CITY OF ANN ARBOR
100% RENEWABLE ENERGY OPTIONS ANALYSIS

Municipal Energy Utility Technical Assessments Addendum

February 2024

Municipal Energy Utility Technical Assessments Addendum to 100% Renewable Energy Options Analysis Report

The City of Ann Arbor requested that 5 Lakes Energy and project partners provide several technical assessments as companions to the Municipal Energy Utility feasibility study element of the 100% Renewable Energy Options study. This addendum provides those assessments.

Table of Contents

Ann Arbor Demand Response Potential

Demand response (DR) is a change in the power consumption of an electric utility customer to better match the demand for power with the available supply. Historically, power generation has changed in response to demand, enabled by dispatchable resources (like coal, gas, and nuclear power plants) whose output can be adjusted in response to demand. Renewable sources of power are not dispatchable because a utility cannot adjust how much the sun is shining or the wind is blowing when customer demand changes. Demand response programs, therefore, are an important complement to renewables because they can adjust energy loads in response to the amount of renewable power available at any given moment.

DR can be systematic and predetermined – for example, time of day rates that incentivize customers to use less power at times that load predictably surges – or situational and responsive, in response to events that cause an imbalance of supply and demand, such as unusually severe temperatures or low-sun or wind conditions. A DR event occurs when demand threatens to outstrip energy supply, and the utility activates various DR methods to reduce demand.

The case for undertaking DR as an element of Ann Arbor's 100% renewable electricity goal is layered and nuanced:

- DR is important for Ann Arbor primarily if it forms a MEU, which would be a load-serving entity (LSE) responsible for meeting power demands at all times. Without a MEU, Ann Arbor's 100% renewable electricity goal would require it only to source as much renewable electricity as it uses over the year, and not to balance demand and supply in real-time, which is the central purpose of DR. In addition, as long as DTE serves as Ann Arbor's LSE, it will implement DR programs.
- If the City forms a SEU, there might be a financial case for DR even if it was unnecessary for the attainment of the 100% renewable energy goal. DR could help adjust total electricity usage in the City in real time to follow BTM PV electricity generation. Doing so could reduce the amount of surplus PV electricity sold to DTE at the low outflow price, and the amount bought back at the higher retail price; it could also reduce the amount of battery needed in the City.

Our analysis considers only the value of DR in the former case, in which Ann Arbor forms a MEU. The use of DR to facilitate BTM PV/PVS has not been studied in Michigan, to our knowledge, and the analytical approach would be complex. Estimation of DR potential in the MEU case is more straightforward because an MPSC-sponsored statewide study has already been published. That study projects DR events based on currently projected generation portfolios, which include significant dispatchable fossil resources, then projects how much DR measures could reduce load in response to those events. Relying wholly on renewable energy sources would increase the frequency, scale, and duration of DR events, and we have not attempted to project those differences compared to the Guidehouse baseline. We do, on the other hand, roughly project the impact on DR measure potential of the City's electrification goals, simply by increasing DR potential in step with increased electricity load.

We do not project how the foreseeable increase of DR events in a 100% renewable electricity scenario would affect DR potential, but there likely would be complex impacts. DR measures rely on voluntary participation of customers, which may be conditioned by their perception of how often, how much and for how long they would be asked to curtail their load. For example, customers are likely to be more receptive to participating in a DR measure that results in changes to heating or cooling of their home once a week than if those changes were needed several times per day.

We applied our analysis only to DR for electricity usage. DR methods are also used to reduce natural gas usage. We assume that Ann Arbor would rather focus on eliminating uses of gas than on making them more efficient.

Customers' Demand Response Capability

All electric customers can participate in demand response. DTE has installed advanced metering devices (AMI) on almost all customers' buildings. AMI with automated communication capabilities is necessary to optimize the efficacy of demand response events. We assume that an Ann Arbor MEU would acquire DTE's AMI infrastructure and its DR capabilities along with it.

Demand Response Scenarios

Demand response is based on utilities having technology capable of accessing and adjusting power delivery to a customer. Demand response is also contingent on customer willingness to participate in demand response programs and events. Thus, our analysis considers Demand Response Potential, as the measure of usage based on the potential or possibility of customer participation in the event based on the technical capability to curtail usage. The most common DR measures are:

- Commercial & Industrial Capacity Reduction –Here the customer formally commits to reduce its load by a set amount during DR events. ($/kW or $/kWh payment)
- Demand Bidding – The customer voluntarily reduces their load during DR event ($/kWh payment)
- Critical Peak Pricing (CPP) – The customer will incur higher pricing due to usage during historical peak load times of the year, which could be changed to "tight hours" of the year based on the balance of demand and supply of electricity.
- Direct Load Control Switch – The customer agrees to the utility's control of space heating and cooling, and electric water heating with a remotely operated load control switch.
- DLC Smart thermostat, Bring your own thermostat (BYOT) – The customer agrees to the utility's control of space heating and cooling using smart thermostats, making small and/or intermittent adjustments in temperature settings.
- Smart Appliances Control, Bring your own device (BYOD) – Smart appliances are controlled by utility via Wi-Fi or smart plugs.
- Time of Use – Customers' charged rates are based on their use during the time of day and season.
- Peak Time Rebate – Charged rates are discounted for reducing load during a DR event.
- Behind the Meter Battery Dispatch – Charged rates are discounted for customer use of BTM battery during DR event.
- EV Managed Charging -- Charging of electric vehicles (EVs) is managed by the utility during DR event.
- Behavioral DR – Peak demand can be affected by customer's behavior during periods conducive to DR events.
- Real Time Pricing – Rates change hourly or at other intervals based on grid conditions and the customer responds either behaviorally or through automated building controls.
- Voltage Optimization –Demand is reduced by lowering or raising site voltage or by improving site power factor. Requires installation of equipment such as capacitors, solid state transformers, etc.

Ann Arbor Demand Response Potential

We modeled demand response potential in Ann Arbor by scaling down the Lower Peninsula demand response study projections included in the Michigan Public Service Commission's 2021 study conducted by Guidehouse. For reasons discussed above, we do not adjust the statewide study to project increased demand response events in a 100% renewable electricity scenario. We also do not attempt to project how customer participation in demand response measures will be influenced by increased DR events.

Michigan Demand Response Potential Study

For the Michigan Demand Response Potential Study, contractor Guidehouse compiled customer data and load data from Michigan utilities, and conducted customer surveys to determine customer interest in enrolling in DR programs and to determine what DR technologies permeate the customer market. The two established market segments are residential customers and commercial and industrial customers. Guidehouse divided the segments further into an Upper Peninsula market and a Lower Peninsula market. Ann Arbor is in the Lower Peninsula market. Therefore, our analysis uses data from Guidehouse's findings for the Lower Peninsula.

Guidehouse obtained data from the following utilities:

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

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

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

The least cost-effective options are:

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

The reduction of peak demand in the Lower Peninsula due to demand response events in 2021 was 300MW. Guidehouse projects program participation under cost-effective customer offers will increase this to 1,850 MW in 2040. Residential non-low-income customers constitute approximately 60% share of electrical DR potential while large C&I customers constitute the remaining 40% share of electrical DR potential. C&I customer potential is mostly from C&I Capacity Reduction.

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

Ann Arbor Achievable Demand Response Potential

We used the DR potential for the Lower Peninsula from the Guidehouse study as a base for the potential for Ann Arbor. Consistent with the Guidehouse methodology, we defined peak demand as the 40 hours with the highest average demand in each season.

We project that the total wintertime peak demand in Ann Arbor in 2030 will be about 229 MW with total DR potential of 20.1 MW.

