CITY OF ANN ARBOR
100% RENEWABLE ENERGY OPTIONS ANALYSIS

October 2023

EXECUTIVE SUMMARY

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The City of Ann Arbor has committed to using electricity generated only by renewable sources by 2030. The current growth trajectory of renewables in Ann Arbor's electricity supply will leave the City well short of 100% renewable energy (RE) in 2030. Achieving the 2030 goal will depend on the City's ability to mobilize additional RE resources and to implement the most favorable organizational structures to deploy them.

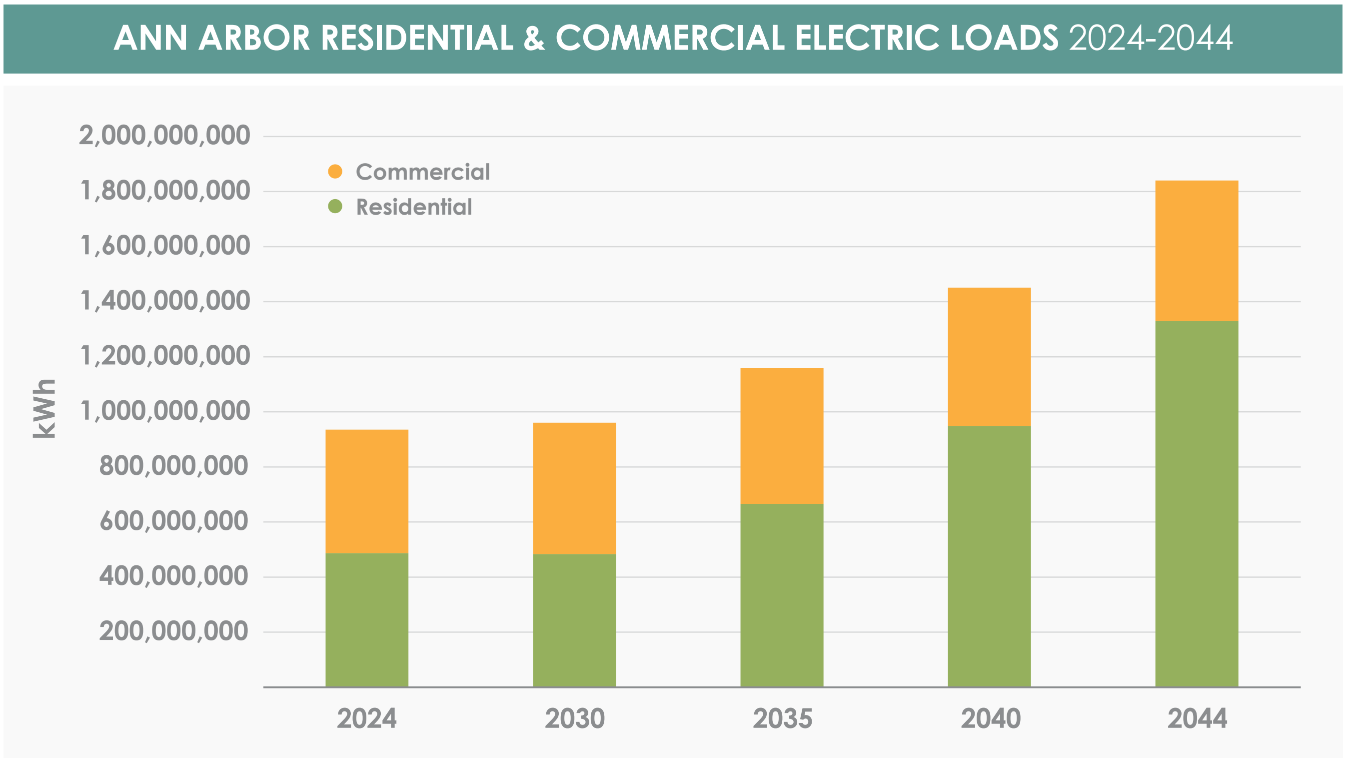
The City of Ann Arbor retained the team of 5 Lakes Energy, SunStore Energy, Potomac Law Group and NewGen Strategies and Solutions to explore potential energy option pathways to achieve the A²ZERO 2030 vision. We analyzed several energy supply options and organizational structures through the lens of the A²ZERO Energy Criteria and Principles (Appendix 1). We identified tradeoffs among the risks and benefits presented by the Energy Options and organizational structures and the A²ZERO Energy Criteria and Principles. We found several plausible, if challenging, pathways for the City to achieve its 2030 A²ZERO energy goals by deploying portfolios of energy resources that in each case depend on the applicable modeled utility structure. In this report, we present the risks, benefits, and tradeoffs of these pathways in a way intended to support decision making by the City's elected leaders and participation by the public and other stakeholders.

A²ZERO's required pace of behind-the-meter (BTM) photovoltaic (PV) and building energy efficiency improvements is ambitious and largely unprecedented, regardless of the utility structure the City pursues. Even if the City achieves a high level of success with distributed energy resources, some non-renewable electricity will almost certainly remain in Ann Arbor's electrical grid in 2030, requiring purchase of virtual assets through such mechanisms as renewable energy credits (RECs) or Virtual Power Purchase Agreements (VPPAs) to make up the difference.

HOW MUCH ELECTRICITY WILL ANN ARBOR NEED IN 2030?

To model the City's options for 100% renewable electricity in 2030, we first estimated how much electricity will be needed. We used public data sources to estimate electricity loads in Ann Arbor today. We then projected 2030 electricity usage based on A²ZERO program goals including energy efficiency and electrification of buildings and vehicles. See Figure 1: Ann Arbor Residential and Commercial Loads, 2024-2044.

Figure 1: Ann Arbor Residential and Commercial Loads, 2024-2044



Electrification and energy efficiency will largely offset each other through 2030 if the A²ZERO goals are met, keeping total usage slightly under 1,000,000 megawatt-hours (MWh) per year.[1] After 2030, however, continuing electrification is likely to greatly increase how much electricity is used compared to today, with the increase driven mostly by residential customers. Our detailed modeling examined only how to meet 2030 loads. We provide projections for later years to serve as context and as inputs to long-term capital spending projections as part of our evaluation of utility structure options.

CURRENT & PLANNED RENEWABLES WILL NOT SUPPLY 100% RENEWABLE ELECTRICITY IN 2030

To estimate how much more renewable electricity will be needed in 2030, we needed first to estimate how much will likely be available in a Business As Usual (BAU) scenario. We divided this assessment into two parts. First, we projected how much renewable electricity DTE will provide to Ann Arbor customers under its default residential and commercial tariffs. Then, we projected how much renewable electricity will be

[1] This figure excludes electricity used by University of Michigan (U of M), because U of M is independent of the City and can choose its own energy goals and methods. Fortunately, U of M also has ambitious climate goals that are reasonably resonant with the City's.

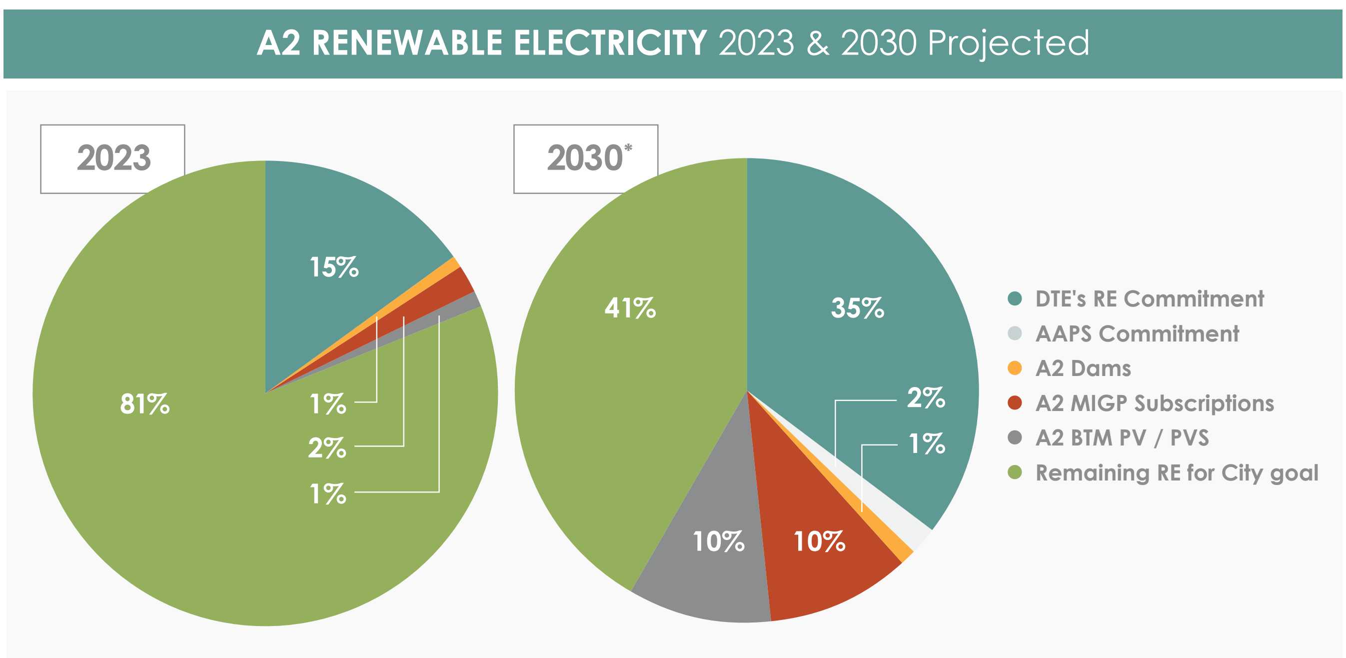
provided through DTE's Voluntary Green Pricing (VGP) program, MI Green Power (MIGP), and through RE efforts of the City, property owners and Ann Arbor Public Schools.

Under Michigan's Renewable Portfolio Standard (RPS), DTE is required to provide a minimum of 15% renewable electricity to all customers. As part of the settlement of its Integrated Resource Plan before the Michigan Public Service Commission (MPSC), DTE recently committed to voluntarily increase that number to 40% by 2035. Although DTE did not set a specific 2030 interim target, we linearly interpolated between today and 2035's target that DTE will provide 35% RE to all customers in 2030. That target leaves a 65% renewable electricity gap to be closed by DTE voluntary programs and customer RE initiatives in 2030.

Next, as shown in Figure 2, we projected how much renewable electricity will be provided to Ann Arbor through voluntary initiatives:

- We estimate that DTE's voluntary MIGP, through which customers can subscribe to receive up to 100% RE, will account for 10% of Ann Arbor's load in 2030. The Wheeler Center Solar Project development is included with MIGP. This estimate is based on current enrollments and pricing trends, extrapolated out to 2030.
- We assume that Ann Arbor Public Schools will meet its target of 100% renewable electricity by 2030 and count the renewable energy credits from locally owned dams; together these cover another 3% of the City's total load.
- We estimate that BTM PV, and PV with battery storage (PVS), will account for another 10% of the City's 2030 load, based on current installations and growth rates.

Figure 2: Renewable Electricity Sources in 2023 and projected 2030



*NB: figures sum to less than 100% owing to rounding.

In sum, we estimate that currently active or firmly committed DTE and other RE initiatives are likely to deliver about 59% of the City's total electricity usage by 2030 from renewables. To achieve 100% RE in 2030, the City must produce a plan to secure the remaining 41% of its annual electric load from renewable sources. This remaining goal amounts to approximately 400,000 MWh per year.

This projection is our Business As Usual (BAU) estimate; more specifically, it is our projection for 2030 assuming DTE and Ann Arbor and its residents and businesses were to effectively implement the programs and commitments that exist today. Its attainment is hardly assured; DTE's substantial renewable energy scale-up and our projected future enrollments in its voluntary MIGP program are both challenging targets. Likewise, the City's active BTM PV/PVS program (Solarize) and the Wheeler Center Solar projects are accelerating the RE transition, but further accelerated growth of Solarize is not guaranteed. Our scope of work was not to solve all logistical challenges; we assumed that current trends and program commitments will meet their stated objectives in 2030. In the same way, we assumed that the 2030 A^{2}ZERO strategies will attain their stated 2030 objectives, even though they also will be very challenging. Thus "Business As Usual" may not adequately suggest uncertainties arising from the challenges of meeting objectives of various existing and promised DTE, City and other programs, but it is a common term that we find useful, nevertheless.

We later examine how these options may deliver more RE than projected here; Figure 2 only shows our estimate of how much they will contribute if current commitments are implemented successfully.

ENERGY OPTIONS TO REACH 100% RENEWABLE ELECTRICITY BY 2030

To reach 100% renewable energy by 2030, the City must plan to mobilize additional resources to further supplement or replace DTE's resources. We examined several Energy Options that may help close the gap and estimated the unit cost of each of them.

The renewable Energy Options we analyzed were:

DTE's MI Green Power Program (MIGP; generically, Voluntary Green Pricing, or VGP) allows customers to subscribe to receive a higher percentage of renewable electricity than provided in DTE's default tariffs, up to 100% RE. The MIGP rate is an adder to the customer's base tariff rate, based on the differential cost of additional renewables versus DTE's existing generation fleet. The adder formula currently results in MIGP customers paying less than non-MIGP customers, but pricing will change as DTE adds resources to its MIGP program. Large DTE customers may have the option to request that DTE develop and operate PV or wind at a site the customer chooses, provided that customer agrees to be responsible for the costs of any electricity not sold to other customers. The City's Wheeler Center Solar Project installation is being pursued under this "customer requested" option.

Behind-the-meter (BTM) Photovoltaics (PV) and PV with battery storage (PVS) are installed on customers' premises on the customer's side of the electric meter. When PV generates more electricity than the customer's load, and they do not have battery storage, the surplus electricity outflows to the grid. If a customer has PVS, surplus electricity is often first utilized to charge the battery system. Customers are typically allowed to design PV systems as large as their annual net usage but not larger.

Community Solar is a development model that allows customers to offset their electricity usage from a specific solar PV plant. It is generally of greatest interest to customers who cannot install PV on their rooftops or elsewhere on their properties. There is no existing statewide community solar policy, and there is no existing DTE policy to allow community solar, so the community solar model applied in this study is derived from draft state legislation. This model contemplates a third-party owner (TPO) developing and owning a PV system and selling subscriptions to customers, who will receive a bill credit based on the value of the PV electricity produced. Community solar models often sell the Renewable Energy Credits (RECs) separately from the generated electricity to reduce customer cost, but the City's 100% RE target would require the RECs to stay in Ann Arbor; therefore, our model bundles the value of the RECs with the electricity. The feasibility of this option will depend on passage of appropriate legislation.

Power Purchase Agreements (Traditional and Virtual): Traditional Power Purchase Agreements (PPAs) are direct contracts between power producers and customers to sell electricity at a predetermined price over a fixed period. PPA contracts sell power and any associated environmental attributes directly to the customer. Since under current state law Ann Arbor cannot buy power from a supplier other than DTE, Traditional PPAs are not currently an option. Like Traditional PPAs, Virtual PPAs (VPPAs) are an agreement between an electricity producer and customer, but VPPAs allow the buyer to take delivery only of the environmental attributes of the

renewable energy generation. VPPAs can thus enable the building of new RE facilities when there is no direct off-taker for the energy they produce, thus making more RE generation economically feasible. VPPA RECs are delivered to the customer and VPPA electricity is then sold on the open market to other customers. VPPAs often include financial mechanisms to settle differences between a set price for the power produced under the VPPA and the actual market price when sold on the energy market. There is a limited but available market for fixed price VPPAs. Ann Arbor can thus enter into VPPAs that allow purchase of the renewable attributes of the electricity generation source without having also to receive the electricity itself.

National RECs: represent the renewable energy attributes or benefits associated with generating RE. They are separate from the physical electricity, which is often sold to the grid or somebody else without the green attributes attached. RECs are denominated in terms of the megawatt-hours of electricity they represent. Their market price depends on several factors, including generating source, additionality and strength of verification, location, and length of contract. A REC purchase resembles a VPPA contract, except the REC purchase conveys only the REC and not the physical electricity. The quality of National RECs varies significantly in terms of additionality and verifiability. In Michigan, since the utilities have already met their state-imposed RE targets, the upshot is that VPPAs generally enable the building of a new RE resource, while purchase of Michigan RECs generally comes from existing RE resources. However, we assume that Ann Arbor would buy only RECs with strong additionality and verification, which might entail buying out-of-state RECs. Accordingly, we model the national REC market.

Virtual Power Reduction Agreements (VPRAs): offer a method for creating RECs from energy efficiency projects, rather than producing renewable electricity, under a special provision of Michigan's energy law. The logic is that energy efficiency improvements displace carbon emissions from existing generating resources comparable to renewable energy displacing fossil-fuel based energy from the grid.

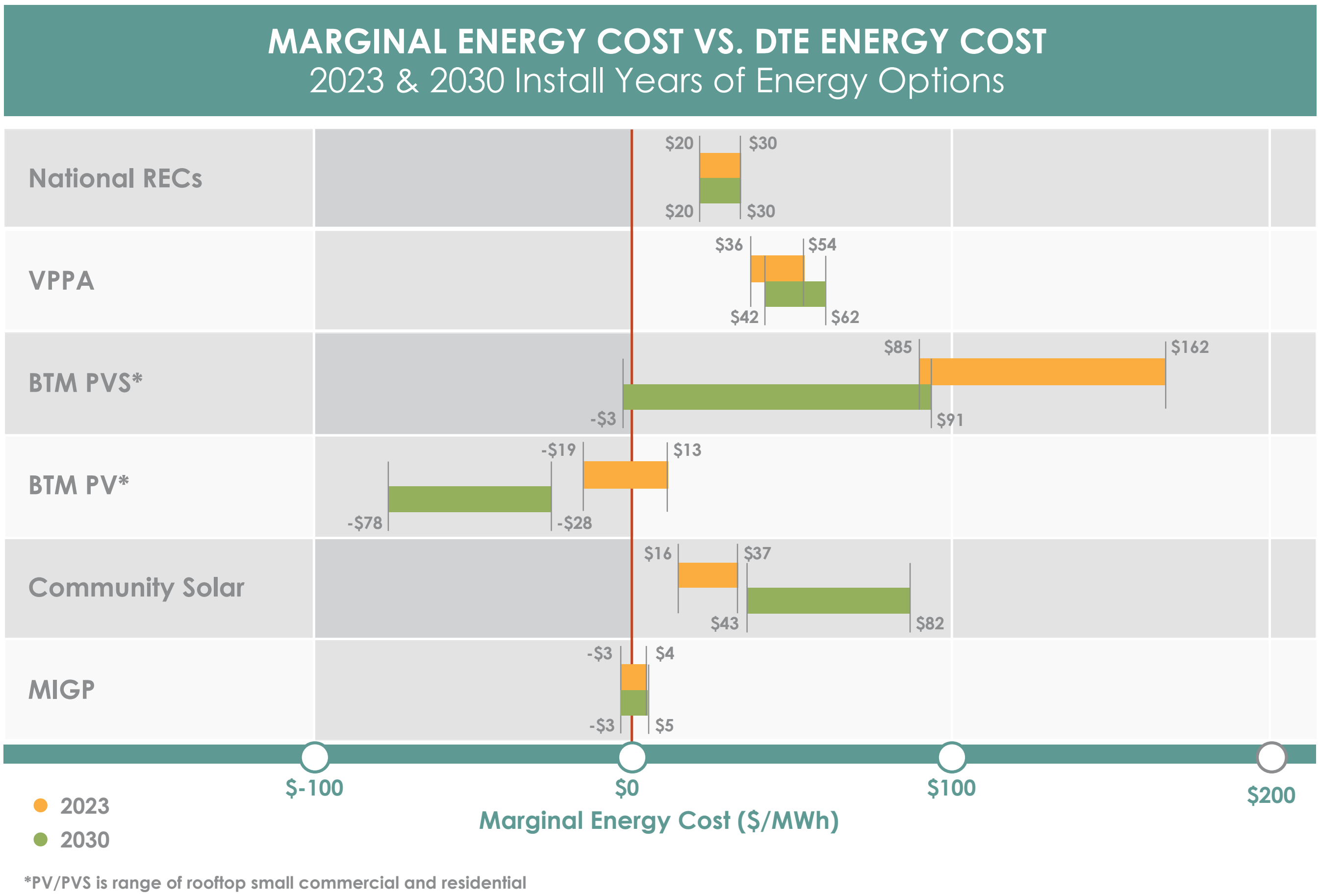
In addition to evaluating energy procurement options, we also evaluated three models of utility organizational structures within which the Energy Options might be implemented: continuing with DTE as primary provider (DTE), starting a Sustainable Energy Utility (SEU), and starting a Municipal Energy Utility (MEU). Because these are organizational structures, rather than ways to generate RE or RECs, we evaluate them separately from the Energy Options.

Energy Options Marginal Costs

In Figure 3, we present a comparison of all Energy Options' marginal energy costs to purchasers compared to DTE's retail energy costs. "Purchasers" for any given energy option may comprise more than one entity: for example, Ann Arbor ratepayers may pay for DTE electricity, but the City budget might bear the cost of RECs that offset the carbon embedded in DTE's electricity. We show total marginal costs paid by all entities in Ann Arbor combined, including residential and commercial ratepayers and the City budget, without differentiating who would pay them.

Figure 3 shows a range of marginal energy costs for Energy Options installed compared to DTE's 2023 rates. It then projects these costs again for new Energy Options executed in 2030. The Energy Options are positioned at various physical locations on the grid, such as BTM and in front-of-the-meter (FOM). The net costs for BTM Energy Options are presented as the difference between the levelized energy cost of the BTM Energy Options and the energy portion of DTE's retail electricity price. The net costs for FOM Energy Options are the levelized energy costs of acquiring the Energy Options versus DTE's acquisition costs through the Midcontinent Independent System Operator (MISO) energy market.

Figure 3: Projected marginal costs of Energy Options vs. DTE costs



Energy Options Satisfy the A²ZERO Energy Criteria & Principles to Varying Extents

The City adopted the A²ZERO Energy Criteria and Principles to guide energy policy decision making. The Energy Criteria must all be satisfied in any energy pathway the City chooses; the Energy Principles may be balanced against each other. The City's explanation of the A²ZERO Energy Criteria and Principles is provided in Appendix 1.

We developed a rubric for evaluating performance against the A²ZERO Energy Criteria and Principles and arrived at the following matrix. Our rating rubrics for the Criteria and Principles are explained starting on page 10. Our explanations of how we applied the rating rubrics are included in the respective Energy Options analyses starting at page 38.

Table 1: Alignment of Energy Options with A²ZERO Energy Criteria and Principles

ALIGNMENT OF ENERGY OPTIONS with A²ZERO Energy Criteria

CRITERION	MI GREEN POWER	(V)PPAs	NATIONAL RECs	COMMUNITY SOLAR	BTM PV& PVS	VPRA
Reduce GHG	YES	YES	YES	YES	YES	YES
Additionality	YES	YES	YES	YES	YES	YES
Equity & Justice	GOOD	FAIR	POOR	POOR	FAIR	EXCELLENT

ALIGNMENT OF ENERGY OPTIONS with A²ZERO Energy Principles

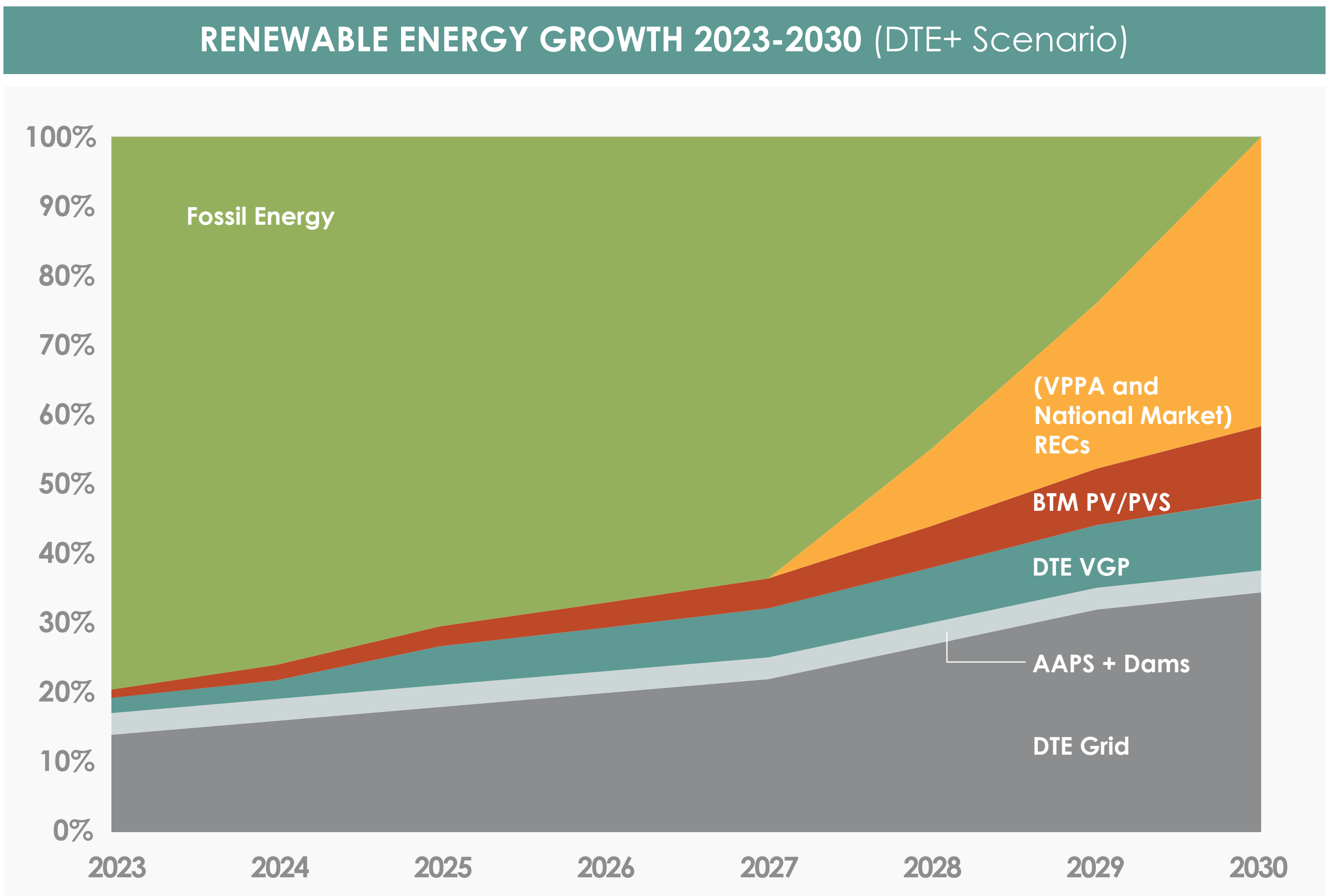
PRINCIPLE	MI GREEN POWER	(V)PPAs	NATIONAL RECS	COMMUNITY SOLAR	BTM PV& PVS	VPRA
Enhance Resilience	POOR	POOR	POOR	FAIR	GOOD	FAIR
Start Local	FAIR	FAIR	POOR	GOOD	EXCELLENT	GOOD
Speed	FAIR	EXCELLENT	EXCELLENT	POOR	GOOD	POOR
Scalable & Transferable	GOOD	EXCELLENT	EXCELLENT	EXCELLENT	EXCELLENT	FAIR
Cost Effective	EXCELLENT	POOR	POOR	POOR	EXCELLENT	POOR

The portfolio must satisfy the Energy Criteria and balance the Principles in a way acceptable to the City. RECs, for example, satisfy the Speed principle, but do little or nothing for Equity and Justice, Cost-Effectiveness, and Resilience in Ann Arbor. BTM PV/PVS, while serving the Start Local principle very well, has maximum potential contribution of 27% of Ann Arbor's load in 2030 and will probably contribute much less. To achieve reliable supply and satisfy the Energy Criteria, while satisfactorily balancing the Principles, a portfolio of energy resources will be needed.

Stacking of Renewable Energy Options

We studied many scenarios and present only what in our estimation are reasonable and achievable example scenarios to illustrate how the Energy Options may be "stacked" to reliably supply energy needs while attempting to best satisfy the A^{2}ZERO Energy Criteria and Principles. Our scenarios show that the City can technically meet its goal of 100% renewable electricity by 2030 with varying combinations of Energy Options. The choice of pathway will depend on how the City chooses to balance costs and risks against the Energy Criteria and Principles, while adapting to external factors.

Figure 4: Example scenario (DTE+) integrating many Energy Options to achieve 100% RE by 2030.



Stacking is necessary owing to the growth potential for any given energy option, and the diversification inherent in stacking also provides risk mitigation in case there are unforeseen limitations to any option. Some Energy Options are already active in Ann Arbor, such as BTM PV/PVS and customer MIGP. However, it is improbable that sufficient BTM PV/PVS could be installed by 2030 to achieve the balance of RE not provided by DTE. We modeled the growth of existing and new Energy Options based on reasonable economic projections, technical conditions, and customer adoption behaviors. RECs are anticipated as useful Energy Options, either through competitive VPPAs or National RECs, to close the gap remaining despite the adoption of more local Energy Options. Figure 4 shows a stack of Energy Options favorable for a baseline scenario called DTE+, which we explain in more detail below.

Scenarios for Stacking under Different Scenarios and Policy Assumptions

We present three scenarios to illustrate stacking options, which feature two utility structures and one policy variation:

- DTE+: continuation of DTE's current role, plus commitment of new City programmatic and financial resources to close the 2030 renewables gap. The City would aggressively promote and support deployment of BTM PV and PVS, follow through on development of the Wheeler Center Solar Project, purchase RECs or VPPAs to offset remaining fossil fuels, and pursue other A^{2}ZERO 2030 targets, within existing City structures and departments.
- SEU and DTE+: Ann Arbor would launch a supplemental SEU to promote, organize and finance distributed energy resources around the City. DTE would continue as the City's main provider of electricity with obligations to serve all customer loads. Assumes continuation of 2023 policy/regulatory environment.
- SEU and DTE+ and Community Solar: the SEU scenario plus a change in state or DTE policy allowing Community Solar. We modeled this hypothetical scenario because community solar is an energy option the City wishes to pursue but which is not otherwise included in our modeling under current policy assumptions; and we assess there is positive momentum in the Legislature to pass enabling legislation.

We show in Table 2 how the three Energy Options scenarios technically can achieve 100% RE by 2030. We present identical growth trends for MIGP adoption and BTM PV/PVS adoption for all three scenarios, to illustrate differences between the utility structures and statewide policy impacts. The rate of growth for MIGP and BTM PV/PVS is significant over the next seven years. DTE MIGP (City) indicates assumed contribution of the Wheeler Center Solar Project to municipal government loads. Additional BTM (SEU) indicates potential contributions of a SEU to growth in BTM PV/PVS, as distinguished from BTM PV/PVS which would not involve SEU financing. If any of these options grows more rapidly, City REC costs could decrease. We modeled a combination of both VPPA RECs and National RECs that would be necessary to achieve the 100% RE goals by 2030.

Table 2: Energy Options Contributions in Three Scenarios

2030 100% RE Three Energy Options Scenarios			
RE OPTION LOAD SHARE	**DTE+**	**SEU & DTE+**	**SEU & DTE+ & COMMUNITY SOLAR**
DTE Grid, AAPS, Dams	38%	38%	38%
DTE MIGP	9%	9%	9%
DTE MIGP (City)	2%	2%	2%
BTM PV / PVS	10%	10%	10%
Additional BTM (SEU)	0%	8%	8%
Community Solar	0%	0%	6%
RECs (VPPA, National RECs)	42%	34%	27%
Total	**100%**	**100%**	**100%**

It may be possible, though challenging, to achieve the 2030 A^2ZERO goals following any of these pathways. Many Energy Options are compatible and flexible in their growth, should the City desire to focus resources in particular areas. We also note each energy option has unique differences in how they may be deployed and evaluated based on their costs, risks, and performance against the A^2ZERO Energy Criteria and Principles.

Energy Option Scenarios Costs to the City

We focused the summary cost tables for these scenarios on costs that would directly flow through City budgets rather than all costs assumed by Ann Arbor electricity customers. For City stakeholders it is important to distinguish costs that may initially flow through the City budget and be recovered from the costs that will not be recoverable. From a broader perspective, whether an energy cost is covered by taxpayers or ratepayers in Ann Arbor may be an unimportant distinction, but from a municipal budgeting perspective the costs that "stick" to the municipal budget are consequential. Therefore, we partitioned the Energy Options into three cost categories:

No costs to City: BTM PV/PVS with customer ownership or third-party ownership, customer MIGP, and Community Solar. The City has developed programs to bolster adoption and bears some staffing costs, but equipment and electricity costs are borne by the customers.

Costs Recoverable to City: We classify costs as recoverable under two conditions. First, if municipal operations use electricity generated by BTM PV/PVS installed at City/SEU cost, then the rates they pay for that electricity will include cost recovery. Second, if the City pays for SEU subscribers' PV/PVS projects, the costs are ultimately recouped from these electricity subscribers through their monthly payments to the SEU. This approach distinguishes between costs that increase the City's budget on a net basis, versus costs the City recovers from ratepayers (including its own departments). These programs can incur significant upfront costs, such as financing a portfolio of BTM PV projects across municipal properties and ownership of SEU assets through debt financing; upfront costs are recovered from customers, over time, via the rates they pay. This category may also include annual energy costs such as SEU management of assets with third-party owners that may have a PPA contract with the SEU.

Costs Non-Recoverable to City: VPPA, National RECs, VPRA. These costs include Energy Options that achieve RE accounting goals without providing physical electricity services to customers in Ann Arbor. Additionally, MIGP serving municipal government loads and Wheeler Center Solar Project may increase net costs in the City budget, depending on project costs and changes in the MIGP tariff rider over time.

In Table 3 we compile cost data to show City RE costs for the year 2030 and a sum of RE costs from 2023-2029. In the two SEU scenarios below, we assume the SEU develops a BTM portfolio with 25 MW of PV-only and 25 MW of PVS. The recoverable costs grow significantly in the SEU scenarios, because the SEU costs flow through the City budget but are ultimately recoverable through subscribers' electricity bills. The non-recoverable costs are effectively the "net costs" to the City budget and would ultimately be borne by taxpayers. Net costs are lower in the SEU scenarios than in the DTE+ scenario because BTM PV and Community Solar reduce non-recoverable REC costs. We note, also, that SEU portfolio expenses are likely to have positive direct and indirect economic impacts in the region, which are not estimated in this Table.

Table 3: Costs to City Budget of Energy Scenarios

CITY COSTS FOR THREE ENERGY OPTIONS SCENARIOS			
CITY COST CATEGORIES ($000s)	**DTE+**	**SEU & DTE+**	**SEU & DTE+ & COMMUNITY SOLAR**
2030 CITY COSTS			
City Costs	$17,890	$24,679	$22,431
Recoverable Costs	$2,327	$12,145	$12,145
Non-Recoverable Costs	$15,563	$12,534	$10,285
2023-2029 CUMULATIVE CITY COSTS			
City Costs	$17,728	$49,098	$48,021
Recoverable Costs	$5,745	$38,787	$38,787
Non-Recoverable Costs	$11,983	$10,311	$9,234

We do not recommend how the City should choose among these scenarios. All three offer pathways to 100% renewable electricity. Instead, our goal here is to provide enough information to help facilitate a robust public discussion of how best to trade off costs, risks and adherence to the A^{2}ZERO Energy Criteria and Principles.

ANALYSIS OF UTILITY ORGANIZATIONAL MODELS

We evaluated the potential for three utility organizational models to contribute to Ann Arbor's goal of 100% renewable electricity by 2030:

- DTE: potential contributions of DTE's resources to the 2030 goals.
- Supplemental SEU: We examined the 2030 potential for what we termed a Phase 1 SEU, which would deploy only behind-the-meter resources without any distribution resources, in part for technical and financial reasons but also to avoid incurring MISO capacity obligations by becoming an LSE. It is introduced above in Scenarios 2 and 3, and below we examine its operations in more detail.
- MEU: evaluated in its launch year, at some indeterminate time after 2030.

We provided scenarios, above, projecting the stack of Energy Options and likely costs for the DTE+ and two permutations of the SEU & DTE+ scenario. In this section we discuss the SEU and MEU structures, outside of scenario context. Having already discussed DTE renewable energy options above, we do not further discuss DTE here, but we do provide our assessment of DTE's contributions to the A^{2}ZERO Energy Criteria and Principles later in the report.

