ASSESSING THE RESIDENTIAL SECTOR DECARBONIZATION POTENTIAL OF DEMAND-SIDE MANAGEMENT RESOURCES: A CASE STUDY OF GEORGIA AND THE ATLANTA METRO AREA

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ASSESSING THE RESIDENTIAL SECTOR DECARBONIZATION POTENTIAL OF DEMAND-SIDE MANAGEMENT RESOURCES: A CASE STUDY OF GEORGIA AND THE ATLANTA METRO AREA

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A mi familia, con amor.

To my family, with love.

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LIST OF SYMBOLS AND ABBREVIATIONS

IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
DSM	Demand-Side Management
EE	Energy Efficiency
DR	Demand Response
EIA	Energy Information Administration
TOU	Time-of-Use
RTP	Real Time Pricing
AHS	American Housing Survey
GPC	Georgia Power Company
MW	Integrated Resource Plan
NGCC	Natural Gas Combined Cycle
NGCT	Natural Gas Combustion Turbine
kWh	Kilowatt-hour
AMI	Advanced Metering Infrastructure
GPSC	Georgia Public Service Commission
TVA	Tennessee Valley Authority
FERC	Federal Energy Regulatory Commission
HER	Home Energy Consumption Reports
PDS	Peak Demand Savings
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress

CBSA	Core-Based Statistical Area
OMB	Office of Management and Budget
HP	Heat Pump
HPWH	Heat Pump Water Heater
ACEEE	American Council for an Energy-Efficient Economy
CO_2e	CO_2-equivalent
Mt	Megatons
HEEHRA	High-Efficiency Electric Home Rebate Act
LCSE	Levelized Cost of Saved Energy
LCOE	Levelized Cost of Electricity
T&D	Transmission and Distribution
DRIPE	Demand-Reduction Induced Price Effects

SUMMARY

The current energy transition necessitates an integration of demand-side management resources into decarbonization efforts. Recognizing the role that demand-side interventions could play in helping decarbonize Georgia's residential sector, this study sets out to assess the residential sector decarbonization potential of demand-side management resources via a case study of the metro Atlanta area. A review of American Housing Survey data for the area identified metro Atlanta's high but inefficient household electrification rates, a pattern that was even more prevalent in low-income households, while a review of Georgia Power's 2022 Integrated Resource Plan highlighted the missed opportunity for deployment of dispatchable retail demand response programs. Installations of heat pumps and heat pump water heaters in metro Atlanta households with existing electrified space and water heating, but with no installed measures of the mentioned appliances, could abate nearly one megaton of greenhouse gas emissions per year, while implementation of deep energy efficiency retrofits to households with already electrified space and water heating were found to yield significant energy burden reductions for low-income households, e.g., an estimated 5% energy burden reduction for households with a yearly income of $25,000. Additionally, those same households (i.e., ones with electrified space and water heating) were found to cumulatively provide demand savings through DR programs that exceed the capacity of the natural gas combustion turbines with planned power purchase agreements by Georgia Power, while also delivering those services as a lower-cost alternative than the combustion turbine power plants in most of the modeled scenarios.

CHAPTER 1. INTRODUCTION

In the past 2 years, the United States has made tremendous progress towards defining a vision for its energy transition. At the national level, the Biden Administration has set goals to reach a carbon pollution-free electricity sector by 2035 and economy-wide net zero emissions by 2050, while particularly singling out the goal of cutting emissions and energy costs for families by supporting efficiency upgrades and electrification in buildings (White House, 2021). These goals were promptly followed by the passing of the "Infrastructure Investment and Jobs Act" (IIJA) and the "Inflation Reduction Act" (IRA), both of which deliver generous tax and rebate provisions towards residential sector and grid decarbonization (IIJA, 2021; IRA, 2022).

This transformation of the current energy system towards a clean and sustainable one will prove challenging, particularly as variable and intermittent renewable energy sources continue to be increasingly integrated into the system (Loskow, 2019; Oree et al., 2017). The energy system decarbonization paradigm has been largely supply-side intervention centric, such as switching fuels and decommissioning emissions-intensive generation resources (Grubert, 2020; Jenkins and Sepulveda, 2017; Ralston et al., 2021; Williams et al. 2021). However, policy and research efforts have started to transition away from supply-side focused interventions and towards more integrative approaches that prominently acknowledge the decarbonization and load balancing potential offered by demand-side management (Behboodi et al., 2017; Charbonnier et al., 2022; Grubler et al. 2018; O'Shaughnessy et al., 2022; Pye et al. 2021).

Electric utility demand-side management (DSM), also referred to as energy demand management, is defined as the planning, implementation, and monitoring of utility activities to influence customer use of electricity in ways that will produce desired changes in the utility's load shape (Gellings & Parmenter, 2016). The two most prominent DSM efforts, and the categorization under which most DSM programs tend to fall under, are energy efficiency (EE) and demand response (DR). Energy efficiency programs offer customers incentives to increase the efficiency of their energy consumption, or increasing the output per unit of energy consumed, in order to decrease their overall electricity demand. On the other hand, demand response programs are often designed to decrease or optimize customer demand during peak demand periods or emergencies (EIA, 2020a; Hasan, 2020; METCO, 2019).

Although both EE and DR are tools contributing towards the same goal of reducing energy consumption, counteracting effects might exist. The less energy needed by consumers due to increased efficiency, the fewer the number of power plants need to be deployed. Yet, with increasing adoption of intermittent or variable renewable energy sources, demand flexibility becomes more valuable. This could lead to some energy processes being operated less efficiently to support flexible demand, which in turn would help operate the energy system more efficiently (Wohlfarth, 2020). However, recent findings by the Lawrence Berkeley National Laboratory challenge this intuition, suggesting that EE and DR largely complement each other to reduce power system costs and emissions. It also found that adding DR to EE, and vice versa, enabled greater emissions reductions as compared to EE or DR in isolation, and that utilities and grid operators could successfully integrate and deploy them in pairings (Satchwell et al., 2022).

The value derived from load flexibility and efficiency investments is mainly driven by energy availability and electricity system characteristics, therefore, it changes during the day and year. These interactions are more so relevant for appliances of interest for both measures, such as heating and cooling appliances (Wohlfarth, 2020).

On average, more than half of a U.S. household's annual energy consumption is dedicated to space heating and air conditioning, with variations in consumption due to seasonality, geography, and household size, structure, equipment, and sourced fuels (EIA, 2021a). Given common challenges associated with heating and cooling decarbonization due to their large scale, seasonal variability, and distributed nature, DSM is emerging as a potential leading strategy to address this sector's hurdles in a cost-effective manner for both end-users and retailers (Lizana et al., 2018).

Georgia's current high household electrification rate positions it as one of the states to most benefit from DSM interventions as a decarbonization pathway (APPA, 2022). Drawdown Georgia, a statewide research-based initiative launched in 2020 to "catalyze a Georgia beyond carbon", has also recognized both EE and DR as 2 of their 20 high-impact climate solutions (Drawdown Georgia, 2022). In addition, Georgia Power's parent company, Southern Company, recently committed to reducing their greenhouse gas (GHG) emissions and reaching net zero by 2050, setting the stage for investments in DSM and the recognition of its potential as a decarbonization tool at the utility level (Southern Company, 2020a). Coupled with the Biden administration's commitment and the recent passing of both the IIJA and the IRA, the residential sector in particular is poised to benefit most from DSM deployment.

With this context in mind, this study focuses on assessing the potential of DSM interventions as tools that could help decarbonize the residential sector in the state of Georgia.

Chapter 2 will provide a broad outlook of the Southeast and Georgia's current state of DSM deployment, as well as DSM implementation gaps.

Chapter 3 presents an overview of metro Atlanta household space heating/cooling and water heating profiles and assesses the potential for electricity demand savings that could be derived from EE and DR program implementation targeting those two aspects of household electricity demand.

Chapter 4 explores an approach to calculate a levelized cost of saved energy to facilitate a comparison of DSM and supply-side generation resources. This approach is then used to estimate the levelized cost of saved energy of implementing a smart thermostat DR program and a water heater DR program in the metro Atlanta area.

Lastly, Chapter 5 reviews the benefits derived from DR program implementation, including avoided costs, ease of renewable integration facilitated by load flexibility, and positive equity impacts derived from induced price effects.

CHAPTER 2. BACKGROUND

2.1 Overview of Demand-Side Management

This section is primarily dedicated towards providing an exposition of DSM's features and characteristics. Content was mostly sourced from Gellings and Parmenter's chapter on DSM in the book *Energy Management and Conservation Handbook*, unless stated otherwise (Gellings & Parmenter, 2016). However, in order to discuss DSM, the concepts of electricity load and peak electricity demand need to be introduced.

2.1.1 Electricity Load and Peak Demand Primer

According to the U.S. Energy Information Administration (EIA), electricity load is usually used to refer to electricity consumption during a given period, with peak demand referring to that time of the day, season, or year during which consumers' demand for electricity is at its highest point. The overall level and shape of total U.S. electricity load varies from year to year, and typical load shapes vary across regions because of differences in weather patterns, types of electrical equipment in use, and daily patterns of energy use by households and businesses. In most cases, hourly electricity load reaches its yearly peak in the afternoon of summer months, as households and business ramp up their air conditioning use. During the winter, hourly loads tend to peak both during the morning, as people turn on lights and hot water for showers, and evening, as people come back to and warm up their homes and cook their meals. Winter peaks tend to be lower than summer peaks given that the most common primary energy source for space heating is natural gas. However, about one-third of U.S. households primarily rely on electric furnaces or heat pumps for space heating, and as that number continues to grow, so will winter peak demand, thus slowly shifting yearly peak demand away from summer days towards winter days (EIA, 2020b).

Peak demand is of critical concern to utilities and system operators, given that if electricity demand exceeds power generation capacity, the utility has to either purchase power from other utilities or build new generating plants, but this approach can increase electricity rates and prove costly for both utilities and customers. Additionally, with increasing amounts of solar and wind energy penetration, power generation prediction is becoming more challenging given how quickly these resources can go online or offline. Utilities across the country are making peak demand reduction a priority by shifting their focus towards the user side of the equation: Demand-Side Management.

2.1.2 DSM Definition and Critical Components

Restating and slightly expanding the definition already introduced, the book's DSM definition is the following:

> "Demand-side management is the planning, implementation, and monitoring of those utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape, i.e., changes in the time pattern and magnitude of a utility's load. Utility programs falling under the umbrella of demand-side management include: load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share."

The book, however, recognizes that this definition is limited by not acknowledging that (1) DSM encompasses management of not just electricity but all forms of energy, and (2) groups other than electric utilities could implement DSM programs. Instead of fixating on a new definition, it suggests considering the following critical components:

1. DSM will influence customer use – any program influencing customer energy use should be considered DSM.
2. DSM must achieve selected objectives – beyond load shape change, the program should achieve its selected objectives, e.g., average rate reductions, increased reliability, customer satisfaction improvement, etc.
3. DSM will be evaluated against non-DSM alternatives – DSM programs should further select objectives to at least as great an extent as supply-side alternatives.
4. DSM identifies how customers will respond – DSM should identify how customers will respond rather than how they should respond.
5. DSM value is influenced by load shape – DSM programs will be evaluated according to how they influence cost and benefits throughout the day, week, month, and year.

2.1.3 DSM Planning Framework

The book identifies five elements of the DSM planning framework, organized into the following five subsections.

2.1.3.1 <u>Set objectives</u>

In the first step of the planning process, strategic objectives tend to be broad, such as energy conservation, peak demand reduction, GHG emissions reduction, etc. Once designated, these objectives can be translated into a desired demand-pattern or load-shape change that can be used to determine the DSM program's impact. The book identifies six load-shape-changing possibilities, recognizing these are not mutually exclusive and can be enacted in combinations.

1. Peak clipping – a reduction of the system's peak loads, usually the main load shape target of demand response programs, often used to reduce operating costs and dependence on critical fuels by economic dispatch. This is generally implemented via time-based rates or incentive-based strategies, with or without enabling technology (see Figure 1).

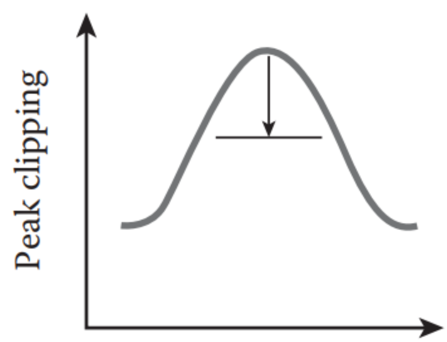

Figure 1 – Peak clipping visualization (Gellings & Parmenter, 2016).

2. Valley filling – consists of building off peak loads, which may be desirable if long-run incremental costs are less than the average price of energy, with valley filling thus aiming to decrease the average price. Popular applications include displacing fossil loads with electric ones operationalized during off-peak hours.

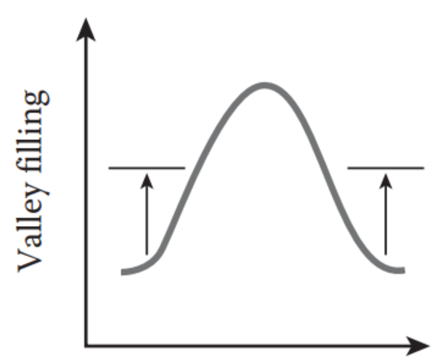

Figure 2 – Valley filling visualization (Gellings & Parmenter, 2016).

3. Load shifting – involves shifting loads from peak to off-peak periods, with popular applications including storage water heating and heating/coolness storage (see Figure 3).

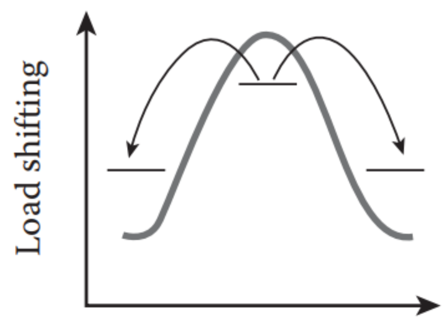

Figure 3 – Load shifting visualization (Gellings & Parmenter, 2016).