Figure 1: Winter Achievable DR Potential, Lower Peninsula and Ann Arbor

DR Measure	MI Lower peninsula total peak demand (MW)	Michigan lower peninsula total DR reduction (MW)[2] [3]	C&I Capacity Reduction (MW)[2] [3]	Smart Tstat BYOT (MW)[2] [3]	Critical Peak Pricing (MW)[2] [3]	Direct Load Control Switch (MW)[2] [3]	Time of Use rates (MW)[2] [3]	Peak Time Rebated (MW)[2] [3]	BTM Battery Dispatch (MW)[2] [3]	EV Managed Chargin (MW)[2] [3]	Demand Bidding (MW)[2] [3]	Behavioral DR (MW)[2] [3]	Real Time Pricing (MW)[2] [3]	Voltage Optimization (MW)[2] [3]
Measure description			fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF
2021	11918	190	50	5	75	40	5	5	2	0	2	2	2	1
% of 2021		1.6%	26.3%	2.6%	39.5%	21.1%	2.6%	2.6%	1.1%	0.0%	1.1%	1.1%	1.1%	0.5%
2030[4]	11934	1050	380	90	200	205	75	50	20	15	2	2	2	2
% of 2030		8.8%	36.2%	8.6%	19.0%	19.5%	7.1%	4.8%	1.9%	1.4%	0.2%	0.2%	0.2%	0.2%
2040[4]	12909	1190	392.7	178.5	178.5	238	59.5	47.6	71.4	47.6	11.9	11.9	11.9	11.9
% of 2040[5]		9.2%	33.0%	15.0%	15.0%	20.0%	5.0%	4.0%	6.0%	4.0%	1.0%	1.0%	1.0%	1.0%

Ann Arbor Winter Achievable DR Potential

DR Measure	Ann Arbor total peak demand(MW)[6]	Ann Arbor total DR reduction (MW)[2]	C&I Capacity Reduction (MW)	Smart Tstat BYOT (MW)	Critical Peak Pricing (MW)	Direct Load Control switch (MW)	Time of Use (MW)	Peak Time Rebate (MW)	BTM Battery Dispatch (MW)	EV Managed Charging (MW)	Demand Bidding (MW)	Behavioral DR (MW)	Real Time Pricing (MW)	Voltage Optimization (MW)
Measure description			fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF
2021	183.264	2.92	0.77	0.08	1.15	0.62	0.08	0.08	0.03	0.00	0.03	0.03	0.03	0.02
% of 2021		1.6%	26.3%	2.6%	39.5%	21.1%	2.6%	2.6%	1.1%	0.0%	1.1%	1.1%	1.1%	0.5%
2030	228.861	20.14	7.29	1.73	3.84	3.93	1.44	0.96	0.38	0.29	0.04	0.04	0.04	0.04
% of 2030		8.8%	36.2%	8.6%	19.0%	19.5%	7.1%	4.8%	1.9%	1.4%	0.2%	0.2%	0.2%	0.2%
2040	577.37	53.22	17.56	7.98	7.98	10.64	2.66	2.13	3.19	2.13	0.53	0.53	0.53	0.53
% of 2040[5]		9.2%	33.0%	15.0%	15.0%	20.0%	5.0%	4.0%	6.0%	4.0%	1.0%	1.0%	1.0%	1.0%

Total summertime peak demand in 2030 will be about 162 MW with total DR potential of 16.4 MW.

Figure 2: Summer Achievable DR Potential, Lower Peninsula and Ann Arbor

DR measure	Lower Peninsula total peak demand (MW)	Lower Peninsula total DR reduction (MW)[2,3]	C&I Capacity Reduction (MW)[2,3]	Smart Tstat BYOT (MW)[2,3]	Critical Peak Pricing (MW)[2,3]	Direct Load Control Switch (MW)[2,3]	Time of Use rates (MW)[2,3]	Peak Time Rebated (MW)[2,3]	BTM Battery Dispatch (MW)[2,3]	EV Managed Charging (MW)[2,3]	Demand Bidding (MW)[2,3]	Behavioral DR (MW)[2,3]	Real Time Pricing (MW)[2,3]	Voltage Optimization (MW)[2,3]
Measure dsscription			fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF
2021	15910	295.6	72.78	23.93	106.43	67.66	5.84	2.29			16.66			
% of 2021		1.9%	24.6%	8.1%	36.0%	22.9%	2.0%	0.8%	0.0%	0.0%	5.6%	0.0%	0.0%	0.0%
2030[3]	15994	1620	439.07	200.81	460.03	247.2	115.87	86.55	5.72	13.71	21.87	9.48	4.23	0.54
% of 2030		10.1%	27.1%	12.4%	28.4%	15.3%	7.2%	5.3%	0.4%	0.8%	1.4%	0.6%	0.3%	0.0%
2040[3]	17379	1850	465.42	390.47	374.55	271.03	110.99	70.63	16.27	51.13	27.13	8.77	4.24	0.56
% of 2040		10.6%	25.2%	21.1%	20.2%	14.7%	6.0%	3.8%	0.9%	2.8%	1.5%	0.5%	0.2%	0.0%

Ann Arbor Summer Achievable DR Potential

	Ann Arbor total peak demand (MW)[6]	Ann Arbor total DR reduction (MW)[2]	C&I Capacity Reduction (MW)	Smart T-stat BYOT (MW)	Critical Peak Pricing (MW)	Direct Load Control switch (MW)	Time of Use (MW)	Peak Time Rebate (MW)	BTM Battery Dispatch (MW)	EV Managed Charging (MW)	Demand Bidding (MW)	Behavioral DR (MW)	Real Time Pricing (MW)	Voltage Optimization (MW)
Year			fixed payment ($/kW) for committed load reduction	space heating and cooling	higher price during critical peak hours	Space heating and cooling, water heating			customer use of BTM battery during DR event		voluntarily reduce load during event ($/kWh)		rates change hourly or at other intervals	reduce demand by lower or raise site voltage or PF
2021	156	2.90	0.71	0.23	1.04	0.66	0.06	0.02	0.00	0.00	0.16	0.00	0.00	0.00
% of 2021		1.9%	0.5%	0.2%	0.7%	0.4%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
2030	162.089	16.42	4.45	2.04	4.66	2.51	1.17	0.88	0.06	0.14	0.22	0.10	0.04	0.01
% of 2030		10.1%	2.7%	1.3%	2.9%	1.5%	0.7%	0.5%	0.0%	0.1%	0.1%	0.1%	0.0%	0.0%
2040	248.741	26.48	6.66	5.59	5.36	3.88	1.59	1.01	0.23	0.73	0.39	0.13	0.06	0.01
% of 2040		10.6%	2.7%	2.2%	2.2%	1.6%	0.6%	0.4%	0.1%	0.3%	0.2%	0.1%	0.0%	0.0%

Although peak summer demand will be higher in 2030 than today, we project demand reduction measures can more than make up for the increase. Owing to building electrification, however, winter peak demand net of demand reduction will grow about 15% in 2030 compared to today.

Building space heating and water heating electrification will present large opportunities for future demand response programs and should result in greater DR potential in winter than in summer. Ann Arbor's electrification emphasis will likely provide a greater opportunity to install new equipment that is DR capable, compared to the rest of the Lower Peninsula; for this analysis, however, we assumed Ann Arbor will have the same adoption rates as the rest of the LP. This assumption makes our projections conservative.