SEU Analysis: Summary

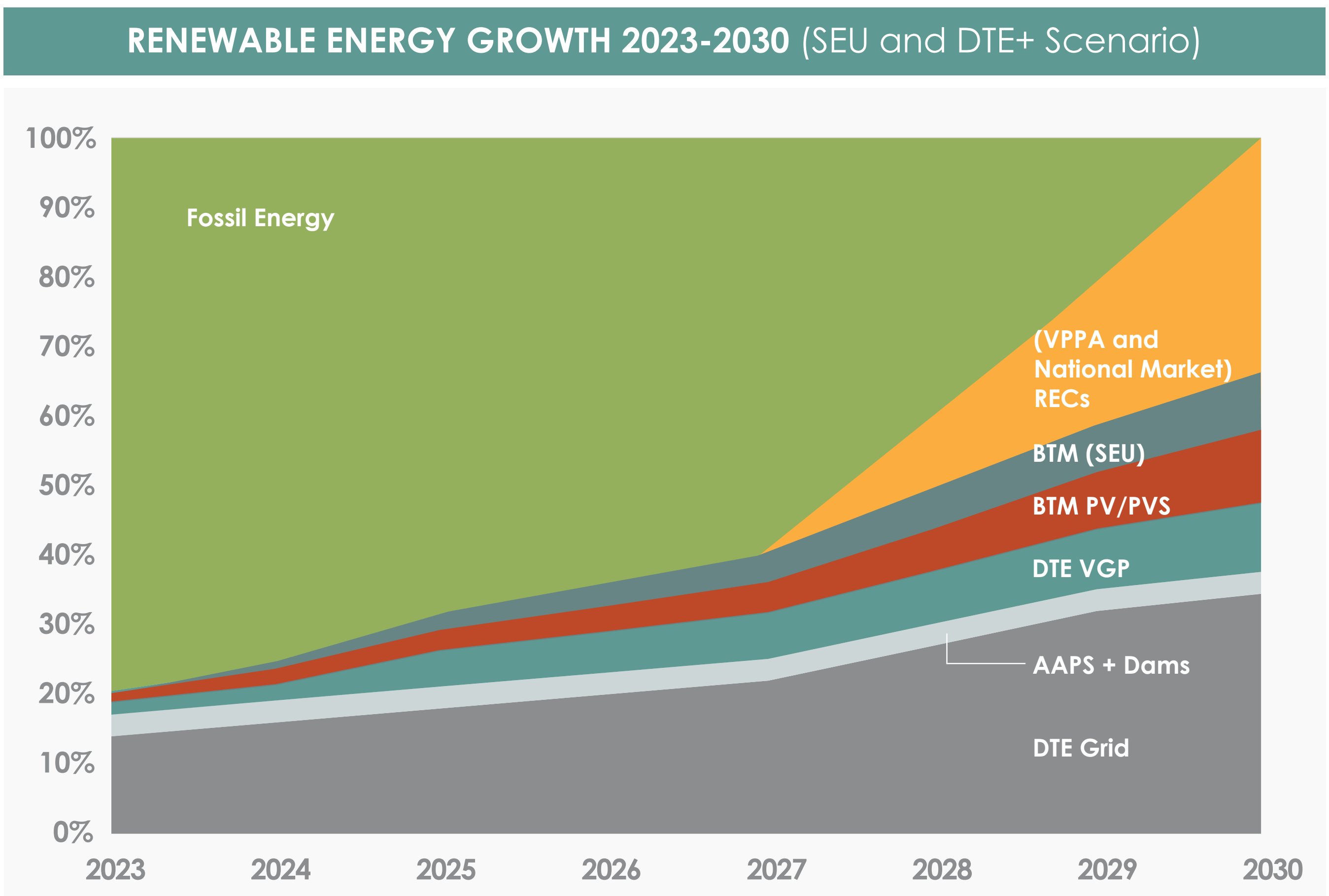
A SEU would be a municipal utility supplemental to the existing electric load-serving entity (DTE). The SEU would operate as an independent City utility with similar operations as other main public services, such as the Ann Arbor Water Utility. While SEUs are not common around the US, Ann Arbor could follow the path blazed by operational SEUs in other parts of the country. We assume the SEU could take a lead role in advancement of many A^{2}ZERO 2030 goals related to energy efficiency, electrification, and non-electricity renewable energy, but we focused our scope of work on renewable electricity solutions. We expect Ann Arbor's SEU model to observe all existing laws and regulations, build development policies, and establish a financial plan that adheres to Ann Arbor's vision.

Ann Arbor provided a vision of a phased SEU. In Phase 1 work, the SEU focuses on accelerating the deployment of BTM PV and PVS portfolios with minimal network connections. These portfolios are effectively independent installations at subscribers' sites where the storage's primary use case in a PVS project is for backup power. Our financial analysis focuses on portfolios of Phase 1 deployments. We found a SEU Phase 1 could be feasible within a range of technical and economic conditions. A Phase 2 portfolio would

significantly change a SEU deployment by establishing microgrid capabilities. Phase 2 work would include building a network of physical equipment connecting subscribers' sites, all BTM, that would enable SEU subscribers to share PV and PVS resources during grid outages or when choosing microgrid operations at select times. We provide a preliminary technical and regulatory analysis of Phase 2 concepts but do not project financial results. There is wide variation in microgrid designs that significantly impact overall costs. A future SEU Phase 2 study could examine microgrid concepts in technical and financial detail.

For the scenario presented in Figure 5, we assumed the SEU would serve subscribers who would not necessarily be installing PV/PVS on their own, and the SEU could achieve 50 MW of additional solar in Ann Arbor by 2030. In this scenario, the SEU would stimulate deployment of more BTM PV and PVS primarily by making it easier (both financially and operationally) for property owners and subscribers. These property owners may live at the site, have established landlord/lessee arrangements, or be commercial businesses or non-profits. Through SEU billing management, the subscribers would pay monthly fees based on electricity consumption (e.g., through a PPA contract) rather than directly financing the upfront costs that can stymie potential adoption. This would also provide more equitable access to BTM RE for lower-income residents, who often cannot afford to pay for, or finance, PV and PVS installation costs. Note that we present Figure 5 to illustrate stacking of Energy Options, rather than to recommend a specific portfolio.

Figure 5: Example SEU scenario integrating many Energy Options to achieve 100% RE by 2030.



There are several paths the SEU can pursue to develop and finance portfolios of Phase 1 (or Phase 2) projects. We considered (i) direct SEU ownership through 100% debt financing, such as a revenue bond or general obligation bond, (ii) third-party ownership where the SEU facilitates development with a company that owns and installs the projects, (iii) potential supporting grant funding from the State of Michigan, federal government, or other organizations, and (iv) any combination of (i) through (iii). For every SEU financing option, we assume the SEU would invoice its subscribers monthly, directly proportional to the amount of electricity generated from the onsite PV system.

In Table 4, we present three Phase 1 deployment portfolios of 10 MW, 50 MW, and 100 MW. The first two portfolios we modeled as 100% debt to convey the potential fiscal impact if the City pursued a new SEU revenue bond or a general obligation bond. For the third portfolio we modeled financing through third-party ownership where the SEU purchases the total portfolio after a 10-year PPA term. We assume that when the SEU is purchasing locally sourced solar power from a PPA, the SEU would still be engaged in subscriber relations and customer billing. Note, the pricing for PVS (integrated battery storage) results in higher portfolio costs that could be billed to subscribers as a higher energy rate, or a PV-only rate coupled with a PVS capacity payment. We assume all costs would be the responsibility of the subscribers, though the City may consider directly paying for battery storage costs as a pathway for resiliency, social equity, and justice.

Table 4: Technical and Financial Description of Three SEU Deployment Scenarios

SEU DEPLOYMENT Three Example Scenarios

SEU DEPLOYMENT DETAILS	1,250 SUBSCRIBERS*	6,250 SUBSCRIBERS	12,500 SUBSCRIBERS
Portfolio Capacity (MW)	10	50	100
PV-Only Capacity (MW)	10	25	50
PVS Capacity (MW)	–	25	50
Overnight Cost ($000)	$24,900	$151,900	$358,980
1st Finance Structure	100% Debt	100% Debt	10-yr PPA (TPO)
2nd Finance Structure	–	–	Year 10 – 100% Debt
SEU Debt Obligations ($000)	$24,900	$151,900	$233,000
Deployment Year(s)	2024-2027	2027-2030	2025**
PV-Only Starting PPA Rate***	$0.125/kWh	$0.135/kWh	$0.128/kWh
(i) PVS Starting PPA Rate****	–	$0.258/kWh	$0.246/kWh
Or (ii) PVS Capacity Payments	–	$67/month	$67/month

* The subscriber count is based on a generalized 8 kW-dc per subscriber. The subscriber count would be higher with residential subscribers that have smaller loads or lower with commercial subscribers that have larger loads. In addition to the information in the above table, our analysis finds that the IRA expands the economic impact of the state policies we modeled.

** 2025 is reference pricing year and deployment would require many years.

*** This is not a complete DTE electricity bill, it is a reference energy portion of the total bill based on typical customer usage.

**** Units are kWh for illustrative purposes. We recommend monthly capacity payments.

The values in SEU Debt Obligations refer to the amount of debt required to fully finance the reference SEU deployments. We assumed this debt is repaid through monthly electricity bills to SEU subscribers over the course of a 22-year PPA term. As shown in the 100 MW portfolio, the upfront capital cost is not inherently required to be financed by debt only. SEU portfolios may be larger or smaller, include PV-only (cheaper), and the years of deployment will impact the overall upfront costs and debt payment obligations.

Overall, we found each of these example scenarios resulted in healthy financial conditions to prove SEU feasibility. We assumed reasonable financial assumptions and note variation in any number of assumptions could result in better or worse financial conditions. The success of any portfolio will rely on:

- Quality development due diligence to establish each candidate subscriber site's ability to install PV.
- Flexibility of financing tools such as timing of debt and interest/repayment obligations.
- A minimum size to achieve economies of scale for equipment and labor, as well as Ann Arbor investment in SEU creation. We assume this economy of scale to be no less than several MWs.

We find the Phase 1 SEU to be feasible for the City, noting that the model is highly scalable to demand. We also note the SEU could start with a small portfolio and grow to more ambitious portfolios over time. We also assess that the Phase 1 SEU would perform very well against the A^2ZERO Energy Criteria and Principles as shown in Table 7, several pages below.

MEU Analysis: Summary

We modeled a potential Ann Arbor MEU as a public utility that owns the electrical distribution infrastructure and sells electricity from third-party generators to its customers who are physically connected to "the grid." When an entity tries to municipalize in this way, it must follow a legal process to determine the value of the incumbent utility's assets and purchase that infrastructure from the utility. If Ann Arbor were to form a municipal utility, it would likely source electricity through a combination of PPAs and solar PV sited around the city and owned by property owners, the municipal utility itself, or energy developers. Note, the MEU analysis did not integrate modeling BTM PV growth throughout Ann Arbor.

The intent of our Preliminary Municipalization Feasibility Study was to provide initial financial estimates for evaluation by Ann Arbor to help the City determine if it should continue with its investigation of a locally controlled MEU. This Phase I Feasibility Study utilized publicly available data and other information sources to determine potential estimates in cost impacts associated with a MEU for the City.

Uncertainty

Our study assessed what it would cost to operate a MEU and how well it would align with the 2030 A^2ZERO goals. We did not assess the costs and risks the City would likely face before it was able to launch the MEU. Municipalization is a complex legal process that has historically been vigorously opposed by the incumbent utility. We see no reason to expect this would be different in the case of Ann Arbor. Historical experience has been that the process takes many years and involves considerable legal expense.[2] We assess that it would be unlikely that a decision to municipalize

[2] "An Analysis of Municipalization and Related Utility Practices," prepared for the District of Columbia Department of Energy and Environment, September 30, 2017.

could be made, clear all obstacles and prerequisites, and be implemented as early as 2030. We have therefore recommended below that if Ann Arbor determines to proceed to create a municipal utility using distribution assets from DTE, arrangements to reach 100% renewable electricity by 2030 should be made outside of that construct but with defined options to move any generation or power purchase agreements to the municipal utility at the appropriate time.

In addition, estimates of the costs of acquiring DTE assets, developing complementary MEU assets and replacing and maintaining them over time are preliminary, and updated and more thorough analyses would be required for use in formal legal proceedings. As described below, the costs we estimated are "overnight" costs in the immediate future and will change by the time that a municipalization transaction would occur.

Finally, while we assess costs the MEU would incur to assure reliable renewable electricity supply, we do not project costs for improving reliability of electricity delivery—that is, the poles, wires and other assets that carry energy from its generating source to the customers. Our study focuses on identifying sources of renewable energy for Ann Arbor, not on delivery of that energy to customers. Our MEU cost model might improve reliability by replacing distribution system equipment on schedule, whereas much of DTE's equipment now appears to be older than normal service life and presumably less reliable. Any reliability improvements gained from such standard renewal and replacement practices is incidental to our scope here, and we do not quantify what improvements might be realized. Rigorously projecting costs of improving reliability would require comprehensive, circuit-by-circuit examination of the current system, whereas we collected only a representative sample in our field examination. Similarly, we do not project costs of undergrounding the system, which are highly situational and cannot be rigorously projected with a sampling approach. A Phase 2 municipalization feasibility study, if the City decides to proceed further, could include gathering the distribution system data needed to project costs of improving reliability, including undergrounding.

MEU Capital Costs

We provide all expenses for the first twenty years after MEU launch, but we modeled capital costs over longer periods as appropriate. We assumed that the MEU would be financed by issuing 30-year bonds at 4.5% for new assets and 5.5% for acquired assets, and that debt service costs would be recovered through the rates MEU customers would pay.

MEU Asset Acquisition Costs

The book value of DTE's assets within the City of Ann Arbor can be estimated with rough accuracy, but the methodology that would be used by a court or regulatory body for setting an acquisition price is less clear, because municipalization processes are uncommon nationally and have no recent precedent in Michigan. We developed two types of estimated values for this Study: cost-based estimates and income-based estimates. These two types of estimated values are then used to arrive at overall estimates of direct costs to the City of acquiring DTE's distribution system.

The cost-based value estimates were developed from the information obtained from the field investigation and GIS inventories and are based on the Original Cost Less Depreciation of DTE assets to be acquired.

The income-based value estimates were developed from projections of DTE retail rates and MISO wholesale rates, following a methodology for determining a retail-turned-wholesale customer's (e.g., a municipalizing customer's) so-called "Stranded Cost Obligation," as defined by the Federal Energy Regulatory Commission (FERC). We have used this "stranded cost obligation" value to approximate a "going concern" value for DTE's business in the City. Some version of this methodology would almost certainly be applied, but there are few actual examples to demonstrate precisely how. For the high "FERC Going Concern Valuation Estimate," we determined DTE's Revenue Stream Estimate for Ann Arbor, which represents revenue lost to the Company in a municipalization, and subtracted the value DTE could realize by selling electricity on the MISO market instead of to retail customers in Ann Arbor. The difference between these two values is the potential Stranded Cost Obligation associated with the DTE delivery assets and business within the City. For the purposes of this analysis, it is assumed that the high Stranded Cost Obligation represents a potential valuation of the assets within the City. The high Stranded Cost Obligation obtained under the FERC methodology is $1,150,000,000. Likewise, the sum of the cost-based estimate and the low SCO obtained under the FERC methodology, which is $281,000,000, represents a low valuation of the assets within the City.

In sum, we estimate a low and high value for acquiring DTE's distribution assets and business in Ann Arbor—excluding substations, as discussed next—of $281,000,000 (low) and $1,150,000,000 (high). This is not to say that DTE might not seek a higher valuation or that a court or FERC might not order a lower valuation. These values are simply reasonable estimates derived for planning purposes and may differ from the values DTE or the City may adopt upon further scrutiny should this scenario be pursued.

MEU Additional Capital Costs

As part of establishing the MEU electric system, the City would need to develop transmission assets and associated equipment to take service directly from the regional transmission provider (ITC) and distribute power to the MEU. The City would acquire all the remaining equipment that conveys, transforms, or otherwise manages the power at the distribution level within the City. These new systems would allow current and future DTE customers beyond the City municipal boundaries and served by the same substations as some City residents or businesses to continue to be served by DTE.

We estimate that the MEU would spend $95,360,000 on development of ten new substations and $19,175,000 on new transmission lines to connect the substations to the ITC transmission system. Owners' overhead would add another $34 million, for a total of $149 million in additional capital costs.

We model that the MEU would incur substantial asset replacement costs annually, in line with expected service lives of different asset types. We do not estimate costs to underground wires, upgrade circuits or improve reliability outside of updating infrastructure at time of replacement; these estimates would require much more detailed data on the existing system, which could be undertaken as part of a Phase 2 feasibility study.

MEU Operating Costs

Using the same estimates of load developed based on the A^{2}ZERO 2030 goals and current usage, and projections of the cost of sourcing renewable energy from the MISO regional grid, we were able to estimate year-one power costs for 100% RE for the MEU.

We estimated maintenance and operations costs, and Administrative and General costs, all based on costs reported by DTE in its rate case filings.

MEU Financial Summary

The low and high valuation estimates necessarily lead to a wide range of financial outcomes for the MEU in its first year of operation. We find that the revenue required for the MEU could range between 9% less to 38% more than the cost of buying all power from DTE (Table 5). Uncertainty over this range is primarily due to uncertain legal outcomes that would impact costs of municipalization and generally cannot be resolved short of undertaking municipalization.

Table 5: Year 1 MEU vs DTE Financial Outcomes, low and high estimates

YEAR 1 MEU FINANCIAL OUTCOMES Low & High Estimates		
ITEM	**LOW ESTIMATE**	**HIGH ESTIMATE**
Total Annual Sales (kWh)	939,751,000	939,751,000
Ann Arbor MEU Average Rate ($/kWh)	$0.1585	$0.2417
Ann Arbor MEU Total Revenue ($000)	$148,993	$227,158
Ann Arbor MEU Power Supply Costs ($000)	$78,000	$78,000
DTE in Ann Arbor Average Rate ($/kWh)	$0.1748	$0.1748
DTE in Ann Arbor Total Revenue ($000)	$164,269	$164,269
DTE in Ann Arbor Power Supply Costs ($000)	$85,000	$85,000
Difference between Ann Arbor MEU and DTE Revenue (Savings) ($000)	($15,276)	$62,890
% Difference	(9%)	38%

In our analysis, over time, MEU financial outcomes improve compared to remaining with DTE. MEU costs remain fairly stable over time, based on projected costs of sourcing renewable energy from the MISO grid, while debt service on costs of initial asset acquisition and construction diminishes. We project, in contrast, that DTE rates will continue to grow steadily: while DTE power costs may stabilize, investments in the distribution system will push rates upwards.

Table 6: Year 20 MEU vs DTE Financial Outcomes, low and high estimates

YEAR 20 MEU FINANCIAL OUTCOMES Low & High Estimates		
ITEM	LOW ESTIMATE	HIGH ESTIMATE
Total Annual Sales (kWh)	1,745,666,000	1,745,666,000
Ann Arbor MEU Average Rate ($/kWh)	$0.1921	$0.2345
Ann Arbor MEU Total Revenue ($000)	$354,068	$432,234
Ann Arbor MEU Power Supply Costs ($000)	$215,000	$215,000
DTE in Ann Arbor Average Rate ($/kWh)	$0.2261	$0.2261
DTE in Ann Arbor Total Revenue ($000)	$416,769	$416,769
DTE in Ann Arbor Power Supply Costs ($000)	$133,000	$133,000
Difference between Ann Arbor MEU and DTE Revenue (Savings) ($000)	($62,701)	$15,464
% Difference	(15%)	4%

Thus, over time, we project that the risk that MEU rates will be higher than DTE rates diminishes. We do not estimate MEU costs of investing in the distribution system for the purpose of improving reliability; the scope of our study includes reliable power supply but not improving distribution system reliability beyond normal equipment replacement schedules. We also do not assess the cost of increasing distribution system capacity over time, as loads increase per our projections. In contrast, rates we project for DTE include its projected investments in the distribution system, which may anticipate many of these changes.

Costs of distribution system improvements and capacity expansion require significantly more granular data than were gathered for the purposes of this study and could be addressed in a Phase 2 Feasibility Study if the City deems our findings here sufficiently promising.

Comparative Assessment of Utility Organizational Structures

We can now compare our assessment of the DTE, SEU and MEU structures across several dimensions. Our comparisons are not meant to illuminate a preferred pathway to 100% RE, but to show how technically feasible pathways differ in their deployment of Energy Options, costs and alignment with the A^{2}ZERO Energy Criteria and Principles, to support an informed and inclusive decision-making process.

First, we illustrate side-by-side how Energy Options might be favorably deployed and evolve over time in the DTE and MEU structures. We then compile our ratings of how the structural options align with the A^{2}ZERO Energy Criteria and Principles to aid comparative analysis.

Energy Option Stacking Varies with Organizational Structure and Over Time

First, we compile the energy stacking pathways from each of our scenarios to illustrate and emphasize that stacking should evolve over time.

Figure 6 depicts all Energy Options applied to the DTE grid. Only the VPRA and Community Solar are considered unavailable at the time of this report, respectively due to an unavailable business model and an unavailable regulatory position. Otherwise, we assume the Energy Options available today will remain available for the foreseeable future.

Figure 6: Energy Options available with the DTE grid

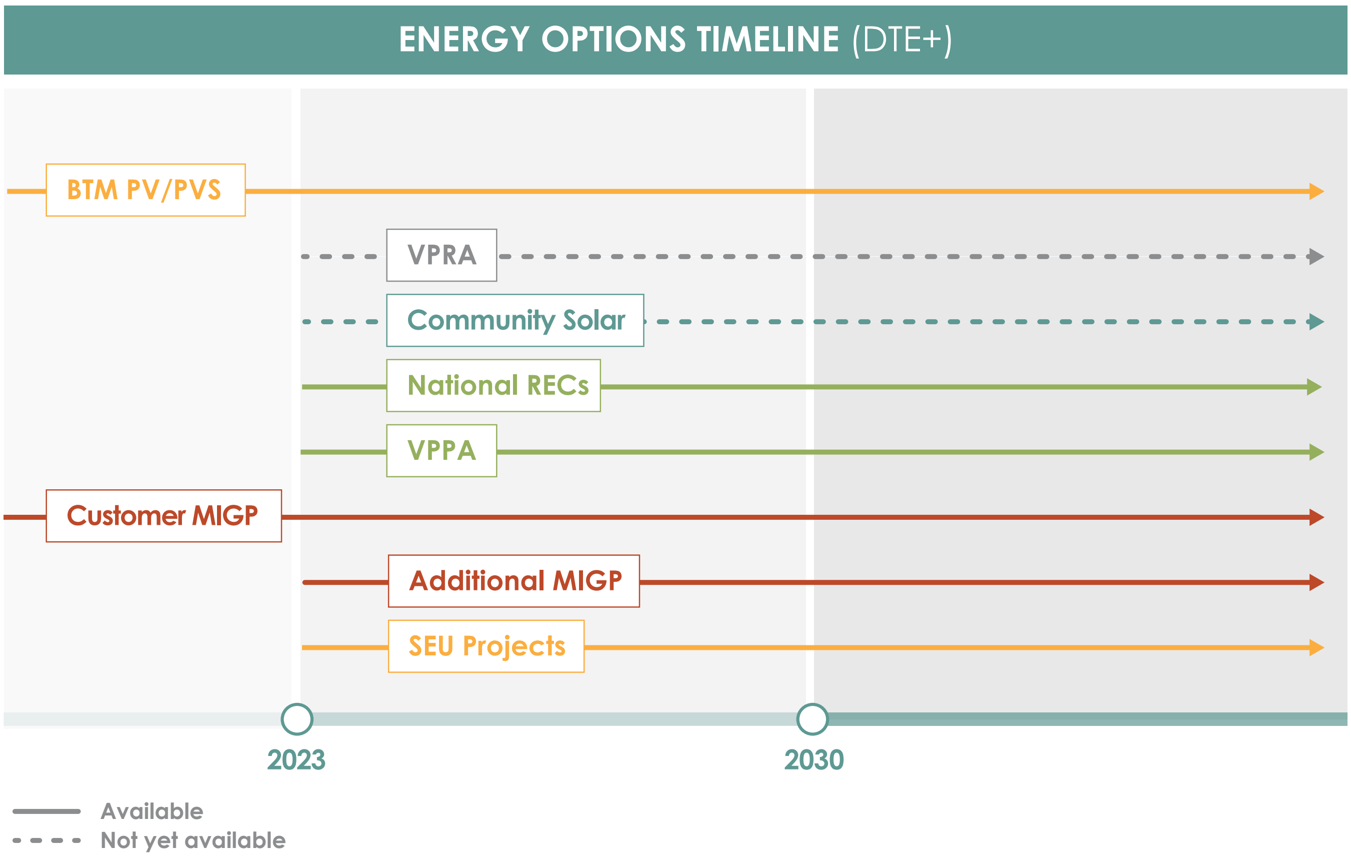
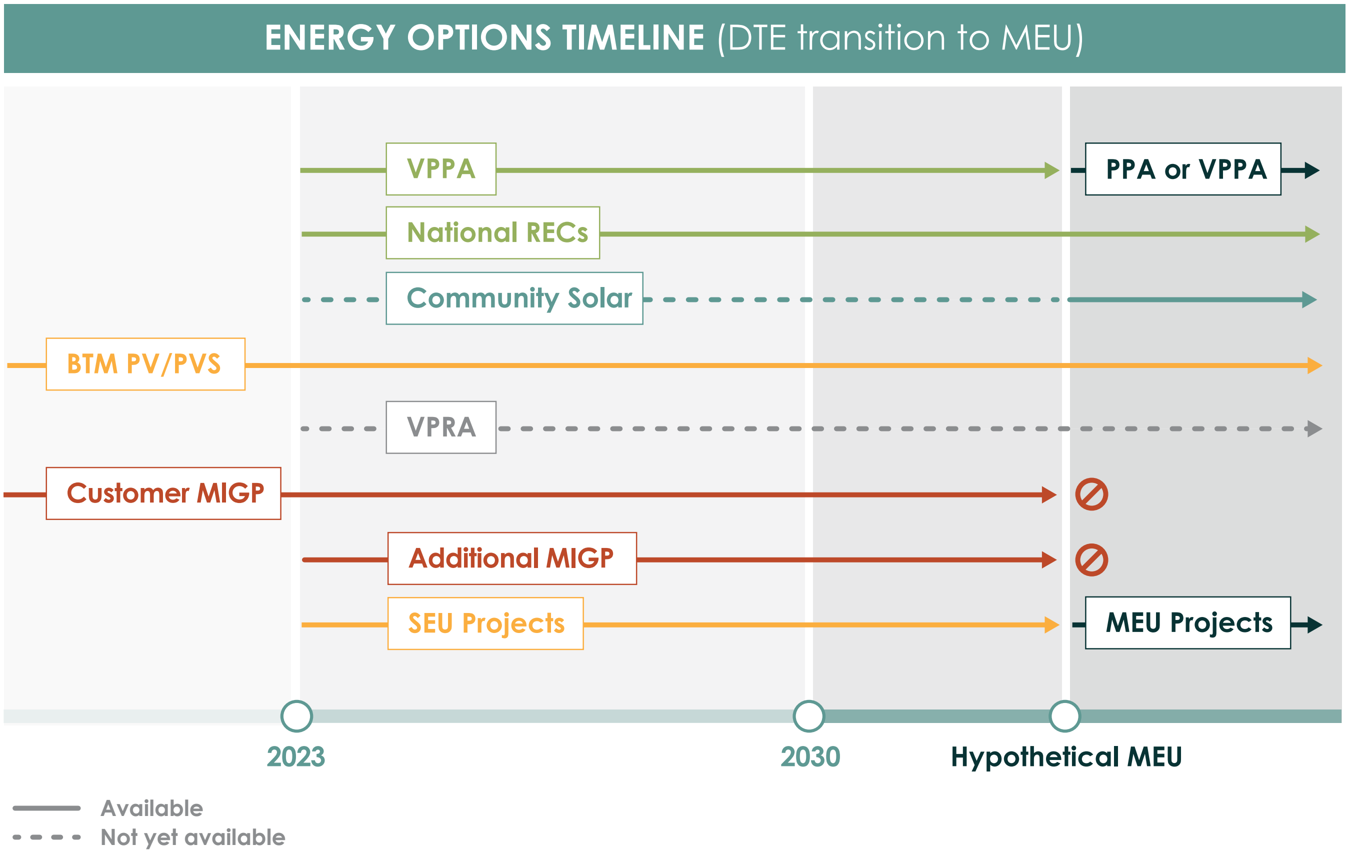


Figure 7 depicts how energy option availability might change over time if the City were to choose to pursue the MEU scenario. All installed BTM PV/PVS would remain operational, and the MEU would assume responsibility for establishing inflow and outflow rates. Any SEU BTM PV/PVS assets would likely transfer management from the SEU to a branch of the MEU. All DTE supported MIGP programs would no longer be applicable so the City would need to secure that RE share from other sources. VPPA contracts might continue in their negotiated form or there could be potential plans to transfer a VPPA into a traditional PPA, highly dependent upon contract status and project location.

Figure 7: Evolution of available Energy Options in DTE transition to MEU Scenario



Alignment of Utility Organizational Options with A²ZERO Energy Criteria and Principles

We evaluate each of the utility organizational structure options against the A²ZERO standards. Unlike all other energy and structure options, our MEU evaluations are not based on a 2030 snapshot. As discussed above, and in greater detail below, we assess that the MEU would be very unlikely to launch before 2030. In our suggested approach to the MEU pathway, deployment of Energy Options before MEU launch would closely resemble the SEU pathway. For example, the City could start right away to offer third-party financing for BTM PV and PVS, whose assets and programs could be transferred to a MEU if launched or remain within a SEU. Here, instead, we offer our assessment of the MEU's performance in its hypothetical launch year with the Energy Options described above. See Table 7.

Our rating rubric for each Criterion and Principle is explained starting on page 10. Our explanations of how we applied the rating rubric to each organizational structure are detailed on page 80 for DTE, page 109 for the SEU and page 134 for the MEU.

Table 7: Alignment of Utility Organizational Structure Options with A²ZERO Energy Criteria and Principles

ALIGNMENT OF ORGANIZATIONAL STRUCTURES with A²ZERO Energy Criteria

CRITERION	DTE	SEU	MEU (>2030)	
Reduce GHG	YES	YES	YES	
Additionality	YES	YES	YES	
Equity & Justice	GOOD	EXCELLENT	POOR	FAIR

ALIGNMENT OF ORGANIZATIONAL STRUCTURES with A²ZERO Energy Principles

PRINCIPLE	DTE	SEU	MEU (>2030)	
Enhance Resilience	POOR	FAIR	POOR	
Start Local	FAIR	EXCELLENT	FAIR	
Speed	GOOD	FAIR	POOR	
Scalable & Transferable	EXCELLENT	GOOD	FAIR	
Cost Effective	EXCELLENT	EXCELLENT	POOR	FAIR

Ratings for the MEU come with caveats. First, ratings reflect only the energy modeling we performed, which sources RE entirely from the MISO grid, without stacking in other Energy Options that might improve policy outcomes. We "stacked" energy options only for 2030, and do not foresee the MEU launching by then. We do not dispute that the MEU might deploy more Energy Options than what we model, but our modeling gives us no basis to assign ratings based on that possibility. Second, the MEU ratings are not for 2030, but for some indeterminate future launch year of the MEU. Third, uncertainties about the costs of acquiring DTE assets require us to assign a range of possible ratings to the Equity and Justice and Cost-Effective principles.

It is tempting to interpret Table 7 like a scoresheet, in which case one might conclude that the DTE structure is as favorable to achievement of the A²ZERO Energy Criteria and Principles as the other structures. This approach would not be constructive, for two reasons. One is that the Criteria should receive greater weight than the Principles; also, the Principles are meant to be evaluated qualitatively against each other, not quantitatively toted up. Secondly, these ratings represent snapshots in time (2030 for the DTE and SEU structures, and some later year for the MEU structure). We judge that ratings of the SEU and MEU structures would likely improve faster than ratings of the DTE structure in the years following these snapshots.

RELIABILITY

Owing to recent, repeated, and lengthy power outages in Ann Arbor, ways to improve reliability increasingly are front and center in the public discussion of the City's energy future. It is important to note that our analysis deals directly only with reliability of energy supply; that is, the ability of various Energy Options to reliably produce the amount of electricity the city will need. We did not directly assess the reliability of the electric distribution system, which has been the source of the growing outage problems in DTE's service territory. At the same time, distribution system issues interact extensively and in complex ways with the renewable electricity focus of our study. Deployment of some of the Energy Options we examine may help improve reliability, while others may prove to be problematic because of the changes they would bring to the distribution system. Ultimately, we did not have data to rigorously assess whether a MEU or SEU would be able to deliver greater distribution reliability than DTE currently provides, at lower cost and/or faster, and in any event this question was beyond the scope of our study. We therefore neither refute nor endorse this possibility.

RECOMMENDATIONS

Our analysis reveals several pathways the City might follow to reach its goal of 100% RE by 2030, differentiated by how they align with the A²ZERO Energy Criteria and Principles. The MEU is promising in its potential alignment with the A²ZERO Energy Criteria and Principles, but our financial analysis indicates it is a risky pathway – without excluding the possibility that it could be cost-competitive with other options. The SEU option is financially feasible, less risky and serves the A²ZERO Energy Criteria and Principles well, but likely has less long-term potential than the MEU to advance the 100% renewable electricity goal; that is, it would continue to rely on energy options provided by DTE. Continued primary reliance on DTE can also achieve 100% RE by 2030 with more-predictable outcomes, but almost certainly would cost the city budget more over time because of the mix of Energy Options it would rely on, and also evaluates somewhat less favorably against the A[2]ZERO Energy Criteria and Principles.

We suggest that the City authorize an expanded Phase 2 Feasibility Study to characterize more precisely the costs and risks of the MEU approach. A standard Phase 2 Feasibility Study would gather more data to estimate costs of acquiring DTE's assets and replacing assets the city would not acquire from DTE, including substations and transmission interconnects. In addition, the City should seek an estimate of the costs to improve distribution system reliability, because acquiring DTE's deteriorated assets and replacing them on a normal schedule would not promptly address the urgent reliability problems many customers in the City are regularly facing. Thirdly, the City should seek an estimate of costs and timeline to upgrade the system capacity from 4.8kV to 13.2kV wherever and whenever necessary, to handle increased loads and peaks we project over the coming 20 years and integrate the many distributed energy assets that should grow enormously over that period.

Because launch of a MEU is not assured and would likely take many years if it were pursued, the City ought concurrently to consider implementation of a SEU to heighten assurance of meeting its 2030 goals. If subsequent study supported launch of a MEU, when the time came the SEU assets and programs could be transferred over; if not, the SEU could continue apace. In short, we see development of an SEU as consistent with, and advantageous to, the longer-term development of a MEU. If the City embraces that concept, the question becomes how to start stacking the Energy Options to attain the 2030 goal while also laying groundwork for a MEU.

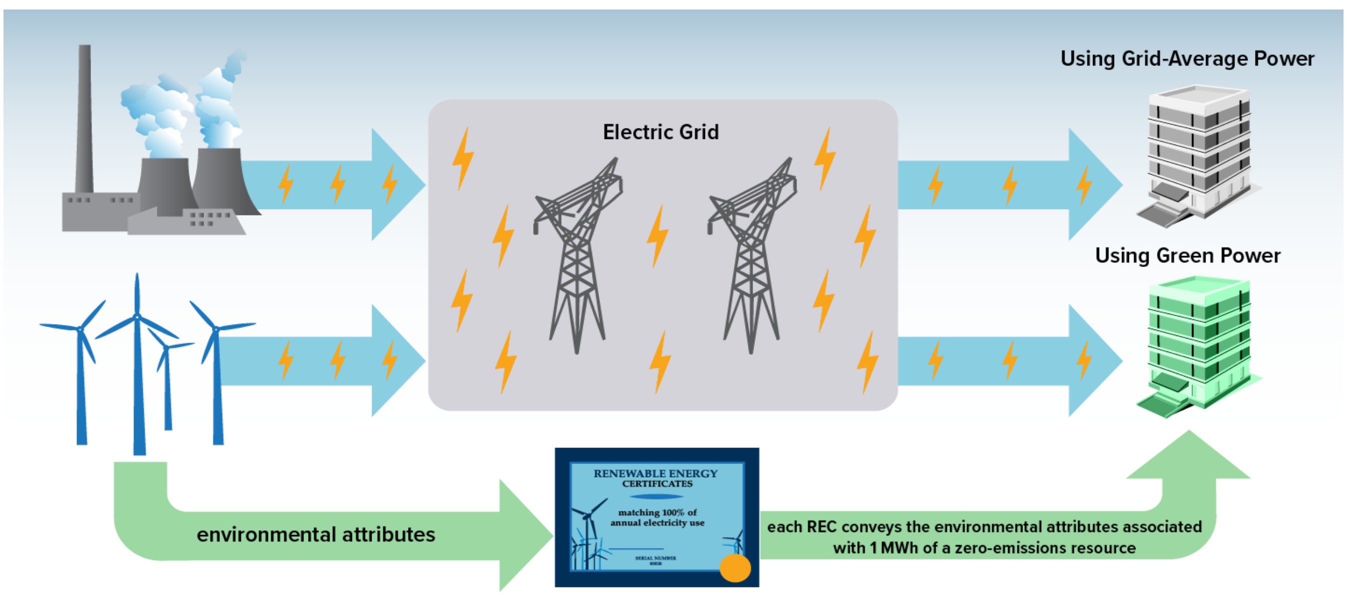
Although behind-the-meter resources and neighborhood solar are favored by many of the A[2]ZERO Energy Criteria and Principles, the long-term potential for these renewable resources falls short of the City's total electricity requirements, and the pace at which these can be developed will likely be gradual because they require individual decisions by many property owners. It is therefore necessary that the City meet the goal of 100% renewable generation by 2030 using a significant amount of utility-scale renewables that are remote from the City.

