policies – i.e. load management's consideration in Minnesota's Conservation Improvement Program and their education program's offer of credits toward state licensure requirements for contractors – means they were concerned with how they legitimated their innovations within a broader sphere of influence. This speaks to a broader, co-created environment of policies, one more than most cooperatives are willing to admit. It also speaks to nests of polycentric governance that stretch beyond the co-ops themselves and greater lessons from these case studies.

With these findings of more broadly-constructed regimes and landscapes, I believe the biggest lesson from the case studies may be that as electricity is taken to be a bundle of goods, so too may an electric utility be theorized as a bundle of intermediary roles. This is different from the traditional view of the electric utility, which with power plants and wires, simply transmits electricity to customers and receives revenue (Figure 5.1). Either vertically-integrated as investor-owned utilities, or deregulated as co-ops are, traditional electric utilities perform intermediary roles only vertically and to aggregate for classes of customers. Intermediary functions in this view are solely technical and economic.

What this study finds, however, is that the electric utility as an actor in a technological innovation system with DER deployment requires intermediary functions between and within levels and across utility and non-utility actors (Figure 5.2). Those roles can loosely correspond to meta-constitutional, constitutional, collective-choice, and operational rules of the grid's voltage levels. Intermediary functions are vertical across layers (as when cooperatives determine incentives for load management based on G&T and wholesale incentives, or when co-ops distribute load management technologies for manufacturers), horizontal between utility actors (as when member-owners help diffuse the adoption between themselves), and horizontal between utility and non-utility actors (as when the cooperatives educate and coordinate contractors). How the utility chooses to intermediate these different roles will impact the speed, effectiveness, and longevity of any energy transition utilizing distributed energy resources such as load management and perhaps other types of DERs. The different roles will include, among other subjects, what the utility chooses to do in-house versus through incentivizing and coordinating third parties or consumers, how it accommodates for regional differences, why it pursues some distributed energy resources over others. All these decisions speak to an inherent polycentricity in the electric grid, resulting in an expanded definition of the electric utility as a polycentric institution (Figure 5.3).

Because the electric grid is polycentric, naturally and through negotiation over time, intermediary functions are created to support connections between actors and institutions. These functions necessitate appropriately scaled rules and governance platforms for DERs. For the decentralized nature of DERs, it seems that only when these innovation functions between polycentric system actors are encouraged and strengthened may the system be successful in the short- and long-run of a DER deployment.

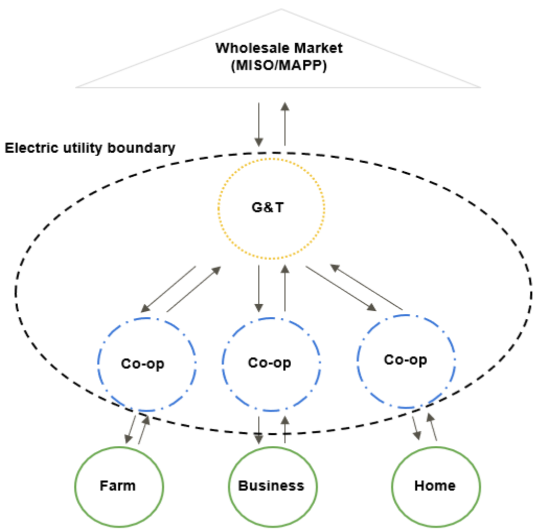


Figure 5.1: Traditional View of an Electric Utility. Here the intermediary functions of the utility are symbolized by the arrows between the layers of the grid. Traditionally, the electric utility is thought of power plants and wires. Thus, its intermediary functions relate mainly to one-way power and revenue flows.