Figure 3: Ann Arbor Summer DR Potential by Measure, 2021-2040

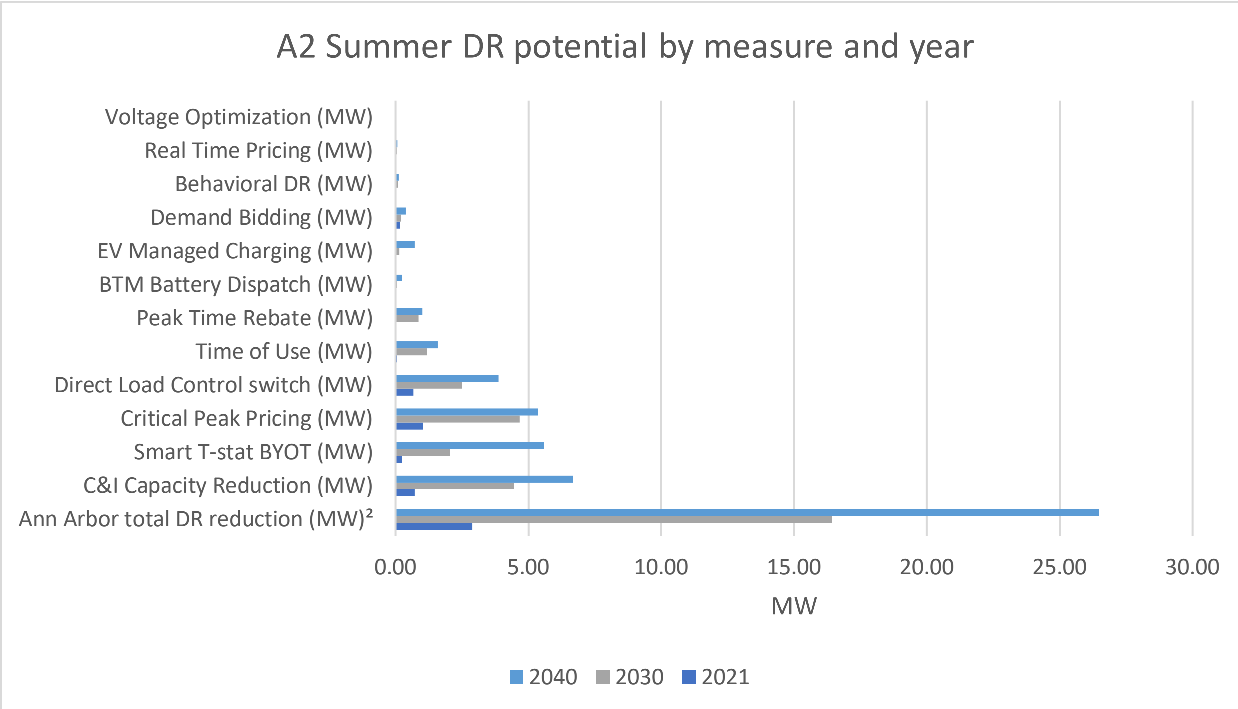
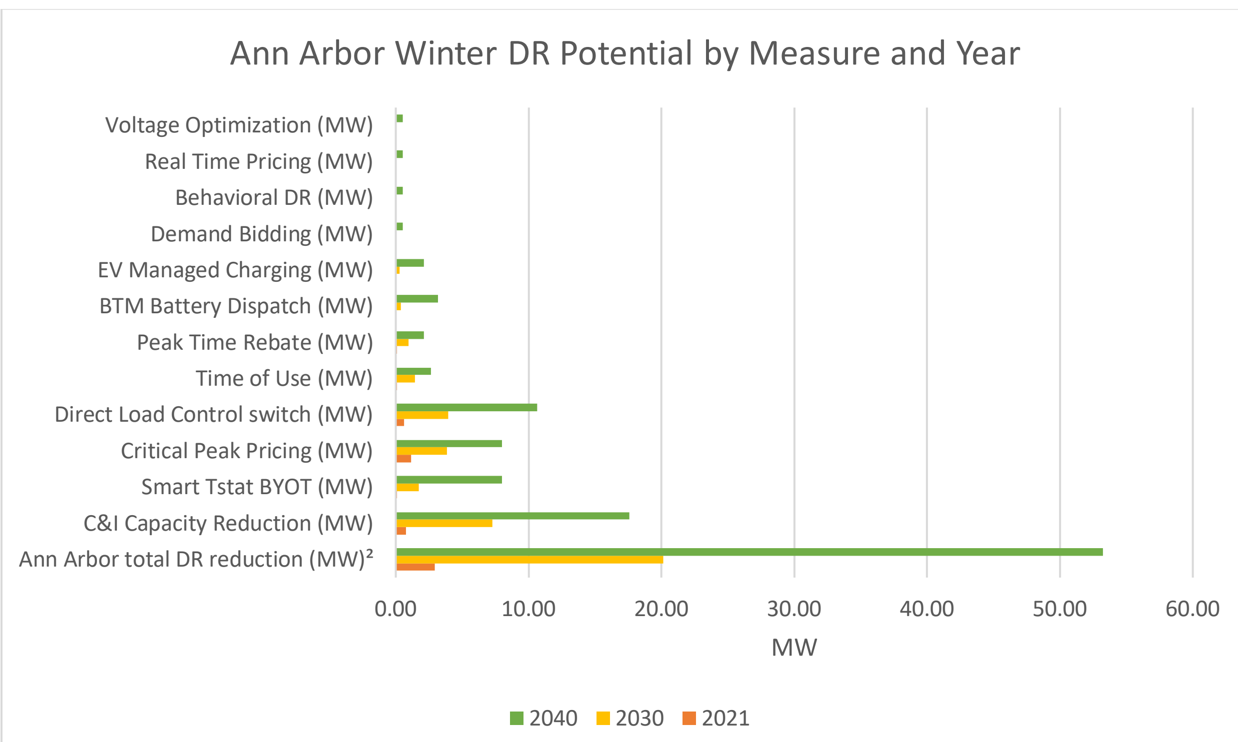


Figure 4: Ann Arbor Winter DR Potential by Measure, 2021-2040



In Guidehouse's study, EV-managed charging and BTM battery dispatch more than double with expected penetration of EVs and battery storage in the market. The much higher adoption rates targeted by A^2ZERO mean that EV charging and BTM batteries will play a much larger role in Ann Arbor's demand response than forecast for the LP overall by Guidehouse, as Figures 3 and 4 make plain.

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

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

Implementing Demand Response

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

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

Unlike other forms of demand response, dynamic volt-var control and conservation voltage reduction can be implemented entirely by the utility without engaging customers. As a result, these are amongst the forms of demand response that are quickest and most cost-effective to implement. We therefore recommend as follows for an Ann Arbor MEU:

> *Recommendation*: As a condition for rebates on electric vehicle chargers, space conditioning equipment, electric water heaters, and perhaps other efficiency or electrification rebates, require that equipment be able to participate in a demand response program.
>
> *Recommendation*: Provide a financial offer for customers to enroll in an automated load management program for vehicle charging, space conditioning, water heating, pumping, electricity storage, smart buildings, or commercial process load that will:
>
> > i) Inform equipment operations about time-of-use rate schedules;
> >
> > ii) Allow real-time management of demand within customer-friendly limits; and
> >
> > iii) Allow (at customer option) emergency management of demand as needed to qualify as MISO capacity resources.
>
> *Recommendation*: Evaluate the cost-effectiveness of implementing dynamic volt-var control and conservation voltage regulation within Ann Arbor's distribution system.

Any DR undertaken by an Ann Arbor SEU would be supplementary to DTE programs and would presumably focus on BTM PV/PVS customers of the SEU. The most important measures to create financial benefits for these customers will be smart thermostats and managed EV charging because both can help to match load to BTM power availability.

> Recommendation: the SEU should consider bundling smart thermostats and managed EV charging devices with BTM PV/PVS packages and assist customers in claiming any available rebates from DTE or taxes.

Recommendation: the SEU should provide data support to BTM DR devices to allow them to anticipate demand response events caused by mismatches between PV availability and load. It should not be necessary to offer special rates for participation in DR programs, because the primary benefit accrues to the customers rather than the utility, as long as the SEU is not an LSE.

Ann Arbor Energy Waste Reduction Potential and Costs

A^{2}ZERO includes ambitious EWR targets for 2030 but does not provide targets for later years. Here, we compare the City's 2030 targets to MPSC's statewide EWR potential study. We also apply the statewide potential projection to Ann Arbor in years beyond 2030.