However, all utility-scale generation delivers power to the transmission grid where it is physically integrated with power flows from all other utility-scale generation on the same grid. In this region, all utility-scale power is sold into a wholesale market from which all power for delivery to customers is purchased by the utility that distributes power to them. Consequently, renewable power loses identity in the power markets. Also importantly, only a utility can purchase actual power from the transmission system and if Ann Arbor purchases power from a specific wind farm or solar system connected to the transmission grid, all it can do with that power is sell it into the wholesale market.

To facilitate tracking the production and use of renewable generation, markets have been created for RECs that can be purchased separately from the actual power so that the buyer can claim exclusive rights to the renewable characteristics of the power. The purchase of RECs provides an economic incentive for renewable generation by adding revenue on top of the energy and capacity sales that the facility can make. Each REC corresponds to one MWh of power generated from a renewable resource. Ann Arbor can reasonably meet its 100% RE goal by purchasing RECs to supplement RE resources provided by DTE and PV resources installed in or by the City. Since every other source of renewable energy that the City could use is either available only in small quantities relative to the City's requirements, or will be slow to develop, or both, the City can meet its 100% RE goal only by significant purchases of RECs produced from utility-scale renewable generation.

RECs vary in quality with respect to the City's principles. RECs sourced from existing renewable energy facilities will not provide additionality. RECs sourced from Texas do not provide benefits local to Ann Arbor. In general, higher quality RECs will be costlier and require longer lead times.

In short, we recommend that the City meet its initial requirements for renewable generation of electricity by purchasing RECs, with attention to the quality of those RECs, with some purchases being for recurring purchases over long periods of time and others being for short periods so that they can be displaced through other Energy Options that will contribute more to load after 2030. In the evaluation of other strategies, over time, the avoided cost of purchased RECs will be one of the quantifiable benefits of the other strategies.



Note: Graphic credit United States Environmental Protection Agency (USEPA)

Our analysis shows that Ann Arbor has viable, if ambitious, pathways to reach its goal of 100% renewable electricity by 2030. The benefits, costs and risks of those pathways change over time and create changing tradeoffs among the A^{2}ZERO Energy Criteria and Principles. We suggest here a strategy that would allow the City to reduce the uncertainties of one potential pathway, while moving ahead now with a strategy that keeps Ann Arbor on track to 100% RE in 2030 without foreclosing other options.

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GLOSSARY OF TERMS AND ABBREVIATIONS

A&G: Administrative and General expenses

A2: the City of Ann Arbor

AAPS: Ann Arbor Public Schools. AAPS is a large electricity customer within the city that has adopted its own climate goals and programs. We include AAPS electricity loads in our projections but assume they will meet their climate goals without city support.

AAATA: Ann Arbor Area Transportation Authority. AAATA operates most of the public buses that serve Ann Arbor. Ann Arbor's A^2ZERO 2030 goals include very substantial diversion of car trips to public transit, and conversion of public transit to EV, both of which impact EV charging loads.

BAU: Business as Usual. Here, connotes the normal execution of existing or committed energy programs, particularly in contrast to a project or program that would introduce change.

BTM: Behind The Meter. Energy that is produced and/or stored by behind the meter systems is separate from the grid and does not need to be counted by a meter before being used, so they are positioned "behind the meter".

CCA: Community Choice Aggregation. CCAs allow local governments to procure power on behalf of their residents, businesses, and municipal accounts from an alternative supplier while still receiving transmission and distribution service from their existing utility provider.

DTE: The investor-owned utility that serves as Ann Arbor's load-serving entity for electric service.

FTM: Front of the Meter. FTM energy resources are positioned "in front of" customers' utility meters, and the electricity must flow through those meters in order to be used at the customers' premises.

IIJA: Infrastructure Investment and Jobs Act of 2021 also commonly called the Bipartisan Infrastructure Bill. The IIJA expanded funding for new research and recycling projects for renewable energy and helps reduce the costs and barriers to clean energy technologies.

IPP: Independent Power Producer, a business other than a utility that produces power for sale.

IRP: Integrate Resource Plan, a planning tool used to assess how to best meet future electric energy needs in a state or utility service territory.

LMP: Locational Marginal Price. The price for electricity in real time at specific points referred to as nodes within a transmission system, in Ann Arbor's case MISO.

LSE: Load Serving Entity. An organization that secures energy and transmission service (and related Interconnect Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

MACRS: Modified Accelerated Cost Recovery System, a feature of the federal tax code that allows accelerated depreciation of assets for tax purposes.

MEU: Municipal Energy Utility, owned and operated by the local government or another public body to provide a public service. Distinguished from an Investor-Owned Utility (IOU), such as DTE Electric.

MIGP: MI Green Power, the market name for DTE's voluntary green pricing program.

MISO: Mid-Continent Independent System Operator. Provides open-access transmission service and monitors the high-voltage transmission system in all or parts of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, Wisconsin and Manitoba, Canada. MISO also operates one of the world's largest real-time energy markets.

MPSC: Michigan Public Service Commission, the state agency that regulates utility rates and tariffs.

Portfolio: Represents a set of power generation assets grouped together within one financing structure.

PPA: Power Purchase Agreement. An arrangement in which a third-party developer installs, owns, and operates an energy system and sells power produced under contract to off-takers such as utilities.

PV and PVS: Photovoltaics and Photovoltaics with Storage (usually batteries).

PV and PVS Capacity: the maximum amount of electricity that an energy resource can provide. Resources receive capacity credits based on how much electricity they can reasonably be expected to provide during peak demand periods.

RA: Resource Adequacy, a set of standards used in the electric power industry to ensure that utilities have adequate power at all times.

RE: Renewable energy. Energy from sources that are naturally replenishing but flow-limited; renewable resources are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time.

RES: Renewable Energy Standard, a legal provision requiring a certain percentage of energy sold by a utility to come from renewable resources.

SEU: Sustainable Energy Utility. A community-owned energy utility that provides clean electricity from local solar and battery storage systems installed on homes and businesses throughout the city.

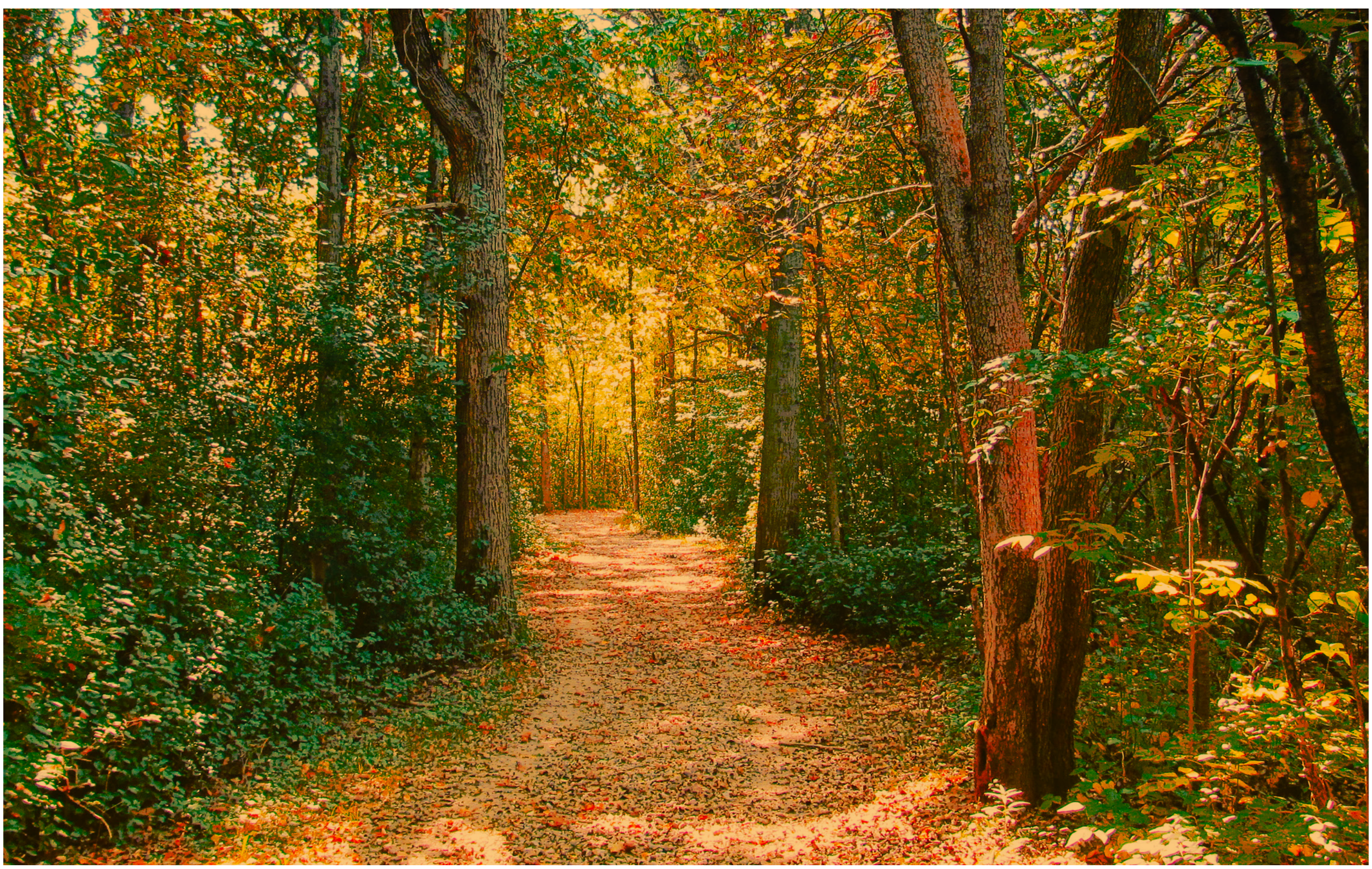
TPO: Third Party Ownership. A financing method often used for energy projects that allows property owners to host energy resources (e.g., rooftop solar PV) without large up-front capital investments. Typically, the third party realizes financial advantages from renewable energy tax credits and depreciation write-offs.

U of M: University of Michigan. Here, we refer only to the Ann Arbor campus.

VGP: Voluntary Green Pricing. A utility program that allows customers to sign up for a higher percentage of renewable electricity than the utility provides by default.

VMT: Vehicle Miles Traveled, a key input to estimating electric vehicle charging load.

INTRODUCTION



INTRODUCTION

The City of Ann Arbor requested guidance on the pathways to achieve its 2030 A^{2}ZERO goal of 100% renewable electricity. Our focus was to model how a set of renewable Energy Options could each contribute to the City's electricity mix by 2030 and beyond and how best to configure those options depending on how the City's electric utility service is managed going forward. Ann Arbor has also articulated a set of A^{2}ZERO Energy Criteria and Principles that are meant to inform how the City weighs the trade-offs associated with the qualitative aspects of the various Energy Options and organizational structures.

In this introduction, we overview how we approached our analysis and the many factors woven into it. Each of the topics introduced below are developed in greater detail in the chapters to follow.

A^{2}ZERO ENERGY CRITERIA AND PRINCIPLES

The City Council adopted the A^{2}ZERO Energy Criteria and Principles to guide decision making.

The energy criteria are requirements for all investments, meaning that any energy-related activity needs to meet these criteria or clearly articulate why it was not possible to meet these criteria to be considered. They are:

- Reducing greenhouse gas emissions.
- Additional to what is already being generated.
- Grounded in equity and justice.

The energy principles represent values the City holds, which should be maximized, to the fullest extent possible, in decision-making related to energy. Principles may, at times, conflict with one another.

- Enhancing the resilience of our people, our community, and our natural systems.
- Start Local.
- Speed.
- Scalable and transferable to other locations.
- Cost effective.

We develop our metrics for evaluating the Energy Options and utility organizational structures against these criteria and principles below. Ann Arbor's publication providing complete descriptions and discussion of the A^{2}ZERO Energy Criteria and Principles is provided as Appendix 1.

SITUATION ANALYSIS: DTE AND THE MISO GRID

To plan for tomorrow, we must first understand where we are today. We describe, at a high level, how the regional energy grid run by MISO (the Mid-Continent System Operator) works, including energy supply, energy costs and capacity requirements that will be in effect no matter who Ann Arbor's primary provider is. We overview the energy resources that DTE provides, and anticipates providing, in both default and voluntary offerings. We briefly describe the City's current renewable energy initiatives, complementary to or in cooperation with DTE. Finally, we discuss the various options for energy asset ownership.

The situation analysis sets the context for the City's 2030 A^{2}ZERO goals and lays the groundwork for a discussion of what other resources will be needed if the City is to achieve those goals.

A^2ZERO 2030 GOALS

In April 2020, the City adopted its A^2ZERO Carbon Neutrality Plan, centered around six core strategies:

Table 8: A^2ZERO 2030 Strategies

A^2ZERO 2030 STRATEGIES	
1	Power our electrical grid with 100% renewable energy.
2	Switch our appliances and vehicles from gasoline, diesel, propane, coal, and natural gas to electric.
3	Significantly improve the energy efficiency in our homes, businesses, schools, places of worship, recreational sites, and government facilities.
4	Reduce the miles we travel in our vehicles by at least 50%.
5	Change the way we use, reuse, and dispose of materials.
6	Enhance the resilience of our people and our place.

The focus of our work was on achieving 100% renewable electricity by 2030, but the second, third and fourth strategies also have direct impacts on how much electricity will need to be provided. Electrifying homes and vehicles will obviously increase electricity consumption, which will be offset to some extent by energy efficiency and vehicle trip reductions. The fifth and sixth strategies have indirect, or difficult-to-project, impacts on electricity use, and we did not model them.

We review specific metrics adopted under each of these core strategies in greater detail further along in this report.

ENERGY OPTIONS

We analyzed the potential for several renewable-electricity or carbon reduction strategies ("Energy Options") to contribute to the 100% renewable electricity goal:

Table 9: Renewable Energy Options

RENEWABLE ENERGY OPTIONS
• DTE's MI Green Power Program (MIGP) • Traditional and Virtual Power Purchase Agreements (PPA/VPPA) • National REC Market • Community Solar • Behind-the-meter (BTM) Photovoltaics (PV) and PV with storage (PVS) • Virtual Power Reduction Agreements (VPRA)

We discuss each of these Energy Options in greater detail below, covering its potential contribution under various utility structures and how it stacks up against the A^{2}ZERO Energy Criteria and Principles.

ANALYTICAL APPROACH

Our conceptual approach was straightforward, although its execution required large amounts of data and analysis.

We began by estimating how much electricity Ann Arbor is likely to need in 2030 and beyond. Using US government sources,[3] we established a baseline of electricity usage in Ann Arbor during every hour of the year.

Next, we estimated how much that baseline is likely to change as the A^{2}ZERO strategies take hold. The A^{2}ZERO carbon neutrality plan sets specific targets for 2030 for each of the strategies; we estimated the load impacts of achieving these targets. We also estimated electric load through 2045 as a foundation for estimating SEU and MEU costs. There are no A^{2}ZERO interim targets beyond 2030, so we assumed that all the goals would be fully achieved by 2050 and projected linear progress toward each of them from 2030 onwards. For example, we assumed that all building uses of natural gas would end by 2050 and projected steady progress from the 2030 interim target to the 2050 endpoint.

We then estimated the ability of each of the Energy Options to contribute to the projected loads, requiring voluminous computations based on projected market costs and capacity constraints of each of the Energy Options. For example, even if BTM solar with the City of Ann Arbor were found to be the cheapest option, it is unlikely that enough individual property owners in the City would prove willing and able to install solar PV, and even if they did, other power sources would be needed – especially at night.

[3] DTE did not provide actual data in response to our request.

We also found, to provide another example, that contracting for renewable energy generated in another state is usually cheaper than installing battery storage in Ann Arbor, and if "stacked" carefully with other resources can deliver similar reliability as battery storage.

In addition to energy costs, we had to consider capacity costs. Most of Michigan, including the City, is located in the footprint of the MISO, which is responsible for the operation of the regional electric transmission grid across the middle of the United States, from Minnesota and the Dakotas in the North to Louisiana in the South.[4] Under MISO's rules, which are overseen by the Federal Energy Regulatory Commission (FERC), any electric supplier that undertakes an obligation to serve customer electric load (whether pursuant to statute, franchise, regulatory requirement or contract) becomes a Load Serving Entity (LSE). LSEs are required to demonstrate that they own or have contracted for sufficient power supply to meet foreseeable demand at the times of regional tight supply, plus a reserve margin.[5] DTE is currently Ann Arbor's LSE, but if the City launched a MEU, the MEU would assume the obligation to serve load in the City and would therefore become the LSE. Because the cost of serving as an LSE can be large, if the City instead opted to establish a SEU, we found it would be best financially for the SEU not to serve as the City's LSE. This decision would nonetheless constrain the SEU's scope of operations.

Finally, we developed comprehensive organizational models of both the SEU and MEU and estimated capital and operating costs for both.

The steps detailed above comprise the quantitative analyses we performed. We also evaluated regulatory issues, including rules for utilities operating in Michigan or in MISO, and legal issues and risks that may constrain the viability or operations of the SEU and MEU. Finally, we developed a scoring rubric for qualitative grading of the Energy Options and utility structures against the A²ZERO Energy Criteria and Principles.

UTILITY ORGANIZATIONAL STRUCTURES

The City asked us to assess deployment of the Energy Options within three utility organizational structures:

Table 10: Utility Organizational Structure Options

UTILITY ORGANIZATIONAL STRUCTURE OPTIONS		
1	DTE	Continued primary reliance on DTE Electric to supply and distribute electricity.
2	SEU	Creation of a City supplemental Sustainable Energy Utility (SEU) that would operate alongside DTE resources.
3	MEU	Creation of a municipal electric utility (MEU) that would take over most DTE Electric assets and business in the city.

[4] See https://www.misoenergy.org/about/media-center/corporate-fact-sheet/.

[5] Similar requirements (referred to as "capacity obligations") are also imposed on LSEs (also known as "electric providers") under state law. See MCL 460.6w.

RELIABILITY

Electric reliability has two interrelated components: supply and distribution. Our study focused on power supply – the ability of Energy Options to generate the amount of electricity we project the City will need in 2030. We did not focus on distribution reliability – the ability of wires, poles, and other distribution system assets to deliver available power to customers.

We emphasize this point because the reliability problems that have plagued DTE's electric service to Ann Arbor have not been triggered by supply shortages but by distribution system problems. Increasingly bad weather and DTE's poorly maintained distribution system have caused repetitive and lengthy power outages in recent years and months, heightening public interest in finding alternatives to DTE to serve Ann Arbor. Because our study was primarily concerned with how power is generated, rather than with how it is delivered to customers, we did not directly evaluate distribution system changes that would be necessary to improve reliability.

All the same, implementation of the A²ZERO strategies undoubtedly will impact reliability because it will require significant changes to the distribution system. Both electrification and deployment of behind-the-meter solar and storage resources require changes to the distribution system which can improve or degrade reliability depending on how well the transition is managed.

First, electrification of buildings and vehicles will greatly increase peak hourly loads, necessitating installation of more distribution capacity. We estimate that the secondary distribution system, which serves most residences, will need to provide about 15% more electricity in the peak-demand hour in

2030 compared to today, assuming the A^2ZERO goals are achieved, and even more in subsequent years as electrification progresses. Circuits will need to carry a lot more electricity, and if those capacity improvements are well-planned, they can also deliver reliability improvements. Electrification without supporting improvements to the distribution system, however, could instead overload the system, further degrading reliability.

Second, installation of large amounts of solar PV and storage capacity behind meters in Ann Arbor will drive changes not only in the capacity but also in the configuration of the distribution system. One can – to oversimplify – envision these changes by recognizing that a system designed to distribute electricity generated on thousands of rooftops needs to be configured differently than one designed to deliver electricity generated at just a few, large facilities like coal, gas, nuclear and utility-scale wind and solar plants. This reconfiguration can result in greater reliability, too, but the cost and complexity of this undertaking mean that reliability improvements are far from assured.

The impact on reliability of electrification and increased renewables aside, it has been suggested that creation of a MEU will also bring reliability superior to what Ann Arbor experiences today while at the same time reducing costs and improving responsiveness and accountability. We did not evaluate current reliability investment needs as part of this study, nor did we project future distribution system investments that will be needed to accommodate changes in peak hourly loads and annual load curves brought about by 100% renewable electricity, significant distributed resources, and beneficial electrification. All these needs will significantly increase MEU costs, but without more detailed distribution system data and analysis that are beyond the scope of this study, we cannot provide a robust cost estimate. At a minimum, such an analysis would need to assess the condition and design of all circuits and substations throughout the City, a much more comprehensive undertaking than the sampling strategy used here.

In short, the scope of this report focuses on various opportunities to achieve 100% renewable energy by 2030, and a reliable supply of energy is part of that scope. The Consulting Team was not specifically contracted to study distribution system reliability now or in the future, though we qualitatively note several potential synergies and challenges. The SEU and MEU organizational structures can develop opportunities to reduce costs and barriers to 100% renewable energy that may, but do not necessarily, enhance distribution system reliability.

A²ZERO ENERGY CRITERIA & PRINCIPLES RATING APPROACH

A²ZERO ENERGY CRITERIA AND PRINCIPLES: RATING APPROACH

The City has adopted several core criteria and principles against which proposed actions must be evaluated.

The Core Criteria are:

- Reducing greenhouse gas emissions
- Adding renewable energy to what is already being generated.
- Actions taken are grounded in equity and justice.
- The core criteria must jointly be achieved along any path the City chooses.

The Principles include:

- Enhancing the resiliency of our people, our community and our natural systems
- Starting local
- Speed
- Scalability and transferability to other locations
- Cost effectiveness

The City recognizes that any pathway it chooses will necessitate tradeoffs among the principles. For example, purchasing Renewable Energy Credits (RECs) for electricity generated far away may be cost-effective and speedy, but it would not be local and would likely do little to promote resiliency of Ann Arbor.

To evaluate the Energy Options and utility organizational structures, we developed a qualitative scoring rubric for each of the A²ZERO Energy Criteria and Principles. Some rubrics lend themselves to binary (yes/no) evaluation, whereas others are best evaluated along a scale. We include notes here on how we interpreted some of the more complex Principles, and we provide additional interpretive notes in the sections where we rate each of the options.

EVALUATION RUBRIC FOR A²ZERO ENERGY CRITERIA & PRINCIPLES

CRITERION/PRINCIPLE	RATING SCALE
Reducing Greenhouse Gas Emissions	**NO** Does not reduce energy demands or power Ann Arbor's electricity needs with carbon neutral renewable energy solutions. **YES** Reduces energy demands and/or powers Ann Arbor's electricity needs with carbon neutral renewable energy solutions.
Additional to what is already being generated.	**NO** Adds no renewable energy or energy efficiency and displaces no fossil-fuel energy. **YES** Increases renewable energy or energy efficiency and displaces fossil fuel energy sources.
Grounded in equity and justice.	**POOR** Contributes nothing to, or erodes, participation of low-income and minority populations in decision making and sharing in the benefits of energy projects. **FAIR** Improves equity and justice marginally. **GOOD** Improves equity and justice significantly. **EXCELLENT** Low-income and minority populations participate equally in energy decision making and share equally in the benefits.
Enhancing the resiliency of our people, our community and our natural systems.	**POOR** Contributes nothing to, or reduces access to power during a crisis and/or does nothing to assure that loss of power does not compound the crisis. **FAIR** Marginally improves resiliency. **GOOD** Significantly improves resiliency. **EXCELLENT** Assures that individuals, especially at-risk individuals, emergency services and their personnel, have power during and after a crisis such that loss of power does not compound an existing crisis.
Starting local	**POOR** Located outside of Michigan. **FAIR** Located within Michigan but outside of Washtenaw County. **GOOD** Located within or near Washtenaw County. **EXCELLENT** Located within the City of Ann Arbor.

EVALUATION RUBRIC FOR A²ZERO ENERGY CRITERIA AND PRINCIPLE (continued)

CRITERION/PRINCIPLE	RATING SCALE
Speed	The Speed Principle required careful definition. It focuses on finding solutions that can be deployed rapidly in order to reduce GHGs. Some energy option projects, like BTM PV, deploy very quickly but in the aggregate don't add up very quickly because each project is small. Other Energy Options, like utility-scale solar or wind offered through MIGP, deploy very slowly but make a large contribution once they come on line. Because our task was to find ways the City can get to 100% RE in 2030, we decided to base this rating on maximum potential contribution to 2030 load under current regulatory and utility practices. **POOR** No likely contribution to load carrying capacity under current regulation and practice. **FAIR** Maximum projected contribution less than 25% of 2030 Ann Arbor load. **GOOD** Maximum projected contribution from 25%-50% of 2030 Ann Arbor load. **EXCELLENT** Maximum projected contribution greater than 50% of 2030 Ann Arbor load.
Scalable and transferable to other locations	Our approach to this Principle also required careful definition, because scalability and transferability are different, if interactive, concepts. The Principle definition adopted by the City states that this principle is concerned with ensuring Ann Arbor finds solutions that other local governments can replicate, which we found to be an easier, unified concept to guide our ratings. **POOR** Several significant financial, legal, regulatory, technical, operational or other barriers to replication by other Michigan communities. **FAIR** One or two significant, or several minor financial, legal, regulatory, technical, operational or other barriers to replication. **GOOD** Minor financial, legal, regulatory, technical operational or other barriers to replication. **EXCELLENT** Replicable by other Michigan communities without significant financial, legal, regulatory, technical, operational or other barriers.
Cost effective	**POOR** Energy solutions that are less affordable than current resources and/or worsen alignment with core criteria and principles. "Affordable" here refers to total cost to the Ann Arbor community, not cost only to ratepayers, the municipal budget or total social cost. **FAIR** Energy solutions that are less affordable than current resources but align better with the core criteria and principles. **GOOD** Energy solutions that are comparable in affordability to current resources and improve alignment with the core criteria and principles. **EXCELLENT** Energy solutions that are more affordable than current resources while also aligning with the core criteria and in support of many principles outlined in this section.

For complete development of the A²ZERO Energy Criteria and Principles, see Appendix 1.

SITUATION ANALYSIS

SITUATION ANALYSIS

In this section, we look at current and prospective renewable energy offerings of DTE Electric, rules and prices of the MISO regional market that apply to any default provider of electricity in the region, and some basics of how energy resources are financed, owned, and managed. This information sets the context for the additional progress Ann Arbor seeks, embodied in the 2030 A²ZERO goals, and for discussion about Energy Options the City, and others, can bring to bear to assure the 2030 goals are attained.

DTE RENEWABLE ENERGY RESOURCES

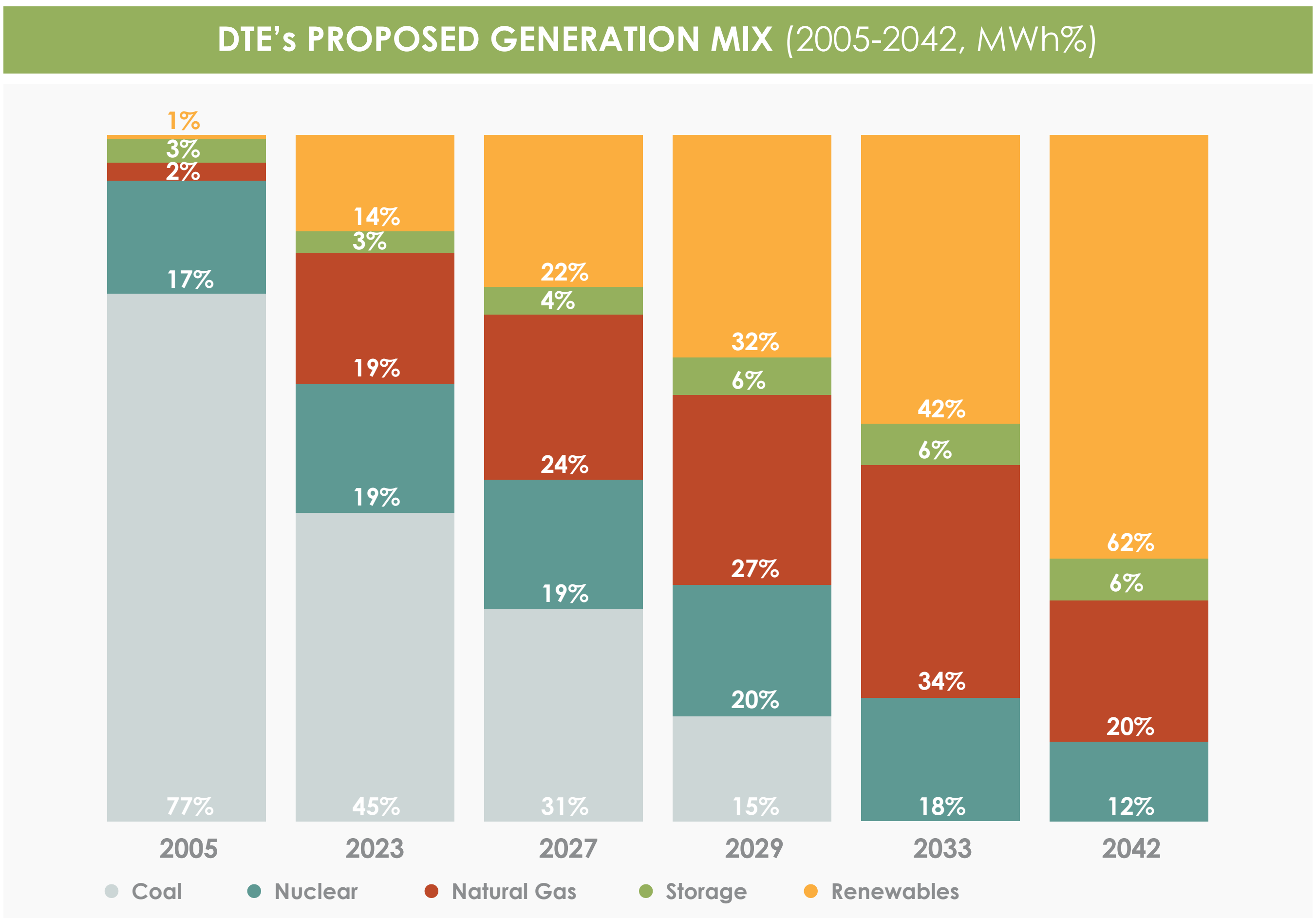
DTE Electric offers both default and voluntary RE programs and promises to expand both substantially in the next ten years. DTE also buys and distributes the power generated by Ann Arbor's hydroelectric dams.

Renewables Included in DTE's Default Electricity Rates

The State of Michigan updated its Renewable Energy Standard (RES) through Act No. 342 in late 2016. This RES required investor-owned utilities to achieve 15% RE by 2021. In plain language, this means that every DTE customer gets at least 15% renewable energy in their electricity mix without having to do or pay anything extra.

In Q3 2023 DTE further committed to voluntarily increase its RE portfolio with benchmarks shown in Figure 8. We understand DTE's targeted RE growth is linear, therefore we modeled DTE would achieve 35% RE electricity in 2030, increasing to 40% in 2032 and 42% in 2033.

Figure 8: Proposed Generation Mix (2005-2042, MWh%)



For Ann Arbor to achieve 100% RE by 2030, with DTE as the grid owner, Ann Arbor would need to source an additional 65% of its load from RE. Some of that difference can come from DTE voluntary RE offerings.

MI Green Power: DTE's Voluntary Green Pricing program

DTE Customers who wish to use a higher percentage of renewable electricity can sign on with MIGreenPower (MIGP), a Voluntary Green Pricing (VGP) program under which DTE customers can add additional renewable electricity to their mix in increments up to 100%. Ann Arbor already has among the highest levels of enrollment in MIGP within DTE's service territory. Currently, MIGP's net rate is slightly cheaper than DTE's default rates because of the way program costs are calculated; the simple understanding is that it is cheaper for DTE to add a new MIGP customer than what the Company can recoup by selling the resulting freed-up fossil fuel generating capacity to other utilities via the regional MISO market.

DTE will probably have adequate renewable resources in 2030 to bring Ann Arbor's energy mix to 100% renewables through MIGP – but we cannot assume every customer in the City will voluntarily sign on. Based on current enrollments and trends, we project that Business As Usual (BAU) would result in 10% of Ann Arbor's total electric load being enrolled in MIGP in 2030.

MI Green Power special and contractual programs

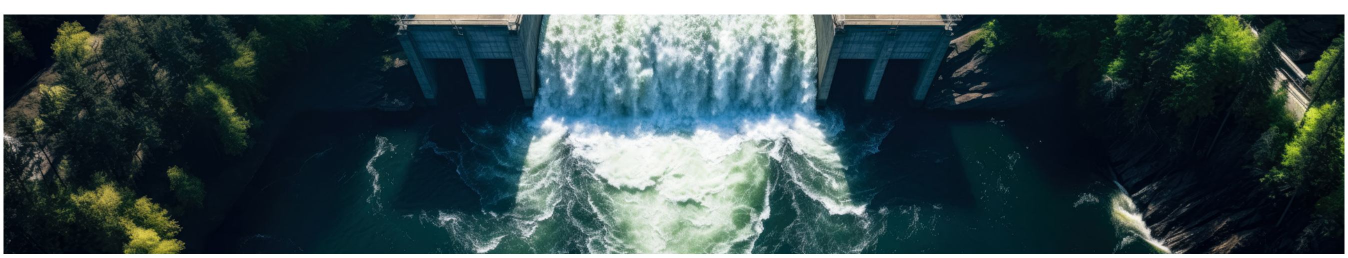
Even if MIGP remains slightly cheaper than DTE's default electric rates, we expect many customers will not sign up. DTE also offers a "customer-requested" option under which the Company can develop a large PV site on behalf of a customer who agrees to be responsible for the cost of any electricity generated that other customers do not buy. The City has been pursuing this opportunity in negotiation with DTE for several years.

The Wheeler Center Solar Project is a ground-mount, fixed-tilt solar PV project planned for the area on and around the Wheeler Service Center landfill in south Ann Arbor. The Wheeler Center Solar Project is currently projected to provide around 20 MW and to commence operations in 2025. It would cover about 4% of the total Ann Arbor electricity load in 2030, which is slightly more than the amount of electricity used by city government operations.

The Wheeler Center Solar Project site would be more expensive to develop than other DTE utility-scale solar installations and would thus not be cost-competitive with the standard MIGP offering. The city is seeking financial support from the state to reduce construction costs, which would bring costs of Wheeler Center Solar Project power closer to par with the MIGP retail rate.

Ann Arbor's Hydroelectric dams

The City owns and operates two hydroelectric dams (Barton Dam and Superior Dam) and sells the energy they generate to DTE under federal pricing rules. Although the City sells the energy to DTE, it retains the associated RECs, which are therefore available to offset non-renewable electricity sources in the energy portfolio.



We assume this arrangement will continue unless the City chooses to launch a MEU, in which case it would not renew the contract with DTE and would use the energy as a MEU resource to serve the City. Either way, we project the dams would supply 0.6% of Ann Arbor's projected electricity needs in 2030.

OTHER ENERGY RESOURCES IN ANN ARBOR

To complete our survey of current and planned energy resources serving the City, we must also consider Behind-The-Meter (BTM) solar PV, the Electric Choice program, and the renewable energy commitment of Ann Arbor Public Schools.

BTM Solar PV and PVS

An accelerating number of property owners are installing solar PV at their premises, minimizing their dependence on grid power from DTE and reducing long-term costs. The City encourages BTM solar PV through its Solarize program, and some additional number of property owners go outside the program to secure their own contractors and financing. We describe how BTM solar works in more detail below.

Based on currently installed BTM solar in the City, and projecting trends forward to 2030 considering market costs and federal tax subsidies, we project that 10% of total electricity use in Ann Arbor in 2030 would be supplied by BTM solar PV. This estimate is only a forward projection based on current levels, rates and prices, not our assessment of what levels might be accomplished if the City brought additional resources to bear.

Electric Choice

The vast majority of electricity customers in Ann Arbor purchase their power through DTE with a few purchasing through Michigan's Customer Electric Choice program. Through available data, we estimated 95% of electricity sales in Ann Arbor are purchased from DTE and 5% is purchased through Michigan's Customer Electric Choice program. We modeled Electric Choice customers as part of DTE's electrical grid and assume this energy would also be required to be 100% RE. Our modeling assumes that Electric Choice customers receive no more than the required 15% share of renewable energy; that is, we assume the Choice providers do not exceed the statutory minimum or offer their customers VGP options like MI Green Power.

Ann Arbor Public Schools

AAPS represents about 2.5% of the total electric load in Ann Arbor. While AAPS facilities are mostly located within City boundaries, it is a politically independent organization not subject to the City's A²ZERO goals – although we do include AAPS loads in our projections for energy use in the City. Fortunately, AAPS has adopted energy goals reasonably comparable to the City's. We assume that AAPS will be supplied with 100% renewable energy by 2030 and do not otherwise include AAPS in our projections of renewable energy the City must secure.