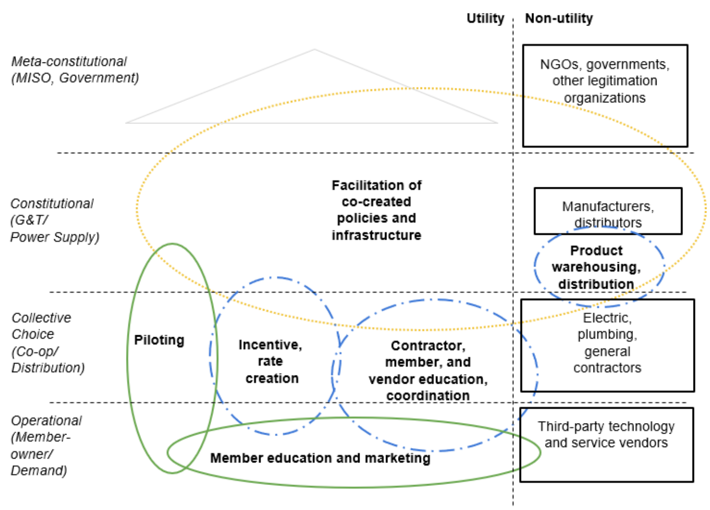


Figure 5.2: Intermediary Functions of the Electric Utility Between Utility and Non-utility Components. From meta-constitutional to operational levels, as detailed by Ostrom (1990), the electric utility has been shown in this study to include bundles of intermediary functions that span horizontal and vertical scales from G&T to member-owner and non-utility partners. These intermediary functions present the type of formal and informal relationships that help negotiate rule and program shifts across and between levels of deployment.

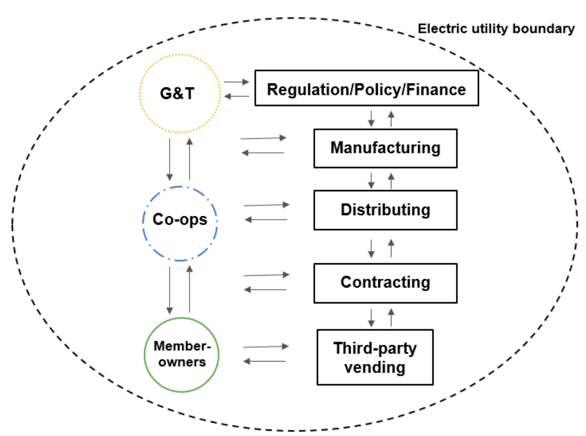


Figure 5.3: Expanded View of the Electric Utility. The electric utility and its intermediary functions (symbolized as arrows) must include non-utility actors and institutions. Innovation therefore can be polycentric in a system that DER deployments. These deployments may be better off in the short- and long-run when these arrows are strengthened.

5.4. Implications for Future Research

It is here, however, that I note my study's limitations in making these claims and note the need for future research. Given my small interview sample and focus on a subset of utilities, more research is needed to clarify the constellations and networks of DER system actors (such as contractors and member-owners and board members) and their roles in forming these programs throughout time. My interviews also focused more on the past, and to reach a more substantial input on the present, more research and process tracing on current technology and dissemination is needed. As this study makes a new connection between polycentricity and the TIS, and between decarbonization and DERs, more research is necessary to understand the applicability of this approach, even in scenarios where top-down or market regulations dominate. Specific examples should also show distinct failures, as these co-op programs are bundles of mostly successes.

There is also need in this study to connect load management with broader demand-side management opportunities; as other utilities have noted the difficulties in connecting the different types of DER with each other (Potter et al., 2018), it would be a fruitful research avenue to compare intermediary functions across different DER offerings within a selection of utilities. There is a definite need to distinguish more specifically between types of DER deployments (e.g. rooftop solar, distributed wind, conservation measures such as LEDs, etc.) and see how system actors and institutions vary across those dimensions. In addition, there may be some DERs (such as rooftop solar or types of energy efficiency) that are not wanted by incumbent actors in an electric grid common pool resource: under what conditions do those resources emerge? Is it polycentric still, or does it require more market-driven and top-down regulation?

Within an electric grid more broadly, and in this study more specifically, more research is needed to clarify the role of political and social power imbalances within and outside of the common pool resource framework, as other studies have done (Klooster, 2000). This study recognizes but could have been more explicit in the sometimes-low voter turnout for electric cooperative board elections (as is common with many consumer cooperatives), the inherent power imbalances between contractors and other third parties and distribution cooperatives or G&Ts, and the technocratic utility ownership that naturally disfavors member-owner agency. These power imbalances, along with disinterested distribution utilities and member-owners, mean a DER deployment could be detrimental to group outcomes, and therefore challenging in CPR governance. Fairness would be important to examine in this light: does the construction of fairness result in more DER deployment? How is fairness (and notions of cross-subsidy) constructed between DER users? Federal and state policies, too, or at least the threat of them, seem to have played a larger role than was admitted by interviewees, so further research could show how incumbent intermediary functions relate to politics and policies. At the least, future studies could show how power shapes expectations and control from the top-down perspective, and how the electric grid as a common pool resource is helped or hindered by these power struggles.