4. Strategic conservation – modifications involving reduction in consumption or changes in use-patterns, particularly targeting those cases that wouldn't have occurred naturally. Common examples include weatherization and appliance efficiency (see Figure 4).

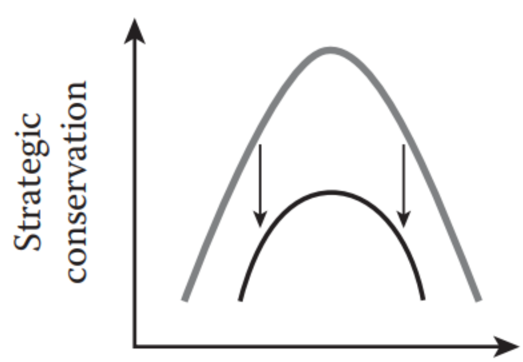

Figure 4 – Strategic conservation visualization (Gellings & Parmenter, 2016).

5. Strategic load growth – a general increase in the overall load beyond just valley filling. This is a common byproduct of electrification motivated by a reduction of fossil fuels and raw materials to improve overall productivity (see Figure 5).

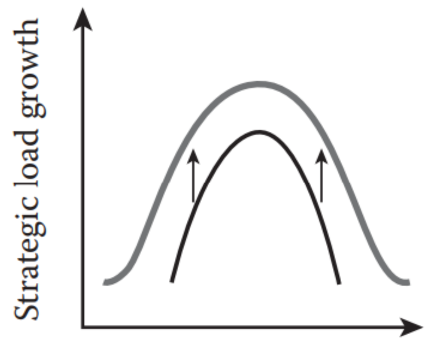

Figure 5 – Strategic load growth visualization (Gellings & Parmenter, 2016).

6. Flexible load shape – a concept which would increase system reliability by adapting demand to generation resources, instead of the other way around. Implementation alternatives include interruptible, curtailable load, or individual customer load control devices (see Figure 6).

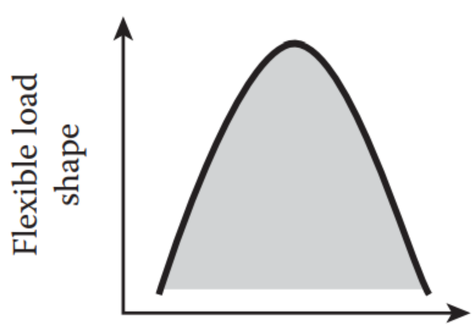

Figure 6 – Strategic conservation visualization (Gellings & Parmenter, 2016).

2.1.3.2 Identify alternatives

This second step initially involves identifying the end-uses where peak load and energy consumption match the requirement of the load-shape objectives (i.e., residential, commercial, and industrial), after which appropriate technology alternatives for the targeted end-use must be selected, such as end-use equipment (e.g., air conditioners, dishwashers, etc.) or load control measures (e.g., thermal energy storage).

2.1.3.3 Evaluate and select the program

The third step seeks to balance customer and supplier considerations in a cost-effective manner. Suppliers must carefully consider how the chosen activity will impact demand patterns, customer participation, and magnitude of cost and benefits to themselves and customers.

2.1.3.4 Implement the program:

The fourth step is a multistage process, involving project team formation with appropriate representation from departments and organizations, pilot experiments as an interim step if limited information is available on prior DSM program experiences, and full-scale program implementation if a pilot or prior experience proves the program's cost-effectiveness.

2.1.3.5 Monitor the program

The fifth and last step is to monitor the program to identify expected performance variations and improve both existing and planned DSM programs.

2.1.4 *Implementation Pathways*

The book acknowledges the market implementation pathway as the most important dimension of DSM, with methods broadly classified into the following six categories:

1. Customer education – the most basic market implementation, involves promoting customer awareness of programs (e.g., websites, brochures, direct mailings, etc.). This should be coupled with other market implementation methods for maximum effectiveness.
2. Direct customer contact – face to face communication with customers through a representative, which could provide advice on topics such as appliance choice or operation and sizing of heating/cooling systems. This tends to be done either through energy audits or exhibits, allowing for customer feedback and concern identification.
3. Trade ally cooperation – a trade ally is any organization that can influence transactions between suppliers/implementers and customers, such as home builders or trade associations. Depending on the trade ally, implementation could involve development of standards and procedures, certification, installation, maintenance, or repair.
4. Advertising and promotion – using various media to communicate a message to customers, this method includes radio, television, newspapers, or point-of-purchase advertising, to name a few.
5. Alternative pricing – an important implementation technique that performs three functions: (a) information transfers to suppliers/consumers regarding the cost or value provided by products or services, (b) incentives for efficient

production/consumption, (c) determines who can afford how much of a product or service. Pricing structures include time-of-use (TOU) rates, real time pricing (RTP), critical peak pricing, off-peak rates, etc.

6. Direct incentives – used to increase short-term market penetration of a cost control/customer option by reducing the net cash required for equipment purchase or by reducing payback period to make investments more attractive. This method includes rebates, billing credits, low-interest loans, and even free or heavily subsidized equipment installation or maintenance in exchange for participation.

2.2 Importance of DSM as a Residential Decarbonization Pathway in the Southeast

Grubert et al. (2021) explored the importance of integrating demand-side interventions into decarbonization-oriented research, focusing on the role of residential interventions, in particular deep energy efficiency, to facilitate decarbonization and increase resilience in the U.S. Southeast. This subsection briefly explores some of the white paper's findings and references some of its reviewed literature.

The study used American Housing Survey (AHS) data to find that electrification is relatively high but inefficient in the Southeast. This opens up the opportunity for deploying high-efficiency electrical appliances like heat pumps to both reduce household costs and electricity demand from space heating and conventional air conditioning. Given the unusually high energy burdens of the U.S. Southeast, attributed mostly to a combination of poverty and energy use, this would create immediate benefits for low-income households while also easing the path to supply-side decarbonization by avoiding increases in electricity demand due to electrification.

The study also highlights that increasing a building's energy efficiency would increase resilience both directly by enhancing thermal stability, and indirectly by enabling affordability of household energy services, all while enabling health benefits from lower indoor and outdoor air pollution (Begay, 2018; Giang & Castellani, 2020; MacDonald et al., 2020; Tessum et al., 2019). Given the increase of extreme weather conditions that stress energy systems to the point of failure, such as wildfires (Guliasi, 2021; Wong-Parodi, 2020), heat waves (Malcolm et al., 2021; Templeton, 2021), and the infamous 2021 winter storm Uri's impact on the Texas electricity grid (Busby et al., 2021), enhancing resilience and safety of households is becoming a paramount issue.

Lastly, the present study underlines the importance of efficient electrification not just as a decarbonization pathway, but also as a tool to address deep societal inequities rooted in unevenly distributed energy burdens alongside the aforementioned need to improve residential resilience to climate change. Inefficient electrification would not only negatively impact household costs (Vaishnav & Fatimah, 2020), but also efforts to decarbonize the power sector. Converting all residential natural gas use to resistive electricity use would increase electricity demand in the state by about 25%, more than the annual output of Georgia's coal fleet, thus jeopardizing their scheduled retirement (Grubert, 2020). This makes careful evaluation of the influence of electrification on slowing or halting plant retirements a worthwhile and pressing exercise.

2.3 Georgia Power DSM Portfolio and DR Opportunity Assessment

This subsection is dedicated towards providing an overview on currently implemented and prospective DR programs by Georgia Power, the electric utility serving most of the state of Georgia's residents in all but 4 of its counties (Georgia Power, 2022a).

2.3.1 Background and Motivation

The Georgia Power Company's (GPC) 2022 Integrated Resource Plan (IRP) features a proposal for the retirement of 12 fossil fuel power plants totaling more than 3,581 megawatts (MW), while aiming to add about 6,000 MW of new renewable generation resources by 2035, more than doubling its current portfolio (Bennet, 2022; GPSC, 2022). Despite Southern Company's 2050 Net Zero goal for both electric and gas business, the GPC IRP simultaneously introduces a supply-side strategy reliant on six power purchase agreements (PPAs) of natural gas fueled generation, with a total capacity of 2,356 MW to accommodate the incremental retirement of coal units (GPSC, 2022a; Southern Company, 2020a). Table 1 presents available information on all six power plants, two of which are natural gas combined cycle (NGCC), with the remaining four being natural gas combustion turbine (NGCT). This supply-side strategy can be linked to GPC's decline in forecasted fuel costs, which lowers the company's avoided cost—decreasing the value of each kilowatt-hour (kWh) saved through DSM programs (GPSC, 2022a).

Table 1 – 2022-2028 capacity RFP values (GPSC, 2020a; Southern Company, 2020b, 2020c, 2020d)

Unit Name	Type	Summer/Winter Capability	PPA Start	Length
Plant Harris Unit 2	NGCC	660/689 MW	12/1/2024	10 years
Plant Wansley Unit 7	NGCC	598/622 MW	12/1/2024	10 years
Plant Dahlberg Units 1, 3, and 5	NGCT	228/256 MW	1/1/2028	10 years
Plant Dahlberg Units 2 and 6	NGCT	152/171 MW	6/1/2025	10 years
Plant Dahlberg Units 8-10	NGCT	228/258 MW	6/1/2025	10 years
Plant Monroe Units 1 and 2	NGCT	309/360 MW	12/1/2024	15 years

In general, DR programs seek to provide load management or demand management to lower peak load and contribute to system reliability while reducing the cost of electricity supply (Smith & Brown, 2015). With these characteristics, DR may serve as a potential cost-effective alternative to displace a portion of the proposed addition of 2,356 MW of capacity from natural gas PPAs, particularly those from NGCT plants that are generally used to meet peak demand (EIA, 2013; Gils, 2016). The characterization of DR as a capacity, load, and demand resource signals the paradigm shift of DR towards developing flexible resources with the largest value being derived from avoided generation capacity in addition to load shifting (Hledik et al., 2019a). Strategic investments in DR serve as an opportunity to yield planning benefits while enhancing reliability, mitigating upward pressure on rates via reduced service costs, and nurturing innovation.

GPC is uniquely positioned to drive increases in both new DR program development and enrollment in existing DR programs, while additionally leveraging technological deployment. DR program advancement has the potential to address the distinctive challenges and changes introduced in the 2022 IRP—including large-scale coal retirements, increasing renewable penetration, forecasted load growth, seasonal shifts in peak demand, and ongoing North Georgia reliability, capacity, transmission, and distribution challenges. DR program advancement is further made feasible via the recent upgrade of all of GPC's 2.4 million customers to smart meters, yielding a grid with advanced metering infrastructure (AMI) that parallels increasing smart appliance and electric vehicle adoption (Georgia Power, 2022b).

2.3.2 Georgia Power's Energy Efficiency White Paper and EE/DR Integration

The Georgia Public Service Commission (GPSC)'s July 29th, 2019 final order in Docket No. 42310 involved the requirement that GPC conduct a competitive analysis of DSM and supply-side resources. Titled "Supply-side Representation of Energy Efficiency Resources in the Georgia Power IRP Model", this white paper was completed in 2021 but was not adequately leveraged in the 2022 GPC IRP (GPSC, 2021). It also included a survey of utilities that rely on a supply-side approach for incorporating EE in resource planning—including the Tennessee Valley Authority (TVA) as a representative of the Southeast. In its resource planning process, TVA modeled both EE and DR as selectable supply-side resources instead of load modifiers, a distinction implemented since 2015. Despite the potential for DR to serve as a fast-burst balancing and dispatchable resource, the 2022 IRP does not offer substantive DR investment or a robust suite of DR programs that can provide synergistic benefits or integration with existing EE programs (MPUC, 2020).

The advent of technologies such as AMI, smart thermostats, wifi-enabled appliances, water heaters, and air conditioning allow for the integration of EE and DR programs. Integrated EE and DR programs feature two primary components: improvement in technology efficiency and a control capability that can respond to remote and/or automated signals to adjust the technology's cycling or operation. The integration of EE and DR programs presents an opportunity to develop benefits for customers, program administrators, and system operators alike. An integrated EE and DR program provides a single program and customer contact that can provide complementary services that address both energy use and power demand. The integrated EE and DR program design presents customer benefits with utility bill savings, ease of program participation, and increased resource and service options. Utility and grid operators also benefit via reduced system costs, improved reliability, and overall optimized grid performance obtained from expanding the complementary value streams of energy savings ($/kWh) and demand savings ($/kW) associated with EE and DR (York et al., 2019).

2.3.3 Demand Response Categorization

DR is defined by the Federal Energy Regulatory Commission (FERC) as "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" (FERC, 2020). Implied by FERC's definition, DR programs can be differentiated as price-based or incentive-based, with programs being offered by utility companies, system operators, electricity cooperatives, municipal power agencies, and other-load serving entities (Baek et al., 2012).

As DR opportunities expand via electrification and AMI deployment, utilities can begin to categorize DR resources as traditional and nontraditional. Traditional DR refers to load management to provide a temporary reduction to system peak. Traditional DR resources are often referred to as dispatchable, as the utility may control them directly as an operational reserve with a similar impact like that of a combustion turbine—being brought online and offline for short periods of time. Nontraditional DR provides demand management opportunities for customers to plan for and manage electricity demand differently. Nontraditional DR allows customers to shift portions of load to lower-cost periods of the day—when renewable generation is at its peak. In systems with high renewable penetration, demand management via non-traditional DR can reduce customer costs via production cost savings of renewables (Xcel Energy, 2020).

Utilities—regardless of their market classification—provide DR opportunities to customers via categories of retail programs, dynamic pricing tariffs, and voluntary programs. Retail programs include incentive-based DR opportunities via curtailable load programs, interruptible load programs, direct load control (DLC), demand bidding programs and emergency programs. Dynamic pricing tariffs provide price-based opportunities including Real Time Pricing (RTP) and Critical Peak Pricing (CPP). Voluntary DR programs involve customers participating in load curtailment without direct financial compensation and include behavioral and educational programs (Bharvirkar et al., 2009). Note that programs within each categorization may be traditional or non-traditional DR, but a combination of both allows for maximized benefits.