Summary of Renewables in Ann Arbor's Energy Supply in the BAU Scenario

When we compile all the above current and committed renewable energy resources and assume diligent and energetic implementation, we project that Ann Arbor would get about 59% of its 2030 electricity supply from renewables (Table 12). This might be considered the Business As Usual scenario.

Table 12: 2030 RE Contributions: DTE Grid

2030 RE CONTRIBUTIONS Existing Resources	
RESOURCE	**RE CONTRIBUTIONS**
DTE Grid	35%
AAPS + Dams	3%
MI Green Power	10%
Behind-the-Meter PV/PVS	10%
Total	**59%***

* Individual contributions do not sum to 59% owing to rounding

If Ann Arbor brings nothing new to the table, and merely allows current DTE, property owner and city programs to play out, we project the City will fall 41% short of its A^{2}ZERO goal of 100% renewable electricity in 2030. This projection alone makes clear that significant additional renewable energy resources will be needed if the City is to reach its 2030 target.

We cannot evaluate only the technical capacity of Energy Options to meet the City's electricity needs: we must also consider how well portfolios of resources advance the A^{2}ZERO Energy Criteria and Principles. Finally, while our study does not directly analyze options and costs for improving distribution system reliability, we recognize that many stakeholders are dissatisfied with DTE's reliability and want to evaluate alternatives. We examine the ability of several alternatives to provide renewable electricity, on top of which a detailed study of costs and benefits of reliability improvements might be performed.

Next, we overview how the energy market works, as context for steps Ann Arbor must take to accelerate its deployment of renewables.

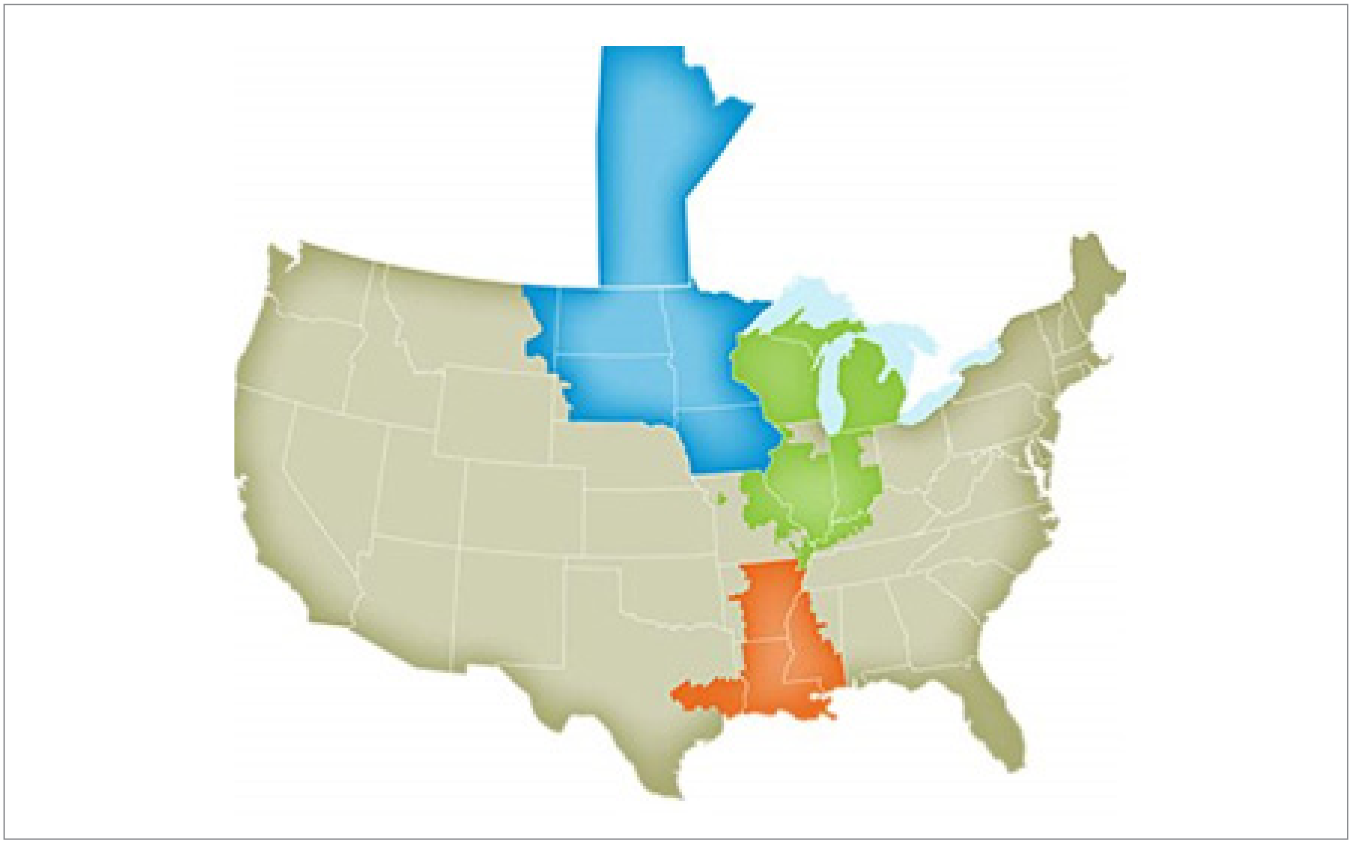
THE ENERGY MARKET

Ann Arbor's ability to improve on its current renewables path is conditioned by how energy markets work. In this section, we overview how the regional energy market operated by MISO (Mid-Continent Independent System Operator) works, and how energy providers and customers participate in the market.

MISO

Most of Michigan, and all of DTE's service territory, is within the MISO, a regional grid that extends from Louisiana to Manitoba. There are several ISOs around the country. They are meant to facilitate transmission of electricity within and across regions to assure reliable supply and efficient generation. Utilities within MISO, including DTE, sell all energy they generate, and buy all energy they supply to retail customers, through MISO market mechanisms. Thus, projecting MISO energy prices in the DTE service territory is foundational to our evaluation of costs under the DTE+ scenario.

MISO is likely to become even more important as renewables gain market share. Renewable energy is not freely "dispatchable" – meaning we cannot turn the sun and the wind on and off as needed – and therefore seamless transmission systems will increasingly be needed to move solar and wind power from wherever it is being generated at any given time to wherever it is needed. As we will discuss later, broad electrification in Michigan will increase wintertime loads, well beyond any reasonable projection of winter wind and solar generation within the state. Serving these loads renewably will likely entail importing power from other states in MISO, principally Great Plains states with significant wintertime wind resources.



Note: Map credit https://www.in.gov/oed/indianas-energy-landscape/electricity/regional-transmission-organizations/miso/

Cost of energy in MISO Zone 7

STEP8760 is a model developed by 5 Lakes Energy that can be calibrated to different wholesale markets to estimate the price of power in each hour of the year as well as project the lowest-cost resource mix for the region given a future load, expected resource prices, and user-defined constraints. The market price of power is an important determinant of the incremental cost, if any, of renewable energy to meet Ann Arbor's 100% RE goal.

DTE and the possible Ann Arbor municipal utility are / would be MISO market participants. Ann Arbor resides in Zone 7 of MISO territory, an area that comprises most of the lower peninsula. Unlike some regions of MISO, power prices in MISO Zone 7 are largely determined by the resources within Zone 7, because of limited transmission into the zone from other regions of MISO or the adjacent ISO, PJM. Consequently, we have calibrated STEP8760 to model the generators and expected demand in Zone 7 alone.

In our modeling for this report, we modeled eleven different Zone 7 scenarios in four model years (2025, 2030, 2035, 2040) using a range of assumptions about the following variables:

- new generation resource costs
- fuel costs
- politically defined renewable energy targets
- demand growth resulting from vehicle and building electrification
- retirement dates for thermal generators
- constraints on the development of new wind in Michigan

The sources for the input values of each of these options are outlined in Appendix 2.

Of these model results, we used just one in determining the expected Zone 7 power pool prices for this report. While we find it valuable to understand a range of scenarios, including extremes, the chosen model results are based on assumptions that are our best, albeit subjective, guess of what is realistic under current law, based on our joint expertise and understanding of current and future macroeconomic and political trends that would also make Ann Arbor's 100% renewable electricity goal challenging. Changes in law or technology could certainly lead to a different future.

In this scenario, we have constrained the build-out of new wind in Michigan to below its technical and economic potential due to the difficulties of siting new wind projects in Michigan given their contentious nature, and the limitations of good wind resource in the state. We assume conservative prices for future renewables due to supply chain constraints and high demand[6]; that demand growth from electric

[6] It is worth noting that the current trend is different. While demand for renewables is high, their build-out is being constrained by siting and grid interconnection issues more than by problems in the supply chain. The net result is still slower and sometimes more costly U.S. renewables development than might be expected in other macro-economic landscapes but for reasons other than those we initially hypothesized.

vehicles will expand quite quickly—in line with projections based on recently released, but not yet implemented EPA tailpipe emissions rules, and that buildings will begin to electrify heating and other uses of natural gas at a moderate pace.[7] A complete description of the inputs in this scenario are contained in Appendix 3. We assume no new legislation requiring a higher minimum proportion of sales in the state to come from renewable sources beyond the current 15% renewable portfolio standard. We assume plant retirements and new resource builds to which utilities already have regulatory commitments.

In this scenario, the STEP8760 model found that the lowest cost build of generation resources in Zone 7 in the year 2040 would include just over 6 GW of new wind, around 15 GW of new solar, and less than one GW of new battery storage. On top of this renewables portfolio the STEP8760 finds the need for an additional 15 GW of natural gas combustion turbines. Consequently, in this model, only 39% of generation in MISO Zone 7 comes from clean sources in 2040, with 5% of that coming from existing nuclear generation. Nuclear generation is about 20% of electricity sales, but much of that is from the Donald C. Cook plant, which is in the PJM energy market, not the MISO market in which Ann Arbor is located.

Although this is not an optimistic outcome for the reduction of fossil fuels used in the state of Michigan as a whole, it underlines the importance of Ann Arbor's goal of serving 100% of its own energy use with renewable generation.

Energy capacity and cost of DTE renewable electricity options

As Ann Arbor considers its options, it should consider to what degree its capacity is served with renewables, as opposed to its energy. Trying to serve 100% of Ann Arbor's capacity with renewables is conceptually analogous, although quantitatively different, to serving its load with 24/7 renewables. To be clear, Ann Arbor can achieve its 2030 100% RE goal without addressing sources of capacity but may wish to be mindful of differences among the Energy Options in the extent to which they "green" capacity.

To maintain grid stability there must always be more than enough generation capacity available in MISO Zone 7 to serve the historical peak load in that season. The capacity value of any generator, including fossil generators, is calculated based on how available that generator is during the tightest hours of the season—the hours in which high demand lines up with low generation availability.

Utilities within MISO are subject to a variety of requirements meant to assure that the region can reliably meet energy needs at any given moment in time. Foremost among these are capacity obligations, which require Load Serving Entities (LSEs) to demonstrate that they have contracted with generating facilities for enough electricity to serve reasonably foreseeable loads, including a safety margin for outlier events (like very hot summer days) and unscheduled plant shutdowns (known as a "planning reserve margin"). In addition to paying for actual energy used, LSEs must also own or contract for capacity. All LSEs must demonstrate that they have

[7] Note that these assumptions are for MISO Zone 7, not for Ann Arbor, where we model EV adoption and building electrification per the A^{2}ZERO 2030 goals.

met their respective MISO capacity obligations, including planning reserve margins.[8] This requirement delineates an important distinction between a SEU and a MEU: a MEU would unavoidably be an LSE and would incur potentially expensive obligations to satisfy capacity requirements. A SEU, in contrast, would be supplemental to DTE, would not supplant DTE as the LSE for Ann Arbor, and would therefore not be subject to MISO capacity obligations. In this DTE+ scenario, DTE remains as Ann Arbor's LSE and is responsible for meeting all capacity obligations.

Because renewables are intermittent, they have lower capacity values per megawatt-hour of energy produced than fossil generators. Furthermore, as more renewables enter a portion of the grid, they drive down their own capacity values by making the tight periods in which they produce less tight. This dynamic can be improved with more transmission and storage but is unlikely to be totally obviated in the near future.

Understanding these details of capacity markets is important to understanding what Ann Arbor would get if it were buying its renewable energy from DTE. In this scenario, even though the equivalent of 100% of Ann Arbor's *energy* would come from renewables, only a small fraction of Ann Arbor's capacity would come from renewables, 10-20%[9] in 2030; the rest will come from thermal generation (fossil or nuclear). While new renewables reduce the need for thermal generators to run, therefore reducing greenhouse gas emissions, they do not readily displace the need for those generators to be maintained and available

[8] Michigan state law contains additional state-level capacity obligations, which require Michigan LSEs to own or contract for adequate capacity four years forward into the future based on projections of future MISO capacity obligations. See MCL 460.6w. MISO's capacity obligations, by contrast, only extend one year into the future.

[9] This is a rough estimation based on 5LE's analysis of the average value of capacity credits from wind and solar in MISO Zone 7.

for hours of short supply. In the long run, for Michigan's grid to run without fossil fuels entirely it will need clean capacity, not just generation. Currently, the easiest way to purchase clean capacity is new battery storage, but new battery storage is expensive compared to old fossil plants. Furthermore, there is no generally recognized method for a MISO market participant to ensure it meets capacity requirements with renewables. Unlike renewable energy, which can be relatively reliably recorded and tracked using RECs, there is no tracking system for renewable or clean capacity.

What this means for evaluating Ann Arbor's options as it considers approaches to decarbonizing its energy use, is that DTE can provide inexpensive renewable energy to Ann Arbor backed by fossil-fuel capacity that is much cheaper than capacity from new renewable or energy storage resources.

If Ann Arbor establishes a municipal utility, it will have the option of approaching its power and capacity supplies with the same, lower-cost approach—serve its energy from renewable sources while entering into contracts for capacity from fossil generators—or it could attempt to develop enough clean capacity to meet its needs without any backup from fossil generators. While this would be expensive and would inevitably increase the rates of Ann Arbor's residents, it is an option that is likely unavailable in other approaches to Ann Arbor's goal of serving its load with 100% renewable generation.

ASSET OWNERSHIP MODELS

For simplicity, we distinguish three ownership classes for RE power generating assets: customers, the City, and a third party. Stacking of Energy Options in any given scenario depends on asset ownership as well as technology.

Customer Ownership

The use of "customers" in this study refers to electric utility customers. Customers are empowered with many decisions for how they may individually pursue goals of 100% RE. References to customer ownership typically mean customers who own BTM PV and PVS assets (aside from those who voluntarily choose MIGP). These customers may be residential or commercial and they are frequently the property owners. We acknowledge electric utility customers may be renting properties that are available for solar projects and the landlord-lessee relationships with BTM solar projects are an important issue for Ann Arbor to resolve to maximize the amount of local deployment. Customers may select Energy Options such as VGP or potentially community solar, but in this study, we do not consider these subscriptions direct ownership.

Ann Arbor Ownership

The City of Ann Arbor is a municipal non-profit entity with good credit and may own projects as the City, a SEU, or a MEU. This study assumes the City and its potential electric utility organization can raise debt capital at market level rates for general obligation bonds, revenue bonds, or low-interest loans. The City may own BTM PV and PVS assets. We acknowledge the startup period for a SEU or MEU may result in higher interest rates for debt capital, but we assume Ann Arbor can refinance interest rates over time to reduce financing costs.

The SEU or MEU would require Ann Arbor to establish a new City utility that may own assets that offset loads beyond municipal consumption. Our analysis is agnostic on the type of bond Ann Arbor may secure and assumes Ann Arbor could potentially finance projects up to 100% debt. Variations can exist in the capital structure, such as City revenue bonds or general obligation bonds, access to grants or low-cost loan opportunities.

Additional financial analysis is provided in the SEU and MEU sections.

Third Party Ownership

Third party ownership (TPO) may include utilities, independent power producers (IPP), or non-profit entities. This study focused on TPO in the form of established, for-profit taxable entities with proven ability to finance projects with reasonable rates for equity and debt. For simplicity, DTE as an owner of RE assets, is included as TPO. TPO may apply to all Energy Options, for both BTM and FOM applications. While the City's tax-free status would generally be considered beneficial, we note TPO can apply accelerated tax depreciation to reduce expenses during an assets' early operational years.

A^{2}ZERO 2030 GOALS

A^2ZERO 2030 GOALS

Armed with a projection of Ann Arbor's current renewable energy trajectory and the energy markets, we have context for understanding the City's 2030 A^2ZERO goals. The goals are fully explained in the City's report, "Ann Arbor's Living Carbon Neutrality Plan." We summarize them here to explain how they shape our projections of future electricity requirements.

Many, but not all, of the A^2ZERO 2030 goals directly support achievement of the 100% renewable electricity goal. We did not independently assess viability of the 2030 goals; rather, we took their attainment as a given and sought to determine how they would shape pursuit of the 100% renewable electricity goal. Here we provide a brief summary of how we included the A^2ZERO goals in our analysis. We do not discuss every A^2ZERO strategy here: for example, fleet electrification goals are a subset of the overall 50% EV goal, and other goals, such as recycling, do not directly impact energy use.

STRATEGY 1: POWER OUR ELECTRICAL GRID WITH 100% RENEWABLE ENERGY

1

This strategy includes goals for Community Choice Aggregation (CCA), community solar, bulk buying of solar PV and batteries and development of a large solar PV project at the Wheeler Center Solar Project in south Ann Arbor. At a high level, our approach was to model physically and economically feasible capacity for solar PV and battery storage behind the meter in the city, and in front of the meter at the Wheeler Center Solar Project. We did not attempt to model impacts of CCA or community solar as vehicles for deployment of solar PV, as we could not assume they would become viable under law and DTE practice before 2030. We assumed that the Solarize bulk-buying program would continue but that a City/SEU/MEU financed solar PV program would have greater deployment impact. We assumed that the Wheeler Center Solar Project will be developed at currently planned capacity before 2030.

STRATEGY 2: SWITCH OUR APPLIANCES AND VEHICLES FROM GASOLINE, DIESEL, PROPANE, COAL, & NATURAL GAS TO ELECTRIC

2

Strategy 2 encompasses several actions:

Action 2.1*: By 2030, 100% of City facilities, 30% of owner-occupied homes, and 25% of rental properties have fully electrified and the electricity powering those homes is coming from renewable energy sources.*

Our data on natural gas use in homes was stratified by building type but not occupancy. Because the overall number of owner-occupied homes (based on census data) is very close to the number of single-family detached homes (based on NREL data), for purposes of calculation we made the simplifying assumption that 30% of gas usage in single-family detached homes would electrify by 2030. By extension, we then assumed that 25% of gas usage in the four other home types (single-family attached and three levels of multi-family housing) would electrify by 2030. Census data indicate that 22% of Ann Arbor residences already use electricity as their main heating source, but NREL data estimate only about 10% of heating energy in the City is electric. This difference is consistent with a reasonable assumption that smaller residences, such as apartments, which require less heating energy, are more likely than larger residences to use electric heating.

Actions 2.2, 4.2 and 4.3*: Bus electrification and ridership*
These actions would electrify all AAATA and U of M buses, quadruple ridership and increase commuting by bus to 25% of inbound riders.

We modeled these actions together because they interact. First, we modeled increased local and commuting ridership, established assumptions about the impact of those changes on bus miles traveled, then calculated charging load accordingly.

Action 2.3*: by 2030, 50% of all vehicle miles traveled are in electric vehicles.*
We developed data for passenger and commercial vehicle counts and miles driven, subsuming electrification of the City fleet (S2.4) and private fleets (S2.5) rather than modeling them separately.

STRATEGY 3: SIGNIFICANTLY IMPROVE THE ENERGY EFFICIENCY IN OUR HOMES, BUSINESSES, SCHOOLS, PLACES OF WORSHIP, RECREATIONAL SITES, & GOVERNMENT FACILITIES

3

Strategy 3 encompasses eleven actions.

*For **Action 3.1**, we modeled the impact of 85% of owner-occupied homes, 80% of tenant-occupied homes, and 80% of businesses achieving a 20% reduction in electricity usage and a 15% reduction in natural gas usage by 2030. We did not separately model the impact of building code changes.*

We also modeled the impact of Action S3.3, converting all streetlights and traffic signals to LED.

We did not attempt to model energy-use impacts of goals for benchmarking and disclosing energy usage, establishing an energy-project loan loss reserve for residents, or developing an energy concierge and community engagement programs, a net-zero energy initiative for affordable housing, a green rental housing program, or a green business challenge and weatherization initiative. We assume all these actions will contribute to the achievement of action 3.1.

STRATEGY 4: REDUCE THE MILES WE TRAVEL IN OUR VEHICLES BY AT LEAST 50%

4

Strategy 4 aims to reduce miles traveled in vehicles (VMTs) through the following seven actions:

Implement Non-Motorized Transportation Plan.
Expand and Improve Local Transit
Expand and Improve Regional Transit
Increase Number of Park and Rides Ensure Seamless Connection to Transit.
Increase the Diversity of Housing
Develop Mixed-Use Neighborhoods
Establish Tiered Parking Rates

We modeled impact on energy use of the first three actions under Strategy 4, as they directly impact how much people drive or use public transit. Assuming vehicle electrification goals under Strategy 2 are achieved, trip reduction and public transit measures would impact electric load in both directions. We model these impacts in our projections.

STRATEGY 5: CHANGE THE WAY WE USE, REUSE AND DISPOSE OF MATERIALS

5

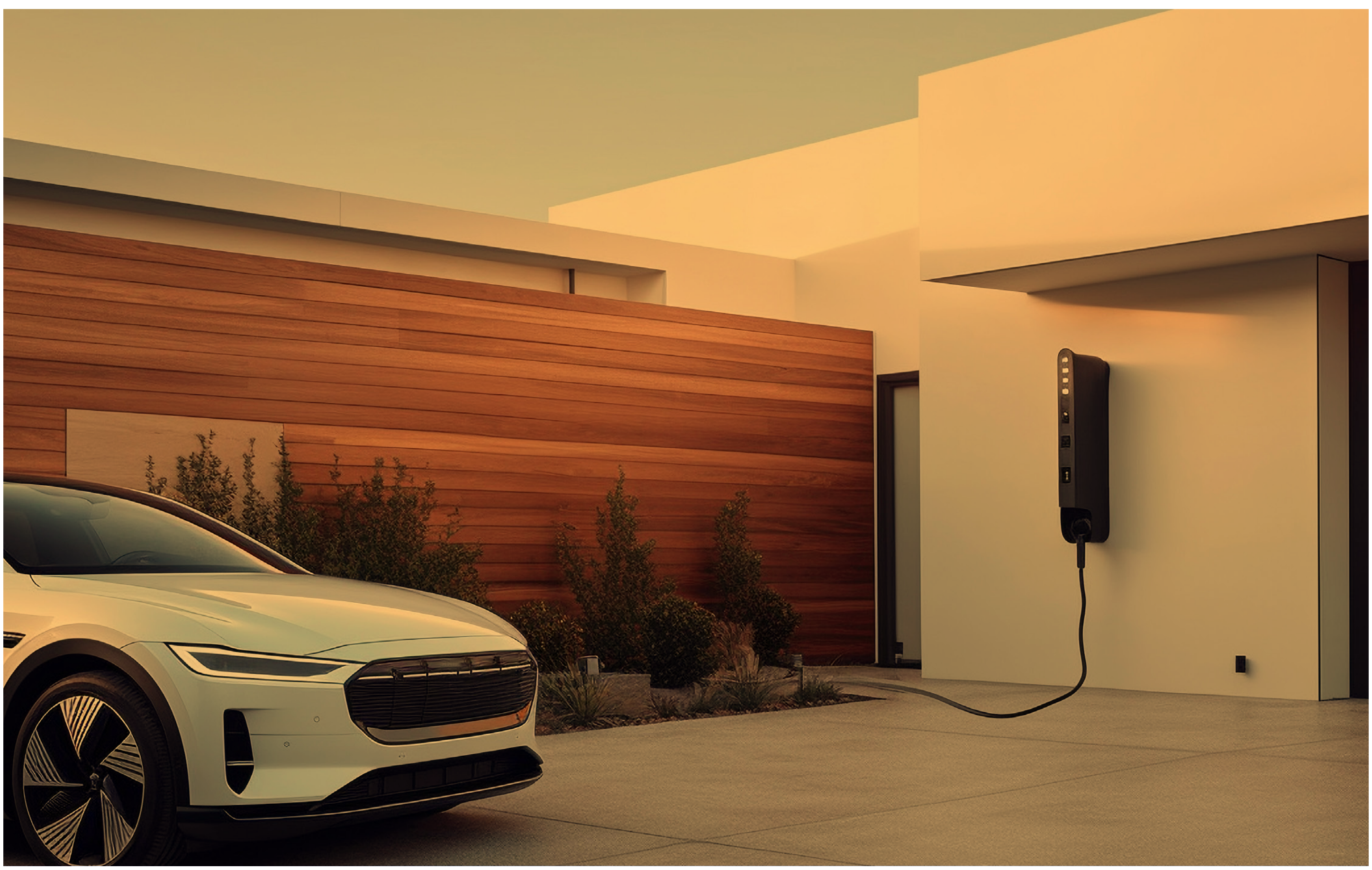
Strategy 5 focuses on changing the community's relationship with what people buy and use and how the materials are disposed of once used. While these choices and behaviors impact energy use somewhere and at some time, most of those impacts occur outside the scope of this study – for example, energy used to produce and transport goods, or in disposal. Because our scope focused on energy use within the City of Ann Arbor, we did not attempt to model the energy impacts of this strategy.

STRATEGY 6: ENHANCE THE RESILIENCE OF OUR PEOPLE AND OUR PLACE

6

Strategy 6 focuses on enhancing the resilience of the community and ensuring that it can thrive regardless of what disruptions or changes may take place. While distributed, renewable energy may provide greater resilience in the energy system, our scope was to analyze options around how the City could make the transition, not to quantify ancillary benefits such as resilience. Therefore, we did not attempt to model the energy impacts of this strategy.

ESTIMATING ANN ARBOR'S CURRENT & FUTURE ELECTRIC LOADS



ESTIMATING ANN ARBOR'S CURRENT AND FUTURE ELECTRIC LOADS

We developed electric load and load-curve baselines as a basis for projecting how much renewable energy Ann Arbor will ultimately need to source, given the A²ZERO 2030 goals, and to inform estimates of electric distribution system size and costs for the municipalization option.

As a first step, we developed load curves assuming all buildings and vehicles were fully electrified at 2018 usage levels. Load curves depict electricity usage by rate class (residential, commercial, industrial) for all 8,760 hours of a (non-leap) year. After that, we applied the impacts of the A²ZERO 2030 strategies. Some 2030 actions increase load projections, such as the building and vehicle electrification strategies; others decrease projected load, including building energy efficiency and vehicle trip reduction actions.

University of Michigan

We excluded the U of M from our analysis and projections. The City includes U of M's energy use in its 2030 A²ZERO goals, but the University controls its own energy purchases and climate planning that are not subject to City programs. Fortunately, U of M has its own, ambitious climate goals that are reasonably consistent with A²ZERO.

ComStock data classifies loads by major building types and does not include most building types on the U of M campus, therefore we assumed that most U of M loads and usage were not included in the baseline data we used to support our load projections.

Although we excluded U of M buildings from our analysis, we did include estimates of vehicle travel to and from U of M to support our estimates of EV charging loads.

BUILDING ELECTRIFICATION LOAD PROJECTIONS

We estimated current baseline loads because actual electricity and natural gas data from DTE were not available. We used 2018 NREL ResStock and ComStock data for Ann Arbor as our primary baseline to project electric load if all building fuel uses were converted to electric. We used 2018 data because that is the year sampled in the most recent ResStock and ComStock databases. Using 2018 data also avoids sampling data from COVID pandemic years when changes in energy use patterns and totals would poorly predict future-year usage and load curves. It was necessary to consider residential and commercial loads separately because they are generally served by different levels of the electric distribution system; for example, the secondary distribution system does not need to be big enough to serve all commercial loads.

In addition to estimating load growth from converting all natural gas and propane uses in buildings to electricity, we estimated the impact of converting electric resistance heating uses to heat pumps. This step was necessary because about 10% of Ann Arbor residential heating energy use in 2018 was electric, which we assumed to be relatively inefficient resistance heating. We assumed resistance heating uses would be converted to air-source heat pumps, although some building owners might choose technologies (for example, geo-exchange or radiant heating) that have different efficiency ratings than heat pumps; and some locations may already have had heat pumps in 2018. On balance, we expect these assumptions would tend slightly to overstate load projections for 2030, which we viewed as erring on the safe side for planning purposes.

For each 15-minute period of 2018, we used the ResStock and ComStock databases for Ann Arbor to determine how much gas and propane were used for space heating, water heating and other uses, and how much electricity was used for space heating.

Because air-source heat pumps and water heaters are more efficient than their gas-powered versions and resistance heating, we needed to develop Coefficients of Performance (COPs) to express the efficiencies realized from electrifying them. For example, depending on outdoor temperature, an air-source heat pump typically requires one-third the energy of a gas furnace to deliver a given amount of heat, indicating a COP of 3. We multiplied the COPs times the raw kWh equivalent energy use of gas furnaces, gas water heaters and electric resistance heating, respectively. For other, relatively minor uses of gas (including clothes dryers, lighting, pool and hot tub heaters, grills and cooktops), we used a COP of 1; in other words, we assumed no overall efficiency gains from electrifying these end uses. These operations yielded estimates for the total amount of electricity that would be needed to electrify all gas-powered equipment and all electric resistance heating in the city, for each 15-minute period of 2018.

Concurrently, we developed estimates of current electric load in Ann Arbor. Our primary sources for these estimates were the ResStock and Comstock databases, which include data on total electric usage in Ann Arbor based on sampling of various end uses, building types and counts. For Ann Arbor residential electric usage in 2018, ResStock estimated about 487 million kWh, and for commercial accounts Comstock estimated about 449 million kWh. Consistent with ComStock's taxonomy of rate classes, we included industrial and lighting customers in the commercial category. While U of M is geographically within Ann Arbor, most U of M buildings are not covered by the ResStock and ComStock building type classifications, which facilitated exclusion of U of M loads from our baseline and projections.

Because the ResStock and ComStock figures are based on samples rather than actual electricity usage of the full customer population in Ann Arbor, we checked our estimates using other sources. First, we used actual 2018 usage and customer-count data for all residential and commercial accounts served by DTE and scaled those data down to Ann Arbor, using US Census counts of households and business establishments in the City. This approach yielded estimates of 413 million kWh for residential customers, a figure about 10% lower than the ResStock estimate. We also know, however, that median household income in Ann Arbor is significantly higher than for most of the region served by DTE, suggesting that residence sizes and residential energy use are also larger than the overall average for DTE's service territory. Accordingly, we concluded that this estimation technique roughly comported with the ResStock estimates for Ann Arbor.

We also checked the ResStock estimate against geographically approximate usage figures that DTE provided to the City of Ann Arbor. For 2021, DTE provided actual residential electricity usage for all Ann Arbor zip codes of 482 million kWh. Although this figure is very close to the ResStock estimate for 2018, there are two, presumably offsetting differences. First, several Ann Arbor zip codes encompass parts of adjoining townships, meaning that DTE's usage figures would exceed those for Ann Arbor alone. On the other hand, residential usage for 2021 would have differed from 2018 in two notable respects: incremental improvements in energy efficiency and increases in residential electricity usage related to the COVID pandemic. We did not attempt to quantify these differences or to estimate their net effect; rather, we observed that their net effect was likely to be small, suggesting that DTE's figure of 482 million kWh was roughly consistent with the estimate we developed using ResStock data. With those provisos, we accepted the ResStock 2018 estimates as reasonably consistent with DTE's 2021 figures.

Validating the ComStock 2018 estimates, we calculated that downscaling the DTE-wide figures based on the census count of commercial establishments in Ann Arbor yielded an estimate of 455 million kWh, a figure very close to the ComStock estimate of 449 million kWh.

Next, we estimated the impact of various A^{2}ZERO 2030 strategies that could be expected materially to impact building electricity usage and demand, as discussed in the preceding section on A^{2}ZERO 2030 Goals.

VEHICLE ELECTRIFICATION CHARGING LOAD PROJECTIONS

Our approach was to project charging load assuming 100% of all vehicles in Ann Arbor were electrified, then to adjust those projections to account for impact of A^{2}ZERO 2030 goals.

We used NREL's EVI Pro Lite to develop our projections. This web-based tool allows the user to set several variables related to vehicle and charger types and locations, weather, user preferences and driving behaviors.

Input assumptions

We determined that there were about 69,000 vehicles registered in Ann Arbor in 2021. We made the generalizing assumption that vehicles registered in Ann Arbor average 25 VMT per day as that is the closest option provided in EVI Pro.

We found that about 18,000 cars registered in Ann Arbor commute to other places daily at an average round trip of 31 miles. Also, over 75,000 cars registered elsewhere commute to Ann Arbor daily. We found that the average commuter to Ann Arbor travels 36 miles per day, which we rounded down to 35 miles per day for modeling purposes.

Vehicle types: we assumed a vehicle mix of 50% sedans, 50% SUVs and small trucks, because, while the current EV mix is weighted towards sedans, we expect to see more SUVs in the future as the mix of EV sales becomes like the current mix of ICE vehicle sales.

Charger types: we assumed that 20% of home chargers would be Level 1 and 80% Level 2. We assumed the same mix for workplace chargers.

Charger locations: we assumed that 75% of A2 resident drivers would have access to a charger at home, but 100% of commuting drivers would, the assumption being that commuters are more likely to be living in single family homes (with garages or easily accessed electrical outlets) than Ann Arbor residents.

Charging behaviors: EVI Pro requires the user to set the extent to which drivers prefer to charge at home or at work. We assumed that future utility tariffs will encourage drivers to charge when renewable energy is usually being supplied to the grid – that is, during the workday. Therefore, we assumed that 60% of vehicle owners would prefer workplace charging. This assumption increases projected charging load substantially because the model assumes that 60% of the 75,000 daily commuters to Ann Arbor would prefer to charge their vehicles during the workday.

EVI Pro also allows the user to specify what rate of charging drivers will choose – as fast as possible, as slow as possible, finish charging by departure, start charging after midnight. We set this variable to "as slow as possible" for both home and workplace charging. This is a best-case scenario and reflects the idea that charging behavior is influenced by rate design and convenience (i.e. improved app design), and demand response capabilities will change as EVs become more prevalent.

Finally, EVI Pro requires the user to set the ambient temperature at which charging occurs, which impacts charging efficiency and speed. We ran the model with all the above assumptions at a range of different temperatures to estimate charging loads at different times of the year.

100% EV Charging Load

EVI Pro outputs a 15-minute charging demand profile for a model weekday and a model weekend day given the input parameters. We constructed our overall 8760-hour charging profile by averaging the demand in each hour and combining results based on daily temperature averages for the 2018 sample year. That is, we strung together 365 daily profiles based on temperature and weekday/weekend designation into a single yearlong charging profile. Home charging was assigned to residential electric load, and workplace and public charging were assigned to commercial electric load. Overall, we found that home charging for 100% EV fleet would require almost 157 million kWh per year and commercial charging (workplace plus public chargers) would require almost 165 million kWh per year. Our hourly profile also allows us to identify peak charging demand that the distribution system must be sized to accommodate, in combination with building electricity demand.

Next, we adjusted our 100% EV charging load curve to reflect A^{2}ZERO 2030 actions:

> ***Action 2.2*** *By 2030, TheRide and UM's entire fleet of buses are electric and their power is drawn from renewable energy.*
>
> ***Action 2.3*** *By 2030, 50% of all VMT are in electric vehicles.*
>
> ***Action 4.2*** *Quadrupling of current bus ridership, with the average of 3.5 miles per trip.*

Impact of A²ZERO Actions on EV Charging Load

Other Actions would impact VMTs and charging load, but we did not model them separately either because they overlap with the goals above, or they are expected to make only a small difference and we lacked data to estimate them:

> ***Action 2.4*** *By 2025, 90% of the City's fleet has transitioned to electric. We did not model this strategy because City fleet miles and charging are modeled as part of Strategy 2.3, 50% EV miles.*
>
> ***Action 2.5*** *By 2030, 50% of private fleets within the City are electric. We did not model this goal because its charging impacts are captured in our estimate for Strategy 2.3 calling for 50% electric VMTs.*
>
> ***Action 4.1*** *By 2030, 25% of in-city trips are conducted by walking or bicycling thanks to ubiquitous and safe infrastructure. We did not model this goal because available data show that more than 25% of in-city trips are already on foot or by bike, indicating no marginal reduction in VMTs and EV charging would be necessary to achieve this goal.*
>
> The following two actions were not modeled separately because they are incorporated into our modeling of EV charging load under Actions 2.2 and 4.2:
>
> > ***Action 4.3*** *By 2030, 25% of the regional community trips into the City are one via regional transit options;*
> >
> > ***Action 4.4*** *By 2030, commuter trips from the border of the City to their destination within the City has declined by 25%.*
> >
> > ***Action 4.6*** *By 2030, 20% of in-city trips are done by walking or biking. Available data show that this goal has already been achieved, and thus no change in vehicle charging will be needed.*

Net of the impact of the A²ZERO 2030 strategies, we found that vehicle charging in Ann Arbor will use 166 million kWh in 2030 with a peak hour demand of almost 43,000 kWh.