There is more need to clarify internal and external governance outcomes as they relate to DER deployment; none of the utilities in this study have the same governance structures, and it would be fruitful to connect structures to DER outcomes, too. The same goes for utilities: understanding their institutional and organizational means for change and interaction may yield substantial understanding for the barriers and opportunities of DER deployments in other subnational or regional settings. Further clarification is also needed to specify how these intermediary functions shift in utilities with different ownership, incentive structures, and countries of origin.

The lens of polycentricity seems more appropriate now than ever, given the number of actors and system changes involved with climate change. Determining the bounds and notions of intermediary functions, and their demonstrated effects on research, development, and deployment, will be another key research contribution.

Finally, future research could focus on larger, longitudinal shifts in landscapes and regimes as they relate to DER deployments. One angle shown in this study was the importance of finance:

the REA and associated financiers provided stable funding for DER expansion and intermediary functions from the co-ops, but what of other utilities or third parties? The role of stable, patient capital, and its shift from utility equity to third-party debt over time, needs to be studied more. In addition, it will be important to understand how the path dependencies of these financial and other technological regimes relate to new frontiers in electrification, new DER deployment, and cross-sectoral work in decarbonization.

6. CONCLUSION

J.A. Baker wrote, “The hardest thing of all to see is what is really there” (Baker, 1967). So it was with the electric cooperatives and their intermediary functions and load management programs, whose history lies outside the utilities’ self-written volumes and the realms of energy policymaking today. From research and interviews with and about these co-ops, this study finds that intermediary functions were necessary to achieve and sustain the co-ops’ distributed energy deployment. These intermediary functions – by facilitating the innovation process between two or more parties – served as rules and actions that allowed the necessarily diverse polycentric governance of the electric grid to compete and cooperate in the co-ops’ deployments. It was only by recognizing the nested social, economic, political, and technological levels that these cooperatives (and perhaps any other electric utility pursuing a DER deployment) were able to sustain a distributed energy adoption for so long. Finding polycentricity, intermediary innovation functions, and a broader network of institutional changes and challenges, I believe that my methods and results could serve to inform other studies, organizations, and policies.

In the near time, I produce analogies for current energy transitions and policymaking. Perhaps the foremost is the revelation of polycentricity within innovation functions, giving credence to what Ostrom (2010) writes, “’One size fits all’ policies are not effective.” The disdain of policy mandates was repeated by electric cooperative personnel in prior projects (Chan et al., 2019;

Lenhart et al., Forthcoming). These refrains are often perceived as reluctance or opposition to change to carbon-free energy, new technology, or new business models. Yet now after assuming this project, I understand there's another facet: the need for aligning social and institutional rules to match the co-ops' innovation functions and, more generally, creating cooperative mechanisms for cross-sectoral and cross-technology intermediary innovation functions within the electric grid and society today. Private and social value must be negotiated within robust, multi-scalar institutions that are commensurate with the level on the grid for which they produce.

These institutions, policies, and values can take many forms. In the following sections, I'll attempt to enumerate some of them through general observations, policy and institutional recommendations, and further research ideas.

At the least, it's important now to say that intermediary functions – serving to facilitate cooperative and competitive actions such as financing, outreach, and a host of institutional arrangements between two or more parties – seem to be entirely necessary to bridge the gaps between sectors and technologies types for further system change for decarbonization, digitalization, and general interconnectedness of the grid today. Though further study is needed to identify types of intermediary actions necessary for these gaps, this study's detailing of cooperatives' experience with intermediary actions shows early insights into how agricultural, heating, and commercial and industrial sectors were approached with novel facilitative techniques to induce them to load management. Further elaboration could be spent on how these intermediation techniques can be more generalized, as in Kivimaa et al. (2019), and applied to local resources and governance models.

Seeing this, I frame my conclusions under three subjects with broader implications: 1) the need for aggregators as translators of risk and value between micro- and macro-levels, 2) the understanding of system efficiency as socially constructed and self-corrected by polycentric networks, perhaps indicating the durability of decarbonized system policies that foster polycentricity, and 3) local institutions and incumbents as able to recreate themselves and facilitate new social and institutional structures.

6.1. Aggregators Connect the Micro- and Macro-levels

Aggregation can be defined as "the act of grouping distinct agents in a power system (i.e. consumers, producers, prosumers, or any mix thereof) to act as a single entity when engaging in power system markets (both wholesale and retail) or selling services to the system operator(s)" (Burger, Chaves-Ávila, Batlle, & Pérez-Arriaga, 2017). As Burger et al. (2017) demonstrate, there are differences in aggregation duties as technology and regulations become more advanced (Figure 6.1). These differences are important and speak to an ideal economically efficient world and similarities to others' definitions of intermediaries.