2.3.4 Georgia Power Company Demand Response Programs

The GPC DR programs presented are limited to those discussed in the 2022 IRP. However, it is imperative for GPC to learn from pilot projects that have not been mentioned in the IRP, such as the Smart Neighborhood pilot "Altus at the Quarter", which includes DR as a feature, in addition to "the grid integration of solar panels and battery storage, smart management of heat pumps and water heating, and electric vehicle (EV) charging" (Brown & Chapman, 2021). As outlined in the 2022 IRP, GPC seeks to request the following actions or adjustments for the following DSM programs, where DR programs are highlighted in green and EE programs are left unhighlighted (Table 2).

Table 2 – Demand response program requests in Georgia Power's 2022 IRP. *Waiver requested due to the DR program not passing the TRC test (GPSC, 2022a).

Customer Sector	DSM Program	Status	Action Requested
Residential	Behavioral	Existing	Certificate Amendment
	Home Energy Improvement	Existing	Certificate Amendment
	Refrigerator/Freezer Recycling	Existing	Certificate Amendment
	Specialty Lighting	Existing	Certificate Amendment
	Home Energy Efficiency Assistance	Existing	Certificate Amendment
	Residential Thermostat Demand Response	Existing	Certificate Amendment and Waiver Requested*
	HopeWorks	Existing Non-certified Program	Grant a New Certificate
	Power Credit	Existing	Decertify
Commercial	Custom	Existing	Certificate Amendment
	Prescriptive	Existing	Certificate Amendment
	Small Commercial Direct Install	Existing	Certificate Amendment
	Behavioral	Existing	Certificate Amendment
	Midstream	Existing	Decertify

Of the proposed 2022 DSM programs, three existing programs with current certification amendment requests were identified: Residential Behavioral, Residential Thermostat Demand Response, and Commercial Behavioral. Although the Power Credit program would have qualified as a DR program, it is currently being decertified due to serving only summer peak events, whereas Residential Thermostat DR programs is designed to address the transition towards winter and summer peak seasons. Note that both behavioral programs serve as dual EE and DR programs, given their design to increase customer engagement with both energy management and EE to ultimately reduce energy consumption (GPSC, 2022a).

2.3.4.1 <u>Residential Behavioral Program</u>

The Residential Behavioral Program is primarily focused on influencing a reduction in electricity consumption through education and awareness to generate cost-effective energy savings. Georgia Power generates home energy consumption reports (HER) to inform customers on how their monthly consumption compares to similar homes and to energy-efficient counterparts. In addition to consumption data, reports include recommendations for consumption-reducing measures. Eligibility for the program is restricted to Georgia Power customers who have at least 13 months of billing history and are metered separately. This requirement is designed to capture the energy consumption patterns across all seasons, providing Georgia Power with enough data to make appropriate recommendations. Customers enrolled in the flat rate billing schedule, FlatBill, are excluded from the pool of customers that receive reports. These represent an untapped customer pool that misses out on the benefits offered by dynamic billing alternatives (e.g., Time-of-Use rates) and that could be leveraged for further energy and demand savings.

2.3.4.2 Residential Thermostat Demand Response Program

The Residential Thermostat Demand Response program is an approach to shift or curtail demand during peak events, managing load from participant's electrically heated and cooled homes by adjusting thermostat setting. As an incentive to join the program, new participants will receive a one-time payment of $50 and existing participants will receive $25 annually (GPSC, 2022a).

Participating customers permit Georgia Power to communicate directly with their smart thermostat and adjust it to reduce demands during critical times. Thermostats will only be adjusted a few degrees from the starting set point and Georgia Power aims to do so in a manner that does not noticeably affect the resident's comfort. After a high demand event has passed, thermostats will be returned to their original set point. Additionally, Georgia Power will "ensure that the participants are informed ahead of scheduled demand response events" when possible (GPSC, 2022b). In addition to remotely controlling the thermostats during critical events, Georgia Power run education and awareness campaigns promoting more efficient set points and conserving behaviors. This program is limited to customers that own a smart thermostat or purchase a smart thermostat from the Georgia Power marketplace. Participants have the option to enroll either through the manufacturer application, through GPC's website, or when purchasing a smart thermostat on the marketplace.

2.3.4.3 Commercial Behavioral Program

The Commercial Behavioral Program is implemented very similarly to its residential counterpart. In place of the HER there is a Business Electric Assessment report (BEA) that serves the same purpose of analyzing a customer's monthly energy demand and providing recommendations on ways to reduce consumption. Similar to the residential program, customers must have at least thirteen months of consumption data available in order to be provided reports (GPSC, 2022b).

2.3.4.4 Water Heater Controller Demand Response Pilot Study

The 2019 IRP Order involved a Commission approval of an annual $3M budget for DSM pilot programs. The 2022 IRP seeks to extend the budget for DSM pilot programs via commission approval of a $3M budget—$1.5M for residential and $1.5M for commercial pilots (GPSC, 2022a). In 2020, the 2019 DSM pilot budget served to develop a "Water Heater Controller Demand Response" pilot program. Implemented in September 2021 and scheduled to end at the end of 2022, the program was launched to investigate technological effectiveness and optimization, as well as customer satisfaction. The pilot is an active program with an estimated annual 2021 utility cost of $186,792 and a projected annual 2022 utility cost of $161,000 with no participant costs (GPSC, 2022c).

2.3.4.5 Demand Response Tariffs

The 2022 IRP includes a continuation of offering demand response tariffs for customers, presented in Table 3. The suite of DR tariffs includes RTP, a Demand Tariff, and TOU Tariff.

Table 3 – 2022 IRP demand response tariffs (GPSC, 2022a).

Demand Response Tariff	Description
Real Time Pricing (RTP)	- Marginal pricing for incremental load. - As prices increase, customers are incentivized to reduce demand.
Demand Tariffs	- Tariffs that align with cost of service to incentivize demand reduction.
Time-of-Use (TOU) Tariffs	- Pricing signals during different periods of the day aligned with the marginal cost of energy to incentivize demand reduction.

2.3.5 External Demand Response Program Assessment

A nation-wide utility DR program assessment was done to evaluate program portfolio of utilities with similar DR capacity potential to GPC, as well as to assess national leaders in DR and take lessons from them that would be applicable to GPC.

2.3.5.1 <u>Selection Approach</u>

External DR opportunities for GPC's consideration were sourced from the "Form EIA-861: Annual Electric Power Industry Report" at the utility level to identify utilities with the largest "Potential Peak Demand Savings" (PDS) and "Actual Peak Demand Savings". For selection, utilities were filtered by largest potential PDS to identify the top fifteen utilities with a similar potential DR capacity to GPC (which places fifth in this metric), with further selection priority given to utilities within GPC's Southeast region. However, utilities were not solely selected on these criteria, as the purpose of this work is to identify utilities that are successfully implementing DR as a capacity resource. Further consideration was given to: the top performing utilities on the metric of actual PDS from those within the top fifteen utilities with the largest potential PDS, as they would provide insight into successfully leveraging high potential PDS from DR; utilities with a large "Number of Customers Enrolled", since they could provide insights into optimal DR program design, marketing, and onboarding; and utilities with both high "Actual PDS" and a high "Actual PDS / Potential PDS" ratio. Utilities that fit some of the listed selection criteria but had scarce DR program documentation or a lack of resource availability were not selected for evaluation.

Consequently, a total of 8 utilities, presented in Table 4, were selected for program assessment to determine their respective DR portfolios and DR program costs.

Table 4 – Selected utilities for demand response program assessment (EIA, 2022a)

Utility Name	Number of Customers Enrolled [# Customers]	Actual Peak Demand Savings [MW]	Potential Peak Demand Savings [MW]	Total Cost (Incentives & All Other Costs) / Actual Peak Demand Savings [$000/MW]	Total Cost (Incentives & All Other Costs) / Potential Peak Demand Savings [$000/MW]
Duke Energy Florida, LLC	426,987	0.0	1,017.0	N/A	89
Northern States Power Co - Minnesota	422,481	0.0	822.0	N/A	53
Commonwealth Edison Co	396,482	141.0	997.0	33	8
Tennessee Valley Authority	1,020	416.3	624.9	99	14
DTE Electric Company	362,366	182.0	774.0	119	115
Idaho Power Co	24,648	292	314	25	23.2
Duke Energy Progress - (NC)	194,987	24.5	522.8	569	27
Duke Energy Carolinas, LLC	198,703	0.0	669.9	N/A	29

DR strategy & program assessment for each selected utility was executed by reviewing each respective utility's most recent resource plan filings and relevant DSM appendices. The programs from selected utilities were used to construct a matrix of available DR offerings by utility to demonstrate the breadth of program designs and implementations.

Recommendations for the GPSC were then derived as GPC has unique resource plan challenges that align it with DR as a potentially cost-effective supply-side resource to provide both load and demand management. The challenges and changes that GPC faces that highlight the demand for DR include large-scale coal retirements, increasing renewable penetration, forecasted load growth, smart meter deployment, smart appliance adoption, electric vehicle adoption, seasonal shifts in peak demand, and ongoing Northern Georgia reliability challenges—in capacity, transmission, and distribution.

2.3.5.2 Results Highlights

The DR program assessment results are summarized in the matrix on Appendix A. Note that the matrix is limited in that it provides an overview of utility DR program portfolios; however, the matrix does not assess the magnitude of impact of each program. The majority of GPC's DR portfolio is driven by dynamic pricing tariffs that are not inherently able to provide dispatchable load flexibility as retail direct load control programs.

A majority of assessed utilities ensure their DR program offerings are efficient and cost-effective prior to implementation. Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) commissioned a Market Potential Study to obtain estimates of economic potential for achievable DR within their service areas, yielding Total Net Benefits per Capacity of 968.6 $/kW and 575.5 $/kW in their residential sectors, respectively, and 6290.5 $/kW and 1016.8 $/kW in their commercial sectors, respectively (SCPSC, 2020a, 2020b). It was also found via The Brattle Group's DR cost-effectiveness assessment that Xcel Energy (Northern States Power) could increase traditional DR resources by 293 MW by 2023 at an annual cost of up to $59/kW per year (Hledik et al., 2019b; MPUC, 2020).

Most of the selected utilities for DR program assessment frame DR as a "selectable resource" rather than referring to it as a load modifier that reduces demand for electricity.

TVA now has DR "...modeled as a selectable resource… that potentially offsets or delays the need for more expensive peaking generation or power purchases." (TVA, 2019); Idaho Power considers DR as a resource "to minimize or delay the need to build new supply-side resources" (IPUC, 2020); DEC considers DR a resource that can help "limit the need for additional peaking generation." (SCPSC, 2020a); and Xcel Energy considers EE and DR as "supply-side resources available to the model in bundles" (MPUC, 2019).

GPC displayed significant underdevelopment in retail DR programs when compared to the assessed utilities, particularly in the domain of dispatchable, flexible load DR resources such as DLC programs. Assessed utilities successfully utilize the large volume of potential demand savings associated with their Commercial and Industrial sectors (C&I) via a combination of retail and dynamic pricing DR programs that yield high avoided peak capacity savings. TVA successfully provides approximately 1,800 MW of peak reduction capacity exclusively through C&I programs (TVA, 2019). DEC leverages about 500 MW of aggregate DR capacity across all of its C&I program offerings (SCPSC, 2020a). Some of the assessed utilities make use of strategic DR opportunities, such as outsourcing aggregate DR programs to third parties and DR geo-targeting to further diversify their DSM portfolios for enhanced grid reliability and renewable penetration opportunities.

2.3.6 Demand Response Considerations & Recommendations for GPSC

The GPSC should approve GPC's Waiver Request of the TRC requirement for the continuation of the Residential Thermostat Demand Response Program in this IRP cycle, as it is a long-term DR investment with expected positive TRC results in 2031 (GPSC, 2022a).

The existing "Water Heater Controller Demand Response" pilot initiative results should be published upon completion at the conclusion of 2022. If the pilot results are favorable over a sufficient time horizon, the program should be fully funded and made available to customers via a single integrated EE/DR program for onboarding and operational optimization.

GPC should build upon their work from the White Paper—"Supply-Side Representation of Energy Efficiency Resources in the Georgia Power IRP Model"— to also incorporate DR into its modeling, given that the original purpose of the paper was "to investigate methodologies to model DSM as an additional scenario in its supply side system planning tools as a part of its IRP development and resource optimization process where DSM will be modeled alongside traditional supply-side options" (GPSC, 2021). Flexibility for determining the cost-effectiveness of DR should be granted where GPC has the authority to decide to incorporate DR options into the resource planning model or conduct a robust cost-effectiveness screening (Xcel Energy, 2020).

As a subsidiary of Southern Company, GPC should be held accountable for contributing to the 2050 Net Zero target where demand response can serve as a strategy for carbon emissions mitigation (Brown & Chapman, 2021).

CHAPTER 3. HOUSEHOLD PROFILING AND SAVINGS CAPACITY ASSESSMENT

According to the EIA, Georgia's residential sector accounted for about 25% of the total end-use energy consumption in 2020 (EIA, 2021b). Additionally, Georgia is one of the few states where at least 30% of household energy consumption is used for space heating, the largest contributor to a household's energy consumption, followed by water heating at 19% and air conditioning at 11% (EIA, 2022b). The previous chapter highlighted the state of Georgia's current underinvestment in retail DLC programs, which could provide dispatchable load flexibility that current DR programs are unable to deliver, while also acknowledging the high but inefficient electrification rates in the state's residential sector. Given the identified missed opportunity for energy consumption reductions, this chapter is dedicated towards profiling households in the metro Atlanta area and assessing their capacity for energy and demand savings.