Streetlights

Streetlights constitute a very small part of the overall electrical load, but we included them because their load is easy to estimate and because there is an A²ZERO 2030 goal:

Action 3.3 *By 2029, all streetlights and traffic signals have been converted to LEDs.*

We found that completing conversion of all city-owned and DTE-owned streetlights to LED by 2030 would reduce overall usage by 32% and peak demand by the same degree, since streetlights use the same amount of energy every hour they are turned on. Total usage would be about 2.6 million kWh in 2030.

Overall load projections

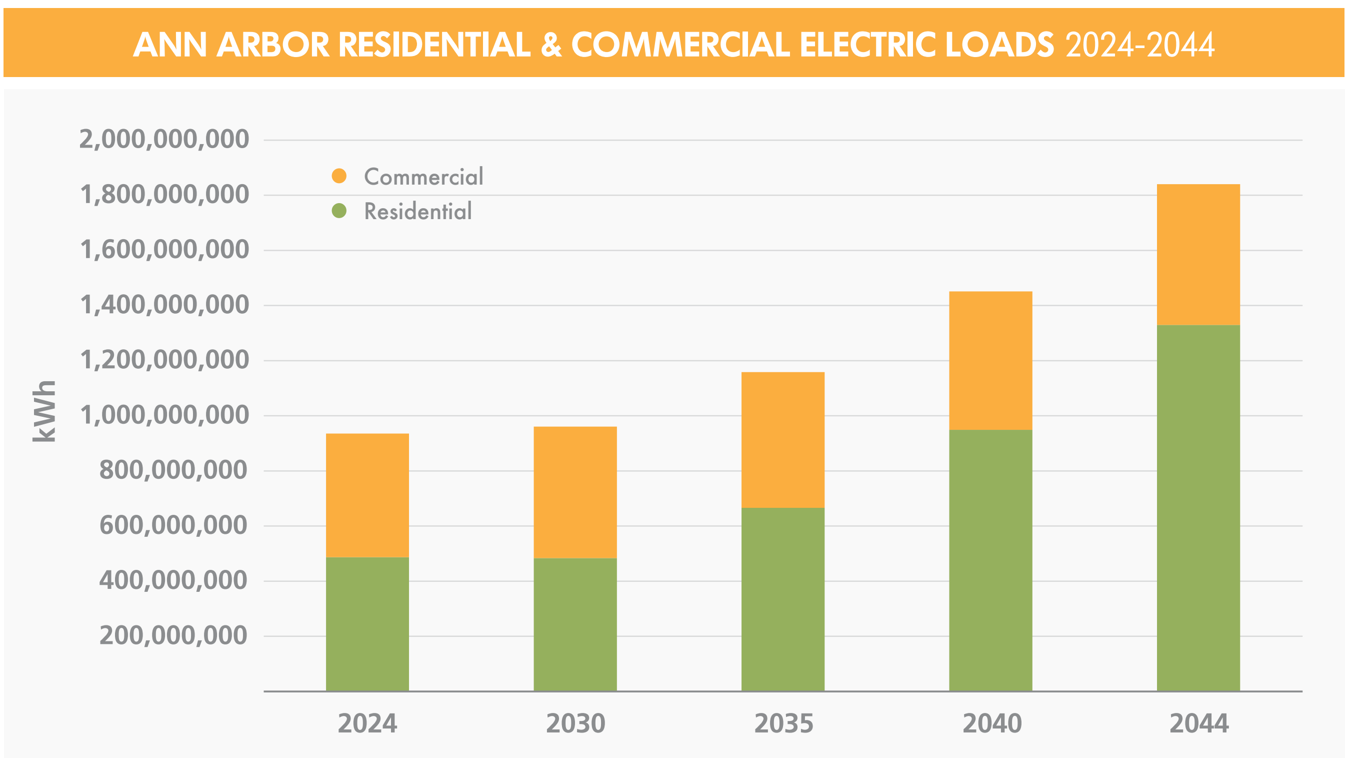
Combining our projections for building electrification and EV charging and net of A^2ZERO 2030 goals, we project that total annual residential load will remain almost steady at 484 million kWh, but that the peak demand hour in 2030 will be 15% higher than the 2018 single-hour peak. Ann Arbor already has a somewhat unusual peak electric demand in winter because of the relatively high use of electric heating, but the winter peak will become much more pronounced owing to electrification of heating. The City is studying thermal energy networks for heating and cooling, which could significantly reduce peaks.

We found that commercial electricity use will rise by about 6% to 477 million kWh in 2030, with peak hourly demand rising 1% to about 124,000 kWh.

Adding together residential, commercial and streetlight usage to arrive at total load, we project that electricity usage in Ann Arbor will rise about 3% overall by 2030 compared to 2018, to 964 million kWh. See Figure 9.

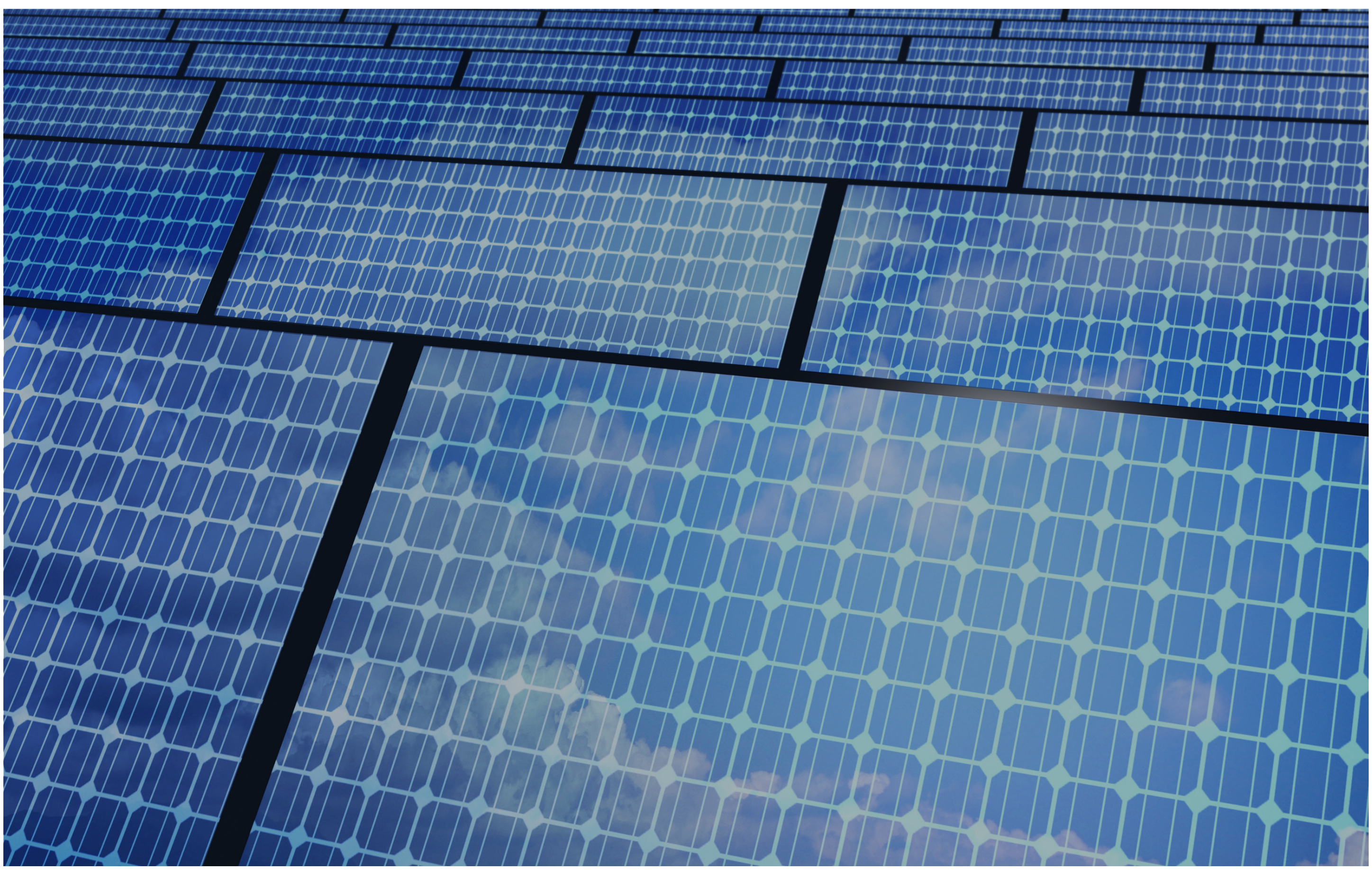
We also projected load after 2030 to support financial projections for our SEU and MEU scenarios. We assumed complete electrification of vehicles and buildings would be achieved by 2050, with marginal offsetting energy efficiency improvements. We used linear interpolation to project loads for the intervening years. We find that load will increase substantially through 2044.

Figure 9: Ann Arbor Electric Load Projections, 2024-2044



The shape of the load curve will also shift, with the highest loads coming in the winter owing to electrification of heating. The distribution system will need to deliver slightly more electricity at annual peak than it does today. We do not model or cost distribution system investments, as doing so would require asset data for every circuit in the City, rather than the sampling of circuits gathered for this study. A Phase 2 municipalization feasibility study would undertake such an analysis.

RENEWABLE ELECTRICITY OPTIONS



RENEWABLE ELECTRICITY OPTIONS

We analyzed the potential of several potential renewable energy sources to contribute to the 100% renewable electricity goal:

Table 13: Renewable Electricity options

RENEWABLE ENERGY OPTIONS
• DTE's MI Green Power Program (MIGP) • Traditional and Virtual Power Purchase Agreements (PPA/VPPA) • National REC Market • Community Solar • Behind-the-meter (BTM) Photovoltaics (PV) and PV with storage (PVS) • Virtual Power Reduction Agreements (VPRA)

We describe each option and our analysis of it in greater detail below. Our analysis spans several dimensions, including cost, reliability, capacity, technical feasibility, legal and regulatory factors and alignment with the A²ZERO Energy Criteria and Principles.

The Energy Options may be stackable, meaning that the City could, and probably should, pursue more than one at once. Options may be compatible with multiple organizational strategies, for example the City can support behind-the-meter PV solar deployment with DTE continuing as sole provider, through a SEU or through a municipal utility.

Some options are already active with the potential to accelerate adoption, while other options are not yet operational and would require legal, regulatory, technical, or business model adjustments to implement. Certain options have the potential to achieve 100% RE by 2030 on their own, though we generally recommend layering options together to provide for a more diverse portfolio that distributes risk and better meets the City's principles.

To evaluate these options, we first had to classify and define them carefully, which included recognizing different business models for implementing them. For example, on-site solar PV and storage can be customer-owned, city-owned, utility-owned, or third-party owned. Different business models for the same project may have very different costs, allocation of risks, timelines and outcomes.

Our analysis illuminates multiple ways the City might stack these Energy Options to achieve 100% RE by 2030. The difficult choice will be how best to stack options to achieve the Energy Criteria and manage tradeoffs among the Energy Principles.

Other Energy Options may be available to the City that we did not examine. For example, we understand that the City plans to pursue geothermal technologies for heating and cooling. This study did not evaluate this opportunity. The Consulting Team also notes BTM wind power solutions may be possible for some customers, but the commercial infrastructure is not yet available to a degree that would allow us to project a significant contribution from BTM wind by 2030.

Energy Option Timeline: We focused our evaluation of Energy Options on the strict interpretation of achieving 100% RE by 2030. The solutions to achieve 100% RE by 2030 are likely to differ from the solutions to maintain 100% RE for longer timeframes. For example, we find that RECs will be needed in 2030, but could likely be phased out over time because their performance against the A^{2}ZERO Energy Criteria and Principles is weaker than other options. Some options, notably battery storage, are also likely to become more financially and/or technically feasible after 2030. We thus recommend revisiting energy option planning when a clearer utility structure path is evident.

Table 14: Overall evaluation of Energy Options against A²ZERO Energy Criteria and Principles

ALIGNMENT OF ENERGY OPTIONS with A²ZERO Energy Criteria

CRITERION	MI GREEN POWER	(V)PPAs	NATIONAL RECs	COMMUNITY SOLAR	BTM PV& PVS	VPRA
Reduce GHG	YES	YES	YES	YES	YES	YES
Additionality	YES	YES	YES	YES	YES	YES
Equity & Justice	GOOD	FAIR	POOR	POOR	FAIR	EXCELLENT

ALIGNMENT OF ENERGY OPTIONS with A²ZERO Energy Principles

PRINCIPLE	MI GREEN POWER	(V)PPAs	NATIONAL RECS	COMMUNITY SOLAR	BTM PV& PVS	VPRA
Enhance Resilience	POOR	POOR	POOR	FAIR	GOOD	FAIR
Start Local	FAIR	FAIR	POOR	GOOD	EXCELLENT	GOOD
Speed	FAIR	EXCELLENT	EXCELLENT	POOR	GOOD	POOR
Scalable & Transferable	GOOD	EXCELLENT	EXCELLENT	EXCELLENT	EXCELLENT	FAIR
Cost Effective	EXCELLENT	POOR	POOR	POOR	EXCELLENT	POOR

We present these ratings out of full context with a note of caution because there would be some variation based on the implemented utility structure (DTE, SEU, and MEU). Additional contextual examples include:

- Behind-the-meter PV and PVS as currently deployed are generally unaffordable for low-income populations; Ann Arbor might develop financing options and other features, consistent with the A^{2}ZERO Energy Criteria and Principles, that could improve access, but this would be a policy decision we do not assume in our modeling.

- National Market Renewable Energy Credits have attracted significant criticism because of weak additionality assurance, among other problems. High-quality RECs are available, and we assume Ann Arbor would pursue RECs only in alignment with the A^{2}ZERO Energy Criteria and Principles. Furthermore, despite our mixed ratings, we assess that the City must buy substantial quantities of RECs to reach the 2030 goal, given reasonably foreseeable load contributions of the other options.

- Community Solar is not an option in light of the combination of the current legal and regulatory environment and DTE's opposition. While the speed, scalability and transferability are listed as Good and Excellent, this assumes changes in state law. In practice, as of today, this option is neither speedy nor replicable because it is not practically available.

We explore more of these nuances in our detailed discussion of each energy option, below.

ENERGY OPTION: DTE MI GREEN POWER PROGRAMS (MIGP)

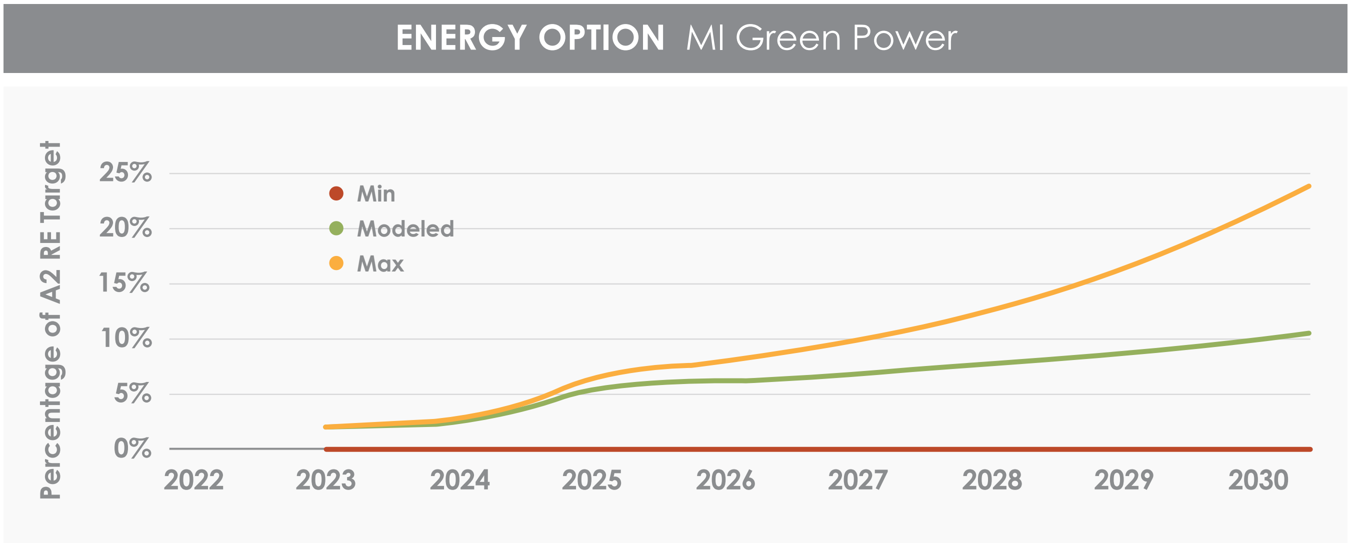
Michigan law requires DTE to provide a VGP program, branded MIGP, an umbrella term for a set of tariffs that allow DTE customers to voluntarily subscribe to preferred additional levels of renewable electricity, beyond what DTE supplies to every customer by default.

Several options are available within the overall MIGP program, each with its own tariff based on differences between energy and capacity costs for renewables compared to costs embedded in DTE's default tariffs. As of this writing the Flex program was the only available offering for residential customers on DTE's VGP website and its costs appear as -$0.0034/kWh. This price results in a bill credit for subscribing customers, which may change over time but is expected to remain as a credit for the near term. Ann Arbor customers have amongst the highest MIGP enrollment rates in DTE's service territory.

DTE also offers a MIGP option for large customers to request development of renewables projects, in return for agreeing to serve as the "anchor tenant." Under this option, DTE develops, owns, and operates the project; the anchor tenant agrees to take financial responsibility for any unsold energy. Rates for electricity from these projects are individually negotiated to reflect site-specific conditions. The resulting arrangement represents a "special contract" that must receive individual approval from the Michigan Public Service Commission. Ann Arbor is presently negotiating a customer-requested MIGP project on city land on and around the Wheeler Center landfill in SE Ann Arbor, which would have slightly higher costs than other DTE utility-scale solar PV installations. The City has requested state support for construction costs that might bring rates for Wheeler electricity down closer to par with DTE default rates.

While Wheeler Center Solar Project electricity could be sold entirely to individual DTE customers who subscribed, we assume the City's subscription to Wheeler Center Solar Project would be included as offsetting a significant portion of municipal government usage. If there were low overall customer subscription levels for Wheeler Center Solar Project, then this single project (combined with ongoing municipal efforts such as BTM PV/PVS) could oversubscribe municipal loads. Thus, we recommend the City consider promoting independent customer subscriptions for the Wheeler Center Solar Project. As an initial estimate, we project 10% of subscribers would be customers outside of Ann Arbor, 30% of subscribers would be within Ann Arbor, and the City would be responsible for 60% of the project's power output.

Figure 10: Projected MIGP potential as percentage of A^2ZERO RE target.



Inclusive of Wheeler Solar Center Project and assuming MIGP conditions remain steady, we project in Figure 10 that MIGP could represent as much 25% of Ann Arbor's 2030 RE target, well above the current 2%-3% Ann Arbor level. DTE has indicated it anticipates challenges in serving growing demand for MIGP subscriptions, in part because of the low price. This potential supply bottleneck poses some risk so our baseline projection for MIGP contribution to load is 10% in 2030.

Policy/City Opportunities:
We recommend Ann Arbor survey local businesses for the opportunity to learn what internal RE goals are established, planned, and/or executed. We would recommend reducing the City's overall RE obligations if local commercial customers have independent plans for securing their own energy through renewable sources, similar to how we incorporate AAPS' renewables commitment into the Citywide plan.

Table 15: Alignment of MI Green Power with A²ZERO Energy Criteria and Principles

ALIGNMENT OF MI GREEN POWER with A²ZERO Energy Criteria

CRITERION	RATING	COMMENTS
Reduce GHG	YES	MIGP brings new renewable generation online.
Additionality	YES	The additional RE would not be produced without the MIGP commitments. This RE is expected to be beyond DTE's plans for RE contributions.
Equity & Justice	GOOD	MIGP price improves RE access for low-income populations but provides marginalized communities little effective opportunity to participate in decisions.

ALIGNMENT OF MI GREEN POWER with A²ZERO Energy Principles

PRINCIPLE	RATING	COMMENTS
Enhance Resilience	POOR	MIGP does not contribute to resilience because it relies on power generated outside of the City and does not reduce distribution system outages.
Start Local	FAIR	MIGP resources are required to be located within Michigan.
Speed	FAIR	We project that MIGP can contribute up to 25% of Ann Arbor load carrying capacity in 2030.
Scalable & Transferable	GOOD	Other cities can emulate A2's promotion of MIGP subscriptions and successful implementation of the Wheeler Center Solar Project.
Cost Effective	EXCELLENT	MIGP electricity currently costs less than DTE's default rates and is expected to continue costing less for the foreseeable future.

Note: In DTE's pending VGP case, it proposed a limited pilot that would allow employers to "sponsor" their employees and purchase RE subscriptions for them to the MIGP program, but that program is in its early stages and has not yet received approval from the MPSC, even as a pilot. A modified and expanded version of this pilot may therefore conceivably be available by 2030 that might allow the City to sponsor its residents, but it is presently unclear how such a program might look and what requirements might be associated with it by the time it might become available to the City.

Note: The City has expressed interest in negotiating MIGP coverage for DTE customers in the City who do not voluntarily enroll on their own. There is currently no tariff or regulatory approval for such a DTE program. Were DTE to offer such a program, it is likely the City's procurement rules would require an RFP process open to other providers. This scenario essentially evolves into a VPPA, which we explore further below, and develop no further here.

Note: The available utility structures for MIGP would be DTE+ and the SEU but not the MEU.

ENERGY OPTION: POWER PURCHASE AGREEMENTS (TRADITIONAL & VIRTUAL)

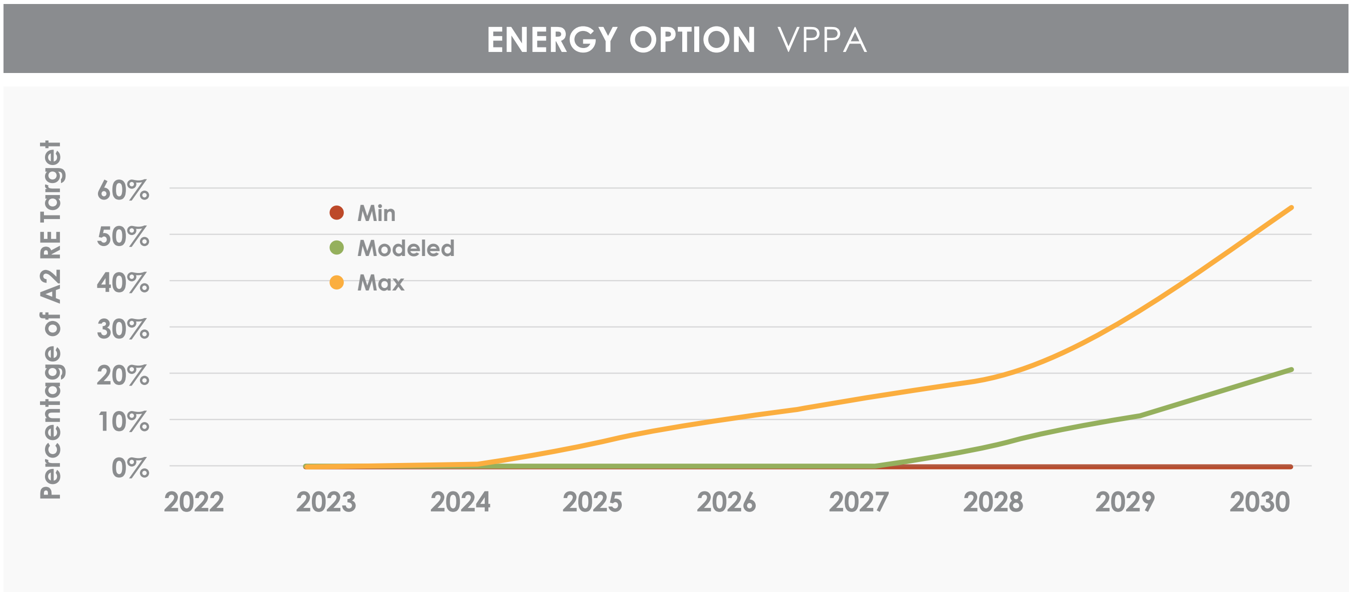
A traditional Power Purchase Agreement (PPA) is a common contract between a power supplier and an off-taker for supplying electricity to the grid. The power supplier may be a utility or an IPP, and the off-(in competitive electricity markets). For utility-scale renewable power generation PPAs in MISO territory, pricing includes the value of a competitive energy rate as well as load balancing values such as capacity. Contemporary PPA negotiations for RE power plants also address whether the off-taker wants to bundle the RECs for an additional fee. Traditional PPAs would be viable contracts only in the MEU scenarios.

A Virtual Power Purchase Agreement (VPPA) is another contract between a power supplier and an off-taker. Unlike a traditional PPA, the project's electricity production is not directly supplied to the off-taker, and the contract resembles a financial instrument more than a traditional PPA. Because a VPPA does not involve direct supply of electricity to the customer, Ann Arbor could participate in the VPPA market while DTE remained as its default electricity provider. VPPAs can be regionally located.

VPPA financial mechanisms can vary, with a common model called a contract-for-differences. In this model, a power supplier shares price risk with the off-taker, and the off-taker's cost varies based on the supplier's economic return from selling the power on the market. We are uncertain how the City would approach a contract-for-differences without significant constraints to mitigate the financial risk of paying more for energy than anticipated. Some market participants offer VPPAs that provide fixed priced contracts, with a focus on the opportunity to purchase RECs, for a higher price than a contract-for-differences since the price risk is no longer shared.

In Figure 11, we project a range of outcomes for VPPAs' ability to contribute to Ann Arbor's RE target. In the scenario models we assumed Ann Arbor would utilize VPPAs as a vehicle for RECs and costs would directly apply to the City's budget. RECs from VPPAs have effectively unlimited availability relative to Ann Arbor's electric load, but our model favors use of REC as a backstop to other Energy Options because RECs have higher marginal cost, as they are simply an add-on to the cost of the DTE electricity which they offset. Although we model VPPA purchases growing through 2030, in later years they would become a declining part of the portfolio as deployment of real Energy Options like BTM PV/PVS and Community Solar caught up to demand.

Figure 11: Projected VPPA potential as percentage of A²ZERO's RE target.



VPPAs typically, but not always, involve long term contracts between 10-20 years. Due to the long duration of project development, if the City engages in VPPA contracts we recommend initiating the process well before 2030 and also considering multiple projects with staggered timelines. The long contract duration may risk Ann Arbor overachieving the 100% RE goals for 2030 (and thus overspending), owing to variances in DTE's projected RE increase as well as continued growth in BTM PV/PVS assets. However, based on the electricity growth projections shown in Figure 1, Ann Arbor may benefit from stable, long-term solutions. We did not model RE stacking beyond 2030 but the City may want to include longer term planning in future studies.

Pricing for VPPAs and their RECs can vary significantly. Through 2030 there may be supply constraints that increase purchase prices. We assume the City would need to establish a fixed-price contract and pay for the RECs, and we also assume bundled RECs would be more expensive than unbundled RECs (discussed in the next section). We model VPPA REC costs in the range of $36-$60/MWh through the years of 2023-2030. This cost model assumes the City would focus on regional projects within MISO Zone 7 and DTE's territory consistent with its Start Local principle.

PPAs and VPPAs perform similarly with respect to the criteria and principles. To the extent there are minor differences, our ratings here reflect VPPAs because they are available to Ann Arbor now.

Table 16: Alignment of (V)PPAs with A²ZERO Energy Criteria and Principles

ALIGNMENT OF (V)PPAs with A²ZERO Energy Criteria

CRITERION	RATING	COMMENTS
Reduce GHG	YES	We assume that VPPAs acceptable to Ann Arbor would displace fossil fuels from the grid.
Additionality	YES	We assume Ann Arbor will invest only in new and high-quality RECs rather than the cheapest RECs available, or from existing RE resources.
Equity & Justice	FAIR	PPAs and VPPAs can increase low-income access to RE, but may add cost unless carefully managed, and they provide no procedural equity element.

ALIGNMENT OF (V)PPAs with A²ZERO Energy Principles

PRINCIPLE	RATING	COMMENTS
Enhance Resilience	POOR	PPAs and VPPAs will have no impact on resiliency because they do not address the usual causes of power loss during crises.
Start Local	FAIR	Although not required by law, Ann Arbor would very likely seek PPAs and VPPAs with resources located in Michigan if not closer by.
Speed	EXCELLENT	We project that VPPAs could plausibly contribute more than 50% of RE load carrying capacity in 2030.
Scalable & Transferable	EXCELLENT	Ann Arbor's approach to PPA and VPPA contracts could have significant scalability potential and could easily be emulated by other communities.
Cost Effective	POOR	RECs from VPPAs add to the cost of buying DTE power, the climate impacts of which the RECs are intended to offset. PPAs might reduce overall cost but will not be available to Ann Arbor before an MEU is launched.

Note: The available utility structures for VPPAs are DTE, SEU, and MEU. Only the MEU is applicable for a PPA.

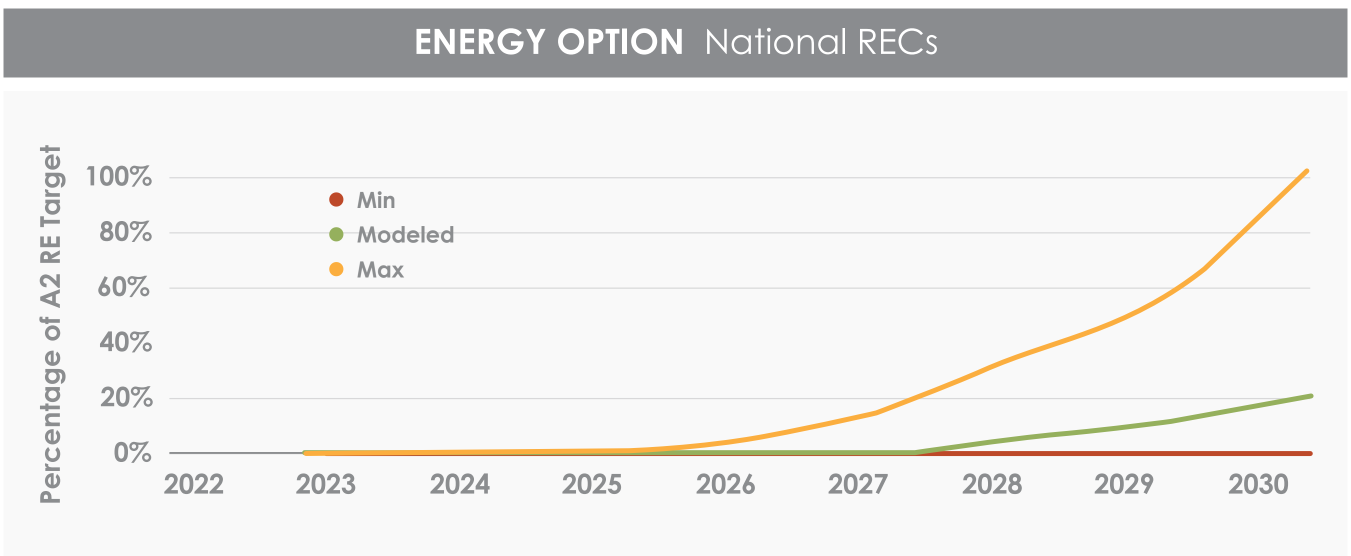
ENERGY OPTION: NATIONAL RECs

The U.S. EPA defines RECs as the environmental attributes of one MWh of renewable electricity that is generated and delivered to the grid. RECs can be used to track and assign ownership of renewable electricity generation and use. Unbundled RECs mean the non-physical attribute has been separated from the physical electricity. Unbundling allows power producers to sell RECs from renewable power facilities located anywhere in the world to customers who are willing to pay to claim the environmental attributes of the generation resources for themselves.

RECs present a welter of marketing and accounting challenges that cause many climate-conscious organizations to view them as a backup option for greening their power supply. Careful accounting is needed to ensure that RECs are not double-counted: for example, a customer whose energy is generated from wind turbines should not claim to be using renewable energy if the RECs are not bundled with the energy but are sold separately to other customers. Most REC buyers also prioritize additionality – seeking to ensure that their REC purchases help to bring new renewable generation online, rather than supporting a project that would have been constructed anyway or is already up and running.

Many customers, Ann Arbor included, prefer their power to be generated locally and to keep RECs and energy bundled together. Buying RECs from, say, a wind energy project in the Great Plains states, or a solar PV project halfway around the world, might have positive global climate impacts but would not satisfy these local requirements. Due to the wide range of possibilities for National RECs, we show in Figure 12 how this energy option could be utilized for all or none of the City's needs.

Figure 12: Projected National RECs potential as percentage of A²ZERO RE target

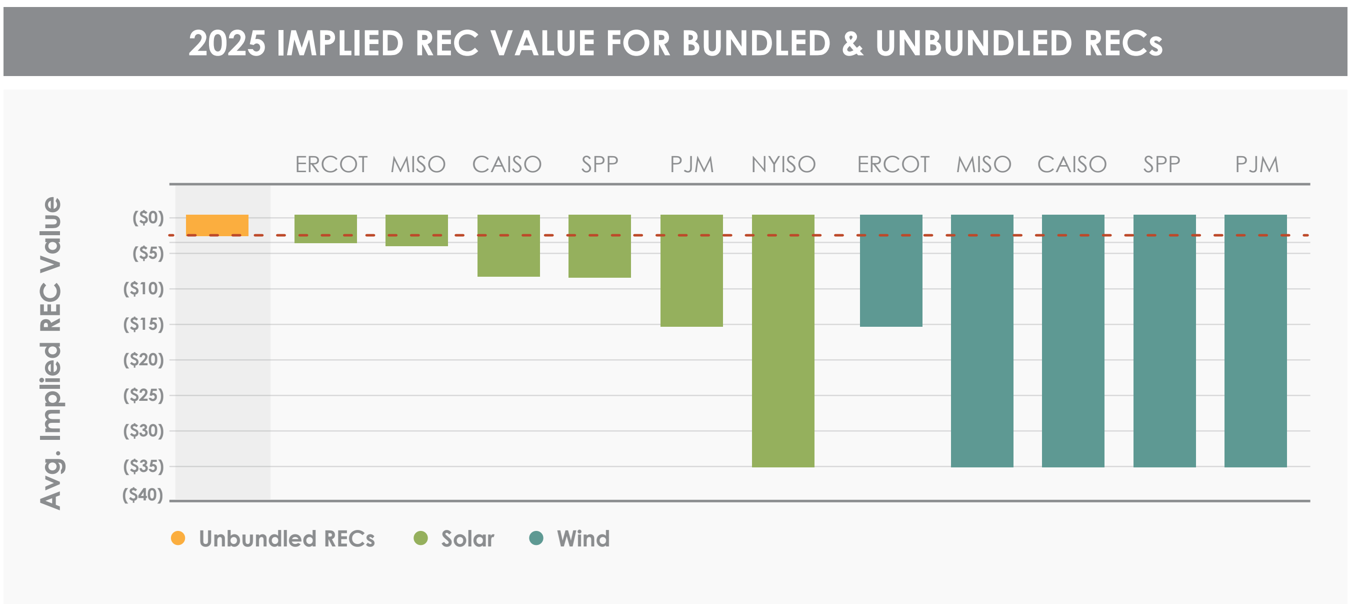


It is difficult to envision Ann Arbor achieving its 2030 goal without VPPAs and/or National RECs. One advantage of unbundled RECs is the flexibility of the contract duration. With transactions allowing purchases for a single year's energy consumption, unbundled RECs could be considered a stop-gap solution, meaning a backup plan in case other Energy Options do not materialize on time or to cover a shortfall.

Projecting future REC prices is a thorny process. One traditional method for evaluating a REC price was to consider the additionality element of the new renewable power generating source. For example, if a utility-scale solar plant was too expensive to compete in the MISO market, RECs could be sold at a price in excess of the wholesale prices of energy and capacity that would provide the balance of the revenue necessary to develop and build the solar power plant. In this example, the REC has intrinsic additionality since the solar power plant could not be built without favorable economics. However, our modeling of the 2030 grid indicates that in many circumstances solar and wind power will be the cheapest energy resource to build. According to this specific additionality concept, the RECs would not have a positive market value, and therefore this REC valuation method is not applicable. We believe a modest REC price will persist due to the cost of accelerating deployment and the high demand for new RE resources.

Many buyers are wary of unbundled RECs so if this option is pursued, we recommend the City conduct appropriate diligence to pursue RECs that match closest to A^2ZERO Energy Criteria and Principles. Shown in Figure 13 is a REC pricing forecast from a reputable source, which clearly shows how policy decisions can impact REC pricing. We considered the unbundled REC pricing benchmark of $20-30/MWh to be a conservative (high-side) range based on Ann Arbor not pursuing the cheapest, low-quality RECs available.