Strategy 3 includes three Actions with direct EWR impacts:

> Action 3.1: 85% of owner-occupied homes, 80% of tenant-occupied homes, and 80% of businesses achieve a 20% reduction in electricity usage and 15% reduction in natural gas usage by 2030.
>
> Action 3.3: By 2029, all streetlights and traffic signals have been converted to LEDs.
>
> Action 3.8: 10% reduction in energy usage in rental properties within the City by 2030.

We did not separately model the impacts of Action 3.8 because it overlaps with those of Action 3.1.

Other Strategies and Actions may have EWR impacts, but they either overlap with the primary Actions listed above, have indirect effects that would be difficult to model reliably, or are not generally included in EWR analyses. For example, trip reduction and bus ridership Actions will reduce energy use but are not usually seen as falling within the scope of EWR.

We estimated that the A^{2}ZERO EWR Actions we modeled would yield savings of about 152 million kWh in 2030 compared to today. Put another way, existing uses of electricity in 2023 would be reduced by a total of 16%, or a compounded annual average reduction of 2.5%, by 2030. For purposes of comparison to DTE's EWR targets, we exclude from this total projected savings from the conversion of resistance heating equipment to heat pumps, because existing EWR plans cannot count fuel-switching projects (the 2023 energy laws removed this restriction). Also, we exclude energy efficiency realized from converting streetlights to LED, because streetlights are not included in EWR targets.

For comparison, we provide findings of the 2021 EWR potential study for electricity use in the Lower Peninsula, conducted by Guidehouse under contract with the MPSC.[1] We also benchmark against DTE's EWR goals.

Figure 5 provides findings from MPSC's contracted 2021 EWR potential study. The Reference case estimates total EWR potential from 2023-2030 of 8.6% (14%-5.4%) and the Aggressive case finds potential of 9.1% (14.8%-5.7%). Ann Arbor's targets are almost double DTE's, with cumulative efficiency from 2023-2030 of 16.1%.

Looking further ahead, the Reference case projects cumulative energy savings of 13% from 2023-2040 and the Aggressive case projects 13.6% savings.

[1] P.15, Michigan EWR Statewide Potential Study.

Figure 5: 2021 Michigan Statewide EWR Potential

Table ES-1. Lower Peninsula Energy Waste Reduction Cumulative Achievable Electricity Potential and Percent of Sales by Scenario

Year	Reference		Carbon Price		Aggressive	
	GWh Savings Net at Meter	% of Sales	GWh Savings Net at Meter	% of Sales	GWh Savings Net at Meter	% of Sales
2021	1,580	1.9%	1,618	2.0%	1,659	2.0%
2022	3,059	3.7%	3,132	3.8%	3,221	3.9%
2023	4,481	5.4%	4,582	5.5%	4,724	5.7%
2024	5,805	7.0%	5,926	7.2%	6,123	7.4%
2025	6,992	8.6%	7,132	8.7%	7,382	9.0%
2026	8,069	9.9%	8,226	10.1%	8,529	10.5%
2027	9,061	11.1%	9,235	11.3%	9,588	11.7%
2028	9,930	12.2%	10,119	12.4%	10,517	12.9%
2029	10,719	13.1%	10,920	13.4%	11,360	13.9%
2030	11,435	14.0%	11,648	14.2%	12,124	14.8%
2031	12,115	14.6%	12,339	14.9%	12,851	15.5%
2032	12,755	15.2%	12,976	15.4%	13,521	16.1%
2033	13,302	15.7%	13,520	16.0%	14,090	16.7%
2034	13,798	16.3%	14,013	16.5%	14,603	17.2%
2035	14,323	16.6%	14,541	16.8%	15,153	17.5%
2036	14,783	17.0%	15,003	17.2%	15,626	18.0%
2037	15,183	17.4%	15,406	17.6%	16,036	18.4%
2038	15,563	17.7%	15,789	18.0%	16,422	18.7%
2039	15,920	18.1%	16,150	18.3%	16,783	19.1%
2040	16,292	18.4%	16,526	18.6%	17,158	19.3%

Source: Guidehouse analysis

Source: 2021 EWR Statewide Potential study, by Guidehouse for MPSC

DTE EWR Targets

According to its EWR plan filing, MPSC case no. 21322, DTE expects to achieve energy savings in both 2024 and 2025 of 2%.[2] Assuming DTE maintained this pace through 2030, cumulative energy savings would be 11.5%. The A^{2}ZERO target is about 50% higher than DTE's projected savings.

DTE does not project savings beyond 2025 in its current filing.

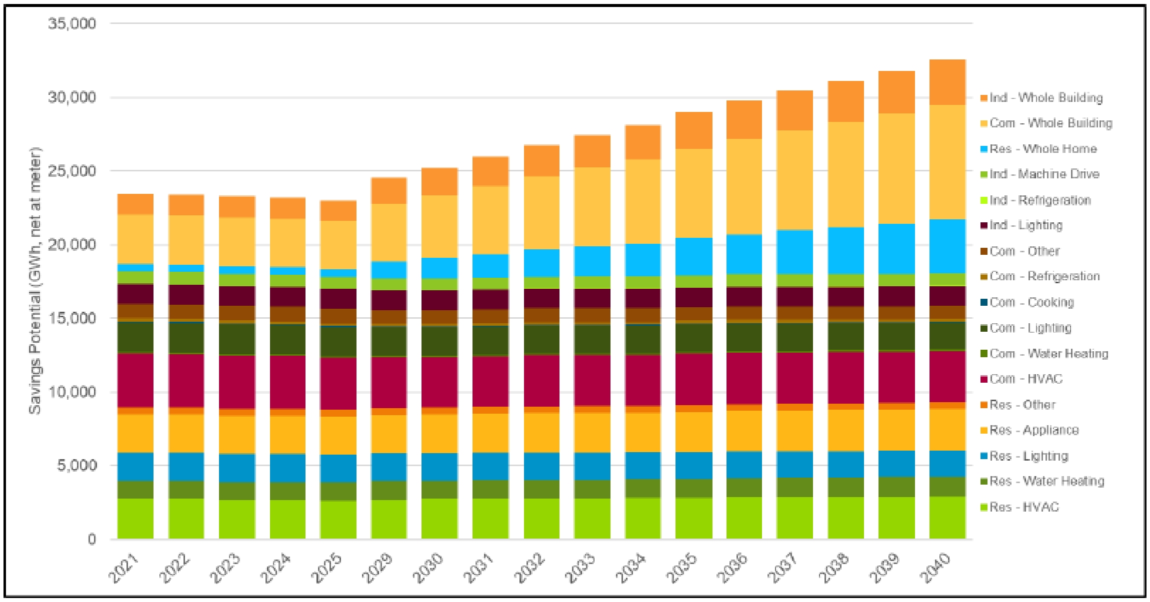
Discussion

EWR measures projected in the statewide study differ from measures described in the A^{2}ZERO goals.

[2] DTE application, MPSC case no. U-21322, p.4.

Figure 6: Michigan Lower Peninsula EWR Potential by Measure, 2021-2040

Figure 5-7. Lower Peninsula EWR Technical Potential, Electricity Savings by End Use, Reference Scenario (GWh, Net at Meter)



Source: Guidehouse analysis

Source: 2021 EWR Statewide Potential study, p.47

Commercial and industrial EWR projects contribute the most savings in the statewide study, whereas about two-thirds of energy savings in Ann Arbor would come from residential projects. A large portion of our EWR projections for Ann Arbor come from the steady conversion of resistance heating to heat pumps over the next 20 years, but heat pumps deliver only about 2% of energy savings in the statewide study.

Costs

Under the 2023 Michigan energy law, municipal utilities must achieve 1.5% EWR per year toward which they can count electrification.

A^{2}ZERO action 3.1 states, "85% of owner-occupied homes, 80% of tenant-occupied homes, and 80% of businesses achieve a 20% reduction in electricity usage and 15% reduction in natural gas usage by 2030." We project that attainment of this objective alone would reduce electricity use in Ann Arbor by 152,000 MWh in 2030 compared to the 2018 baseline, a roughly 16% reduction in building energy use. This is the equivalent of 2.5% annual average EWR from 2024 through 2030, or an average of 23,400,000 kWh reduced per year.