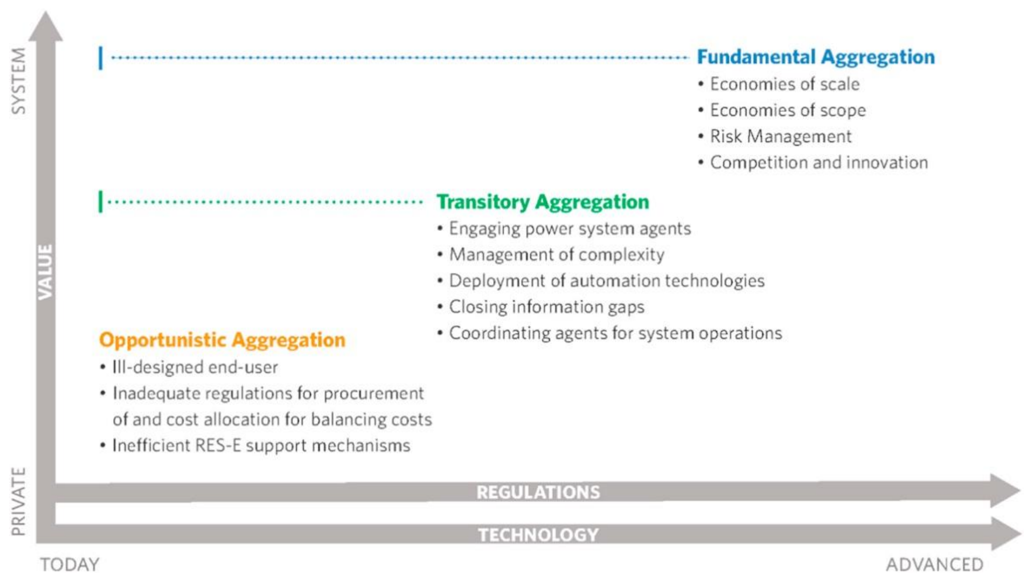


Figure 6.1: The Value of Aggregators Based on Technology and Regulatory Contexts. Fundamental aggregation values are time- and customer-independent, while transitory aggregation values are based on present or near-future regulations and markets. Opportunistic aggregation values emerge as aggregators take advantage of system "flaws" and arbitrage for private gain. Taken from (Burger et al., 2017).

But the real value of Burger et al.'s aggregators may be in the "Transitory Aggregation" tenets, which speak more broadly to the intermediation functions that cooperatives and third parties could provide for each other in the future. They could close information gaps for each other and customers; deploy advanced technology where either has resource limitations; and translate and coordinate for other system agents. As the grid and society will be processing many micro- and macro-level challenges of decarbonization for years to come, my study shows that while managing the complexity will be a challenge, research on common pool resource management shows it is the muddling-through of best practices through "Transitory Aggregation" that can produce the best long-term results. Utilities are aggregators, as are third-parties: if they are to succeed in long-term DER deployment together, they need governance and institutional rules to match their polycentric nodes of decision-making

6.1.1. Potential Policy/Institutional Solutions

Facilitating for system goals and hedging between private interests of each other and the greater social interests, G&Ts and distribution utilities showed that in practice, aggregation is a political, polycentric process. With that history, there are two futures ahead for the co-ops in this study: one where DERs can actively participate in the wholesale market, and one where they can't. These front-of-the-meter and behind-the-meter futures, respectively, require different strategies and depend on if and how third-parties can participate in aggregation, as well (Thomas & Dennis, 2019).

The front-of-the-meter future is one where the independent system operators, guided by FERC, its own stakeholders, and docket commenters, will open a more-complete DER aggregation. Aggregation rules will be with or without third-party involvement, geographic allowances, and other requirements. Other ISOs operate DER aggregation markets, but markets like MISO and SPP are currently limited in their offerings and co-ops might be limited in their appetite to participate. Therefore either through the ISOs or FERC, the co-ops could push for (or accept) broader meta-constitutional system rules to recognize their legacy DER aggregating systems and policies, as has been recommended in other papers (Gundlach & Webb, 2018). Co-ops might keep in mind the ways in which they can work with the rules of the commons to re-align themselves toward system benefit and innovation, updating their communication systems to include distributed energy resource management systems and other two-way communication systems. As such, relationships with other utilities, regulators, third-parties, and customers will need to be maintained and explored increase visibility and connections between the transmission and distribution levels. For co-ops specifically in this future, aggregator subsidiaries should be explored at the G&T level, or at least on a joint level between member utilities, and standard working procedures with third-parties should be formalized within the cooperative institutions.