Figure 13: 3Degrees[10] assessment of 2025 implied REC value for bundled and unbundled RECs



In light of several of our ratings of RECs against the A^2ZERO Energy Criteria and Principles (Table 17), we recommend unbundled RECs be considered as a means to an end and not a final solution. This energy option is compatible stacked with nearly all other Energy Options to reach 100% RE, with the exception that RECs and VPPAs are essentially substitutes for each other aside from differences in financial structure and risk. Incremental REC purchases could allow local RE Energy Options, such as BTM PV/PVS and Community Solar more time to grow and serve more of the load.

[10] https://3degreesinc.com/resources/us-renewable-energy-market-pricing-trends-and-projections/

Table 17: Alignment of RECs with A²ZERO Energy Criteria and Principles

ALIGNMENT OF RECs with A²ZERO Energy Criteria

CRITERION	RATING	COMMENTS
Reduce GHG	YES	An expectation of National Market RECs would be sufficient quality of RECs that bring new renewable generation online.
Additionality	YES	Assuming Ann Arbor invested in RECs from new, rather than existing RE resources, RECs could offset a large proportion of the City's fossil-fuel generation.
Equity & Justice	POOR	Unbundled RECs would not increase access by marginalized populations to RE, and there is limited opportunity for local participation in REC decision making.

ALIGNMENT OF RECs with A²ZERO Energy Principles

PRINCIPLE	RATING	COMMENTS
Enhance Resilience	POOR	RECs will have no impact on resiliency because they do not address the causes of local power loss during crises.
Start Local	POOR	The primary reason to buy RECs, rather than contracting for a PPA from the same power source, is because the source is far away.
Speed	EXCELLENT	We project that RECs can contribute more than 50% of Ann Arbor's RE load carrying capacity in 2030.
Scalable & Transferable	EXCELLENT	RECs are highly scalable because of their flexibility and availability, and the approach can easily be emulated by other local governments.
Cost Effective	POOR	RECs are additive to the cost of buying DTE electricity, the climate impacts of which they offset.

Note: National RECs would be available for all utility structures.

ENERGY OPTION: COMMUNITY SOLAR

There are many definitions of Community Solar, generally distinguished by the financing model and ownership of the PV assets. We modeled a version of Community Solar in which a third party owns a small, utility-scale PV project and sells subscriptions to electricity customers through the local utility. Frequently the TPO can provide a single electric bill to the customer that includes regulated utility charges, and the TPO applies economic credits for the customer's subscription level to the Community Solar project. Community Solar is appealing to a significant market population since not all customers (residents and businesses) can or want to install PV on their premises owing to insufficient solar exposure, landlord-tenant relationships, and financial barriers, among other issues.

In general terms, Community Solar occupies a hybrid marketplace between large utility-scale solar power plants and rooftop PV. Community Solar projects are usually small utility-scale, ground-mount PV projects connected to the grid's distribution circuits. These projects can theoretically be located closer to interested customers due to the size range and often face simpler interconnection processes and fewer siting challenges compared to large utility-scale PV projects.

We would not normally include this energy option in our analysis since it is not currently required under Michigan law and DTE is not supportive. However, Community Solar is a priority energy option for Ann Arbor, and legislative modifications (or changes to DTE's opposition) that would clear the way for this option appear more likely now than they did in the past. Our third portfolio scenario, described below after all the Energy Options, assumes Community Solar will become feasible in the relatively near term and that customers would willingly subscribe.

Figure 14: Projected Community Solar potential as percentage of A²ZERO RE target.

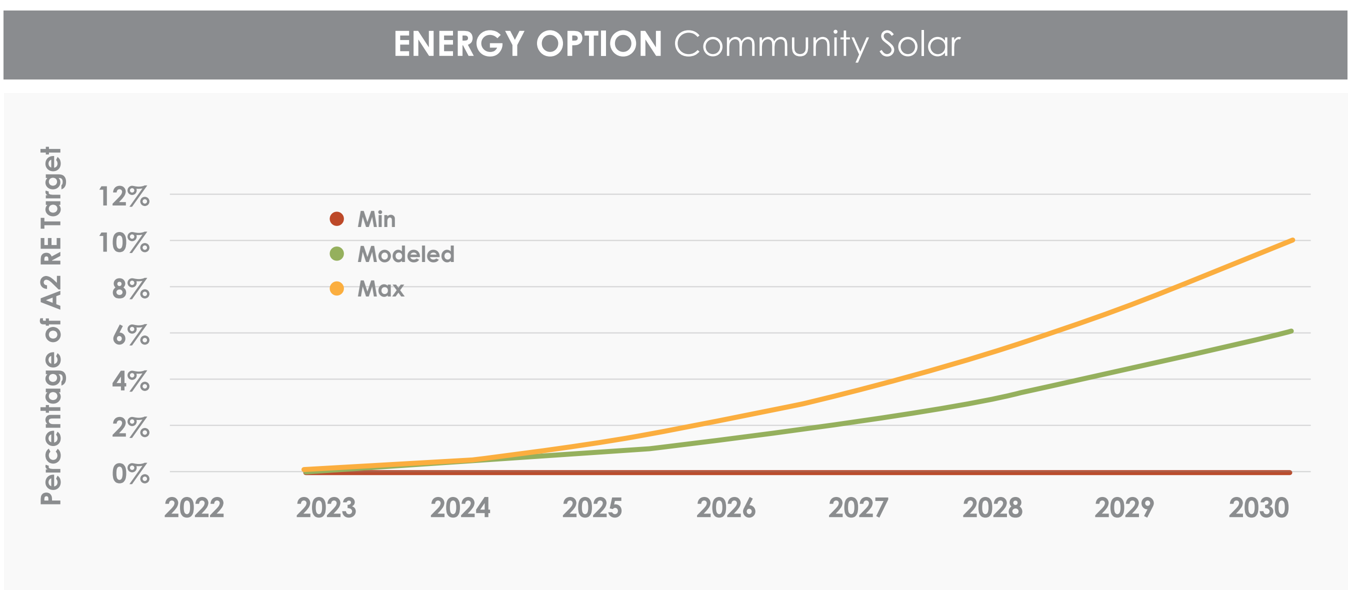


Figure 14, Community Solar has the potential for significant adoption due to its proven national appeal and reasonably favorable pricing conditions. Nationally, some Community Solar projects deliver modest savings to customers and others result in marginally higher rates. In many Community Solar projects, the customer receives a bill credit but does not necessarily receive the RECs associated with the project. This reduces cost for the customer but results in some ambiguity about who claims additionality.

Because the RECs need to stay within Ann Arbor to count toward the A²ZERO 2030 goal, we modeled a TPO Community Solar version whereby customers purchase both electricity and RECs. Without bundled RECs, our modeling indicated Community Solar would be about the same price as DTE power. Our scenario modeling, though, assumed a bundled REC price based on VPPA REC pricing. With the inclusion of the VPPA REC price, Community Solar costs would range between $16-$82/MWh; that is, Community Solar bundling RECs with electricity would be more expensive than DTE energy options in 2030.

The TPO Community Solar with RECs approach would be a logical way for Ann Arbor to count subscriptions as part of the 100% RE accounting. However, the City would not have direct control over customers' decisions to purchase RECs or not. If the City wished to reduce the cost of Community Solar to customers, for example to improve access for low-income customers, then the City could buy the RECs and commensurately reduce direct customer cost. The expense would presumably not be recoverable from ratepayers and would directly impact the City budget.

The SEU might be able to construct a community solar project within a microgrid in Ann Arbor, which would be a Phase 2 SEU project and beyond our scope here. We note the SEU is modeled in this report as having projects with either City ownership or TPO but does not include customer-owned and SEU-managed portfolios.

The MEU would be able to enact multiple business models for Community Solar within its territory, but we have not reviewed a business model or other relevant material to properly vet this version of Community Solar.

Table 18: Alignment of Community Solar with A²ZERO Energy Criteria and Principles

ALIGNMENT OF COMMUNITY SOLAR with A²ZERO Energy Criteria		
CRITERION	**RATING**	**COMMENTS**
Reduce GHG	YES	Community Solar would bring new renewable generation online.
Additionality	YES	Community Solar will clearly be considered additional RE generation.
Equity & Justice	POOR	Community Solar is more expensive than DTE electricity assuming RECs are bundled with the electricity.

ALIGNMENT OF COMMUNITY SOLAR with A²ZERO Energy Principles		
PRINCIPLE	**RATING**	**COMMENTS**
Enhance Resilience	FAIR	Locations outside of Ann Arbor would provide no resilience benefit. A Community Solar program within the distribution system or integrated into a neighborhood microgrid including storage resources could enhance resilience.
Start Local	GOOD	We assume Ann Arbor would prioritize locating any community solar installation either within the City itself or close by within Washtenaw County.
Speed	POOR	Although Community Solar could hypothetically contribute to load carrying capacity, under our assumption that current regulations and practices will remain in place, we project no contribution in 2030.
Scalable & Transferable	EXCELLENT	Community Solar is considered highly replicable given its modular nature and available locations on distribution circuits.
Cost Effective	POOR	Given our assumption that either the customer or the City will buy the RECs then Community Solar is more expensive than DTE electricity.

Note: Community Solar as defined above would be available with DTE only if state law or DTE policies changed. Similarly, we assume the SEU would be able to facilitate Community Solar with the same constraints as DTE, for projects outside the Ann Arbor city limits.

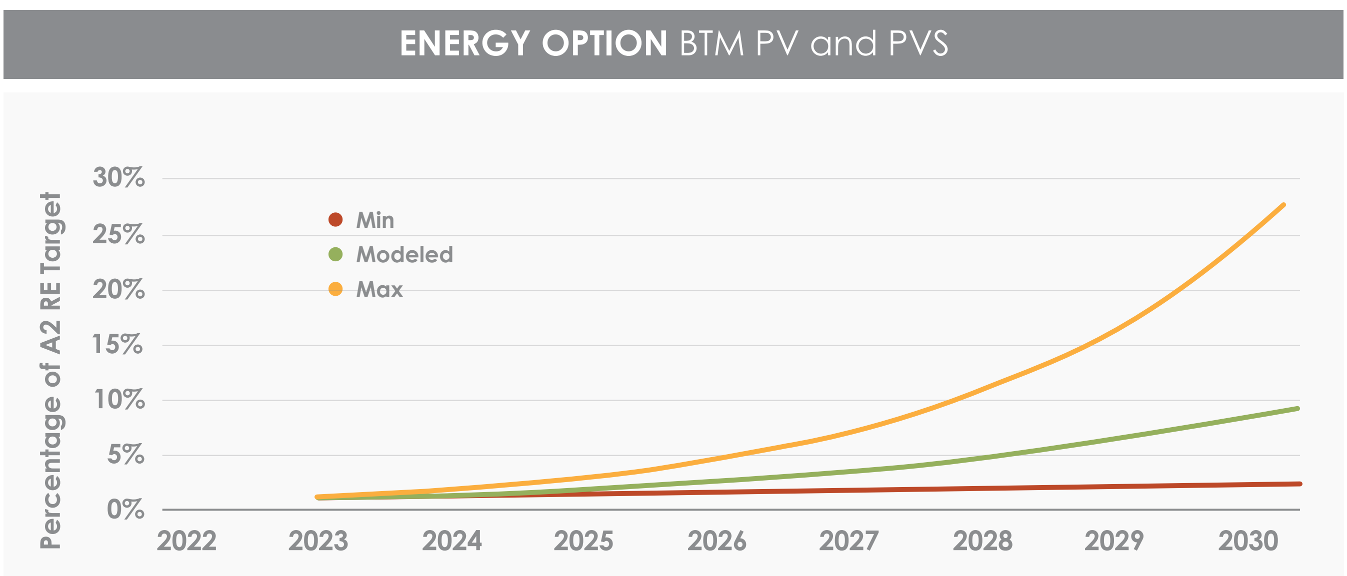
ENERGY OPTION: BEHIND-THE-METER PV AND PVS

Electricity customers can self-generate power on their premises most readily through BTM PV power generation. PVS adds a battery that allows the customers to store RE for later use. The most common BTM PV systems are installed on rooftops and constitute the primary focus of our study. BTM PV systems can also be deployed on ground-mount racking or tall structures called canopies that can be installed on parking lots or other areas as shade structures. There are other novel approaches like building integrated PV (BIPV) or floating PV not studied in this report.

Many factors influence PV/PVS adoption such as: site suitability and technical design potential, compensation for surplus generation onto the grid (outflow), technology price and performance, customer electricity consumption patterns, customer relationship to site (residential, commercial, landlord, lessee, etc.), financing options, technology maturity, regional installers' influence, ability to integrate backup power with PVS, labor pool, ability to monetize PVS beyond backup power, governmental and permitting rules, and social factors.

In the following descriptions we provide rationale for the range of potential RE contributions shown in Figure 15. This is the range of generation for private development of Ann Arbor electricity customers, while we also later considered additional development through SEU financing. We modeled significant growth in BTM PV/PVS systems for private development based on historic trends, technology commercialization, and decreasing costs. We modeled BTM incentives with an assumed 30% tax credit or rebate based on the owner's tax status. Local adoption may accelerate with a SEU or MEU because they could offer TPO financing that reduced the customer financial outlay, or potentially offer other local financial incentives such as a tailored inflow/outflow tariff structure (in the case of the MEU).

Figure 15: Projected BTM PV/PVS potential as percentage of A²ZERO RE target.



The lifetime cost of PV systems is highly dependent upon the installed cost of the system, operations and maintenance costs, performance, shading, financial terms, and many other factors. At the time of this report, PV pricing has dramatically decreased over the past decade and many market indicators suggest PV pricing will continue to decrease. The National Renewable Energy Laboratory's (NREL) most recent Annual Technology Baseline (ATB) projects PV's levelized cost of electricity from in the range of $133-$138/MWh in 2023 with cost declines (in Ann Arbor's geographic region) to $86-$120/MWh by 2030. The lifetime cost of PVS is even more variable due to even more dramatic cost decline projections for lithium battery storage. We modeled a typical residential battery system size of 5 kW, 12.5 kWh and through ATB calculations we projected LCOE values of $235-$287/MWh for 2023 and $159-$230/MWh by 2030.

Survey of PV Site Suitability Within Ann Arbor

We performed a high-level, desktop analysis of PV site suitability for BTM rooftop projects and canopy projects on parking lots. Many technical constraints were considered and applied such as tree shading, orientation, minimum size, commercially available technology, and space within City limits excluding U of M. Utilizing data from a Google EIE study and our industry expertise, we assumed reasonable performance expectations.

The maximum technical rooftop capacity for PV across the whole city was estimated to be 440 MW-dc, with an estimated 159 MW-dc available on residential sized rooftops, 146 MW-dc on small commercial sized rooftops, and 135 MW-dc on large commercial and industrial rooftops. We assumed U of M rooftops were included in the Google EIE study, and assumed those larger rooftops were generally included in the sizes of large commercial and industrial. These values represented a theoretical maximum for each customer class. Through satellite data analysis we also observed the potential for over 75 MW-dc of PV on large commercial and public parking lots for canopy installations. The PV canopy potential was not modeled further in this study because canopies are generally too expensive to be cost-effective, but we note potential price declines or City incentives could increase motivation for multi-use project locations.

We further analyzed the available DTE rates and found the available residential rooftops (of various roof orientations) to be economically viable. We determined that under existing DTE outflow rates approximately 58 MW-dc was considered economical on small commercial properties and another 8 MW-dc was potentially economical on large commercial and industrial properties. We also note this quantity may increase with anticipated future cost reductions. The economical valuation considered the building profiles, all available DTE rate structures, and contemporary project pricing and costs. We assumed that the capacity of solar PV we evaluate as economical would not exceed DTE's territory-wide cap on PV. If it did, some larger locations would still be financially feasible under PURPA rates, the same federal energy-pricing law under which Ann Arbor sells electricity from its hydro dams to DTE.

This study focused on commercially available modules and rooftop projects. We acknowledge many additional racking technologies and PV technology advancements (e.g. solar shingles, multi-junction cells, etc.) may increase the total available capacity and we recommend the City re-assess their feasibility periodically. Additional technology applications such as residential ground mount PV projects and building integrated PV projects may increase their market share in the next decade but were not modeled due to the level of uncertainty.

PV Tariff Rate Structure

PV technology is a weather-dependent renewable power generation resource that can be both intermittent and predictable. For example, PV power generation is reliably modeled as higher during summer months and expected to not generate at night. PV is not considered load-following, meaning generation and customer consumption are unrelated in real time, and DTE customers are allowed to send surplus electricity to the grid. Customers are allowed to design systems up to the size at which their PV system is projected to generate an annual electricity offset equal to their annual consumption (e.g. net-zero).

When customers self-consume PV electricity it is generally considered a cost-savings as compared to the price of utility energy (inflow). When customers send surplus electricity to the grid (outflow) they are credited with an energy rate typically lower than the inflow rate. The spread between the inflow and outflow rates represents a loss of value to the system owner. Consequently, prudent system designs balance multiple considerations to assess whether net-zero will be their top priority, or a lesser annual offset percentage will be appropriate for their economics. Customers who finance third-party PPAs with TPOs do not always pursue net-zero as it may not be economically beneficial. This is an important factor to consider how a SEU or MEU may approach system designs and rate designs.

DTE has capped the amount of BTM PV that can be installed and receive the full outflow tariff rate at 6% of its peak load. Because this cap applies to DTE's full-service territory, Ann Arbor should be able to greatly exceed 6% of local peak load as we assume most other communities served by DTE will deploy PV much more slowly, leaving room for Ann Arbor to deploy PV much higher than average levels for areas served by DTE.

Adoption Rates of PV and PVS

We needed to develop an estimate of PV and PVS adoption in Ann Arbor to include them in the stack of resources contributing to the 2030 A^{2}ZERO goal of 100% renewable electricity.

Nationally, the US Energy Information Administration reported residential installations of 1.9 GW for the first quarter of 2023, setting a US record for most residential PV installed in a quarter.[11] Similarly, the Commercial and Industrial (C&I) market achieved 700 MW of installations in this quarter, a new C&I record. We believe there is an undeniable trend of PV growth in the US and sufficient market indicators that PV growth will continue to flourish nationally and locally.

It is well documented that many PV deployment forecasts in the US from 2010-2020 consistently underestimated annual installations. Among the reasons noted for underestimated installations were changes in energy policy at all governmental levels and substantial price decreases. NREL has published a market-demand modeling tool called dGEN[12] that works to refine local adoption models and integrates local utility billing rules, project costs, consumer behavior and adoption rate tools, among other variables.

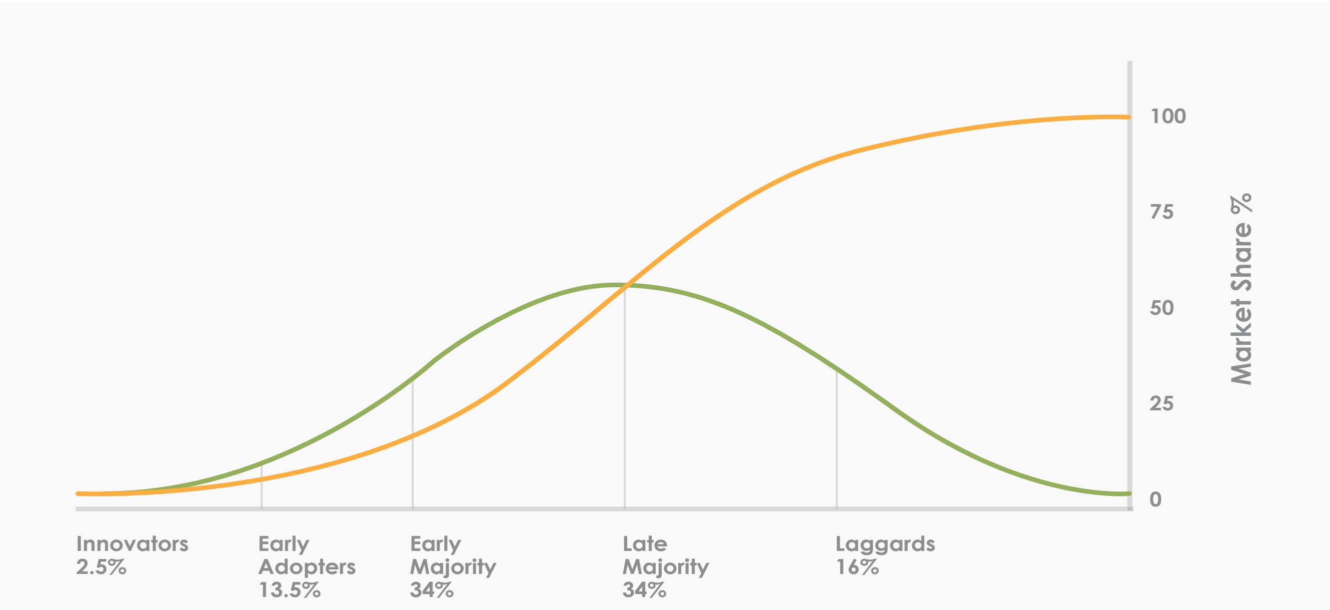
We consider BTM PV and PVS policy in Michigan to be highly variable going forward, affected by utility billing rules, net metering policies, incentives, and project costs. We therefore modeled PV adoption in a simplified manner from large probabilistic ranges, while still considering dGEN's use of a Bass-style adoption model. We projected adoption rates of PV based on the diffusion of innovations model from Everett Rogers, as shown in Figure 16. Like the Bass-style diffusion model, the "S-Curve" for technology adoption is commonly referenced when discussing adoption for factors that can include social factors beyond pure economic considerations.

[11] NREL Summer 2023 Solar Industry Update, David Feldman et al.

[12] The Distributed Generation Market Demand Model (dGEN): Documentation. Bejamin Sigrin et al, 2016.

Figure 16: Example concept of Diffusion of Innovations[13]

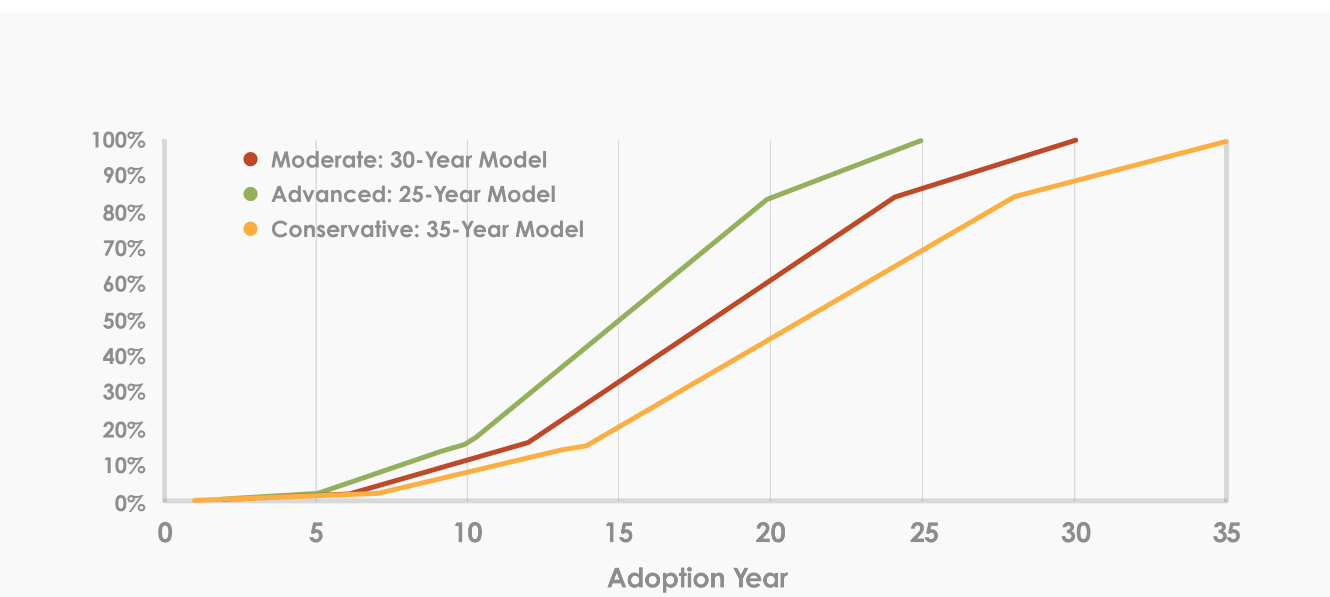
EXAMPLE CONCEPT OF DIFFUSION OF INNOVATIONS



We observed a significant increase in BTM PV projects installed in Ann Arbor over the past several years, including significant growth from the Solarize program. Figure 17 shows three example S-curves for Ann Arbor adoption of BTM PV technology. We aligned the estimate of current BTM PV in Ann Arbor, under 7 MW, to estimated maximum residential 159 MW and found Ann Arbor was estimated to be entering the “early adopters” phase. We estimated the available residential installations could be fully installed between 2042-2050.

Figure 17: Simple adoption curves for residential BTM PV installations in Ann Arbor

BTM PV ADOPTION MODELS



[13] https://en.wikipedia.org/wiki/Diffusion_of_innovations

Commercial PV installations have historically been a smaller market than residential PV installations. For example, the EIA data mentioned previously shows the commercial and industrial (C&I) market's record quarter is 36% of the residential PV installed capacity.[14] There are many rational reasons for the lower commercial adoption rate, including land and building ownership issues, long-term investment challenges, and utility rate structures. For reference, we also noticed this trend in the adoption rates for MIGP, where residential subscriptions represented as much as 97% of the region's energy offsets and commercial subscriptions just 3%. For the scenarios modeled in this report, we assumed minimal private ownership for C&I and for small commercial to adopt PV at 15% of the residential PV adoption rate.

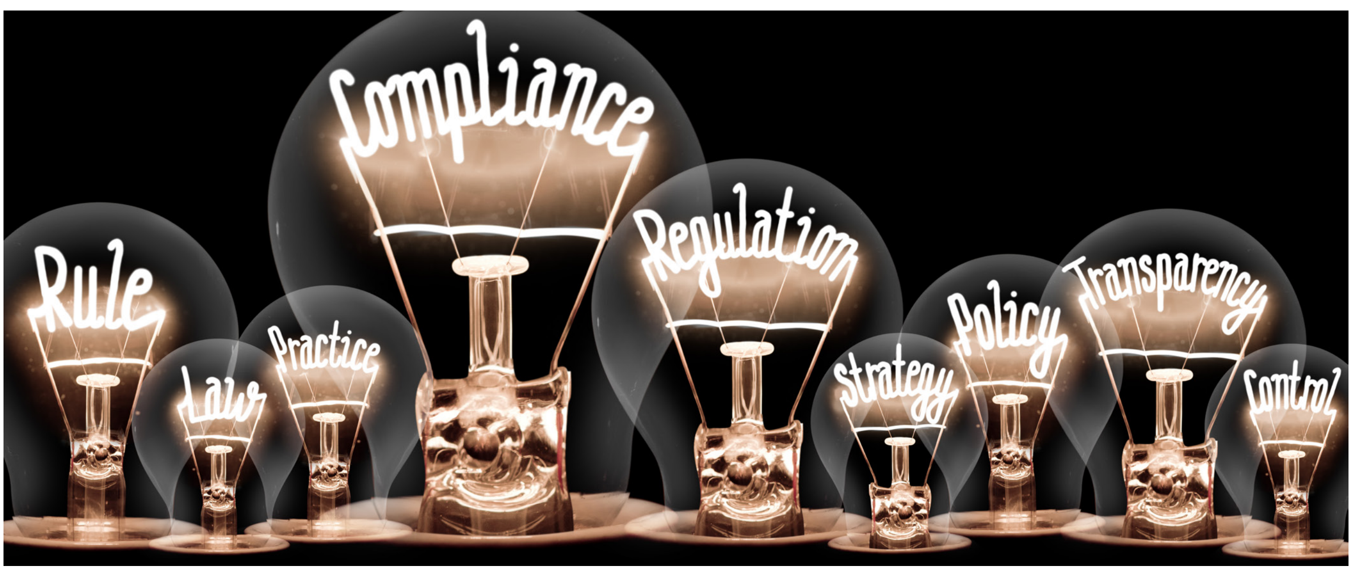
Customer ownership of PV systems is closely linked to the customer's motivation and ability to secure long-term loans for most project costs. TPO, however, can result in greater PV adoption by offering customers long term contracts (PPAs) at an energy price lower than the utility provider's rates.

As a result of evolving and economically competitive technology, and market incentives, we assumed customer ownership of PV systems may increase on three tracks: conservative, moderate, and aggressive adoption rates. The adoption rates were assumed for the status quo grid, also called DTE BAU. Adoption rates with higher customer ownership intrinsically result in a reduced maximum deployment level for the SEU.

The largest individual building rooftops are with commercial and industrial customers that have the lowest electricity rates. The Phase 2 SEU, discussed later, may benefit by integrating the larger customers' rooftops into potential local microgrid applications.

Adoption Rate of PVS

We defined the primary use case for energy storage as resiliency, battery backup for outage events. This implies the value of the additional costs for battery backup are based on the value of continuity of electrical service, rather than for direct economic gain from rate structure. Charging battery storage from the grid does not directly achieve Ann Arbor targets of 100% RE by 2030; therefore, PVS was modeled assuming all energy storage will remain charged solely from PV.



[14] For this study, we call C&I the combination of large commercial and industrial companies, which is distinguished from small commercial companies that have utility rates similar to residential customers.

We estimated about 180 PVS systems already installed in the Ann Arbor area, largely from the Solarize program. We assumed battery backup would increase dramatically in the A2 area particularly given the frequency and duration of grid outages as a motivation, and steady cost reductions. We assumed compound annual growth for PV systems with battery backup between 20%-40%.

Several developments suggest the market for PVS will grow. Federal laws such as the Inflation Reduction Act of 2022 have effectively increased the market participants who may receive a broad range of financial incentives for new renewable technology deployment. Our modeling assumed the equivalent of a 30% tax credit or rebate, while recognizing specific project conditions may realize a higher rebate potential (or lower).

Further, market trends indicate storage integration will become cheaper, more widely available, and may receive more economic opportunities. For example, several states allow for aggregation of BTM storage assets for virtual power plant operations. In the coming decade, MISO will implement FERC Order 2222 (a FERC order requiring wholesale market access for aggregators of small resources) rules and can be expected to deploy pricing signals for a storage-based market where PVS would be able to participate. This might create an opportunity for PVS site owners for energy shifting at half-load basis for minor energy arbitrage events. In plainer language, this practice would involve storing grid-sourced energy when it is cheap and feeding it back to the grid when it is more valuable. This scenario is likely but prospective and is not included in our modeling assumptions.

Technical and Modeling Considerations

The scope of this study did not include identifying the maximum PV capacity in any Ann Arbor area, but we note that areas with 4.8 kV distribution lines will generally have less hosting capacity than 13.2 kV distribution lines. Increased deployment of BTM storage may alleviate distribution system capacity constraints but would require smart-grid and technological capabilities not currently deployed.

We analyzed the range of the levelized cost of electricity prices for BTM PV power between ownership models, and we did not find one ownership model to be a clear winner to recommend for widespread city deployment. A typical customer owner is generally less likely to pay a third party for annual O&M fees though they may require maintenance fees on occasion. This appreciable annual cost reduction is offset by typically higher upfront costs and potentially higher interest rates, financed through independent loans. SEU ownership and TPO may have higher costs to support annual inspections such entities might conduct to protect their portfolio investments, though this cost may be offset through bulk equipment purchases and potentially lower interest rates. The SEU may finance without an expectation for equity return like TPO, though TPO can typically reduce lifetime costs through accelerated depreciation. The SEU can also manage assets through TPO and minimize non-system operating costs through development support and customer billing. These examples of trade-offs show wide overlaps in lifetime costs for various ownership models.

Table 19: Alignment of PV/PVS with A²ZERO Energy Criteria and Principles

ALIGNMENT OF PV/PVS with A²ZERO Energy Criteria		
CRITERION	**RATING**	**COMMENTS**
Reduce GHG	YES	BTM PV and PVS would bring new renewable generation online.
Additionality	YES	BTM PV is clearly additional.
Equity & Justice	FAIR	Low-income communities may lack capital and/or access to suitable rooftops or ground space for solar PV. SEU or MEU financing and ownership of BTM solar may reduce financial barriers but would not likely alleviate physical capacity constraints.

ALIGNMENT OF PV/PVS with A²ZERO Energy Principles		
PRINCIPLE	**RATING**	**COMMENTS**
Enhance Resilience	GOOD	BTM solar without storage contributes little to resiliency because it must shut down during outages. PVS can continue to operate during outages but we project that most PV systems will not include storage by 2030.
Start Local	EXCELLENT	BTM solar and storage are inherently local.
Speed	GOOD	We project that PV/PVS could contribute 25%-50% of RE load carrying capacity in 2030.
Scalable & Transferable	EXCELLENT	BTM PV and PVS are widely adopted nationally and are growing in Michigan.
Cost Effective	EXCELLENT	BTM PV is cheaper to customers on a lifetime basis than buying electricity from DTE. PVS is not currently cheaper than DTE power but is expected to be nearly cost-competitive by 2030.

Note: BTM PV/PVS is available in all utility structures. There are greater limitations to BTM PV/PVS with DTE, lesser limitations with the SEU, and the least limitations with the MEU.

ENERGY OPTION: VIRTUAL POWER REDUCTION AGREEMENTS

Virtual power reduction agreements (VPRAs) are a novel concept for funding energy efficiency strategies wherein a participant receives carbon offset credits for financing third-party power reduction projects. Michigan law uniquely allows third-party project finance contributors to earn RECs for realized carbon reductions. So, for example, the City of Ann Arbor could earn RECs by paying for energy efficiency projects in economically distressed communities nearby, or even within Ann Arbor. However, we know of no VPRAs implemented to date in Michigan, apparently because of limits on RECs that may be awarded. Specifically, Michigan EWR accounting methodology only credits the power reductions for the first year of project deployment, rather than lifetime savings as is more common with other EWR projects. While apparently infeasible now, VPRAs may remain an opportunity to explore at a modest scale. However, VPRAs are likely to provide diminishing carbon reductions over time as the proportion of renewables in DTE's electricity increases: as fossil fuels represent a diminishing proportion of DTE's power mix, each kWh of energy saved through efficiency programs realizes less and less carbon reduction.

Policy Opportunities:
The City of Ann Arbor could advocate for changes to state law that would award RECs for VPRAs based on lifetime projected energy savings and carbon reductions, rather than only the first year.

While VPRAs evaluate strongly against several of the criteria and principles, they are unlikely to contribute to achievement of the 2030 100% RE target, because they offer a poor financial return under current accounting rules for Michigan's energy waste reduction programs.

Table 20: Alignment of VPRAs with A²ZERO Energy Criteria and Principles

ALIGNMENT OF VPRAs with A²ZERO Energy Criteria		
CRITERION	**RATING**	**COMMENTS**
Reduce GHG	YES	VPRAs reduce electric loads, leading to prompt reduction in fossil fuel generation.
Additionality	YES	VPRAs support new energy efficiency projects and reduce use of fossil fuels.
Equity & Justice	EXCELLENT	VPRA projects can be focused on marginalized communities often underserved by energy efficiency and renewables.

ALIGNMENT OF VPRAs with A²ZERO Energy Principles		
PRINCIPLE	**RATING**	**COMMENTS**
Enhance Resilience	FAIR	VPRAs that improve building envelopes may reduce public health and other community impacts of power outages, but are unlikely to reduce the duration of outages. Only those VPRAs implemented in Ann Arbor could impact the City's resilience.
Start Local	Good	We assume that the City would prioritize VPRA projects in Ann Arbor itself or within Washtenaw County.
Speed	POOR	Although VPRAs could hypothetically contribute to load carrying capacity, under our assumption that current regulations and practices will remain in place, we project no contribution in 2030.
Scalable & Transferable	FAIR	Many VPRA projects must be individually implemented, making them potentially difficult to scale. The operational capacity required to manage VPRAs might limit transferability to other Michigan communities.
Cost Effective	POOR	VPRAs do not offer a positive financial return under current Michigan energy waste reduction accounting rules.

Note: Virtual Power Reduction Agreements would be available in all utility structures.

ENERGY OPTIONS MODELING RESULTS

The Energy Options discussed above generally represent partial solutions to achieve 100% RE by 2030. We recommend applying a balance of several Energy Options over the course of many years. By stacking multiple Energy Options the City mitigates the risk that a single point of failure could result in not achieving 100% RE by 2030. Additionally, the Energy Options contain varying profiles of A2 Core Values and Principles such that combining several options may improve Ann Arbor's overall goals. Energy Options also have varying compatibility with all utility structures so diversification may also decrease the risk of missing the 100% RE status if the City should pursue municipalization of DTE's local electrical infrastructure.