For modeling purposes, we assume that Ann Arbor's EWR costs would be proportional to DTE's costs. In its 2024-2025 EWR plan filing with the MPSC (Case no. U-21322), DTE projects electric EWR costs of $0.001750/kWh. Because Ann Arbor targets 2.5% annual improvement, 25% higher than DTE's 2.0% annual target, and unit costs of EWR savings do not increase with saving rates, then the MEU's charge per kWh should likewise be 25% higher, or $0.00219/kWh. For Ann Arbor's baseline 2018 electric usage, this rate implies a total annual EWR program cost of $2,054,000 assuming the objective is to recover all EWR program costs through rates.

This estimate should likely be seen as a minimum cost. A high percentage of DTE's historic and projected EWR gains come from industrial programs, which offer a high return on investment because they focus services on a small number of very large electricity users. In contrast, Ann Arbor aims to realize most of its EWR improvements from residential building energy shell and equipment improvements. Thus, every saved kWh may cost Ann Arbor more, on average, than DTE's EWR program does today. Additionally, Ann Arbor would be standing up a new program which would incur startup costs and might realize fewer economies of scale than DTE's much larger program. Lacking any better benchmark, however, we project Ann Arbor's potential costs with reference to DTE's EWR program.

Furthermore, Ann Arbor may wish to consider paying a higher share of EWR project costs than DTE does. In the first place, Ann Arbor may consider reducing required participant contributions to EWR projects because substantial out-of-pocket costs often discourage customers from following through on a project proposal. Regulated-utility EWR programs rebate the participant (customer) a predefined amount of capital cost based on projected lifetime energy savings. EWR case intervenors have advocated, instead, for rebates based on avoided costs for the utility, which would generally yield a higher rebate. This approach would increase up-front costs for the MEU but would still save the MEU money over time while reducing the required participant contributions.

Ann Arbor should also consider spending more than the DTE benchmark would indicate because it is focusing on project types that offer lower return on investment to participants, and because EWR projects to residences achieve important social objectives beyond their financial returns.

Because DTE's EWR programs are funded with ratepayer dollars, its costs are included in our projections of DTE rates. We did not build any EWR revenue into our MEU rate forecasts. Also, we estimate only gross costs of EWR programs; avoided costs to the utility and ratepayers would largely, if not entirely, offset gross costs over time.

Ann Arbor Undergrounding Analysis

We prepared an estimate of the cost of undergrounding power lines in Ann Arbor, and the revenue streams that would be necessary to recover that expense.

We caution, in preface, that the City should not assume that undergrounding wires will be the most effective way to improve reliability or the most cost-effective approach. The MPSC has contracted with an engineering firm to assess the causes of poor reliability performance in Michigan, with a final report due in the summer of 2024. While the work will not be specific to Ann Arbor, we would recommend that the City wait for the MPSC report to be issued before undertaking an Ann Arbor-focused assessment or committing investments.

Inputs and Assumptions

We estimate that there are 316 miles of overhead DTE distribution lines in Ann Arbor.

We assume the City would underground all lines “overnight”. This assumption facilitates financial modeling but is not operationally realistic; undergrounding would likely take several, if not many, years.

It may also be feasible to reduce the marginal costs of undergrounding by coordinating with other infrastructure projects, which would further attenuate the timeline. We discuss possibilities below.

DTE Benchmark

To assess potential costs and rate impacts of undergrounding, we benchmarked DTE’s costs, an approach with pros and cons:

- DTE’s reported undergrounding costs are not specific to Ann Arbor. Undergrounding in a fully developed city, with difficult-to-access back-lot overhead distribution lines, is likely to be more expensive than most other undergrounding projects. DTE, however, does serve Ann Arbor, and its overall service territory is reasonably representative of Ann Arbor.
- DTE has different costs and cost structure than a MEU would. We control for different financing costs by using municipal financing rates for any investments Ann Arbor might make. We do not assume that Ann Arbor would incur lower direct project costs than DTE in general, though it might be reasonable to assume that unit costs of an ongoing undergrounding program would be lower than those of a pilot project.

DTE Undergrounding Pilot Outcomes

In MPSC case no. U-21297, DTE Electric reported on outcomes of a completed pilot to convert backlot overhead electric lines to rear-lot underground infrastructure (URD, or underground residential distribution) in Detroit (the “Apolline project”). DTE also proposed a second pilot (“Fairmount”) that would relocate backlot URD to the frontlot.

Apolline Undergrounding Pilot

The goals of the Apolline pilot were to determine actual installation costs, understand customer acceptance, and determine opportunities to improve cost and construction efficiency. DTE’s report on the project is provided here as Exhibit UG1.

The circumstances and goals of the Apolline pilot appear to be relevant for Ann Arbor, where much secondary distribution infrastructure is installed in the back of lots and, if converted, would presumably remain in the back of lots. The Apolline neighborhood, while not served by alleys, appears to feature less tree cover, flatter topography, and more empty lots than typical Ann Arbor neighborhoods, which would ease access to backlot lines and reduce obstacles to undergrounding compared to Ann Arbor.

The Apolline project focused on service to sixty-one residential customers in two blocks in Detroit. The circuit had a history of poor reliability performance and down-wire incidents. The scope of the pilot project included the installation of a looped Underground Residential Distribution (URD) system with approximately 1,300 feet (about ¼ mile) of primary conductor, six transformers, and underground service lines to forty of the sixty-one residences. It also included removing the overhead infrastructure when the underground scope is complete.

Because URD is harder to service than overhead conductor when damaged, DTE installs URD in a loop, meaning that every customer can be served from two directions. If part of the URD is compromised, customers continue to receive service from the other direction of the loop. This practice improves reliability and resilience but effectively doubles the amount of conductor installed per unit of distance served and increases costs. Given Ann Arbor's commitment to reliability and resilience, we assume it would also install new URD in loops.

The original 2019 budget for the project was $395,731. The project is now forecasted to cost $983,000. The forecasted cost implies an average cost per mile of $3.932 million. The original cost implied an average cost per mile of $1.582 million.

Fairmount Undergrounding Project

In the same rate case exhibit, DTE also describes an upcoming pilot in Detroit to relocate backlot overhead distribution infrastructure to front-lot underground infrastructure. The project would "relocate OH rear-lot assets to front-lot URD in a two-block area served by Fairmount DC 1593 in the City of Detroit. It includes installing two cable poles, conduit, and primary conductor to establish the URD loop around the two blocks. This project will install fourteen pad-mounted transformers, forty-three secondary pedestals, and other necessary equipment to serve approximately ninety-eight customers in the area. All the equipment and the system design will be completed in preparation for conversion to 13.2kV at some point in the future. Once the URD loop is established, and the new services have been completed; the existing OH assets will be removed from the rear lot."[3] The forecasted cost of the project is $3 million.

DTE's rate case filings do not state the length of overhead (OH) cabling that will be relocated. The Fairmount and Apolline projects both serve two blocks in Detroit, so we assume Fairmount will also convert about ¼ mile of cabling. This simple calculation suggests a cost of $12 million to convert each mile of backlot OH cable to front-lot URD.

The MPSC staff brief in Case no. U-21297 criticized DTE's failure to provide cost-benefit analyses for either the Apolline or Fairmount projects and recommended the Commission disallow recovery of project capital. The Company may yet provide the requested analyses and recover its investment, and the staff's recommendation should not be understood to suggest that the cost of undergrounding is not worth the expense. Rather, the jury is out.

Consumers Energy Undergrounding Pilot

In MPSC case no. U-21389, Consumers Energy proposes an undergrounding pilot for low-voltage distribution circuits at a cost of about $400,000 per mile. [4] Consumers evaluates the Present Value of the Revenue Requirement (PVRR) for undergrounding as comparable to other hardening investments, but

[3] Testimony of DTE witness Deol, MPSC case U-21297, p.SSD-40, lines 16-25.