3.1 Distinguishing Between Energy and Demand Savings

Before continuing with this chapter, it is important to define what is meant by energy savings and demand savings. Energy consumption is usually measured in kWh to represent the amount of energy, in this case electricity, consumed during a given period. This amount can be decreased by reducing consumption either directly, e.g., turning off energy consuming equipment when not in use, or indirectly, e.g., increasing EE to reduce the amount of energy needed to operate appliances. Therefore, energy savings straightforwardly refers to savings in the amount of energy consumed over a period of time, also measured in kWh. On the other hand, energy demand represents the amount of power, measured in kW, that must be generated at a given time. This mean that an electric utility must deliver enough electrical power during the day to meet the customer's demand. As demand increases, more power sources must be deployed. Demand savings then refers to the amount of power that was averted from deployment, measured in kW (McCrea, 2021). Demand savings can also be accomplished through EE, reducing overall household power needs, and DR, which could directly curtail demand.

3.2 Methodological Approach & Data Sourcing

American Housing Survey data was used to identify current electrification rates, heat pump adoption, and electric water heater adoption in the metro Atlanta area. This area corresponds to the "Atlanta-Sandy Springs-Roswell, GA Metropolitan Statistical Area", or Core-Based Statistical Area (CBSA) 12060, as defined in the U.S. Office of Management and Budget's (OMB) 2013 Standards for Delineating Metropolitan and Micropolitan Statistical Areas, including a total of 29 counties. The area was chosen due to the readily available data tables provided by the AHS, which projects estimates along with margins of errors at 90% confidence interval based on the area's survey responses. The "Heating, Air Conditioning, and Appliances" table was sourced using "Household Income" as the organizing variable. The table's estimates were presented in thousands of housing units and rounded to four significant digits (U.S. Census Bureau, 2022). Refer to Appendix B for a table of sourced values.

For space heating profiles, estimates were first sourced from the "Main House Heating Fuels" section of the table and organized by household income. To include heat pumps in the profile, the estimates for electric heat pumps per household income were extracted from the "Main Heating Equipment" section of the table, with those extracted values then being subtracted from the Electricity values from the "Main House Heating Fuels" section to distinguish between electric heat pumps and other electric space heating appliances.

For water heating profiles, "Water Heating Fuel" estimates per household income values were directly sourced from the data table.

EE derived energy savings estimates for heat pump (HP) installation, heat pump water heater installation (HPWH), and a deep efficiency package were sourced from the Residential Home Energy Improvement Program, which seeks to improve energy efficiency in existing homes. Georgia Power's 2022 IRP's DSM Appendix included energy savings and demand savings estimates for implementation of each individual measure, with those that had "Electric" in the fuel category being picked for assessment. Note that the document does not specify what the state of the previous component was, with estimates being used mainly for internal program evaluation (GPSC, 2022b). Key measures to implement for the deep efficiency package were identified using a report on household deep retrofits by the American Council for an Energy-Efficient Economy (ACEEE) (Amann et al., 2021). Any additional sources that serve to contextualize the issue, along with corresponding calculations and assumptions, are explained in Section 3.4.

DR-derived Demand savings values for electrified space heating were sourced from the Residential Thermostat DR Program in the 2022 IRP's DSM Appendix. Note that the program does not distinguish between targeted electrical appliances (e.g., heat pumps vs.

electric furnaces) but only that the household should be electrically heated and cooled to be eligible (GPSC, 2022b). DR water heating demand savings values were sourced from an Illume Advising (2019) report with findings from a water heater DR pilot conducted by Georgia Power. Both winter and summer average demand reduction values were made available in the report, with the pilot sample including both electric resistance and heat pump water heaters. To calculate total demand reduction potential in the metro Atlanta area, the demand savings for space heating/cooling and water heating were multiplied by the total # of households with electricity as their main space heating fuel and water heating fuel, respectively. Most households already rely on electricity-powered air conditioning, so that was not taken into account since households needed to be both heated and cooled with electricity to be eligible.

Lastly, program descriptions and values were directly sourced from the IRA document (IRA, 2022), with additional sources for relevant values to contextualize the issue, along with any additional calculations and assumption, explained in the corresponding section 3.6.

3.3 Space Heating/Cooling and Water Heating Profile of Metro Atlanta Area

3.3.1 Electrified Heating and Heat Pump Penetration

Figure 9 below summarizes metro Atlanta households' main fuel for space heating, organized by household income.

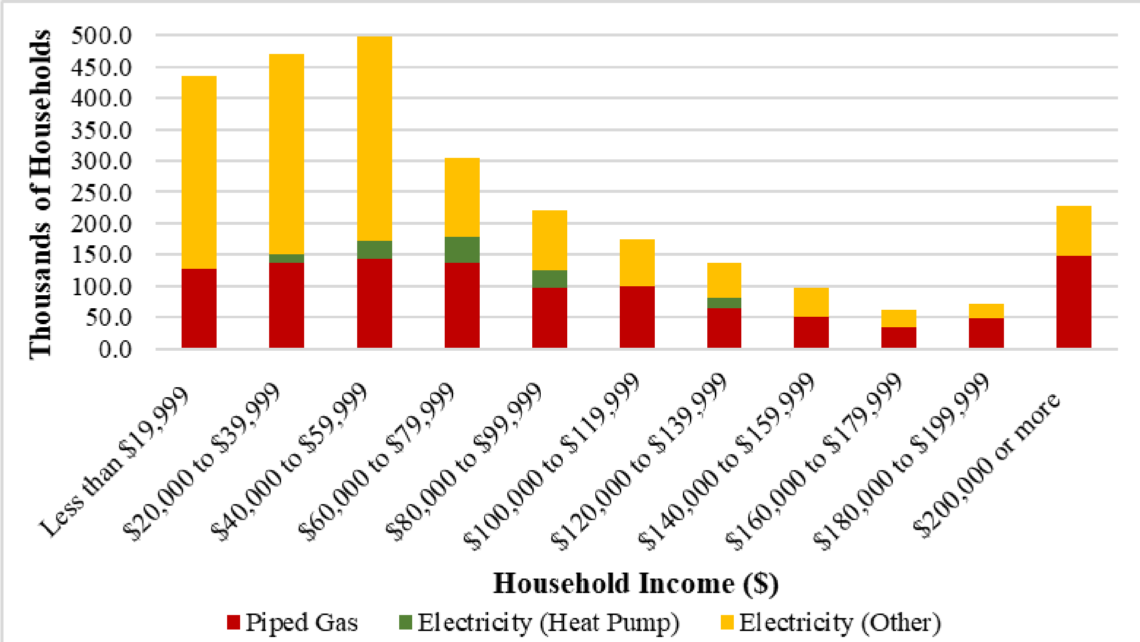

Figure 7 – Metro Atlanta households' main house heating fuel by household income brackets (U.S. Census Bureau, 2022).

Out of the estimated 2.3 million households, the survey estimates that about 204,300 households have heat pumps installed for space heating, which are included in the estimated total of 1,157,200 households relying on electricity as their main space heating fuel (bottled gas only accounted for about 50,500 of total households, with no per household income estimates provided).

The pattern of high but inefficient electrification in the Southeast, presented earlier in this report, is also reflected in metro-Atlanta's household profiles – there's a high share of households relying on electricity for space heating, but very few of those rely on heat pumps as their main heating equipment, at about only 18%. That number is even lower (about 9%) when accounting for all household units in the area. Another notable emerging pattern is that lower-income households represent a higher share of total electrified-heating households, with the share of electrified households within an income bracket decreasing as the household income increases.

With Atlanta ranking as one of the cities with the highest low-income household energy burden levels in the nation, facilitating these households' transition away from low-efficiency electrical heating and towards more efficient space-heating appliances, like heat pumps, would bring about co-benefits of just equitable development for these communities and more stable energy demand (Brown et al., 2018; IEA, 2021).

Figure 8 below showcases the same data as Figure 7, but as a percentage of total households within an income bracket that rely on a heating fuel, to facilitate visualization of the distribution of space heating profiles.

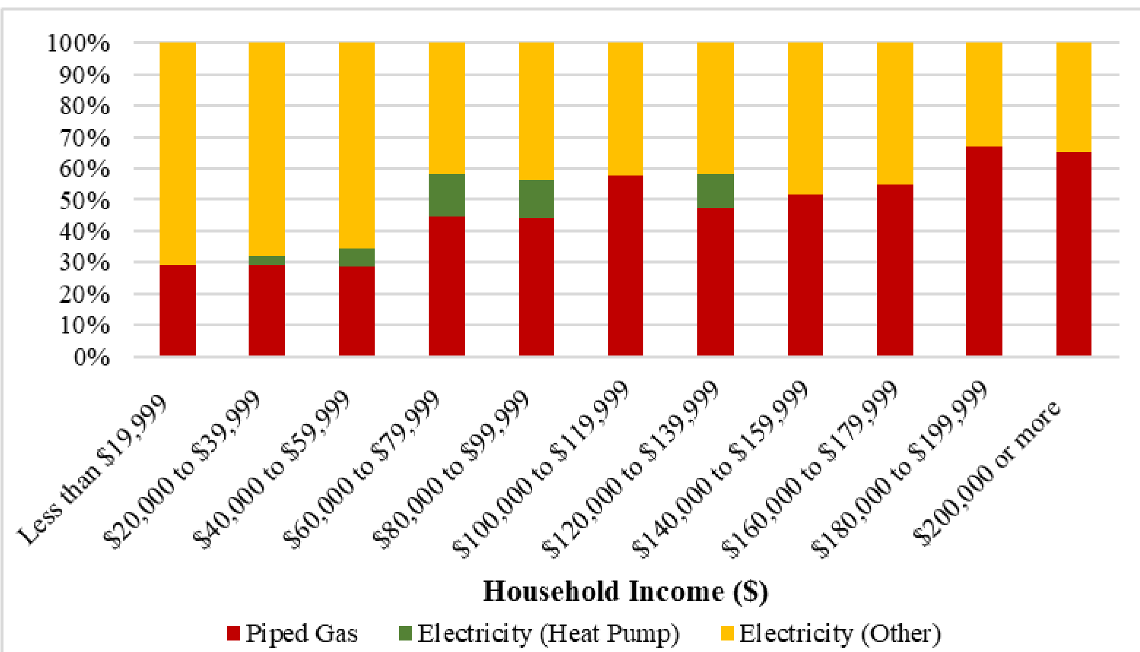

Figure 8 – Metro Atlanta's distribution of main house heating fuel by household income brackets (U.S. Census Bureau, 2022).

3.3.2 Electrified Water Heating Penetration

Figure 9 below summarizes metro Atlanta households' main fuel for water heating, organized by household income.

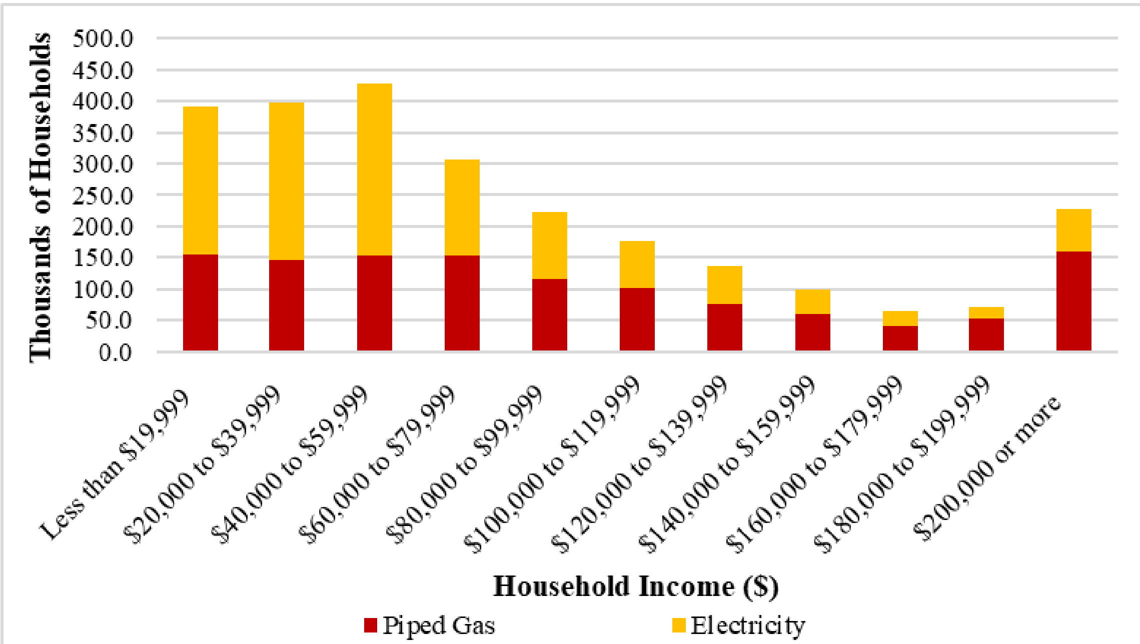

Figure 9 – Metro Atlanta households' main water heating fuel by household income brackets (U.S. Census Bureau, 2022).

Out of the estimated 2.3 million households, the survey estimates that about 1.1 million households rely on electricity as their main water heating fuel, with the remaining 1.2 million relying on piped gas (bottled gas only accounted for about 26,000 of total households).

Similar patterns as the space heating profiles can be found in the water heating profiles, with high existing electrification rates for this application, with lower-income households representing the majority of electrified water-heating households. However, unlike with the space heating profiles, the sourced data did not differentiate between main equipment used for water heating. With heat-pump water heaters making up only 2% of the overall market in 2020 (USITC, 2022), it is likely that most of the electrified water heating households rely on conventional electric resistance water heaters. If that were the case, water heating profiles are subject to a similar assessment as that provide for space heating profiles.

Figure 10 below showcases the same data as Figure 9, but as a percentage of total households within an income bracket that rely on a heating fuel, to facilitate visualization of the distribution of water heating profiles.