We present three distinct scenarios to demonstrate how Ann Arbor has an abundance of opportunities to achieve 100% RE, to build on existing RE trends, and adapt in a rapidly evolving energy environment. These scenarios do not represent our recommended pathways; they are intended to be illustrative. The first scenario, "DTE+" utilizes the existing grid and available tools at the time of this report. The second scenario, "SEU", utilizes the DTE+ conditions and assumes Ann Arbor has invested in a SEU model that helps develop, finance, and engage customers for BTM PV and PVS. The third scenario, "SEU + Community Solar", builds on the previous two scenarios and incorporates the concept of statewide community solar legislation. We recognize the third scenario may not be possible under current regulation and DTE policy, but we preferred to study it here in case legislation does pass prior to the next study.

We do not offer a MEU-based scenario here because we judge it highly unlikely that the MEU could launch by 2030. Our three scenarios are focused on solutions within the existing DTE infrastructure, and we observe the flexibility of the scenarios to transition into a MEU.

Due to policy changes, economic variations, and potential technical advancements that may occur by 2030, we recognize there may be hundreds of practical scenario variations. We consider the three scenarios to be representative of the overall concept of incorporating Energy Options that are already active and likely to accelerate, while also incorporating new Energy Options and acknowledging DTE is pursuing a cleaner electrical grid. We focused reporting on costs that will either be paid by the City or costs that flow through the City budget and note the three scenarios provide varying cost requirements.

All three scenarios include REC purchases starting in 2027 and increasing through 2030. Energy Options such as BTM PV/PVS are likely to continue growing in the years past 2030. Long term contracts for RECs and VPPAs will bind the City to long term commitments; we recommend layered purchasing strategies to balance the City's costs of virtual-asset purchases against foreseeable growth of real assets such as PV/PVS.

The majority of Energy Options have sub-options that are more clearly defined in context of utility structure. Importantly, the MEU is not feasible to achieve overnight. If the MEU option is pursued in conjunction with achieving 100% RE by 2030, we recommend building the MEU RE portfolio with plans that also more reliably meet the 2030 target. This implies a MEU plan commencing at the time of this report would utilize an initial RE procurement plan that is either the DTE+ or SEU.

Budgetary Impacts of Energy Options

We focused reporting on costs that will either be paid by the City or costs that flow through the City and note the three scenarios provide varying cost requirements. For City stakeholders it is important to distinguish costs that may flow through the City budget and be recovered from the costs that will not be recoverable. Therefore, we partitioned the Energy Options into three cost categories.

Figure 18: Budgetary Impacts of Energy Options

BUDGETARY IMPACTS OF ENERGY OPTIONS

No costs to City

BTM PV/PVS with customer ownership or TPO, customer MIGP, and Community Solar. The City has developed programs to bolster adoption and bears some staffing costs, but equipment and electricity costs are borne by the customers.

Costs Recoverable to City

We classify costs as recoverable under two conditions. First, if municipal operations use electricity generated by BTM PV/PVS installed at City/SEU cost, then the rates they pay for that electricity will include cost recovery. Second, if the City pays for SEU subscribers' PV/PVS projects, the costs are ultimately recouped from these electricity subscribers through their monthly payments to the SEU. This approach distinguishes between costs that increase the City's budget on a net basis, versus costs the City recovers from ratepayers (including its own departments). These programs can incur significant upfront costs, such as financing a portfolio of BTM PV projects across municipal properties and ownership of SEU assets through debt financing; upfront costs are recovered from customers, over time, via the rates they pay. This category may also include annual energy costs such as SEU management of assets with TPO that may have a PPA contract with the SEU.

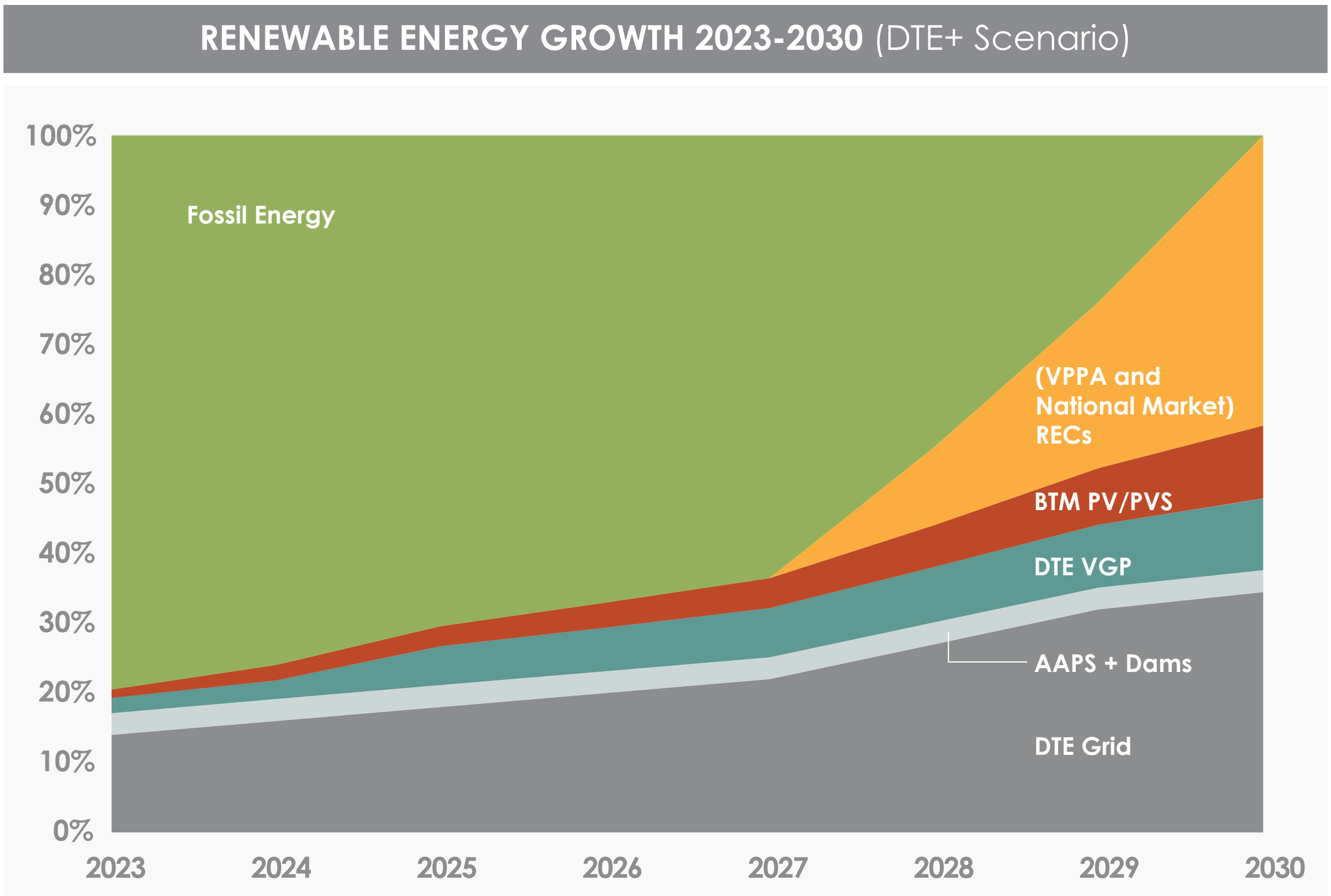
Costs Non-Recoverable to City

VPPA, National RECs, VPRA. These costs include Energy Options that achieve RE accounting goals without providing physical electricity services to customers in Ann Arbor. Additionally, MIGP serving municipal government loads and Wheeler Center Solar Project may increase net costs in the City budget, depending on project costs and changes in the MIGP tariff rider over time.

Scenario 1: DTE+

In Scenario 1 we examine how the City might meet its 2030 A^{2}ZERO goals if current and planned DTE and City RE programs continue and grow. We assume DTE meets its recent IRP commitment of 35% RE by 2030. As shown in Figure 19, we combined AAPS achieving its 100% RE target (with an independent budget) with the assumption that Ann Arbor preserves the RECs from local dams in perpetuity at no City cost. In light of current residential and commercial MIGP options offered at no, or negative, net-cost, we modeled increasing subscriptions for MIGP. All scenarios also include Wheeler Center Solar Project successfully going online in 2025 with a majority of subscribers being either Ann Arbor residents or the City's subscription (crediting the overall municipal load budget). All together, these resources can plausibly, but will not necessarily, get Ann Arbor's electricity supply to 59% RE in 2030.

Figure 19: DTE+ scenario Energy Options that aggregate to 100% RE electricity by 2030.



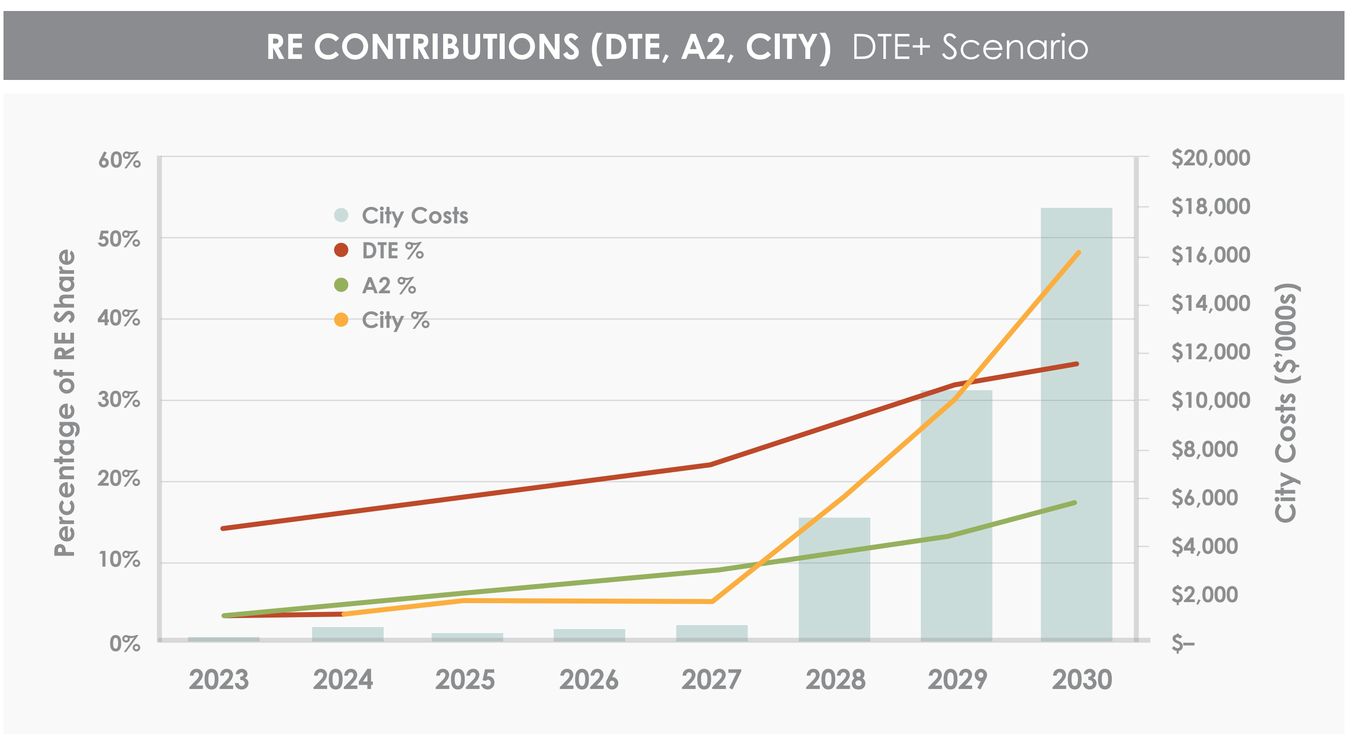
The BTM PV/PVS growth in this scenario is appreciable yet still represents a relatively early stage for the total amount of PV/PVS that is possible in Ann Arbor. Lastly, REC subscriptions commence in 2027 in order to build the City's procurement process skills and to potentially stagger the duration of contracts so the City can proactively review the necessity of various RECs through the decade of 2030-2040. For pricing purposes, we assumed the RECs were a mixture of VPPAs (both wind and solar) and National RECs.
The RE contribution percentages and associated cost to the City for the year 2030 are shown in Table 21. Modest MIGP costs to the City are a result of Wheeler Center Solar Project, while BTM PV/PVS represents an annual investment cost for a steadily increasing quantity of municipal PV projects, and the bulk of costs are associated with REC purchases.

Table 21: Scenario 1 RE Contributions and City costs

2030 RE CONTRIBUTIONS DTE+ (Scenario 1)			
RESOURCE	**RE CONTRIBUTIONS**	**RECOVERABLE CITY COSTS ($000)**	**NON-RECOVERABLE CITY COSTS ($000)**
DTE Grid	35%	$ —	$ —
AAPS + Dams	3%	$ —	$ —
MIGP	10%	$ —	$125
BTM PV/PVS	10%	$2,327	$ —
BTM PV/PVS (SEU)	0%	$ —	$ —
RECs (VPPA + National Market)	42%	$ —	$15,438
Community Solar	0%	$ —	$ —

We identified three primary entities responsible for achieving RE commitments in this scenario. While DTE has made commitments with the MPSC, the City would need to observe BTM PV/PVS progress with its residents to determine the level of REC purchasing. Figure 20 provides an illustration of responsible parties over time and the City's annual cost burden. In this scenario, DTE achieves its 35% goal while Ann Arbor residents provide over 10% of the RE requirements through DTE VGP and close to 10% through private investments in BTM PV/PVS. The City remains responsible for almost 50% of the cost burden for RE procurement.

Figure 20: RE growth by DTE, A2 (general public), and City (government)



The cumulative costs for the City are shown in Table 22 for both the calendar year 2030 and the cumulative total for 2023-2029. As discussed in the modeling results introduction, the "Recoverable Costs" include direct purchases of electricity, such as municipal BTM PV and City subscriptions to MIGP programs. The "Non-Recoverable Costs" are considered costs where the primary purchase is RECs.

Table 22: Scenario 1 City costs for 2023-2030

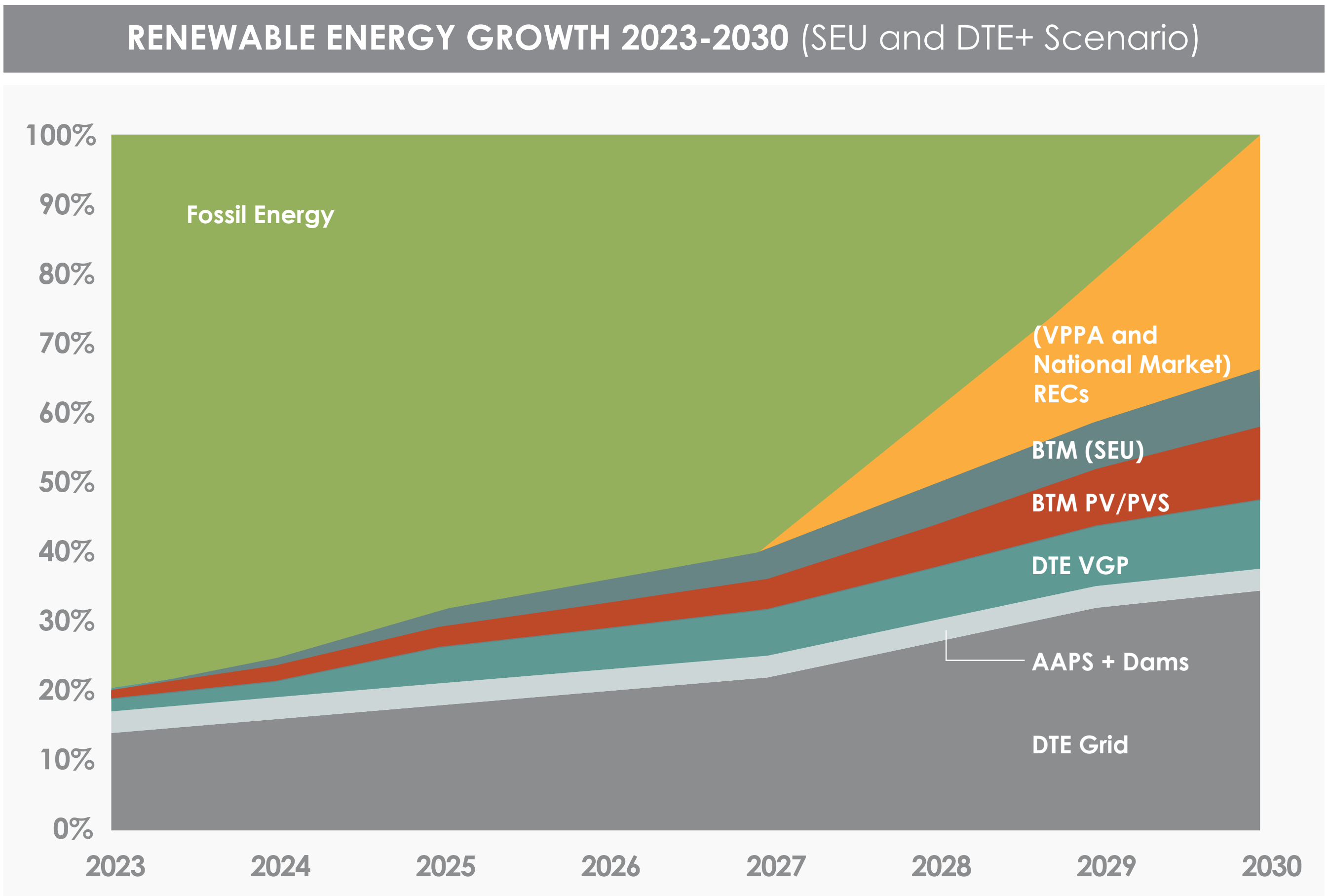
COSTS FINANCED BY CITY ($000)	YEAR 2030	CUMULATIVE 2023-2029
City Costs	$17,890	$17,728
Recoverable Costs	$2,327	$5,745
Non-Recoverable Costs	$15,563	$11,983

Ann Arbor has many options for achieving 100% RE and RE growth is expected for the DTE Grid and BTM PV/PVS well beyond 2030. Since the contract nature of VPPAs can extend many years, we recommend Ann Arbor revisit long term electricity growth projections beyond 2030 to minimize overexposure to RE investments. Prior to executing long term VPPAs the City could also choose to vet National RECs and purchase quality RECs with shorter contractual commitments.

Scenario 2: SEU and DTE+

In Scenario 2 we assume similar success for DTE's IRP commitment, AAPS, and local dams. Figure 21 shows continued growth of MIGP subscriptions and BTM PV/PVS, and new BTM PV/PVS growth for the SEU. In the overall BTM market, the SEU and private ownership may be considered competitors. Due to the large market capacity and the available residential and commercial load, we modeled in this scenario SEU customers would be distinct from private ownership. The SEU in this scenario may focus on a customer base with less interest or ability in self-financing or have developed programs to improve small commercial adoption.

Figure 21: Scenario 2 Energy Options that aggregate to 100% RE electricity by 2030.



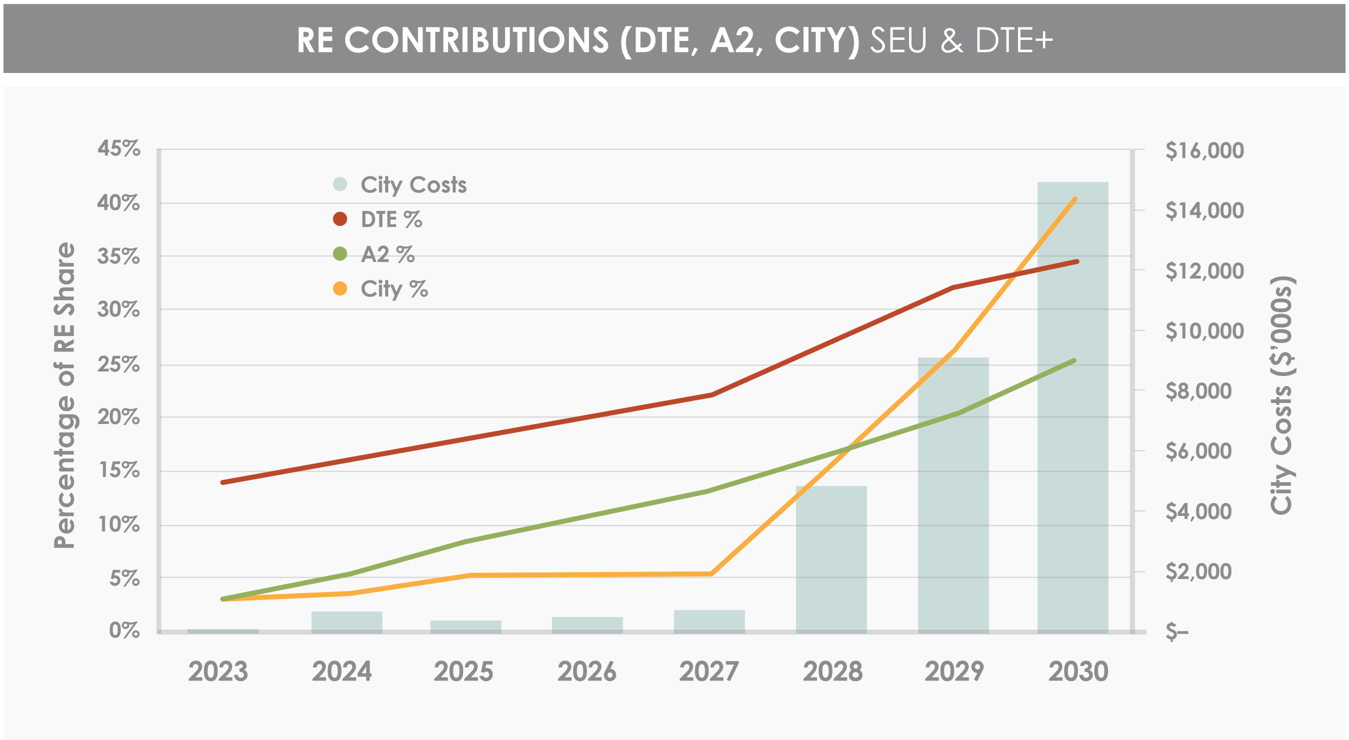
While Table 23 shows approximately $9.8M for the BTM PV/PVS (SEU) for the City, these costs would be reimbursed through SEU customer revenue. As discussed in more depth in the SEU section, the City would need to provide financing for the SEU or utilize a TPO through a series of BTM PPA type contracts. The percentage from RECs declines from Scenario 1 and thereby reduces the out-of-pocket burden to the City.

Table 23: Scenario 2 RE Contributions and City costs

2030 RE CONTRIBUTIONS SEU & DTE+ (Scenario 2)			
RESOURCE	**RE CONTRIBUTIONS**	**RECOVERABLE CITY COSTS ($000)**	**NON-RECOVERABLE CITY COSTS ($000)**
DTE Grid	35%	$ —	$ —
AAPS + Dams	3%	$ —	$ —
MIGP	10%	$ —	$125
BTM PV/PVS	10%	$2,327	$ —
BTM PV/PVS (SEU)	8%	$9,818	$ —
RECs (VPPA + National Market)	34%	$ —	$12,409
Community Solar	0%	$ —	$ —
TOTAL	**100%**	**$12,145**	**$12,534**

We modeled a similar REC procurement strategy for Scenario 2 as shown in Figure 22. The growth in Ann Arbor contributions is due to SEU subscriptions. While the City has the burden of establishing the SEU and determining how to finance projects, it would be the general Ann Arbor population that would be responsible for the increase in RE share.

Figure 22: RE growth by DTE, A2 (general public), and City (government)



The total costs shown in Table 24 are considerably higher for the "Recoverable Costs" due to the SEU, and again these costs would be transferred to Ann Arbor subscribers during the routine billing process. There may be ancillary benefits for the considerable SEU costs, such as additional local expenditures on construction labor, materials, and long-term operations and maintenance. We also observe the "Non-Recoverable Costs" in 2030 are $3M less than in Scenario 1.

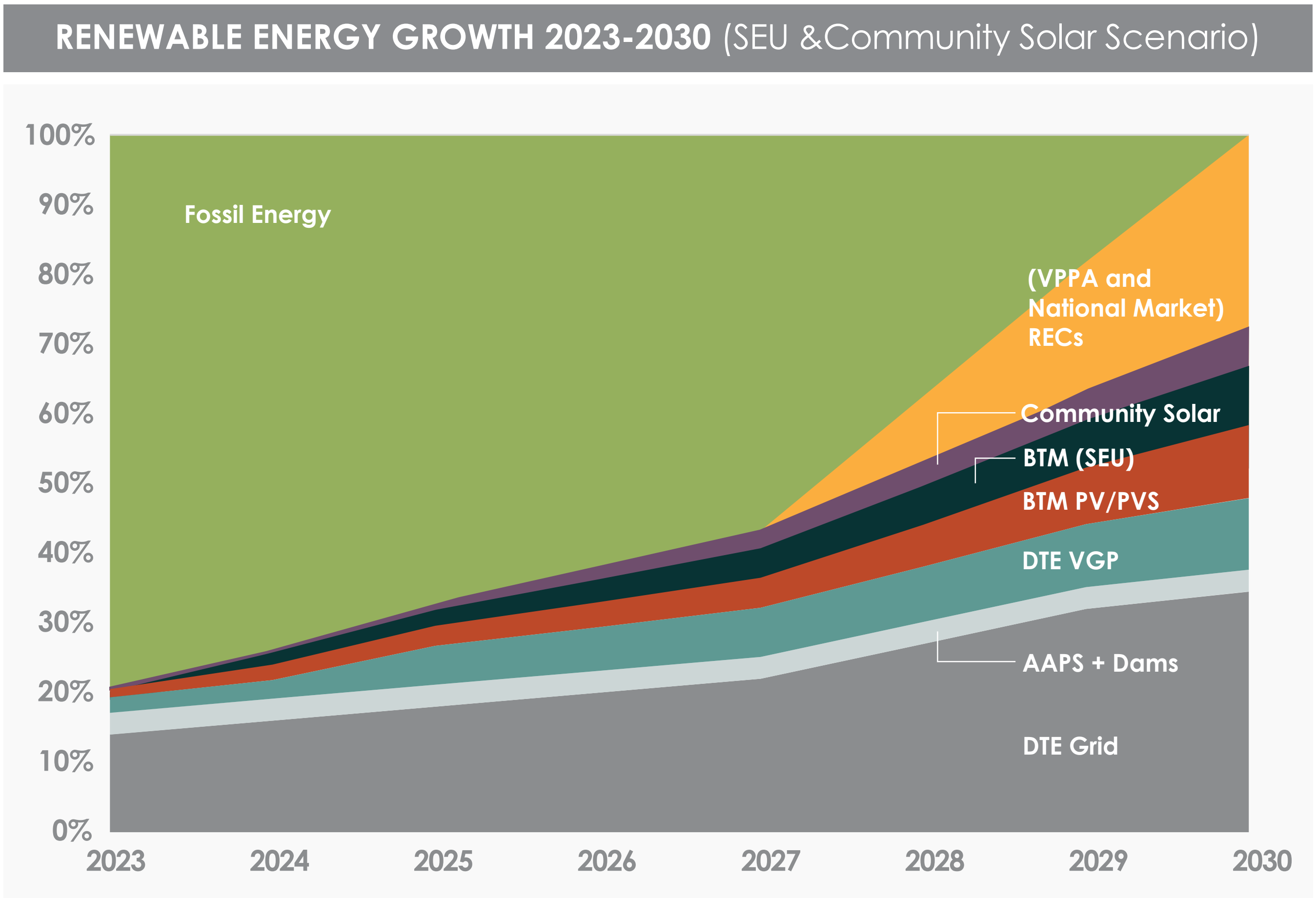
Table 24: Scenario 2 City costs for 2023-2030

COSTS FINANCED BY CITY ($000)	YEAR 2030	CUMULATIVE 2023-2029
City Costs	$24,679	$49,098
Recoverable Costs	$12,145	$38,787
Non-Recoverable Costs	$12,534	$10,311

Scenario 3: SEU and DTE+ with Community Solar

In Scenario 3 we assume similar success for DTE's IRP commitment, AAPS, local dams, MIGP subscriptions, BTM PV/PVS (both customer ownership and SEU). Figure 23 shows the growth of hypothetical Community Solar programs. In Scenario 3 we modeled Community Solar subscribers as new RE subscribers, although some may also cross over in a zero-net-sum transaction from MIGP or another RE option. Overall, though, diversifying choices for customers is likely to result in an overall increased RE adoption rate.

Figure 23: Scenario 3 Energy Options that aggregate to 100% RE electricity by 2030.



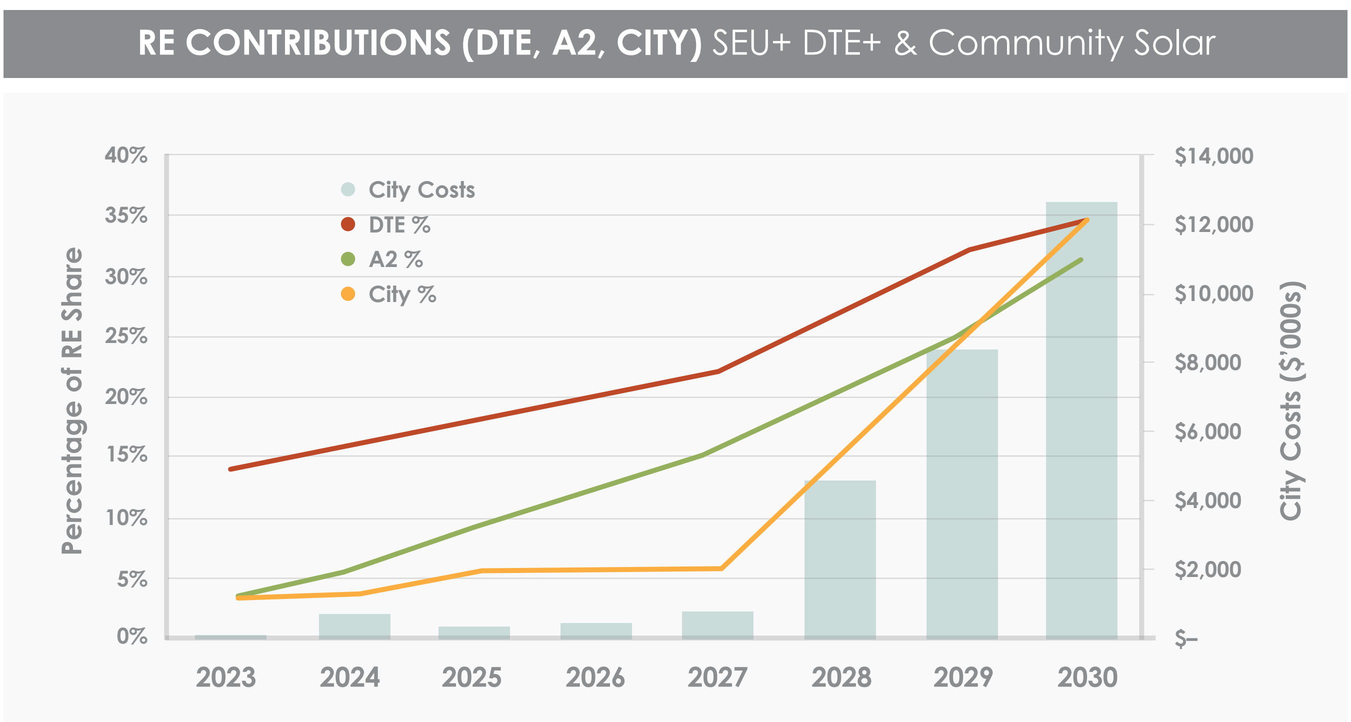
The addition of potential legislative changes to remove barriers to third-party Community Solar would not directly increase the City's cost burden. As the proposed legislation is contemplated, the TPO would own RECs. We understand the City would prefer to negotiate with potential developers to offer bundled RECs and energy to customers. We are uncertain how this could fully develop though for the purposes of this study we assume Community Solar subscriptions would contribute to Ann Arbor's RE Contributions goal while not increasing the cost burden on the City. To reduce the cost of Community Solar for subscribers, though, the City might choose to purchase any RECs not purchased by the subscribers themselves.

Table 25: Scenario 3 RE Contributions and City costs

2030 RE CONTRIBUTIONS SEU & DTE+ & Community Solar (Scenario 3)			
RESOURCE	**RE CONTRIBUTIONS**	**RECOVERABLE CITY COSTS ($000)**	**NON-RECOVERABLE CITY COSTS ($000)**
DTE Grid	35%	$ —	$ —
AAPS + Dams	3%	$ —	$ —
MIGP	10%	$ —	$125
BTM PV/PVS	10%	$2,327	$ —
BTM PV/PVS (SEU)	8%	$9,818	$ —
RECs (VPPA + National RECs)	27%	$ —	$10,160
Community Solar	6%	$ —	$ —
TOTAL	**100%**	**$12,145**	**$10,285**

With the addition of Community Solar in Scenario 3, the RE contribution levels for the general city "A2" have increased and all three entities are approaching similar contribution levels (Figure 24). We note City efforts to engage the community in Energy Options financed by the community tend to reduce the City's direct cost burden.

Figure 24: RE growth by DTE, A2 (general public), and City (government)



The total costs shown in Table 26 provide the quantitative evidence that additional A2 resident participation will reduce the City's burden. The Scenario 3 results show an additional $2M reduction in 2030 from Non-Recoverable Costs as compared to Scenario 2, and an additional $1M less in cumulative costs from 2023-2029.

Table 26: Scenario 3 City costs for 2023-2030

COSTS FINANCED BY CITY ($000)	YEAR 2030	CUMULATIVE 2023-2029
City Costs	$22,431	$48,021
Recoverable Costs	$12,145	$38,787
Non-Recoverable Costs	$10,285	$9,234

While we modeled Community Solar as the additional energy option in Scenario 3, we observe there are several Energy Options that may behave similarly to reduce City cost burden. TPO Community Solar is an energy option that has gained significant traction across the nation in recent years.

Energy Options Modeling Conclusions

As shown in the presented scenarios, we believe Ann Arbor should rely on multiple Energy Options to achieve the 100% RE goal by 2030. In the following figures we provide additional perspective on the interrelations of Energy Options and their compatibility with utility structures.

We provided costs for the Energy Options, though some Energy Options are priced differently according to their physical location on the grid and the associated pricing mechanisms. Figure 25 shows marginal levelized costs of the Energy Options compared to DTE's rates. For example, BTM PV costs between $19 less and $13 more per MWh today than average DTE rates and will cost between $28 and $78 per MWH less than DTE power in 2030. RECs will consistently cost more than buying power from DTE, since a REC is simply an additional expense incurred to offset a MWh of DTE power. Note, BTM costs are compared to retail energy costs while all other costs relate to wholesale market prices.

Figure 25: Projected marginal costs of Energy Options vs. DTE costs

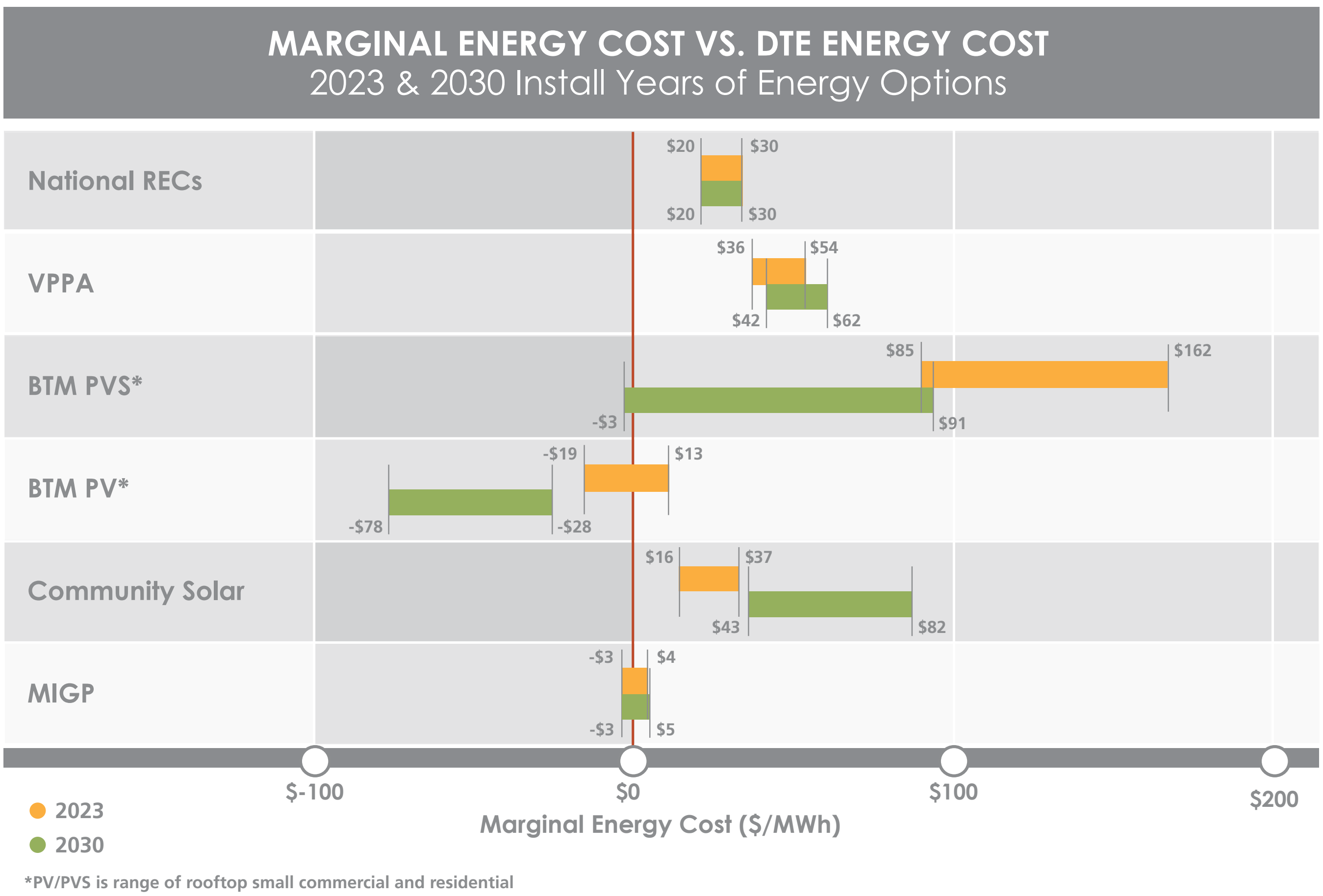


Figure 26 shows the Energy Options with DTE as the utility. The solid lines represent Energy Options available today, while dotted lines represent Energy Options that may be available in the near future with updated laws, regulations, and/or improved business models. Two of the Energy Options are presently active in Ann Arbor and are shown starting before 2023. Energy Options shown starting between 2023-2030 may already be available but not yet applied in Ann Arbor or may become available in the near future.