But as Illinois is the only state in the MISO footprint that allows DER aggregation, and with NRECA advocating for opt-out provisions for co-ops at FERC, a behind-the-meter future for co-ops' load management programs seems just as likely (Migden-Ostrander, Shenot, Kadoch, Dupuy, & Linvill, 2018). This behind-the-meter future, as so operates today, creates a world where the co-ops have more uncertainty at the wholesale level and have self-determined, but more limited opportunities with third parties and their member-owners. In this future, it seems member-owners will have more power over their own loads, regardless of what the G&T or member co-op may do in the short- and long-runs. The co-ops may have to consider moving outside the traditional utility control of devices, further incentivizing voluntary programs for load reduction, as some co-ops have done already. System technological innovations must be further incentivized through proper price signals and third-party aggregators must be worked with on an ad hoc basis for specific technological functions. Because the behind-the-meter future involves sporadic private benefits of member-owners and individual member co-ops, G&T systems and state policy might create further education, intermediation, and incentives and for DER adoption among member-owners.

To ease the transformation toward simultaneous futures of community aggregation goals (front-of-the-meter) and individual member-owners (behind-the-meter), in the present the co-ops should look for a dual-pronged approach to load management and DERs. They might provide resources at the G&T or state level for continued voluntary programs outside their direct control, and where a common platform and long-run benefit exists for system integration, they might seek some centralized control of loads, either at the G&T or distribution level. Centralized control might facilitate fluctuations on the retail grid, as well as the wholesale, depending on the member-owners' risk appetite and penetration of intermittent renewable energy technology.

The move toward new business models takes years of trial-and-error, so effective governance through more committees, informational meetings, and other platforms seem necessary to handle changes in the short- and long-runs, regardless of wholesale market outcomes. In general, to better integrate third parties into these governance platforms, and as before with contractors, co-ops could vet and educate vendors with their member-owners and boards. The G&T and its member utilities might also consider seriously to include provisions for buying services from distribution cooperatives and their third-party partners to further incentivize member-owner acceptance of new DER technologies such as electric vehicles, distributed storage, and newer DERs such as smart thermostats.

6.1.2. Research Needs

Further research is needed on aggregators to identify future business models and how well governance platforms currently incorporate them (S.P. Burger & M. Luke, 2017). Research could also specify disaggregate intermediary functions as examples of aggregation in a new market: for example, the intermediary functions that solar developers play in customer acquisition and management could be compared against utilities' functions in load management customer acquisition and management. Additional research could also more clearly explain the ways in which aggregators translate rules and span boundaries between levels of an electric grid, and how exactly electric cooperative business models might fit into these new paradigms.

6.2. Polycentric Networks Self-correct in Supply and Demand Policies for Durable Decarbonization

Fighting climate change is often thought of as policies that restrict demand or support the supply or demand for clean energy substitutes (Green & Denniss, 2018). A strong case, however, is for the evolution of existing institutions, structures, technologies, or practices to ease those and other policies to come into play (Davidson, 2019). As the importance of polycentric networks is in their ability to self-correct, the ability to manage and experiment in different policy mixes may be their biggest advantage in a climate-concerned world dealing with urgent costs and crises (Aligica & Tarko, 2012; Markard, 2018b). Policymakers at states and co-ops can therefore look to stronger institutional policies and models to develop polycentric learning, experimentation, and urgency in the age of decarbonization.

6.2.1. Potential Policy/Institutional Solutions

Just as markets allow price discovery, and mandates force the alignment of system goals, polycentric organizations can be used for institutional discovery, to see the best practices for aligning system and private goals within a regime. It seems important, therefore, that locally-connected institutions be created, empowered, and/or connected to electric grid decarbonization plans to test policy sequencing and feedback loops, showing new approaches to cross-sector and cross-technology decarbonization practices. In practice, this might look like the aggregators in the previous section, or simpler ad hoc aggregators such as DER cooperatives or community groups. Even current distribution cooperatives can perform this locally-relevant experimentation.

To build toward that polycentric future, policymakers at the co-ops or states could also spend resources on making current governance platforms at co-ops and other utilities more inclusive and understandable to other sectors, third-parties, and customers. Policymakers could also aim at empowering different types of intermediaries between sectors and technologies, such as contractors or distribution cooperatives, with more education and resources on current and future technologies. As there were generational disputes and laggards in the past with the load management programs, more education and contact with trusted networks could help bring member-cooperative personnel and member-owners along with current trends, however long it might take. The focus should be on long-term engagement. And alongside long-term engagement, more resources will be needed to expand implementation of common infrastructures, such as electric vehicle charging networks or distributed energy resource management systems, for these polycentric schemes to co-evolve with their institutions.