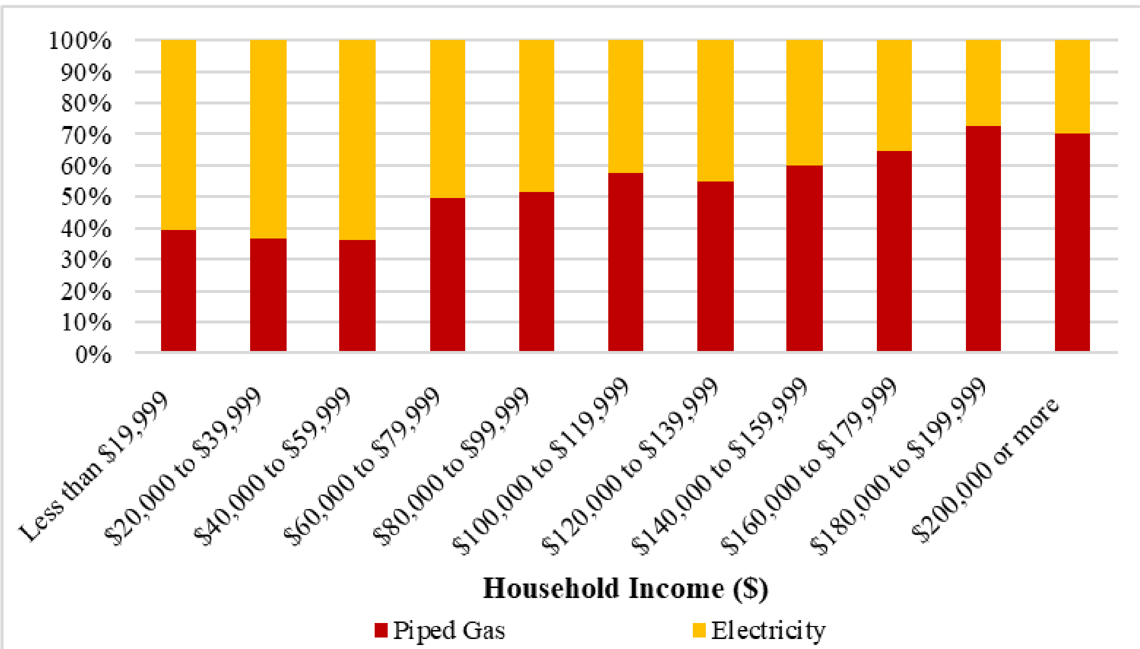

Figure 10 – Metro Atlanta's distribution of main water heating fuel by household income brackets (U.S. Census Bureau, 2022).

3.3.3 Profiling Limitations

A key limitation in the assessment for both space and water heating values stems from the data tables only providing estimates for the main heating fuel used on the household, with no accounting of supplemental heating fuel consumption for the given households. This leads to the assessment having to assume that a household might rely only on that main heating fuel for a particular application. Additionally, the data does not provide estimates per household income for all presented heating fuels, e.g., bottled gas. However, this does not significantly skew the assessment, with bottled gas, the third main heating fuel source after electricity and piped gas, being the main fuel for only 2% of total households for space heating and 1% of total households for water heating.

3.4 Energy Savings Potential of EE Measures

Table 5 below presents the values used to identify the potential for energy savings of implementing heat pump, HPWH, and other deep efficiency measures identified in the ACEEE's report on deep retrofits (Amann et al, 2021).

Table 5 – Energy savings values for assessment of EE measure implementation (GPSC, 2022b)

Efficiency Measure	Gross Energy Savings (kWh per year)
Conversion to Ductless Mini Split HP	1,819
HP Water Heater - Energy Star (3.2)	2,233
Ducting - Repair and Sealing	791
Insulation - Ceiling Installation	3,156
Building Shell - Air Sealing	1,350
Connected Smart Thermostat	484
Conversion to Ductless Mini Split HP	1,819

According to Georgia Power, the average annual residential electricity consumption was 12,033 kWh in 2021 (Georgia Power, 2022a). Assuming that the energy savings in Table 5 apply to the average household, the impact of these measures and the net energy consumption are visualized in Figure 11.

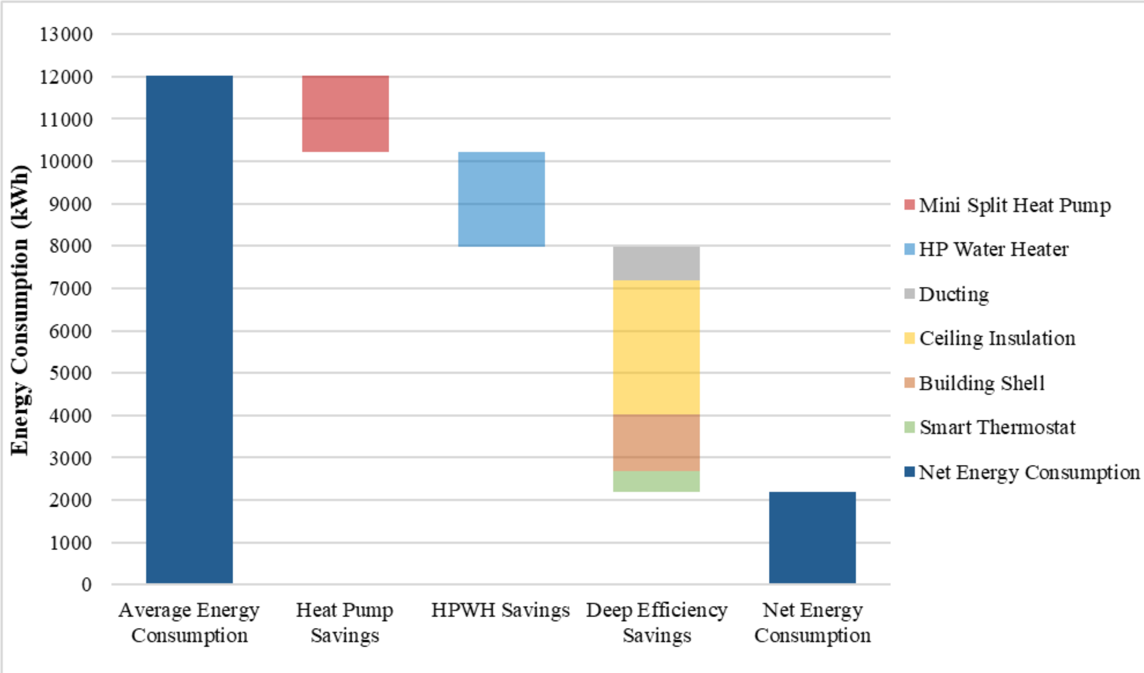

Figure 11 – Energy savings from implementation of select EE measures

Drastic savings in energy consumption are derived from implementing all of the identified measures, bringing the average consumption down by about 81% to ~2,200 kWh, saving a household close to 10,000 kWh per year. This estimate is slightly about those found by the ACEEE report, which found that deep retrofits could cut a home's energy use by 58% to 79% (ACEEE, 2021). Note that the energy savings correspond to appliances that already used electricity as a fuel, so this rough estimate would not apply for households with appliances relying on natural gas.

Implementation of these savings could also greatly reduce Atlanta's extremely high average for low-income households' energy burden of 10.2% (Brown et al. 2018), particularly since a majority of low-income households are already electrified. Assuming the 2021 average price paid by customers of 13.22 cents per kWh (Georgia Power, 2022a), implementing the deep retrofit would bring household bills from a yearly ~$1,590 down to

~$290, saving households a total of ~$1,300. For a household making $25,000 a year, that would mean a reduction of about 5.2% of their total energy burden.

3.4.1 Decarbonization Potential of EE Energy Savings

When only considering energy savings from heat pumps (1819 kWh per year) and HPWH (2233 kWh per year), if applied to all of the 952,900 households with electrified space heating/cooling, but no heat pump installations, and all of the 1,102,100 households with electrified water heating (assuming no HPWH installations) respectively, a total of ~2.1 million MWh could be saved through heat pump installations and ~2.4 million MWh could be saved through HPWH installations for a total of ~2.5 million MWh of saved electricity each year in the metro Atlanta area alone. Assuming a grid emissions factor of 350 kilograms of CO2-equivalent (CO2e) per MWh, this energy savings could lead to a reduction of ~0.88 megatons (Mt) of CO2e per year for the state of Georgia, which currently emits about 125 Mt each year (Drawdown Georgia, 2021).

3.5 Demand Savings Potential of DR Measures

Table 6 below showcases the sourced demand savings values for space heating/cooling DR, implemented via a smart thermostat, and water heating DR, implanted directly via electric water heaters.

Table 6 – Sourced DR demand savings per household (GPSC, 2022B; Illume Advising, 2019). *Estimated demand savings were not differentiated between summer/winter.

Curtailment Program	Summer Demand Savings (kW/year)	Winter Demand Savings (kW/year)
Smart Thermostat DR	0.74*	
Water Heater DR	0.11	0.2

When accounting for the 1,157,200 households with electrified space heating/cooling that would be eligible for the Smart Thermostat DR program, and the 1,102,100 households eligible for the Water Heater DR program, the total potential demand savings for the metro Atlanta can be calculated. Those calculated values, this time presented in MW instead of kW, can be found in Table 7.

Table 7 – Potential demand savings from DR programs in the metro Atlanta area.

Curtailment Program	Summer Demand Savings (MW)	Winter Demand Savings (MW)
Smart Thermostat DR	856	
Water Heater DR	121	220
Total	977	1076

3.5.1 Decarbonization Potential of DR Demand Savings

Given that demand reductions from DR programs could be implemented to help curtail peak electricity demand or shift demand load to off-peak hours, DR programs could serve to reduce reliance on high cost and high-emissions peaking generation units (Gilbraith & Powers, 2013; GPSC, 2022b; Smith & Brown, 2015). Assessed potential demand savings for both winter and summer periods slightly exceed the total summer and winter capacity of the four NGCT listed as part of the six PPA's in GPC's 2022 IRP to meet supply-side generation needs (GPSC, 2022a), with these values displayed in Table 8. Although the DR-derived demand savings likely won't completely displace NGCT plants, mainly due to the latter's comparably higher dispatchability and reliability, these programs would still serve a role as important tools to reduce reliance on these generation resources.

Table 8 – Comparison of DR demands savings and NGCT power plants summer and winter capacity.

Peak Demand Resource	Summer Demand Capacity (MW)	Winter Demand Capacity (MW)
DR Demand Savings	977	1076
NGCT Power Plants	917	1045

3.6 Inflation Reduction Act Beneficiaries

The Inflation Reduction Act is a recently passed bill that seeks to both lower the cost of living for families and combat the climate crisis as two of its primary goals (White

House, 2022). There are two key programs that households could leverage to reduce the costs of improving the efficiency of their households: the High-Efficiency Electric Home Rebate Act (HEEHRA) and the Energy Efficient Home Improvement Credit.

HEEHRA offers up to $14,000 in rebates per household, with rebates of up to $8,000 for heat pumps and $1,750 for HPWH. Eligibility for the program was defined as follows: 100% cost coverage for households with an income less than 80%t of the area median income, and 50% cost coverage for households with an income of more than 80 percent but less than 150 percent of the area median income (IRA, 2022). There is no current implementation date, although the rebate program could start as soon as 2023, and the state of Georgia was allocated more than $109 million for the program (Beasley, 2022).

Energy Efficient Home Improvement Credit, on the other hand, provides a yearly tax credit that would cover up to 30% of the costs for eligible home improvement purchases starting in 2023 up until 2032. Annual credit limit for both heat pumps and HPWH is capped at $2,000 (IRA, 2022).

Assuming a median household income of $71,193 for the metro Atlanta area (Data USA, 2021), 80% of the area's median income would be about $57,000 and 150% would amount to about $107,000. Rounding these values to the closest income brackets from the AHS data results in households with less than $60,000 being eligible for HEEHRA's 100% cost-coverage rebate, and households with more than $60,000 and less than $100,000 being eligible for the 50% cost-coverage rebate. Households with more than $100,000 could instead apply for the 30% of costs tax credit offered by the Energy Efficient Home Improvement Credit.

Excluding households with heat pumps already installed, these programs could lead to about 830,000 low-income households eligible to receive free heat pumps, about 360,000 middle-income households eligible to receive a half-off heat pump, and about 910,000 households that could instead receive a 30% annual tax credit, assuming no program overlap. On the other hand, about 980,000 low-income households could apply to receive free HPWH, about 530,000 middle-income households could apply to receive a half-off HPWH, and about 790,000 households could apply for a 30% annual tax credit.

It is important to note, however, that the HEEHRA fund of $109 million would only allow for 13,625 households to receive free heat pumps (assuming all households cash in the $8000 rebate) or for 62,285 households to receive free HPWH (assuming all households cash in the $1,750 rebate).

CHAPTER 4. LEVELIZED COST OF SAVED ENERGY OF DEMAND RESPONSE PROGRAM IMPLEMENTATION

Chapter 3 explored the potential for demand savings from a smart thermostat DR and a water heater DR program while proposing that these programs could help decrease reliance on NGCT peaking power plants, which are part of Georgia Power's supply-side strategy in their 2022 IRP (GPSC, 2022a). Chapter 4 presents an approach to calculate a levelized cost of saved energy (LCSE) that is used to facilitate cost-comparison of the smart thermostat DR and water heater DR to supply-side generation resources, which rely on the levelized cost of electricity (LCOE) for cost comparison.

4.1 Methodology

4.1.1 Levelized Cost of Saved Energy Formula

The Cost of Saved Energy (CSE), as defined in Georgia Power's IRP, is the "total cost per kWh of realizing the efficiency improvement" (GPSC, 2022a). It is calculated by dividing levelized program costs by the annual energy savings, as shown in the equation below.

$$CSE = \frac{Program\ Costs\ (\$)\ x\ CRF}{Annual\ Energy\ Savings\ (kWh)} \tag{1}$$

Where CRF stands for the Capital Recovery Factor. This equation would also yield \$/kWh much like an LCOE. However, it fails to incorporate further costs such as incentives or capital investments that an LCOE would account for. In addition, that definition fails to account for energy savings from curtailed demand derived from implementing a DR program. Due to those reasons, an expanded version of the CSE formula is introduced below to calculate an LCOE-analog value for DR programs, named "Levelized Cost of Saved Energy" to distinguish it from the CSE equation.

$$Demand\ Response\ LCSE = \frac{\sum_{t=0}^{n} \frac{CI_t + IC_t + PC_t}{(1+r)^t}}{\sum_{t=0}^{n} \frac{ES_t}{(1+r)^t}} \tag{2}$$

In the LCSE formula (2), t refers to the year t, with t = 0 being the program's starting year; n stands for the program's lifetime; r is the discount rate; CI_t stands for the program's capital investments at year t; IC_t stands for the program's incentive costs at year t, PC_t stands for the program's O&M costs at year t; and ES_t stands the program's energy savings at year t.