[4] Testimony of Consumers witness Lynd, Case no. U-21389, p.150 (Figure 57). See also testimony of Consumers witness Kelly starting at p.35.

more expensive than traditional vegetation management while yielding better reliability and resiliency benefits.

The Consumers undergrounding projects, while much cheaper on a unit basis than the DTE projects, appear to be less comparable to Ann Arbor's situation than the DTE undergrounding projects. The Consumers projects do not appear to be targeted at urban neighborhoods. They are in Fennville, Parshallville, Genesseeville, Hudsonville, Trowbridge, Greenville, Saugatuck, and Tawas; more-specific information on project settings is not provided in the case filings.

Generic National Cost Benchmark

Project subcontractor NewGen provided estimated costs for undergrounding in Ann Arbor based on generic national cost benchmarks. The cost for each asset type is marked up to include labor, indirect, and administrative and general costs.

Total estimated costs are approximately $365M, which presumably would be debt funded with the debt service cost recovered through rates. The MEU could implement a surcharge specifically for its undergrounding project. Assuming a 4.5% interest rate for debt issued over 30 years, the average surcharge would be approximately $0.022/kWh if the costs were allocated equally across all customer classes.

Figure 7: Electric Infrastructure Undergrounding Costs, national benchmark.

Total for Overhead to Underground Conversion		
Item		**Total Cost**
Primary Feeders	$	90,496,800
Conduit and Duct Bank	$	73,317,480
Transformers - 3 Phase	$	32,612,963
Transformers - 1 Phase	$	36,456,000
15kV Elbows	$	4,856,309
Secondary and Services	$	37,887,840
Total Installation Costs	**$**	**275,627,392**
Removal of Existing Facilities (very rough estimate)	**$**	**90,000,000**
Grand Total	**$**	**365,627,392**
Note - ROW acquisition not included - assumes utilizing existing ROW.		

Discussion of Costs

DTE's and Consumers' costs are for pilot projects. Projects undertaken at scale are likely to experience lower unit costs. For this reason, it would be reasonable to assume that Ann Arbor's URD conversion costs might come in closer to the original budgeted cost of DTE's Apolline project.

Ann Arbor might not convert all overhead conductor to URD. It might not be cost-effective to convert circuits with lower vulnerability to reliability problems. Other circuits might be judged as so expensive to convert that other reliability approaches would be deemed preferable. For example, installing battery storage at locations with poor reliability histories may be cheaper than converting to URD, and could help provide the storage resources necessary for complete conversion to renewable energy.

At the same time, selective URD conversion might not reduce unit costs since that strategy might entail a focus on areas with the most challenging access issues but would reduce total cost.

It is also possible that Ann Arbor would experience conversion costs closer to those that Consumers reports for its pilot. This possibility seems unlikely because Consumers appears to have chosen suburban or rural circuits to convert, and does not appear to be converting backlot infrastructure, which poses significant access challenges. It is also more challenging to install URD in urban areas because there is much more existing above- and below-ground infrastructure to work around.

It may be possible to reduce the project costs estimated above by coordinating with other infrastructure projects. One approach might be to underground wires when circuits need to be replaced anyway, a cost already built into the MEU projections as renewals and replacements. Another approach could be to relocate underground backlot wires to the street side when major road, water or sewer projects require excavation.

Financing costs

DTE depreciates underground conductor at a rate of 3.47% per year or 28.8-year service life; we assume an Ann Arbor MEU would experience similar equipment survival curves.

We assume that undergrounding would be financed at a bond rate of 4.5%, consistent with our assumptions for other MEU capital expenses other than for the acquisition of DTE property. We further assume 30-year financing, consistent with the expected service life of URD and with financing assumptions for other assets included in our study.

If we assume that all 316 miles of overhead conductor in Ann Arbor were converted to backlot URD and apply the Apolline unit cost per mile of $3.5 million, then the total cost of undergrounding in Ann Arbor would be about $1.1 billion. Total bond payments would be about $67.5 million per year. We consider this a reasonable high-end estimate of potential costs.

If project costs came in at the original Appoline unit cost of $1.582 million per mile, annual payments after converting all OH to URD would be about $30.5 million. We consider this a reasonable low-end estimate.

If project costs followed national benchmarks, total cost would be about $366 million and annual debt payments would be about $22.4 million. We cannot exclude the possibility that costs would align with national benchmarks but recommend using the DTE project benchmarks because they have Michigan costs and are known to be based on the conversion of backlot wires.

Rate Impacts

Allocated evenly across all 1.02 billion kWh we project Ann Arbor will use in 2030, this range of annual costs implies a rate impact of $0.030/kWh to $0.066/kWh. The national benchmark costs would result in a cost of $0.022/kWh.

However, most electric utilities allocate distribution costs according to how much each rate class uses each level of the system. In Ann Arbor, most overhead wiring serves residential customers. Assuming the MEU would adopt a rate structure reflecting the actual cost of service to each rate class, then most conversion costs would be allocated to residential customers, who use roughly half of the electricity in Ann Arbor. Allocating all conversion costs to residential customers would roughly double the volumetric rate impact.

On a per-customer basis, and again assuming that undergrounding costs would be allocated to residential customers, the annual cost for Ann Arbor’s roughly 51,000 residences would range between $598 and $1,324. If national benchmark costs were obtained, the annual cost per residential customer would be about $438.

Non-financial Impacts of Undergrounding Electric Wires

While we were asked to evaluate the costs of undergrounding, aesthetic and tree-health impacts are also worth brief discussion here.

Many people find overhead infrastructure to be aesthetically unappealing, which is one reason why overhead wires are often installed in the backlot. On the other hand, underground lines installed in the frontlot can limit or disrupt landscaping.

Impact of undergrounding electric lines may have both positive and negative impacts on tree health:

- Undergrounding of electric wires eliminates the need to trim trees, at least for electric reliability purposes. Tree trimming for overhead line clearance limits the natural growth of trees, and tree trimming done poorly or behind schedule can damage or even kill trees.
- Installing underground electric wires where trees are present has the potential to harm the root systems. Underground cable is usually installed using directional boring, which can be installed with more locational flexibility (depth and lateral position) and less damage to trees and infrastructure than open trenching. Careful planning and construction techniques can mitigate the risk of root damage.[5] Most trees recover from initial root damage within a few years.[6]
- Servicing of underground cable (e.g., when damage causes a power outage) generally requires excavation, which can damage tree roots and other infrastructure. It is also more expensive and takes longer than servicing overhead infrastructure, though less frequent. Utilities typically address potential outage restoration delays by installing URD in a loop so each location can be served from both directions of the circuit, but repair of the failed conductor segment still usually requires excavation.
- Some tree species are more vulnerable to root disruption than others.[7] The risk of root attraction to electromagnetic fields appears to be minimized with the lower field strengths of modern cable.[8]

In sum, it appears unlikely that many street or backlot trees would have to be removed, or would be permanently damaged, if URD was installed in place of overhead infrastructure. Overall, replacing overhead infrastructure with URD may impact trees in both positive and negative ways that depend heavily on tree species, constraints imposed by infrastructure (street, sidewalks, other underground systems), soil types, location of overhead infrastructure with respect to trees and access, and planning and installation methods.

[5] "The Environmental Impact of Power Lines," Scenic America (2023).
[6] "Undergrounding of electric power lines: Impacts on the urban forest," Arboriculture & Urban Forestry (2010)
[7] Arboriculture & Urban Forestry, ibid.
[8] "Root attraction to underground electric cables," Journal of Arboriculture & Urban Forestry (2002)

Known or Potential MEU Operational Risks or Concerns

The MEU would be responsible for the operations and maintenance of the distribution system during extreme weather events, including windstorms, and periods of extreme hot and cold. Each of these events can place stress on the distribution system in terms of physical limitations (damage to conductors, poles) as well as electrical requirements (increase load, pushing the systems to their extreme capabilities). Generally, these risks can be managed by investing in over-engineering the design of the system (to meet extreme electrical requirements), as well as in human systems (response teams, adequate inventory, etc.). Most municipal electric utilities make the required investments in their systems to meet these potential events.