In their way, cooperatives are already practicing institutional evolution and self-correction alongside innovation, but existing policy frameworks could better support as exist as facilitative regimes them as decarbonization becomes the main goal of society. As fossil-fueled power plants may have to be retired ahead of schedule, and rates may see increases, policymakers could identify ways in which the co-ops could deploy DERs while simultaneously paying down debts and other fixed costs. GRE, for instance, was mentioned by an interviewee to use accelerated depreciation on their coal plants, effectively closing them in the 2020s. Meanwhile Basin extended the useful life of their coal plants decades into the future. This exemplifies that, given the breadth of the climate problem, local institutional self-determination may not be enough for short-term change, in the co-ops or in other utilities or countries, but there remains an array of financial and social solutions to the perceived stickiness of current and future problems.

To remedy, policymakers at the federal or state levels could simulate the past external shocks of the oil or farm crisis with carbon pricing or clean energy standards to align cooperative and utility networks with a broader social and economic goals. Cooperative boards could simulate external shocks by taking precautionary measures unto themselves, self-taxing or creating DER options (such as community solar) for member co-ops and member-owners to elect agency for decarbonization. These DER options would mirror the use of load management as a pressure valve for co-ops in the economic crises of the ‘70s and ‘80s. They would also require the same effort and intermediary functions as was deployed then. For the purposes of political durability within the co-ops, top-down actions such as clean energy standards or carbon pricing must be coupled with serious consideration of local impacts, equity, and conditions. G&T systems and other state or national networks might work together to create innovation networks and allocative strategies for DERs in the coming decades of decarbonization.

As co-ops focus more on provisioning DER services, whether due to member-owner needs or broader landscape pressures, a direct policy and economic link must made between DERs and climate change for the broader goal of decarbonization to work. For some co-ops, that link is not appetizing or demanded by current member-owners. But looking into these co-ops histories and central system concepts, one could see that just as load building once propped up existing coal plants, load building could also decrease their usage and pay them and other fossil-fueled assets off early. Policymakers and cooperative personnel might therefore consider policies to help them strategically build load once again (seeking "area coverage," as in the beginning of the REA), whether it is through electric vehicles, decarbonized appliances, or larger commercial and industrial electrification, and connect that extra load growth to stranded fossil-fueled asset repayments. Facilitative regimes at the federal level could use RUS debt, or even cooperative financing institutions, to help fund such a transition.

6.2.2. Research Needs

Because there are no large-scale examples of quick, large-scale energy transitions available, examples of smaller-scale cooperation and competition through polycentricity could perhaps be the intermediary building blocks for a larger transition (Schot & Kanger, 2018). Future research could focus on how smaller clusters of polycentric organizations help build (or don't) toward larger cumulative emissions reductions. There is also a greater need to identify if polycentric organizations can supply large-scale changes in short amounts of time. It remains a large question as to how much time we have left, if any, at this point to see these long-lasting institutions develop. In all, the co-ops must seriously research and pilot how their intermediary functions can be communalized and strengthened toward system aggregator goals in this greater age of individualized energy transitions.

6.3. Active Incumbents Are Able to Change and Lead Consumers

Utilities today, on the whole, still struggle with customer engagement and segmentation (Trabish, 2019). In deploying their distributed energy resource-based programs, they have sometimes failed to realize the importance of education, coordination, and marketing (Thill, 2019). Yet their collective histories have shown they've always been leading customers to join the electric grid and increase their demand. From Insull's "load management" to the electric cooperatives' "area coverage" and this study's focus on load management, utilities have always cultivated electricity demand and technological adoption. To say that utilities are just responding to customers is a truism at this point, and perhaps for the fragmented responsibilities of their customer-sided business practices, they lack the appropriately-scaled intermediaries to comprehensively interact with them. This is important as the DER solution space expands, and the need for cross-sector greenhouse gas emission reductions increase.