4.1.2 Input Data Sourcing for Base Case

Each of the values used to address the LCSE parameters are listed below. When ranges of values were available, conservative values were selected to avoid calculating the lowest possible LCSE value that would characterize DR as a low-cost resource. Additionally, note that value sourcing and LCSE calculation itself are all done from the perspective of utilities/system operators leveraging the energy saving resource to service the electricity grid. Values were mostly sourced from the Smart Thermostat DR Program's provided estimates in the IRP's DSM Appendix Program Plans (GPSC, 2022b), unless otherwise noted. These serve to inform a reference "Base Case" by which to benchmark and design alternative cases, which are explored in subsection 4.1.3.

For Program Lifetime, 10 years is used accounting for that being the lower end of program equipment lifespans, with estimates for a smart thermostat lifespan being 10 years on average (Living Smarter, 2021; Smart Home Starter, 2021; Tabaloc, 2022), heat pump lifespans being somewhere between 10 and 20 years (ConditionedAir, 2022; Poston Brothers, 2021; Termo+, 2019), and HPWH lifespans being somewhere between 10 to 15 years (Schwartz & Vila, 2020; Trout, 2022).

For the Discount Rate, a value of 7% was used, slightly higher than the weighted average cost of capital (WACC) used by utilities to assess supply-side generation resources (EIA, 2021c; Molina, 2014). This average estimate was used instead of GP's WACC since it was not readily available in the IRP, having been left out as redacted.

For Capital Investments, no values are used for the Base Case, as it's not accounted for in the DSM Program Plan. Note that this assumes that customers are shouldering these capital investments costs. Alternative cases that incorporate utilities covering the cost of program enabling infrastructure, such as rebates for purchase of smart thermostats, heat pumps, and HPWHs are explored and defined in subsection 4.1.3.

For Incentive Costs, 12 years of projected estimates are provided in the DSM Program Plan documentation, of which the first 10 are used for the LCSE calculation. Note that incentive values per customers are also provided: a one-time payment of $50 for new participants and an annual payment of $25 for returning participants.

For the Program Costs, similarly, 12 years of projected estimates are provided in the DSM Program Plan documentation, of which the first 10 are used for the LCOE calculation. A further breakdown of these Program Cost values is explored in the Alternative Cases subsection.

For Energy Savings, the value provided for yearly Demand Savings (MW) is used to determine annual energy savings (MWh) for 10 years. There are projected estimates for 12 years of demand savings, of which the first 10 are used for the LCSE calculation. A value for demand savings per participating customer is also provided, which is used to determine energy savings for the alternative cases.

A "Derating Value" is used as a substitute for capacity factor in the calculations, which represents the constraints associated with the number of load curtailment events that can be called during a year, as well as the window of hours that the event could be enacted for, that limit the capacity value of a DR program. Derate factors are usually estimated as the relative availability of DR during hours with the highest loss of load probability, loss of load referring to times in which the available generation is less than the system load. Although the derating value is program specific, some historical utility derating values have ranged from 0 to 50% of a program's capacity. The Brattle Group considers that a 25 percent derate value as a reasonable estimate, a value that is kept static for the base and alternative cases of the LCSE calculations (Hledik & Faruqui, 2015).

Lastly, the # of program participants/customers used for the base case is 25,000 continuing participants, although that value does not influence calculations in the base case since incentive costs, program costs, and energy savings value projections estimates are either provided or calculated independently. However, it is still noted since it serves as a benchmark value for alternative cases.

4.1.3 Assumptions for Alternative Cases

8 alternative cases were modeled in order to explore scenario variability when calculating the LCSE of the DR programs, with 3 cases dedicated to the Thermostat DR program, 2 cases to the Water Heating DR program, and 3 cases for joint implementation of both programs. With the base case assumptions having been detailed in the calculations, each of the remaining cases and their assumptions are defined below.

4.1.3.1 <u>Thermostat DR Potential Case</u>

Assumes all potentially eligible households with electrified space heating/cooling, i.e., about ~1.1 million households identified in chapter 3, would enroll to the program by the first year of operation. All incentives remain in place, and this case operates under the assumption that all these customers will receive the "new participant" $50 incentive on the first year, and the "returning participant" $25 incentive for the remaining years, updating the Incentive Cost component accordingly. Program Costs are increased to reflect the increase in O&M costs, with value increases from the base case presented in Table 9.

Table 9 – Program costs increases for alternative cases.

	Base IRP Case	DR Potential	Difference
Customers	25000	1100000	-
Program Admin/Mgmt	$ 190,000	$ 8,400,000	$ 8,210,000
Contracting Costs	$ 1,000,000	$ 44,000,000	$ 43,000,000
Program Marketing	$ 5,000	$ 220,000	$ 215,000
Program Evaluation	$ 50,000	$ 2,200,000	$ 2,150,000
Total Cost	$ 1,245,000	$ 54,820,000	**$ 53,575,000**

The "Base IRP Case" column in Table 9 showcases values for year 1 of the projected estimates, "DR Potential" represents new values, and "Difference" represents the value difference, with the final total sum of these differences, i.e., the "Total Cost" in the "Difference" column, being added to the yearly program costs for each year. All components of program costs were linearly increased proportionally to the total number of program participants. Program costs are likely an overinflated estimate, given that a linear increase in costs would not account for program management efficiency increases derived from experience and economies of scale, allowing program implementers to onboard more customers at lower marginal costs.

Lastly, total yearly demand savings for this case are calculated as a function of the participant enrollment, with a yearly demand savings of 0.74 MW per participant, as sourced from chapter 3.

4.1.3.2 Thermostat Rebate Case

All the "Thermostat DR Potential" case assumptions apply to this case, with the added assumption that GPC would fully cover for the cost of Smart Thermostats for all new participants. Cumulative rebate cost for all new customers will be implemented as a Capital Investment costs at year 0. Smart Thermostat costs were sourced from the Georgia Power Marketplace, assuming the highest costing thermostat ($250) would be fully rebated by GPC (Georgia Power Marketplace, 2022).

4.1.3.3 Thermostat + HP Rebate Case

This case considers all "Thermostat Rebate" case assumptions while also including a fully rebated cost for a ductless mini-split heat pump purchases, with a rebate ceiling of $5000 serving as a conservative high-end estimate for the given heat pump's cost (This

Old House, 2022). However, the rebate only applies to 900,000 of participants, since ~200,000 of eligible participants would already have heat pumps installed in their households, as established in chapter 3. This new utility cost will be implemented at year 0 as part of Capital Investments.

4.1.3.4 Water Heating DR Potential Case

The first of two Water Heating DR cases, this case assumes all potentially eligible households with electrified water heating, i.e., about ~1.1 million households identified in chapter 3, would enroll to the program by the first year of operation. All program enrollment incentives in the Thermostat DR Potential case remain in place, with all of these customers receiving the "new participant" $50 incentive on the first year, and the "returning participant" $25 incentive for the remaining years. Program Costs are also the same as the Thermostat DR Potential case, given the similar eligible household estimates. Lastly, yearly demand savings of 0.15 kW per participant are implemented in this case, an a sourced from chapter 3.

4.1.3.5 HPWH Rebate Case

This second Water Heating DR case considers all assumptions from the "Water Heater DR Potential case while also including a fully rebated cost for HPWH purchases, with a rebate ceiling of $2500 serving as a conservative high-end estimate for the given HPWH's cost (Thomas, 2022). This new cost will be implemented at year 0 as part of Capital Investments.

4.1.3.6 Thermostat + Water Heating DR Case

This case presents a joint implementation pathway for both DR instances, assuming all eligible households for both programs perfectly overlap. Assuming the same 1.1 million participants, program costs will remain the same as those already presented in Table 9. No rebates are offered by the utility, but the enrolling incentives are implemented, i.e., the "new participant" \$50 incentive on the first year and the "returning participant" \$25 incentive for the remaining years. Lastly, a yearly demand savings per participant value of 0.89 kW is implemented, a sum of both programs' demand savings.

4.1.3.7 Thermostat + Water Heating DR Rebates Case

This case keeps all the assumptions from the "Thermostat + Water Heating DR" case, but adds all previously listed rebates, i.e., the \$250 smart thermostat rebate, the \$5000 heat pump rebate, and the \$2500 heat pump water heater rebate, all at year 0.

4.1.3.8 IRA's HEEHRA Case

Lastly, this final case considers all of the "Thermostat + Water Heating DR Rebates" case assumptions while implementing utility rebate savings derived from customer's applying for the IRA's HEEHRA rebates, which offers up to \$8,000 in rebates for heat pumps and \$1,750 in rebates for HPWH, among other appliances (IRA, 2022). A caveat of this program is that Georgia was assigned \$109 million for the program, which would only allow 13,625 participants to get the full heat pump rebate or 62,285 participants to get the full HPWH rebate. Therefore, HEEHRA's benefits will simply be implemented by subtracting the program's $109 million fund, assuming these will only be implemented to HP and HPWH, from the year 0 Capital Investments.

4.2 LCSE Results & Discussion

The LCSE calculations for the Base Case of the Thermostat DR program yielded a value of $15 per MWh, or 1.5 cents/kWh, as well as a cost of saved demand of ~$130,000 per MW, calculated by directly dividing the LCSE by the amount of hours in a year. These values are included here to serve as a reference, given that the base case served as the benchmark of the alternative cases, but will not be included in the remainder of the section.

4.2.1 Comparison of Alternative Cases

Figure 12 visualizes the calculated LCSE for all alternatives cases. For a table of LCSE values of all alternative cases, both in $/MWh and $/kWh, as well as their costs of saved demand, refer to Appendix C.

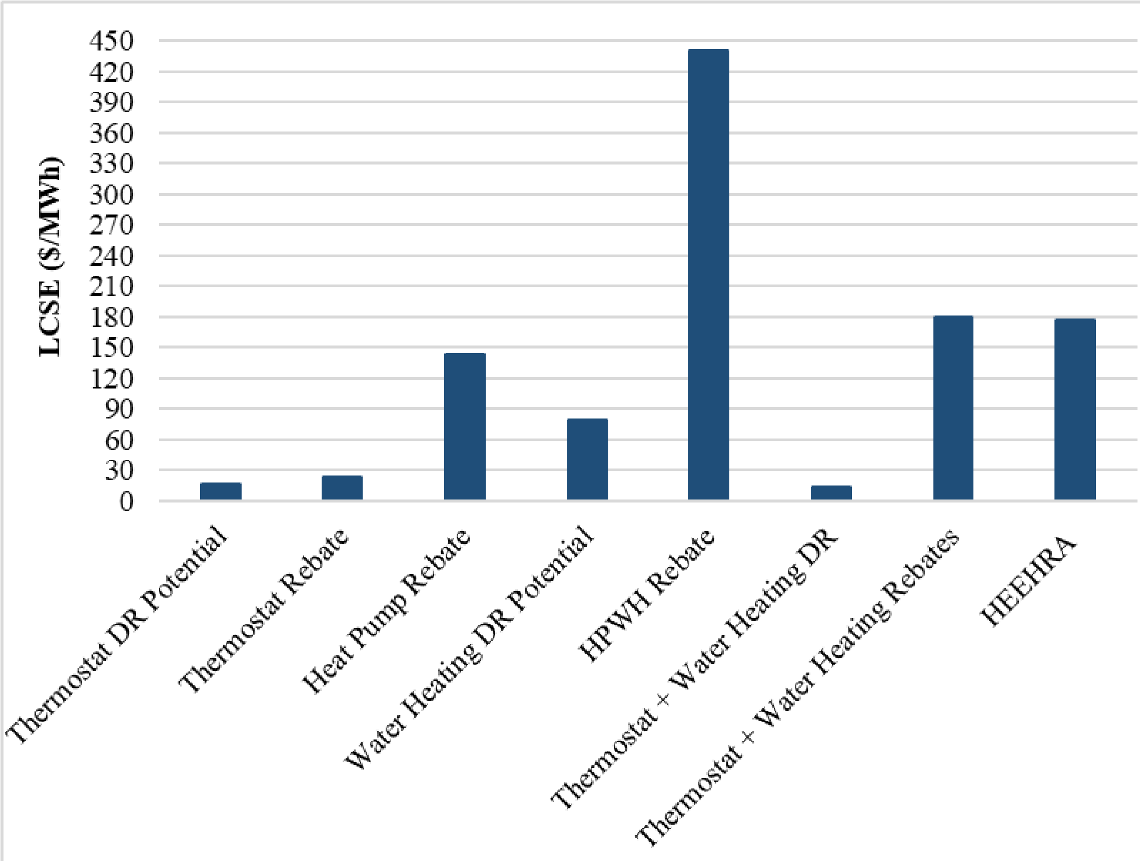

Figure 12 – LCSE of alternative cases.

Unsurprisingly, two of the three cases with no rebates, i.e., Thermostat DR Potential and Thermostat + Water Heating DR, exhibited the lowest LCSE values by a wide margin, at $16 and $13 per MWh saved, respectively. Although one might be inclined to assume that these are the most representative LCSE values for implementation of DR programs, one must also take into account that utilities do tend to offer rebates for the suggested appliances. However, these rebates tend to be offered as part of EE programs and are usually much lower than assumed in the LCSE calculations, with customer's still shouldering most of appliance and other costs, such as installation costs. The actual utility LCSE would likely fall somewhere between the non-rebate and rebate cases, given that all of the assessed customers already have electrified space and water heating appliances.

On the other hand, the Thermostat Rebate case's LCSE was surprisingly lower than the Water Heating DR Potential case ($23/MWh vs $79/MWh, respectively). This is likely due to the lower expected saved demand associated to water heating DR compared to Thermostat DR, leading to costs being spread out over fewer energy savings over the assessed period. This also leads to implementing full heat pump rebates only leading to an LCSE that is double that of the Water Heating DR Potential case ($143/MWh vs $79/MWh, respectively) despite the capital investment intensive nature of the former. Applying rebates to the latter yields the highest calculated LCSE, with the HPWH rebate having an LCSE of $440/MWh.