To the extent that an event is prolonged or more damaging than expected, municipal systems do have access to the American Public Power Association (APPA) Mutual Aid Network that connects utilities, state associations, and federal partners to support the safe and efficient restoration of power in the aftermath of a natural disaster. The network comprises over 2,000 organizations in the public power sector that can provide or receive help from other utilities and coordinate with authorities during natural disasters. Utilities that have experienced a natural disaster can request short-term assistance from fellow member utilities in the form of line-worker crews and equipment, to expedite the restoration of damaged infrastructure.

Potential Social Responsibility Initiatives that Ann Arbor Might Consider as Part of Creating a MEU

If Ann Arbor formed a MEU, it might wish to replace DTE's social responsibility initiatives, which presumably would no longer be available in the City. For this discussion, we focus only on the provision of energy-related services outside of regular tariffs. DTE also operates a corporate foundation from which it supports education, arts, culture, and many other charitable activities. It would be unusual and arguably inappropriate for a MEU to generate a surplus that could be allocated for philanthropic purposes; thus we do not speculate here regarding whether and how the City might replace lost gifts from the DTE Foundation. We focus only on potential MEU, or City, efforts to improve energy access, equity, and security.

We note, as a prefatory matter, that rates for municipal utilities are user charges, not taxes.[9] In practice, this means that a MEU in Michigan cannot, without implicating the *Bolt* analysis, charge some customers rates higher than their cost of service to generate revenue that can be used to fund other initiatives, such as reduced rates or billpay assistance. However, the City may choose to use other revenue sources to fund social responsibility initiatives that reduce some customers' bills.

Categorically, DTE operates programs to help customers reduce their energy costs, to contribute toward bills they cannot afford to pay and to prevent harm coming to vulnerable customers from shutoffs owing to non-payment.

Billpayer assistance

Residential customers who cannot afford to pay their utility bills may be eligible for various forms of billpayer assistance. Assistance programs supported by state or federal agencies would remain available to Ann Arbor customers if service changed from DTE to a MEU. However, DTE also provides billpayer assistance, which Ann Arbor should consider replacing if it launched a MEU. The *Bolt* decision against Lansing Board of Water & Light, which interpreted the Headlee Amendment, likely would hinder an Ann Arbor MEU from recovering the costs of ratepayer assistance programs through its rates. Rate recovery that is not cost-of-service based could face challenge as a tax requiring voter approval under the Headlee Amendment, rather than a user fee tied directly to electric services received by individual customers. Therefore, unless specifically approved by voters, the costs of assistance offered to MEU customers would best be paid from other City revenue sources.

Per testimony[10] submitted in DTE Electric rate case no. U-21297, DTE offers:

- Affordable Payment Plan (generically, Low-Income Self Sufficiency Plan or LSP);
- Senior citizen discounts;
- Residential Income Assistance (RIA) and Low-Income Assistance (LIA) credits;
- Low-Income Home Energy Assistance Program (LIHEAP or MEAP);
- Payment Stability Plan (PSP; generically Percentage of Income) pilot

Rather than assuming Ann Arbor or a MEU would replicate DTE's assistance framework, we assume that Ann Arbor should spend at least as much money, per dollar of revenue, as DTE. We do not have access to data showing how many DTE customers in Ann Arbor currently receive various forms of assistance,

---

[9] *Bolt v Lansing*, 459 Mich 152, 587 NW2d 264 (1998).

[10] See testimony and exhibits of DTE witness Tamara Johnson, case no. U-21297.

which might allow us to estimate program replacement costs more accurately. Although we might use median household income in Ann Arbor, compared to DTE's overall service territory, to interpolate assistance rates in Ann Arbor, we suspect that the high number of student households in Ann Arbor would make this estimation approach inaccurate – reasoning that many student households may have low median incomes but stay current on their bills thanks to family assistance. Thus, we simply assume that the need for assistance in Ann Arbor is proportional by population to the overall assistance need throughout DTE's service area.

LIHEAP/MEAP

LIHEAP is funded by a per-meter bill surcharge set by the state, currently $0.88 per month. Municipal utilities can - and most do – opt into assessing the LIEAF surcharge, which is allowable under the Headlee amendment because the funds are managed by the state. Customers of participating utilities who qualify for State Energy Relief (SER) also become eligible to receive LIHEAP assistance. Utilities that do not elect to participate in LIHEAP cannot disconnect customers for nonpayment during the winter heating months.

Utility-managed assistance programs

The other DTE assistance programs listed above are all ratepayer-funded and Ann Arbor would likely need to find ways to pay for equivalent assistance other than through MEU rates. We interpolate Ann Arbor's likely costs using DTE's costs and customers served.

RIA, LIA, and Senior Discounts

DTE's annual cost of LIA, RIA, and senior discounts is $27,728,000 (as proposed in rate case no. U-21297), or an average of $13.41/year per residential account. If Ann Arbor adopted equivalent eligibility standards and assistance levels (without necessarily emulating DTE's program structure), its cost to replace these programs with 51,000 residential accounts would be $683,677 per year.

Low-income Self-Sufficiency Plan and Percentage-of-Income Pilot

DTE's Percentage of Income Payment Pilot (PIPP) is being tested as an alternative to the Affordable Payment Plan/LSP. Low-income advocates generally prefer PIP because it is available to customers up to 200% of FPL (versus 150% of FPL for the LSP). DTE's PIP also ensures customers pay no more than 10% of their income for energy (electric and gas combined) and offers arrearage forgiveness for customers who pay their current bills on time.

Because it is still a pilot, firm and detailed cost figures for DTE's PIP are not yet available. When DTE proposed the PIP pilot, its estimated PIP operating costs were consistent with annual assistance per electric customer of about $900.[11] This figure represents a very high percentage of the $1,400 average

[11] In its PIP pilot filing with the MPSC, DTE projected its operating costs would be $3 million per year to enroll 2,000 customers, or an average of $1,500 per customer, but did not break out that figure into gas and electric subtotals. The average monthly DTE residential gas bill is about $75, and the average electric bill is about $118, so we would assume that about $1.8 million of the PIP program cost is attributable to electricity bills, suggesting an average PIP cost per participating electric customer of $900. From DTE's PIP figures, we can roughly interpolate Ann Arbor's potential costs. The US Census 2022 American Community Survey estimated that 15.2% of families in the Ann Arbor metro area were below 200% of FPL. We assume the same rate for Ann Arbor city, yielding an estimate of 7,729 households in the City that would qualify for PIP assistance. At a cost of $900/year for each PIP customer, Ann Arbor would need to spend about $7 million per year to replicate DTE's PIP pilot for electric service only.

annual DTE residential electric bill, especially considering that PIP participants are likely eligible for other assistance programs as well.

A likely explanation for this apparent discrepancy is that PIP assistance includes progressive arrearage forgiveness for customers who pay current bills on time, and not only reduction of current bills. Currently available program data gives us no straightforward way to estimate how much of the $900 per year reduces current bills and how much is for arrearage forgiveness. Disaggregation of these costs of support for current bills versus arrearages would be important for estimating Ann Arbor's costs because the City presumably would not assume ownership of arrearages owed to DTE when customers switched over to the MEU; it would need to provide support, at least initially, only for current bills.

DTE's PIP pilot costs might also be high on a per-customer basis because, like most pilots, PIP likely has high administrative costs included within the operating budget.

While DTE's PIP pilot costs might be higher than Ann Arbor would experience, they might also be lower, for example, if Ann Arbor set a different PIP cap. Many advocates favor limiting energy expenditures to 6% of income, lower than the 10% threshold DTE is using for combined (electric and gas) customers, which represents most households in Ann Arbor. Adopting the 6% combined threshold would increase costs compared to DTE.