6.3.1. Potential Policy/Institutional Solutions

Given the results from this study, electric utilities might be thought of now as central coordinating agents for cross-sector and -technology work. The cooperatives' load management programs, most notably, showed this in their work with agriculture, fossil-fueled heating, and commercial and industrial regimes. With agriculture, they incorporated locally-relevant knowledge and practices to accommodate distinct individual farms and their irrigation units. With heating, they were directly competitive, with interviewees often pricing their products to the marginal price of a coal plant or the dominant heating fuel in the area. Commercial and industrial facilities were made interruptible or facilitated with utility-controlled generators and negotiated with on a case-by-case basis. Today, as these co-ops are again engaged with electric vehicle regimes, bringing their electric "power" to bear to reduce transportation emissions in the United States, it seems natural they should continue to expand their social and political boundaries once more to more sectors and technologies.

Then as now, limitations on internal staff capacity and expertise should be bridged by G&T resources or state policymakers. Resources should be leveraged to help bring on more permanent and/or knowledgeable member services and board directors, more specifically, to help bridge these gaps between utility and non-utility spheres. Policymakers should also encourage broad suites of policy mixes to further allow utilities to be social actors for the greater good. They could provide base incentives or different types of DERs (i.e. solar-and-storage facilities to replace generators at C&I facilities) or loosen restrictions on demand-side management programs such that they can include the testing and involvement of new technologies and practices. This last point is important for other utilities, as current practices and regulations often segment DER planning and personnel from each other (Potter et al., 2018).

Under top-down mandates, policymakers could also encourage cross-sector experimental projects such as Washington's proposed "Energy Transformation Projects" (ETPs) that might better facilitate the social, political, and institutional polycentricity of the co-ops (Roberts, 2019). Utilities and other could use ETPs to reduce system emissions, rather than individual emissions (similar to the CIP's difference individual efficiency versus systems efficiency). ETPs could also be used for compliance with a larger clean energy standard and promote utilities engaging in more intermediary practices for their customers to conserve or strategically grow their usage. In this way, facilitative regimes could once again foster polycentric governance to build cross-sectoral competence at a time when cross-sector work is desperately needed.

6.3.2. Research Needs

Future research now should continue to look at past efforts in utility and third-party engagement strategies with customers and what types of policies best encourage of facilitate these measures. Other studies might look at incumbents and how they change through time across various regimes, picking up the slack for each other as technologies and energy sources come and go. More research is also needed on the past successes and failures of cross-sector work and what considerations to take when engaging in it.

6.4. Final Statement

The cooperatives' load management programs are insights into local and regional history, showing diverse technological practices for diverse needs and people. Presented with great uncertainty, these organizations co-created rational sets of problems and solutions that involved all levels and geographies of their state-sized service areas. They changed themselves and their member-owners' habits to endure through trying times.

Now their authority in having created a distributed energy transition endows them and others with the authority to recognize that larger, more systematic changes can be built on the back of smaller changes. These smaller changes are social as well as technological: the co-ops included marginalized perspectives in their facilitation of easing rate increases for certain ratepayers; they sought social learning and capacity building through novel shared governance platforms; and they performed innovation intermediary functions to ease collaboration between many parties on the polycentric electric grid.

Because of this study, utilities are better known as social, political, and constructive institutions of innovation, and innovation within DER deployments can be thought of as a result of broader polycentric system negotiations. Further research is needed, but I hope now that utilities and others will better recognize their systems for the diverse values they encourage. Co-ops are worthy, and always have been, of weathering greater challenges, facilitating more participation, encouraging more decision-making and negotiation, with the greater aim of encouraging large-scale, long-term cooperation as we all decarbonize.

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APPENDIX A

Interview Protocol

Load Management Interview Protocol

Research Questions

1. How did your utility deploy load management technologies in the 1970s, ‘80s, and ‘90s?
2. How was fairness constructed between utilities as deployment started and increased? How were decisions made to deploy?
3. How were the supply chains constructed between utilities, contractors, and customers?
4. How was urgency maintained?

Opening Script: Thank you for meeting with me today. I am a Graduate Researcher and Masters Student at the Humphrey School the University of Minnesota, and have been working with Prof. Gabe Chan and an interdisciplinary team studying energy policy, technology deployment, business models and rural economic development. I am now working on my masters thesis, for which the primary goal is to investigate how electric cooperatives deployed load management technologies from the 1970s onward. I’ll be speaking with people familiar with what happened at that time all throughout the Midwest. The insights I gain will be synthesized into materials and a final thesis summarizing the process and history through which electric cooperatives grew and maintained their load management programs.

My questions are meant to be a conversational guide to help me understand your experience with load management.

If it’s still ok with you, I would like to turn the recorder on now.