Lastly, implanting all of HEEHRA's $109 million funding to reduce utility burdened costs only slightly dents the fully rebated joint program implantation for similar high capital investment intensity of implementing full-coverage rebates, with the HEEHRA case having an LCSE of $177/MWh, only $3/MWh lower than the Thermostat + Water Heating Rebates case at $180/MWh.

4.2.2 Comparing LCSE of DR to Literature Cost of Saved Demand Values

Values by which to compare the LCOE calculations were source from EIA Form 861, which includes demand savings, incentive costs, and program costs for all accounted for Georgia DR programs, as well as self-reported Georgia Power values (EIA, 2022a). These were used to calculated cost of saved demand in $/MW by adding up both incentive and program costs and dividing said sum by the reported demand savings. Additionally, a report by the Lawrence Berkeley National Laboratory finds $200,000/MW to be the median cost for demand savings of all its sampled Auto-DR systems, with the lower boundary value being $20,000/MW and the higher boundary being $2,000,000/MW (Piette et al., 2017).

Cost of saved demand for alternative cases were calculated by directly dividing the LCSE by the amount of hours in a year. These were then grouped by program implementation type, i.e., Smart Thermostat DR, Water Heating DR, and Joint Smart Thermostat + Water Heating DR, to provide a range of potential values by which to compare both calculated and literature sourced values. This comparison is showcased in Figure 13. See Appendix C for a table including all of the figure's values.

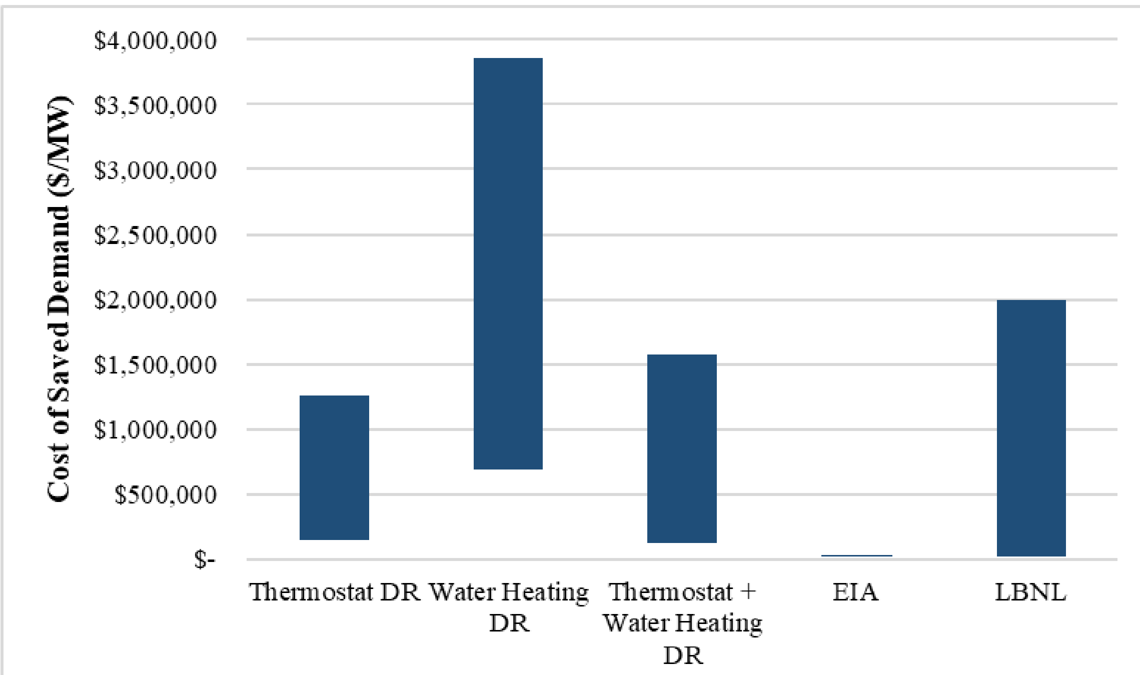

Figure 13 – Comparison of calculated and literature sourced costs of saved demand.

Most cases seemed to be validated by literature values, except for the exceedingly high value of the Water Heating DR, attributed to the HPWH Rebate case being very capital investment intensive with comparatively low energy savings.

4.2.3 Comparing LCSE of DR and LCOE of NGCT

LCOE values for combustion turbines power plants, peaking generation resources that could be partially displaced by DR, were sourced from Lazard's LCOE publication. The gas peaking units LCOE values sensitive to fuel prices was chosen to showcase a wider range of values (Singh, 2021). As similarly done in the previous subsection, LCSE values were grouped by program implementation type to provide a range of potential program values for comparison. Figure 14 visualizes these values. See Appendix C for a table including all of the figure's values.

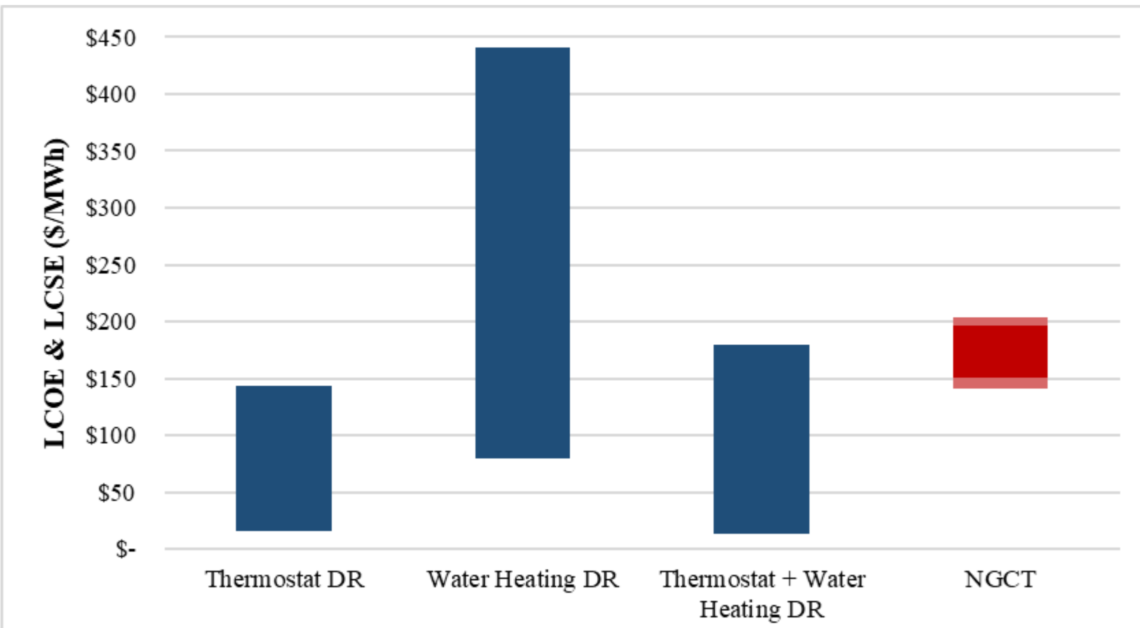

Figure 14 – Comparison of NGCT LCOE and DR LCSE values. *Fuel sensitivity values are showcased in a lighter shade of red.

All cases within the thermostat DR boundary fall below the base NGCT LCOE, but the former's higher end slightly overlaps with the latter's lower-end fuel sensitivity adjusted values. Most of the Thermostats + Water Heating DR range also falls below the

NGCT LCOE, with the higher end falling within the range of the base NGCT LCOE that does not account for fuel sensitivities, suggesting that NGCT could be a cheaper alternative in a highest-possible joint DR program cost and low fuel prices scenario. However, all other scenarios favor the joint DR program. Lastly, although the lower end of the water heating DR range falls well below the NGCT LCOE values, the higher end is also considerably higher than said values due to already stated high capital costs of the HPWH Rebate case. Without accounting for this outlier case, all of the assessed LCSE values portray DR programs as a lower cost alternative for utilities to address peak demand events via its provided demand curtailment services, at least when compared to NGCT providing equivalent electricity generation services.

4.3 Approach Limitations & Considerations for Future Studies

4.3.1 Limitations of the LCSE Metric

The LCSE metric, having been inspired by the LCOE, shares both of its strengths and its limitations. The LCSE can be calculated without having to account for the price at which the electricity would have been sold to the market, as would be the case for other financial metrics. This allows for easy comparison between technologies regardless of electricity market dynamics and other external factors impacting the assessment. Additionally, the LCSE can be used to quickly determine the average price at which the curtailed electricity should have been sold for so that the project is financially viable (EIA, 2021c).

One could also assess that ease of comparison between resources as one of the metric's limitations, since the LCSE not capturing all investment decision factors or accrued benefits could lead to misleading comparative economic assessment between resources. A way to somewhat address this limitation, could be to use the levelized avoided cost of electricity (LACE) along with the LCSE to develop a value-cost ratio. The LACE attempts to quantify the value of a resource in serving the electric grid by comparing how the sale of electricity from the prospective new generation resource (in the LCSE case, the curtailment of electricity) measures up against new and existing generation resources that it would displace. It is important to note, however, that estimating LACE is a complex process that requires grid operation data to assess how the new resource would impact electricity markets in its presence or absence. Regardless, using LACE-to-LCSE ratios could provide a more intuitive approach to value-cost analysis, addressing some of the LCSE metric limitations (Tamburini et al., 2021).

Other limitations of the LCSE include not being able to account for: future policy-related factors (e.g., environmental regulations, tax credits) affecting investment decisions, local system reliability considerations such as differing derating values, investors/plant owners looking to diversify portfolios, lack of temporal resolution (e.g., the time at which a resource services the grid, and the value associated with service during that period, regardless of cost), and other unaccounted for risk-related considerations (Tamburini et al., 2021).

4.3.2 Limitations of Input Assumptions & Considerations for Future Studies

The assumption that all capital investment installations occur at year 0, as well as the application of incentives for all new participants in year 1, leads to an LCSE that is lower than if these installations were assumed to be spread out throughout the program's lifespan, resulting in a more realistic distribution of capital & incentive costs and program derived energy savings. Future studies could attempt to implement a more realistic spatiotemporal deployment that would address this limitation.

The distribution of IRA's HEEHRA beneficiaries, be it customers or targeted technology, was not considered in the assumptions, having been implemented as a lump sum of available funds at the beginning of the time period. Once the state of Georgia decides on the implementation pathway for these funds, in accordance with IRA guidelines, these calculations could be revised and incorporated alongside the suggested spatiotemporal deployment revision so as to distribute fund deployment across the program's lifetime.

Other considerations to take into account for future studies include: use of alternative discount rates more appropriately reflect DR investments, estimation of derived benefits from avoiding buyout/buildout of fossil intensive and costly peak generation resources, estimation of displaced carbon emissions from said generation resources, how future policies (e.g., carbon taxes) could impact the valuing of demand response, accounting for the snapback effect (i.e., offset in energy savings as DR equipment returns to its set point) when estimating energy savings, quantified estimation of equity impacts from installations of DR-enabling efficient appliances, valuation of benefits and synergies derived from integrated EE + DR household packages, and further comparative assessments of clean alternatives to address peak electricity demand periods, such as other DERs.

CHAPTER 5. VALUE STREAMS OF DEMAND RESPONSE

The previous chapter, which focused on assessing the cost of saved energy from DR program implementation, found that DR could be a lower cost alternative to address peak demand periods than NGCT. However, this was a purely cost-focused assessment that did not account for any benefits derived from program implementation. Chapter 5 aims to provide a brief but comprehensive review on these benefits, which could be accrued by both utilities and/or customers, and which should be considered by utilities and system operations when assessing the value streams provided by DR resources.

5.1 Avoided Costs

In the past, demand response's curtailment services have been mainly leveraged to defer new peaking capacity buildout, reduce energy costs during peak periods, and defer transmission and distribution (T&D) investment needs. This section explores those benefits by mainly sourcing from two reports developed by the Brattle Group (Hledik & Faruqui, 2015, Hledik et al., 2019a), unless stated otherwise.

5.1.1 Avoided Generation Capacity

Electrical grids must plan to have enough generation capacity to service the system during coincident system peak times. DR resources are most often used to curtail demand during these system peaks, thus lessening the need to invest in generation capacity. This avoided or deferred cost of new generating capacity is still the largest source of value provided by DR.

Peaking units usually have low capital costs but high operating costs, i.e., they are cheap to build but expensive to run, so they tend to only be dispatched to service the system during top peak load hours. Given their similar operational profiles, peaking units are typically the type of capacity displaced by DR programs. Under this assumption, the Brattle Group estimates that avoided generation capacity would remain the dominant source of national load flexibility value until 2030, accounting for about 57% of annual benefits.

5.1.2 Avoided Energy Costs

While avoided generation capacity costs have driven the bulk of DR benefits historically, there are other significant sources of avoided costs that can also be derived from DR implementation, such as avoided energy costs.

A typical benefit of EE programs, reductions in consumption will avoid the marginal cost of generating electricity. For DR programs, these reductions are only concentrated during the few hours of the year at which they are deployed, making the avoided energy costs a time-dependent source of value. However, since DR reductions often occur during peak hours and help avoid a higher marginal cost due to dispatching of less efficient generating units, benefits from avoided energy cost tend to be quite significant. The Brattle Group estimates that avoided energy costs would account for about 29% of annual national load flexibility benefits until 2030.

5.1.3 Transmission & Distribution Capacity Deferral

The last of the three main avoided costs value sources is derived from reductions in peak demand lessening the need to expand the T&D system.

T&D investments are partially driven by the need to have the capacity to move enough electricity to where it is needed during peak time periods without compromising reliability. This need for geographic expansion of the system naturally requires high-cost investments and often results in an increased peak demand. DR peak demand curtailment could be geographically targeted to reduce the need for new T&D capacity and avoid associated investments. The Brattle Group estimates that avoided energy costs would account for about 12% of annual national load flexibility benefits until 2030.