In all, it seems reasonable to project that an electric-only PIP offered by an Ann Arbor MEU would cost at least $5 million per year, but that amount is subject to great uncertainty. This cost could not likely be recovered through utility rates without a public vote and would otherwise likely need to be covered by other City revenue sources.

Philanthropic Sources of Assistance

DTE provides philanthropic support to energy assistance non-profits such as The Heat And Water (THAW) Fund. These gifts may result from routine philanthropic activities or MPSC or other legal settlements. We have no reliable way to estimate what portion of DTE's energy assistance-oriented grants benefit customers in Ann Arbor. DTE also provides grants for other purposes and grants around $2.5 million per year in total. If Ann Arbor started a MEU, DTE would presumably sharply reduce grants to beneficiaries in the City. It would not be appropriate for a MEU to make up for lost DTE gifts, but they do represent an opportunity cost to the City.

Billpayer Assistance conclusion

Ann Arbor could likely improve significantly on DTE's assistance programs, serving more needy customers and delivering assistance more cost-effectively. Many customers are confused by the overlaps and differences among assistance programs, a problem not unique to DTE. As a result, many customers either do not apply for all available assistance or receive less assistance than they are eligible for. DTE's assistance programs may offer the best available benchmark for Ann Arbor, but DTE's costs probably provide a very inaccurate benchmark, nonetheless.

Shutoff Protections

Regulated utilities offer winter shutoff, medical, and vulnerable customer shutoff protections. Ann Arbor would presumably adopt similar, if not stronger protections. Customers who have been granted shutoff protection remain responsible for balances that accrue during the exemption period. Narrowly construed, then, shutoff protection programs do not require direct allocation of assistance funds.

However, many customers find their account balances to be unmanageable after their shutoff protections end and apply for financial assistance. This relief can be provided by government- or utility-funded programs. Here, we assume that any relief that Ann Arbor might provide is already reflected in the billpayer assistance amount estimated above.

Also, customers who have received shutoff notices and meet income eligibility criteria may receive State Energy Relief to pay down their arrearages and additionally receive MEAP support to reduce current bills. Ann Arbor MEU would not need to contribute to SER costs, and, per our recommendation above, would participate in MEAP through a bill surcharge. While we encourage the City to adopt the strongest shutoff protections, these programs, along with well-funded and effective billpay assistance programs reviewed in the preceding section, could well achieve the City's energy equity and security goals.

Cost of Professional Services Related to Acquisition and Start-up

We foresee four categories of professional services costs the City may incur during MEU acquisition and startup:

- Phase 2 MEU feasibility study
- Reliability study
- Legal costs
- Technical experts and witnesses for court, FERC, and MPSC proceedings.

The first two categories can be estimated with reasonable accuracy; the third and fourth categories involve many independent variables that could vary significantly. Expenses would be incurred over several years, starting in 2024 and likely extending until the MEU started up if not beyond.

Phase 2 MEU Feasibility Study

An estimated cost for a Phase 2 MEU Feasibility Study would depend on the scope of services provided. If the purpose of a Phase 2 study would be to reduce the uncertainty around the cost value / inventory of the distribution assets, the estimated cost, per NewGen, would be between $750,000 and $1,000,000. This would include a thorough field review (two or three weeks), updated mapping of the system, inventory of the assets to be acquired, revised / updated financial feasibility model and report, and various meetings / presentations of results. This work would serve ONLY to address questions around the inventory of the assets, and an updated cost analysis. Outputs would include an updated income valuation approach, utilizing the assumptions used during the Phase I assessment and any updates appropriate for a Phase II study (for example a revised wholesale power price forecast would need to be provided by 5 Lakes Energy, as was provided during the Phase I study).

The City may, instead, wish to focus a Phase 2 study on a strategy to reduce the uncertainty around the valuation methodology of the assets to be acquired, which in our judgment represents a greater source of variance in potential costs than asset conditions and quantities. That is, a careful and comprehensive study of DTE's physical assets would nevertheless yield a wide range of potential valuations because the legal standards for acquisition costs are so unclear and contestable. To clarify the legal questions, quicker and at lower cost, we suggest that the City consider making a test case of the street lighting system, by moving forward with acquiring the existing streetlight system to see how the courts may decide valuation methodology (income or cost basis). To support this effort, NewGen could assist with a Fair Market Appraisal of the streetlight system, comprising inventory and valuation of the streetlighting system, a much more structured approach to evaluating costs than the valuation estimate described above, and that would include the development of testimony to support litigation. An estimated budget for this scope of work would be $350,000 to $500,000. This estimate does NOT include any legal analysis or fees.

Reliability Study

A reliability study would require a good functional model of the distribution system within the Ann Arbor boundary, which DTE is very unlikely to provide voluntarily. A key issue would be trying to figure out what part of the system is underground, and what "typical loads" exist. We would need to understand and have access to the reliability statistics (CAIDI, CAIFI) at least at the feeder segment level over the past five years or so to be able to evaluate specific issues or types of issues (Right-of-way clearing, overhead feeder configurations/locations, etc.). Ann Arbor could potentially obtain the specifications of the distribution system within the City limits, reliability statistics for specific feeders, and typical loads through discovery in a DTE Electric rate case at the MPSC, which would facilitate the development of a functional model of the system. Additional work would be needed to determine where new underground conversions could be constructed to address at least some of the reliability issues; DTE would not likely make any such evaluation available unless it was seeking to recover associated costs in a rate case.

We estimate a Phase 1 Reliability Study would cost between $300,000 and $500,000, with the primary variable being how much data about the existing distribution system could be discovered [and provided in an applicable format for analysis] in a rate case.

We strongly recommend that the City not undertake such a study until the MPSC's statewide study of reliability problems is completed, now due in summer 2024. The findings of that study should help narrow the scope of work and provide useful data for Ann Arbor's assessment, thereby reducing costs.

Legal Representation Services

Litigation costs are notoriously difficult to predict. That is particularly true in this case, in part because, as the Report notes, municipalization cases are relatively rare, meaning there is little precedent on which to judge the level of effort and resources required. Much will depend on whether the utility would be willing to negotiate a sale of its assets, whether a condemnation action in state court would be brought or if an action would be brought at the Michigan Public Service Commission, and whether a FERC proceeding would be required—or all the above. Which of these various courses would be necessary is difficult or impossible to predict in advance as it will be affected by facts not yet known and the actions of other parties, particularly DTE. Any appeals that might be taken from the initial decisions of any of the above tribunals would add further costs. Ultimately, a municipalization effort would likely require multi-year, multi-forum, complex litigation. Litigation at the FERC alone could run as much as $325,000, and state court or MPSC litigation seems almost unavoidable. Based on all these various contingencies, it would not be unreasonable for the City to anticipate spending at least $1 million to $2 million in direct legal costs on a municipalization effort.

Technical Experts and Expert Witnesses

Technical studies and expert witness fees for litigation are subject to the same kinds of uncertainties as legal fees: it is difficult to predict in which venues expert witness services would be needed and how extensive those proceedings would need to be. Hiring necessary consultants for the required studies and to serve as expert witnesses in formal proceedings could likely add another $1 million or more.

Ongoing Costs for Regulatory Compliance

MISO and FERC compliance requirements would be handled by MPAA, for which we have budgeted membership.

Municipal utilities are required to provide annual Renewable Energy Plan updates to the MPSC. While the 2023 energy law requires municipal utilities to have EWR plans, they are not subject to MPSC approval. Because A2 ZERO has ambitious EWR goals that predate the 2023 law, we do not view EWR planning as a marginal cost driven by compliance mandates.

We recommend that Ann Arbor be prepared to spend approximately $50,000 per year to prepare and file its Renewable Energy Plan and for other ongoing MPSC proceedings in which it may be required, or elect, to participate.