Interview structure

Section Goal: Gain background information, general load management information

1. Could you briefly describe your experience at UTILITY / involvement with UTILITY?
    a. How long did you work there? What roles did you have?

2. What was your experience with load management technologies or programs prior to the program and through the program’s course?

3. What prompted the creation of the program?
    a. Who took the lead in initiating the project [or opposing the project]? What percentage of cooperatives were supportive in the beginning?
    b. What were the program’s overall goals?

4. What was the role of local, state, or federal policy in this process at the beginning?

5. How did load management technologies affect the relationship between the power supplier and the member utilities? How did they affect the relationships between member utilities themselves?
    a. How would you describe the [G&T or JAA/dependent utilities] influence in decision-making?
    b. How did member utilities vary in their deployment strategies?

c. What were some common disagreements?
d. What formal or informal structures helped smooth over these disagreements?

6. In all, at the beginning, what most enabled you to pursue these innovations?
    a. Could you tell me about where you first learned about these technologies or programs?
    b. Where did you get advice from at the beginning?

7. After the program was rolled out, how did you connect the supply chain between the utility, customers, and contractors?
    a. What other parts of the chain did you have to connect?
    b. What changes were made and why?
    c. How did you manage the complexity?
    d. What formal or informal processes did you institute?

8. What about your system characteristics or utility circumstances led to changes in the program design or rollout?
    a. Were there events or things that happened that changed the philosophy of the programs?
    b. What internal policies changed as you learned from the program? What external policies changed because of the program?

9. What most helped you deploy quickly?
    a. What slowed your deployment the most?
    b. What in the consumers, the environment, or your networks helped?

10. What issues arose during the construction of this program? And how were they managed?
    a. From members/customers?
    b. From member utilities?
    c. From others?

11. How did new technologies or customers classes come to be integrated into the program?
    a. How were members differently affected by these changes?
    b. How were utilities differently affected by these changes?

Section Goal: Get an overall sense of attitude, perceptions, etc. for changes in the industry.

12. What would you have done differently, in hindsight? What could others have done differently?

Concluding Questions

13. Is there anything that you think is important that I haven't asked about?

14. Who else should I be speaking to understand load management as it arose in the 1970s and '80s amongst these electric cooperatives?

15. Are there any implications for today that you think are important?

APPENDIX B

Though electric cooperatives are declared "private" organizations by the National Rural Electric Cooperative Association, they are still public in generating, transmitting, and distributing electricity, information, and policy to local, state, and federal governments (National Rural Electric Cooperative Association, 2017). These cooperatives are public in another way: much of the background research was already readily available through commission websites, online presentations, books, and news articles. Still, retired and current employees and associated actors need informed consent to ethically inform a more general history of their cooperatives' histories. These individuals could reasonably be offered anonymity, and so could the distribution electric cooperatives, as their individual characteristics could be blended with other regional cooperatives of the G&T systems. As G&Ts within this study are the focus of the scale of the study, they're simply impossible to anonymize without losing the meaning of the study.

There are also good reasons beyond the "inability to conceal identities effectively" to state actors' names, as Guenther (2009) says:

> Concealing the names of the organizations I study would result in lost meanings as the names of these organizations represent specific histories, goals, and ideologies which even the cleverest pseudonyms would be unlikely to capture. Hiding these names would both devalue the [organizations] and reduce the strength of my analysis. In mobilizing data that I can reasonably foresee could negatively influence an organization, I either omit the data or disconnect the data from an organization name and characteristics.

Here I follow Guenther's case and reasonably omit or disconnect pernicious data from the organization's name.

Still, there are further political implications for naming the institutions involved. As a research project devoted to finding generalized findings with implications for policymaking, this thesis is intentionally posing these generation and transmission cooperatives as public entities, bringing along both the benefits and drawbacks of public scrutiny. However, given the historical nature of this project and the dynamic nature of distributed energy and electric utilities, in general, using real names seems more likely to result in positive outcomes for the organizations involved.

To quote Guenther, 2009: “[M]y hope is that using the actual names of organizations and cities will bring voices, places, and histories that are too often forgotten back into view.”

Electric cooperatives, as part of the national conversation on energy and climate change, and rurality in general, are often forgotten, a fact that endears them to me. In the process of gathering background information, I was comped for a Beneficial Electrification League conference, and as a student working with current cooperative general managers, I often worked only a few degrees away from my interviewees. I used methods drawn from participatory action research, such as co-creating thesis conclusions with them in and out of interview settings and allowing them to edit my background and results, perhaps any feeling of bias is more engagement in general.