5.2 Load Flexibility & Renewable Integration

The integration of renewable energy resources at high penetration levels in the existing grid is primarily hindered by their variable and uncertain nature, which manifests through the following energy system issues: increased intra-hour variability in supply (Tselika, 2022); ramping-related issues, be it large ramp up requirements from these resources going offline or near-instantaneous ramp production ramps from these resources coming back online (Cui et al., 2017; Engeland et al., 2017; Godoy-Gonzalez et al., 2020); and over-generation concerns (Denholm et al., 2015; Rothleder & Loutan, 2017).

The use of DR to provide ancillary services is becoming a topic of increasing interest, in particular as a way to address renewable integration issues, since DR resources could deliver fast-response load changes, be it decrease or even increases in load, in response to unpredictable fluctuations in power generation (Hledik & Faruqui, 2015). Newly emerging technologies and DR initiatives could eventually help to address some of these barriers while attempting to assign a value to these ancillary services (Almehizia et al., 2019; Hungerford et al., 2019)

5.3 Equity Implications of Demand Response Induced Price Effect

Even though DR program participation would end up mostly benefitting participants due to the net energy savings resulting from demand curtailment events and cost reductions from demand shifting to off-peak hours, demand-reduction induced price effects (DRIPE) would lead to accrued savings for non-participating households as well, who will also benefit from lower energy bills resulting from lower electricity prices. This makes DR a more equitable alternative compared to other clean-energy technologies and policies that shift costs to non-participants. The scaling of DR and the derived DRIPE benefit also presents an opportunity to indirectly reduce energy burden in low-income households, particularly since their program participation benefits may be limited by residential status, less flexible daily routines, and potential lack of DR-targeted and compatible appliances (Brown & Chapman, 2021).

5.4 Other Benefits

5.4.1 Post-Outage Restoration

To avoid over-stressing the system after an outage, the rate at which power is restored to the grid needs to be controlled. DR direct load control technologies could allow for end-uses to come back online in a controlled manner to ease the ramping of load post-outage (Hledik & Faruqui, 2015).

5.4.2 Potential Environmental Benefits

There are potential environmental co-benefits that could be derived from previously mentioned DR benefits. Net energy conservation derived from demand curtailment events would lead to indirect emissions reductions from a decrease in electricity consumption, with the magnitude of emissions reductions being a function of the grid's emissions factors. Peak demand savings would reduce the need for peaking power plants, which tend to be high-emitting NGCT. Lastly, DR's role in helping integrate renewables onto the electric grid would reduce the emissions factor of consume electricity (Dahlke & McFarlane., 2015).

5.4.3 Systems Resilience to Climate Change Effects

Lastly, DR's potential to help decrease the energy system's reliance on fossil-based peak generation resources is not only a decarbonization issues, but a systems resilience issue, with climate change-induced changes in air temperature, water temperature, and water availability potentially leading to the derating of thermal units, decreasing their dispatchability and reliability (Ralston et al., 2021).

CHAPTER 6. CONCLUSIONS AND RECOMMENDATIONS

Acknowledging both the urgency of the current transition towards a clean and sustainable energy system and the importance of integrating demand-side interventions into the energy system's decarbonization conversation, this study had set out to assess the potential of DSM strategies as a pathway to decarbonize the residential sector in the state of Georgia by conducting a case study bounded to the metro Atlanta area. The study's review of the literature and publicly available datasets, along with its calculated estimates and projections, led to the following conclusions and recommendations:

A review of American Housing Survey data for Metro Atlanta revealed the area's very high but relatively inefficient electrification profile, a pattern markedly exhibited by the area's low-income households. Targeting this demographic for implementation of deep efficiency retrofits would yield bring about co-benefits of just and equitable development, more stable energy demand, and decarbonization via reduced consumption of emissions intensive electricity.

The study's calculated estimates for energy savings potential suggest that implementing a deep efficient retrofit package could ease the energy burden of a household with a yearly \$25,000 income by about 5%, nearly having the state's 10.2% average energy burden for low-income households. Additionally, the state could abate nearly one Mt of CO2e per year if it were to implement heat pump and heat pump water heater retrofits for all households with electrified space and water heating that did not already have one.

A review of the Georgia Power Company's DSM portfolio highlighted the company's glaring underinvestment in dispatchable retail DR programs when compared to peer utilities. However, the state's assessed high existing space and water heating electrification penetration coupled with the recent upgrade if all of GPC's 2.4 million customers to advanced metering infrastructure positions GPC to exponentially increase DR program development and implementation.

The study's calculated estimates for demand savings potential found that current households with electrified space and water heating in the metro Atlanta area would provide enough summer and winter demand savings through DR programs to exceed the current planned capacity of natural gas combustion turbines' power purchase agreements in GPC's 2022 Integrated Resource Plan. Additionally, most of the estimated scenarios for a levelized cost of saved energy of DR programs in the metro Atlanta area suggested DR programs could be a lower cost alternative for utilities to address peak demand events via its provided demand curtailment services when compared to NGCT.

Three key recommendations for future assessment include: developing innovative ways to quantify benefits from DR program implementation that go beyond simply calculating avoided costs and fully integrate additional DR value streams, such as the impact of load flexibility and ancillary services for facilitated grid integration of renewable resources, DRIPE equity implications, and environmental benefits, among other co-benefits; developing integrated EE and DR programs and assessment methodologies that identify and adequately capitalize on synergistic development opportunities and co-benefits; and conducting further comparative assessment of DR programs against other clean technology resources that could also provide demand savings and load flexibility services, such as customer owned, behind-the-meter distributed energy resources.

APPENDIX A. DEMAND RESPONSE PROGRAM ASSESSMENT MATRIX

Appendix A contains a matrix (Table 10) that summarizes the results from the DR program assessment conducted in Section 2.3. Existing DR programs are represented as green cells with an "X". Pilot or In-Development DR Programs are represented as yellow cells with an "*X*". Considered or modeled DR programs are represented as blue cells with a "C". Empty cells represent no DR program consideration.

Table 10 – Demand response program assessment matrix.

Utility Name	Georgia Power Company	Tennesee Valley Authority	Duke Energy FL, LLC	Northern States Power Co. (Xcel Energy)	DTE Energy	Commonwealth Edison	Idaho Power Company	Duke Energy Carolinas, LLC	Duke Energy Progress, LCC
State	GA	AL, GA, KY, MS, NC, TN, VA	FL	MN	MI	IL	ID	NC, SC	NC, SC
BA Code	SOCO	TVA	FPC	MISO	MISO	PJM	IPCO	DUK	CPLE
DR Considered a Selectable Resource	No	Yes	N/A	Yes	N/A	N/A	Yes	Yes	Yes
Advanced Metering Infrastructure(Smart Meters)	Yes	Yes	Yes	In Progress (2023 goal)	Yes	Yes	TBD	Yes	Yes
Retail Programs - Residential									
DLC HVAC			X	X	X	X	X	X	X
DLC Pool Pump			X						
Building Controls (Auto DR)				C					
Smart Thermostat	X	C	X	X	X	X		X	X
Timed/Smart Water Heating	*X*	C	X	X	X				X
EV Managed Charging				C	*X*				
Retail Programs - Commercial/Industrial									
DLC HVAC						X		X	X
DLC Generator			X						
DLC Irrigation Pumps							X		
Building Controls (Auto DR)				C	X				X
Smart Thermostat	X			X		X		X	X
Timed/Smart Water Heating	*X*			X		X			
Thermal Storage (Load Shifting)				*X*					
Metals and Electric Process Heat					X				
Battery Storage Solutions					C				
Solar Plus Battery Energy Storage System (BESS)					*X*				
Behind The Meter (BTM) Battery					C				
Flexible Load-Shedding (Designed to Customer Needs)				*X*					
Interruptible / Curtailable Program(s)	X		X	X	X			X	X
Dynamic Pricing Tariffs - Residential									
Critical Peak Pricing (CPP) (Opt-In)					X	X			
Interruptible Tariff					X				
Real-Time-Pricing (RTP)	X				X	X			
Demand Tariff	X				X				
Time-of-Use (TOU) Tariff	X			*X*			X		
Peak Time Savings					*X*				
Battery Time-of-Use Rates		C							
EV TOU Rate	X	C		*X*	*X*				
EV Subscription Service (Flat Monthly Fee for Off-peak)				*X*					
Dynamic Pricing Tariffs - Commercial/Industrial									
Critical Peak Pricing (CPP) (Opt-in)				*X*	X	X			
Interruptible Tariff	X	X	X		X			X	X
Real-Time-Pricing (RTP)	X				X	X			
Demand Tariff	X				X				
Time-of-Use Tariff (TOU)	X			*X*	X				
Peak Time Savings							X		
Battery Time-of-Use Rates		C							
EV TOU Rate		C							
Voluntary Programs - Residential									
Behavioral ("Hands-off") DR	X			*X*					
IFTTT (If This Then That)						X			
Voluntary Programs - Commercial									
Behavioral ("Hands-off") DR	X			*X*					
IFTTT (If This Then That)						X			
Capacity Release					X				
Strategic Programs									
Geo-Targeting (capacity deferral)				C					
Reverse DR (balancing excess energy)									
Voltage Optimization	X	X						X	X
Third-Party Aggregate DR		X		*X*					

APPENDIX B. AMERICAN HOUSING SURVEY SOURCED VALUES

Appendix B contains the values referred to in the methodological approach of section 3.2, with those values found in Table 11 below. Estimates are shown in thousands of housing units. Blank cells represent zero; '.' represents not applicable or no cases in sample; S represents estimates that did not meet publication standards or withheld to avoid disclosure.

Table 11 – American housing survey sourced values

Classifications	Total	Less than $19,999	$20,000 to $39,999	$40,000 to $59,999	$60,000 to $79,999	$80,000 to $99,999	$100,000 to $119,999	$120,000 to $139,999	$140,000 to $159,999	$160,000 to $179,999	$180,000 to $199,999	$200,000 or more
Total	2,302.6	309.3	320.1	353.9	308.9	223.5	178.1	139.4	100.6	65.8	71.3	231.6
Main Heating Equipment												
Heat Pumps	204.3	S	13.2	27.6	41.3	27.5	S	14.9	S	S	S	S
Warm Air Furnace	1,994.7	255.7	276.0	299.1	256.6	194.7	163.7	122.9	89.4	59.6	66.4	210.7
Other	75.9	S	S	S	S	S	S	S	S	S	S	S
Main House Heating Fuel												
Electricity (Total)	1,157.2	309.3	320.1	353.9	168.2	123.4	73.4	72.3	46.7	28.1	23.5	79.1
Electricity (Heat Pump)	204.3	S	13.2	27.6	41.3	27.5	S	14.9	S	S	S	S
Electricity (Other)	952.9	309.3	320.1	326.3	126.9	95.9	73.4	57.4	46.7	28.1	23.5	79.1
Piped Gas	1,085.4	126.4	136.6	144.4	136.5	97.0	99.7	65.1	49.7	34.5	47.8	147.8
Bottled Gas	50.5	S	S	S	S	S	S	S	S	S	.	S
Water Heating Fuel												
Electricity	1,102.1	236.2	252.6	273.8	155.7	107.3	74.8	61.7	39.3	22.5	19.6	67.7
Piped Gas	1,171.3	154.9	145.8	153.7	152.4	114.7	101.4	75.5	59.1	41.1	51.6	161.1
Bottled Gas	26.1	S	S	S	S	S	S	S	S	S	.	S

APPENDIX C. LCSE AND COST OF SAVED DEMAND TABLES

Table 12 showcases all calculated LCSE values of the base case and the alternative cases, both in \$/MWh and \$/kWh, as well as their costs of saved demand.

Table 12 – LCSE and cost of saved demand of the base case and alternative cases

	Base IRP Case	Thermostat DR Potential	Thermostat Rebate	Heat Pump Rebate	Water Heating DR Potential	HPWH Rebate	Thermostat + Water Heating DR	Thermostat + Water Heating Rebates	HEEHRA
LCSE(\$/MWh)	\$ 15.07	\$ 16.07	\$ 23.38	\$ 143.18	\$ 79.28	\$ 440.46	\$ 13.36	\$ 179.93	\$ 177.52
LCSE(\$/kwh)	\$ 0.02	\$ 0.02	\$ 0.02	\$ 0.14	\$ 0.08	\$ 0.44	\$ 0.01	\$ 0.18	\$ 0.18
Cost of Saved Demand (\$/MW)	\$ 132,024.06	\$ 140,780.05	\$ 204,777.84	\$ 1,254,243.46	\$ 694,514.94	\$ 3,858,459.44	\$ 117,053.08	\$ 1,576,216.45	\$ 1,555,080.40

Table 13 showcases all program grouping values for comparison with literature sourced costs of saved demand.

Table 13 – Groupings of LCSE-derived cost of saved demand values for comparison with literature sourced costs of saved demand.

	Thermostat DR	Water Heating DR	Thermostat + Water Heating DR	EIA	LBNL
Low Cost of Saved Demand (\$/MW)	\$ 140,780.05	\$ 694,514.94	\$ 117,053.08	\$ 14,823.31	\$ 20,000.00
High Cost of Saved Demand (\$/MW)	\$ 1,254,243.46	\$ 3,858,459.44	\$ 1,576,216.45	\$ 17,088.88	\$ 2,000,000.00

Table 14 showcases all program grouping values for comparison with natural gas combustion turbine LCOE.

Table 14 – Groupings of LCSE values for comparison with NGCT LCOE value ranges.

	Thermostat DR	Water Heating DR	Thermostat + Water Heating DR	NGCT LCOE
Low-End Fuel Sensitivity	-	-	-	$ 141.00
Low LCOE/LCSE ($/MWh)	$ 16.07	$ 79.28	$ 13.36	$ 151.00
High LCOE/LCSE ($/MWh)	$ 143.18	$ 440.46	$ 179.93	$ 196.00
High-End Fuel Sensitivity	-	-	-	$ 204.00

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