Figure 26: Energy Options timeline with DTE as the utility

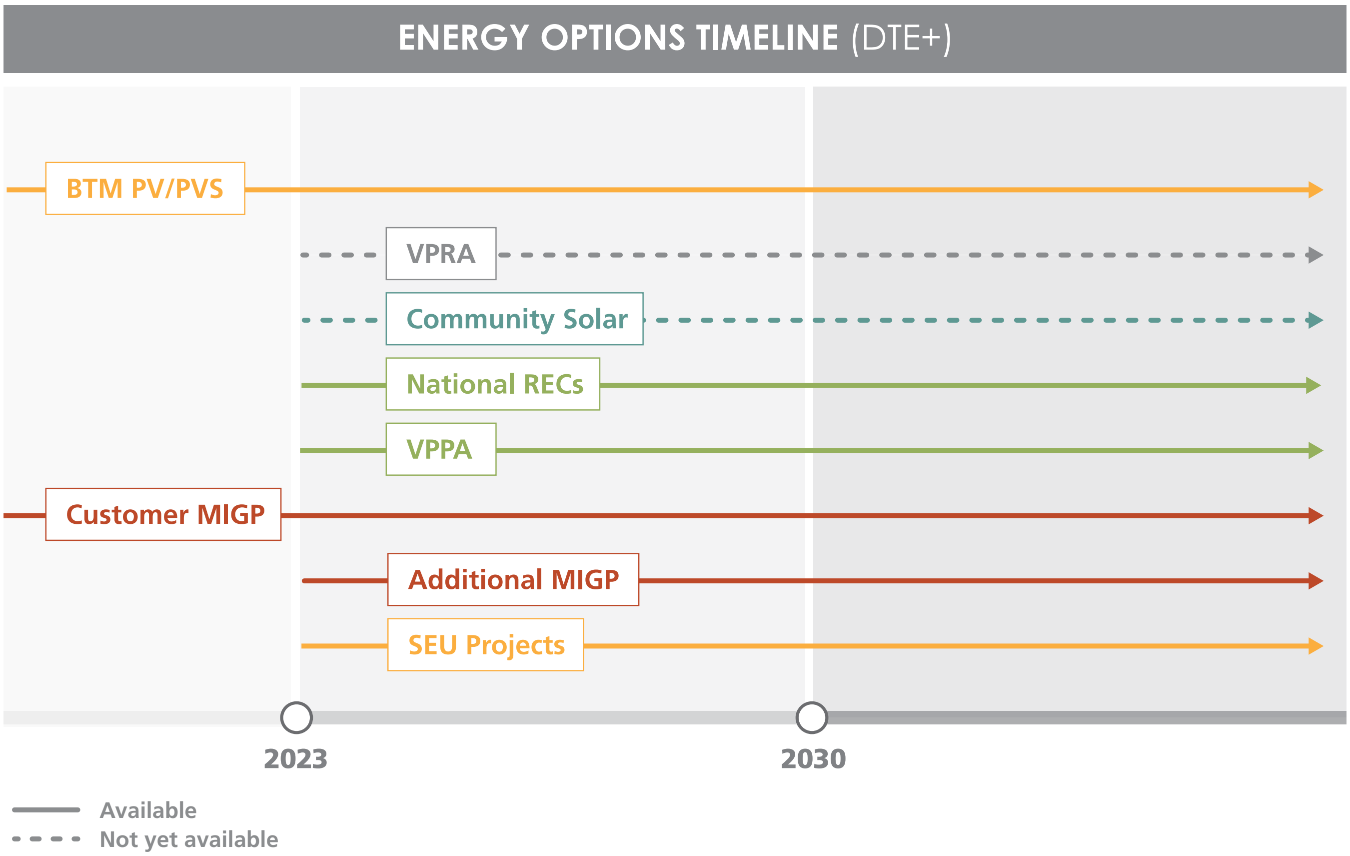
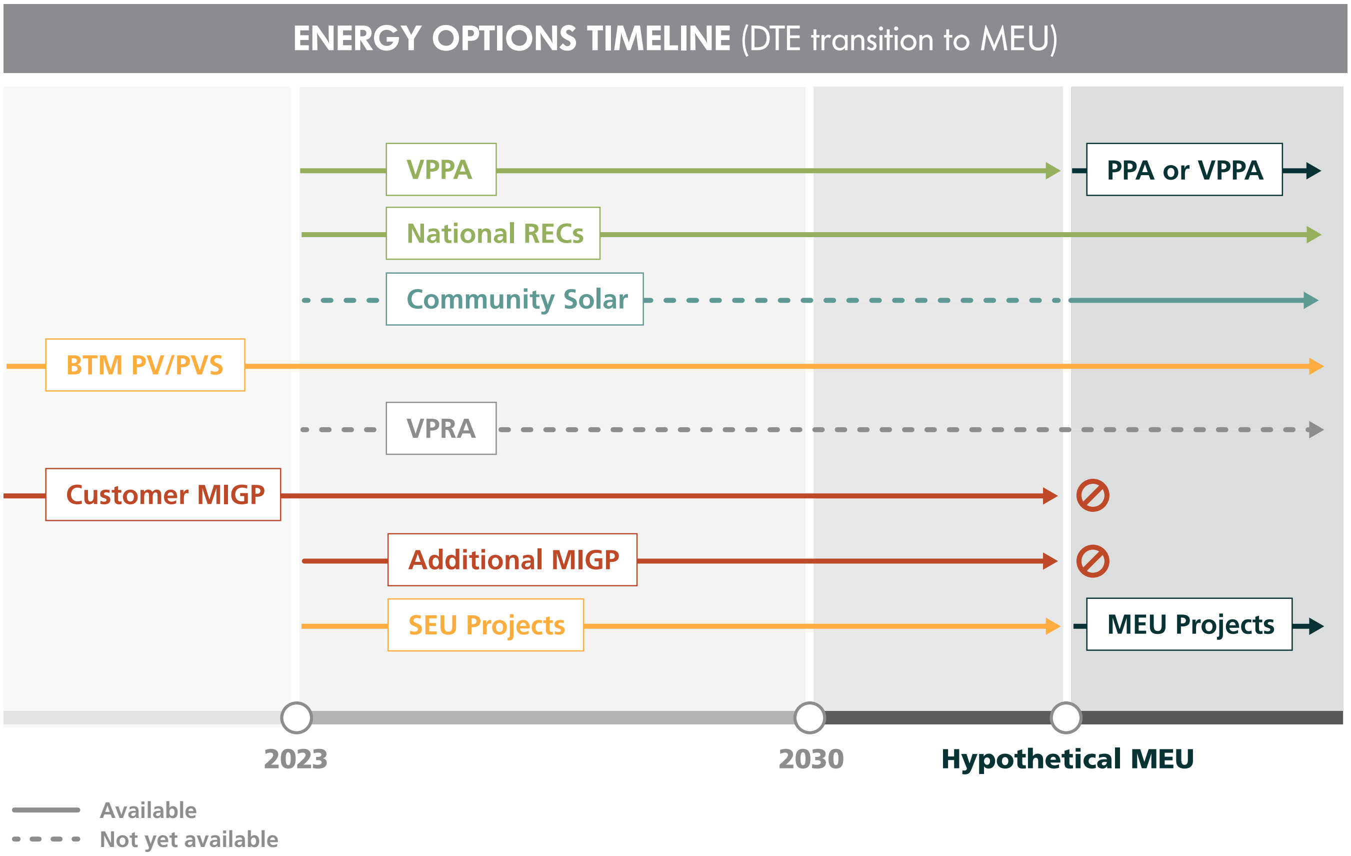


Figure 27 depicts potential staging and stacking of Energy Options before and after the launch of an Ann Arbor MEU. As discussed in the Executive Summary and in the Municipal Energy Utility Analysis section, we recommend Ann Arbor consider Energy Options that achieve 100% RE by 2030 and are not contingent on an operational MEU. The majority of Energy Options would be compatible with a transition from DTE to a MEU, while DTE's MIGP would not transfer to a MEU. We would expect the role of VPPAs to likely shift to the role of PPAs, and contract nuances would be required at the project level to complete a potentially direct contract transition. We would also anticipate any operating SEU assets and contractual obligations would transition well to a MEU.

Figure 27: Energy Options timeline with a transition from DTE as utility to a MEU



While Energy Options may stack and sequence well under several organizational scenarios, issues of cost, risk, speediness and support for the A²ZERO Energy Criteria and Principles are separate, but equally if not more important, to the City's choice of pathway. We will review those issues more in the next section.

ENERGY OPTIONS ANALYSIS: CONCLUSIONS AND RECOMMENDATIONS

In Table 27 we compile cost data to show City RE costs for the year 2030 and a sum of RE costs from 2023-2029. In the two SEU scenarios below, we assume the SEU develops a BTM portfolio with 25 MW of PV-only and 25 MW of PVS. The recoverable costs grow significantly in the SEU scenarios, because the SEU costs flow through the City budget but are ultimately recoverable through subscribers' electricity bills. The non-recoverable costs are effectively the 'net costs' to the City budget and would ultimately be borne by taxpayers. Net costs are lower in the SEU scenarios than in the DTE+ scenario because BTM PV and Community Solar reduce non-recoverable REC costs. We note, also, that SEU portfolio expenses are likely to have positive direct and indirect economic impacts in the region, which are not estimated in this Table.

Table 27: City Costs for the Three Energy Options Scenarios

CITY COSTS FOR THREE ENERGY OPTIONS SCENARIOS			
CITY COST CATEGORIES ($000s)	DTE+	SEU & DTE+	SEU & DTE+ & COMMUNITY SOLAR
2030 CITY COSTS			
City Costs	$17,890	$24,679	$22,431
Recoverable Costs	$2,327	$12,145	$12,145
Non-Recoverable Costs	$15,563	$12,534	$10,285
2023-2029 CUMULATIVE CITY COSTS			
City Costs	$17,728	$49,098	$48,021
Recoverable Costs	$5,745	$38,787	$38,787
Non-Recoverable Costs	$11,983	$10,311	$9,234

We do not recommend how the City should choose among these scenarios. All three offer pathways to 100% renewable electricity. Instead, our goal here is to provide enough information to help facilitate a robust public discussion of how best to trade off costs, risks and adherence to the A^{2}ZERO Energy Criteria and Principles. We foresee similar tradeoffs in the choice of utility structures, which we take up next.

Instead, our goal here is to provide enough information to help facilitate a robust public discussion of how best to trade off costs, risks and adherence to the A^{2}ZERO Energy Criteria and Principles. For example, the principles to "Start Local" and "Enhance Resilience" are probably most favored by a focus on behind-the-meter PV and PVS resources within the City, but virtual resources such as VPPAs and RECs rate better for "Speed" because they could contribute much more load carrying capacity by 2030. We discuss these tradeoffs further below. We foresee similar tradeoffs in the choice of utility structures.

ANALYSIS OF UTILITY ORGANIZATIONAL MODELS

ANALYSIS OF UTILITY ORGANIZATIONAL MODELS

Above we evaluated the potential for three scenarios to contribute to Ann Arbor's goal of 100% renewable electricity by 2030. Here, we evaluate the ability of three utility models, alone, to contribute to the 100% RE goal and the A^{2}ZERO Energy Criteria and Principles, out of context of likely scenarios. For example, our DTE+ scenario envisions DTE resources supplemented by private BTM PV/PVS investments and significant city REC purchases, plausibly reaching 100% RE in 2030; here, though, we evaluate DTE's 2030 contribution in isolation. The three models, or structures, we analyzed, are:

- DTE: potential contributions of DTE's resources to the 2030 goals.
- Supplemental SEU: We examined the 2030 potential for what we termed a Phase 1 SEU, which would deploy only behind-the-meter resources without any distribution resources, in part for technical and financial reasons but also to avoid incurring MISO capacity obligations by becoming an LSE. It is introduced above in Scenarios 2 and 3, and below we examine its operations in more detail.
- Municipal Energy Utility: evaluated in its launch year, at some indeterminate time after 2030.

We provided scenarios, above, projecting the stack of Energy Options and likely costs for the DTE+ and two permutations of the DTE+SEU scenario. In this section we discuss organizational issues that attach to the three utility structures, outside of scenario context.

DTE

Having already discussed DTE+ under Scenario 1 above, we will not repeat the stack of Energy Options and cost analysis we provided there. We have also already discussed RE contributions of DTE's default electricity tariffs and its MI Green Power program. Thus, we focus here on DTE's capacity to advance the A^{2}ZERO Energy Criteria and Principles. We rate the DTE scenario in 2030 compared to today.

Table 28: Alignment of DTE Structure with A²ZERO Energy Criteria and Principles

ALIGNMENT OF DTE with A²ZERO Energy Criteria		
CRITERION	**RATING**	**COMMENTS**
Reduce GHG	YES	Increase in DTE RE resources will displace fossil-fuel sources from the grid.
Additionality	YES	DTE RE resources will be additional, assuming A2 buys high-quality RECs.
Equity & Justice	GOOD	Access to benefits of RE is boosted by high % of RE in DTE default rates, plus low-cost and easy enrollment in MIGP. However, there are effectively no opportunities for marginalized communities to participate in decision making about DTE's programs.

ALIGNMENT OF DTE with A²ZERO Energy Principles		
PRINCIPLE	**RATING**	**COMMENTS**
Enhance Resilience	POOR	DTE has no firm plans to help at-risk individuals, emergency services and critical facilities maintain access to power in a crisis.
Start Local	FAIR	DTE plans to source its RE within Michigan.
Speed	GOOD	We project that DTE can provide over 50% of Ann Arbor's RE needs in 2030.
Scalable & Transferable	EXCELLENT	There are no barriers to communities continuing to receive service from DTE or other existing investor-owned utilities.
Cost Effective	EXCELLENT	DTE's RE offerings are offered at lower cost than its default energy rates.

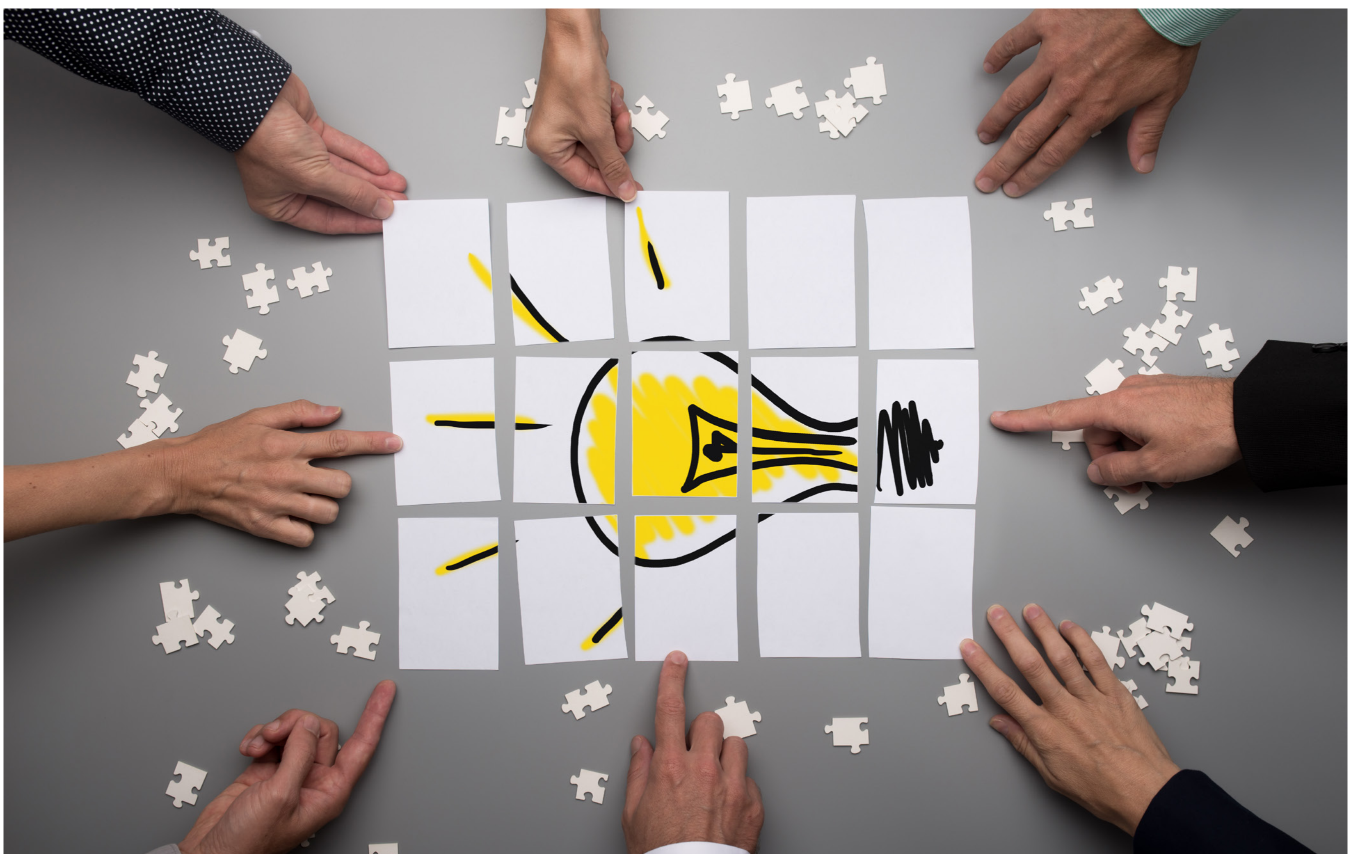
SUSTAINABLE ENERGY UTILITY

In 2021, the City published a defining report[15] with the vision of a SEU. This framework described how a local sustainable energy utility could accomplish specific A^{2}ZERO goals, such as accelerated adoption of RE technologies, local and equitable opportunities, and 100% RE electricity usage by 2030.

The SEU would be a municipal utility supplemental to the existing electric load-serving entity, the utility DTE. The SEU would operate as an independent City utility with similar operations as main public services, such as Ann Arbor Water Services. The operational territory for the SEU would be the city limits based upon the limitations of Ann Arbor's Franchise territory. Ann Arbor could follow the path blazed by operational sustainable utilities in other parts of the country, though Ann Arbor's model would be adapted to all applicable laws and regulations as well as Ann Arbor's vision and financial plan.

DTE's Relationship with the SEU

DTE would continue to serve as the City's Load-Serving Entity (LSE), avoiding any need for the SEU to contract for potentially expensive electric capacity. DTE would provide most of the City's electricity, at least early in the SEU's evolution, with the default customer tariffs reaching 35% renewables by 2030 and MI Green Power providing additional, voluntary subscriptions to higher levels of RE. DTE would continue to own and operate its primary and secondary electric distribution systems, including substations, wires, poles, transformers and more. SEU resources would presumably grow, supplanting services provided by DTE over time, but in foreseeable evolutions of the SEU it would always remain supplementary to DTE and would not become the City's LSE.



[15] A2_Sustainble_Energy_Report_2021_v7.pdf

SEU Structure

A SEU is a publicly owned municipal utility that does not own or utilize large-scale poles and wires (known as the electric transmission and distribution system). A SEU is supplemental to the primary, load-serving utility, in Ann Arbor's case DTE Electric. Ann Arbor's vision of the SEU generates power through local renewable energy installations such as SEU-installed solar/battery systems that provide power to homes or businesses, and microgrids or geothermal systems that allow neighbors to share power generated in the neighborhood. In addition to providing power from local renewable energy, the SEU could provide services such as more holistic energy waste reduction (efficiency) upgrades, support with beneficial electrification, and billing and payment options that DTE does not offer (e.g. on-bill financing).
In our evaluation, we focused on what we came to call the Phase 1 SEU, which would deploy energy generation (PV solar) and storage equipment only behind customers' DTE meters, while continuing to rely on DTE's electric distribution system to move electricity between customers. The Phase 1 SEU would not own wires, poles, or transformers, and would not develop shared resources such as community solar. There are both technical and regulatory hurdles to a SEU providing distribution services in parallel to a legacy distribution utility (DTE). We discuss these challenges in more detail further along.

Federal law describes a load-serving entity (LSE) as a distribution electric utility or an electric utility that has a service obligation to end users.[16] As long as the SEU only provided services supplementary to DTE (without undertaking any obligation to serve customer load), then the SEU would avoid becoming an LSE and incurring the associated regulatory obligations.[17] In particular, LSEs in MISO are subject to resource adequacy obligations, also known as capacity obligations. Capacity prices in MISO have historically been volatile and sometimes very high. Unlike a MEU, which would incur resource adequacy obligations, the SEU could avoid such obligations by limiting its scope of activities. At the time of this writing, we understand the SEU would not intend to assume responsibility for resource adequacy and the associated capacity obligations under the MISO tariff or under MCL 460.6w. Therefore, our approach to the conceptual design calls for the SEU to operate supplementary to DTE.

DTE would remain the LSE – a key difference from the MEU, which unavoidably would incur obligations imposed on LSEs.

Energy Options Offered by the SEU

We modeled SEU renewable energy opportunities that align with existing legal and regulatory structures, technical and economic limitations, as well as pragmatic operational considerations. While the SEU may consider operating novel technology components, the SEU would generally manage power generating assets that have a proven track record of successfully operating in parallel with DTE's electrical services. The 2021 SEU Report discussed other renewable energy generation options, including geothermal technology for heating and cooling applications; additional renewable energy electricity generation technologies are available, such as residential wind turbines and micro-hydroelectric turbines. While we take note of technologies that may become technically and financially feasible in the future, we focus on currently bankable and scalable PV and PVS technologies, with significant market competitors and

[16] 16 U.S. C § 824q - Native load service obligation. See also Module A of the Midcontinent Independent System Operator ("MISO") FERC Electric Tariff, which defines Load Serving Entity in relevant part as follows: "Any entity that has undertaken an obligation to serve Load for end-use customers by statute, franchise, regulatory requirement or contract for Load located within or attached to the Transmission System, including but not limited to purchase-selling entities and retail power marketers with the obligation to serve Load."

[17] LSEs in Michigan are subject to even more extensive capacity obligations. Michigan LSEs are required under state law to demonstrate that they will be able to meet their annual capacity obligations to MISO for four years into the future rather than simply the upcoming year, as required by MISO. See MCL 460.6w.

reasonable assumptions for forward looking cost curves and adoption. Future SEU study updates could include additional RE electricity generating technologies.

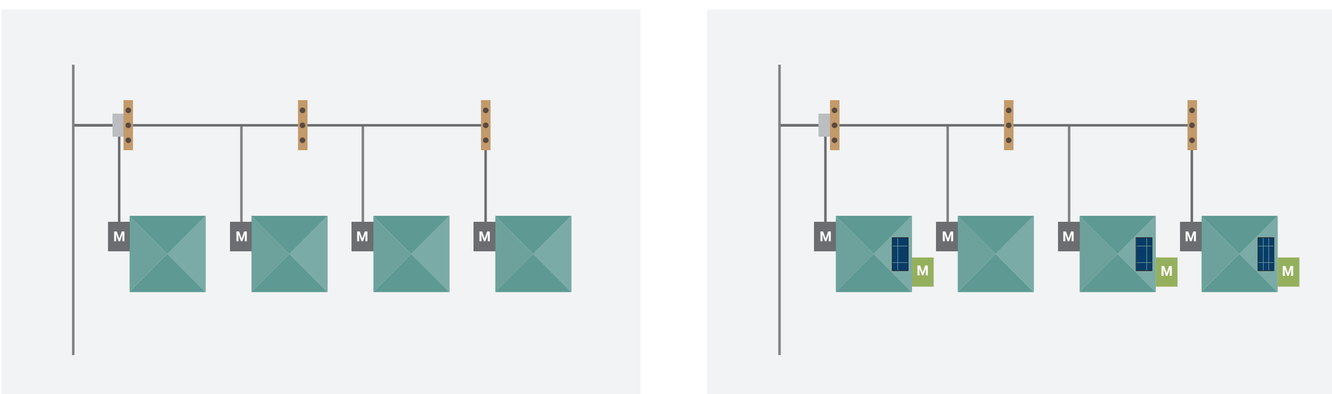
SEU Phases of Development

The City's SEU vision includes multiple developmental phases, two of which apply to RE electricity generation. Phase 1 technology in this report represents PV and PVS technology deployment on individual properties, largely rooftops. Phase 2 would add neighborhood-scale distribution assets to allow nearby properties to exchange electricity.

SEU Phase 1

In both images, every DTE customer has an independent meter with an independent address. The Phase 1 subscribers would allow the SEU to install PV or PVS on the subscribers' site, while DTE would maintain its existing distribution and metering infrastructure. The subscriber would purchase electricity generated from the solar panels, metered by the SEU, and electricity production that exceeded the subscriber's use would be sold to DTE at the tariffed outflow rates. Figure 28 shows a distribution circuit without solar projects and a conceptual distribution circuit with SEU Phase 1 PV installed. The Phase 1 design is comparable to how individuals have historically installed PV on their properties, the difference being that the SEU would develop, finance, build, and maintain the PV equipment. This is a version of TPO with the third party being the SEU rather than a private entity like a solar developer.

Figure 28: (left) Simplified diagram of single DTE secondary circuit. (right) Simplified diagram of SEU phase 1 on single DTE secondary circuit.



The Phase 1 SEU installed projects would operate in parallel with DTE and PV only projects would shut down during a grid outage. PVS projects may continue to operate during a grid outage with appropriately designed and permitted off-grid functionality. Conceptually, the Phase 1 projects may be installed on distribution circuits with pre-existing PV and PVS systems and would not assume to alter their operations. We anticipate Phase 1 projects would be eligible for the prevailing outflow tariff rate (i.e., DTE's Rider 18) and would not necessarily receive lower outflow credits associated with PURPA projects.

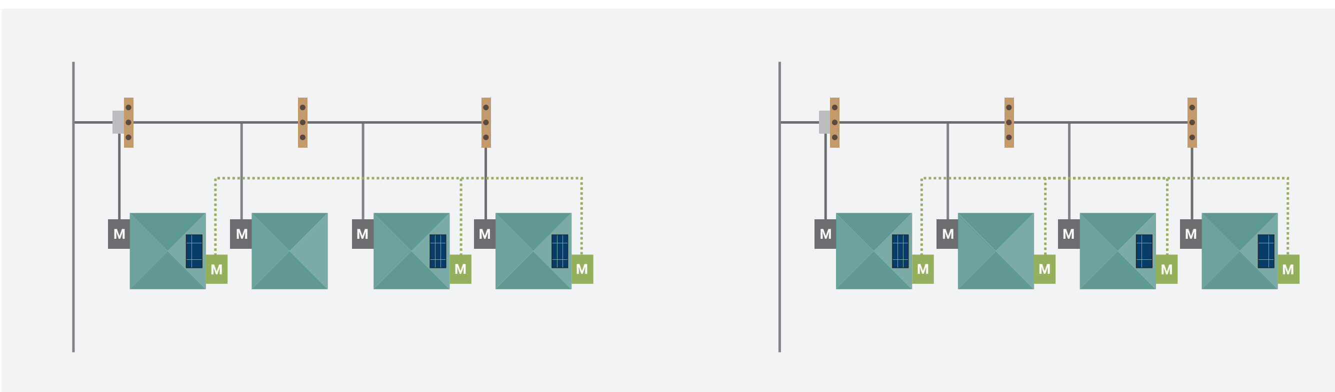
SEU Phase 2

The 2021 SEU Report also envisioned a microgrid component we call Phase 2, where the SEU installs new, physical connections among subscribers' premises. The new physical cables and associated electrical infrastructure would be SEU property and managed with similar easement and access requirements as existing utilities acquire in residential and commercial areas. The earlier report envisions the new microgrid, between participating subscribers, would bolster PV and PVS penetration and allow for cooperative usage of available space for PV and increase reliability opportunities through shared energy storage.

In theory, electricity generation from one subscriber's system may directly supply another subscriber's electricity consumption within design limitations. Multiple providers deploy technology that could perform services for Phase 2 operations, and we recommend well-planned deployments to ensure compliance with applicable legal and regulatory requirements. Phase 2 operations would require a more sophisticated financial accounting system.

Two Phase 2 design concepts are shown in Figure 29 below, for SEU subscribers sharing an existing single distribution circuit. In the left image, the SEU builds only new connections between buildings with SEU subscribers that can install PVS. In the right image, the SEU builds new connections for all buildings on a distribution circuit and the SEU serves subscribers whose buildings do not accommodate solar installations. All Phase 2 designs would preserve the DTE infrastructure in that all DTE customers would have independent meters with independent addresses. While we call Phase 2 the microgrid option, microgrid functionality is not explicitly required in the Figure 29 designs. We assume for microgrid operations the SEU would pursue automatic transfer switching at each individual building, and we are aware of multiple technologies with this capability. We recommend the SEU pursue transfer switch options that would comply with utility protocols.

Figure 29: Simplified diagram of SEU phase 2 on single DTE secondary circuit. (left) One house non-subscriber. (right) One house subscriber who cannot install PV.



The simplified images in Figure 29 depict four buildings on the secondary distribution circuit (down current from a line transformer). The national average is four to seven residences per secondary circuit, and we observed some DTE secondary circuits serving up to 13 premises. Phase 2 portfolios may be more applicable in areas with potential capacity on DTE's grid. The SEU would also need to consider whether to build microgrid technology on the DC circuit or on the AC circuit, and whether the overall SEU subscribers would prefer one technology across the city or varying microgrid technologies that may evolve in the next decade.

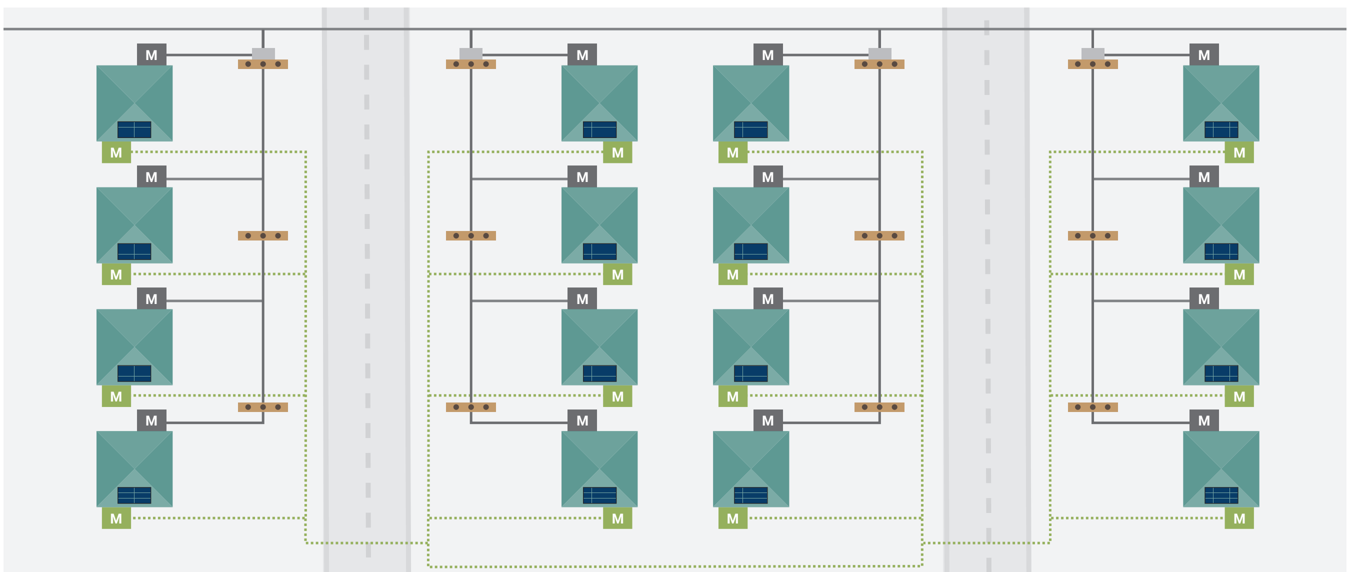
SEU connections may be buried cables that are known to have higher upfront installation costs but also higher reliability and typically require fewer maintenance visits – for example, less work to trim tree branches or repair storm damage. At the same time, underground infrastructure costs more to repair and may take longer to repair owing to reduced access.

Although some level of uncertainty remains on account of the relative novelty of such an arrangement, based on our present legal understanding, we believe DTE would be required to allow these Phase 2 projects to interconnect and operate as intended. We do not believe non-export interconnections would be required. The outflow rate, however, would most likely be the PURPA rate for all SEU subscribers owing to the shared design, which would likely disqualify the systems from participation in DTE's tariff Rider 18.

We recommend the City consider the impacts of Phase 2 portfolios:

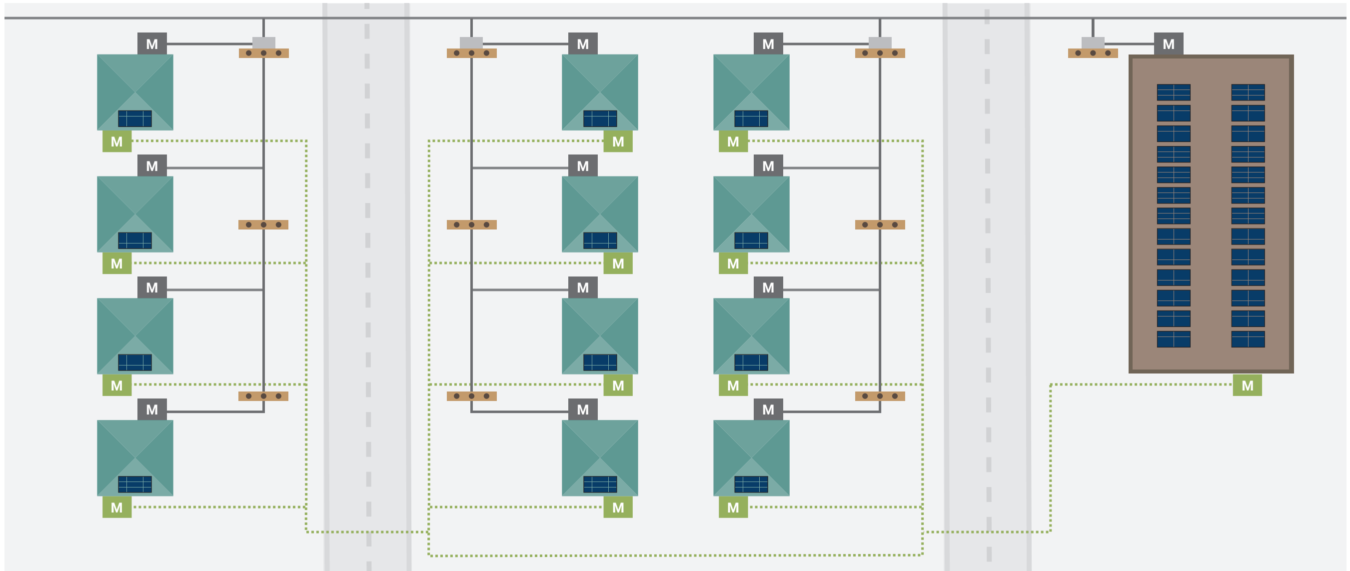
- on existing and new distribution circuits,
- whether participation is expected for all buildings on a distribution circuit (opt-in or opt-out models),
- whether the SEU would install new connections between buildings that do not participate,
- microgrid technology maturity, bankability, reliability, and replaceability,
- the maximum practicable size of a microgrid.

Figure 30: Simplified diagram of SEU network across multiple DTE secondary circuits



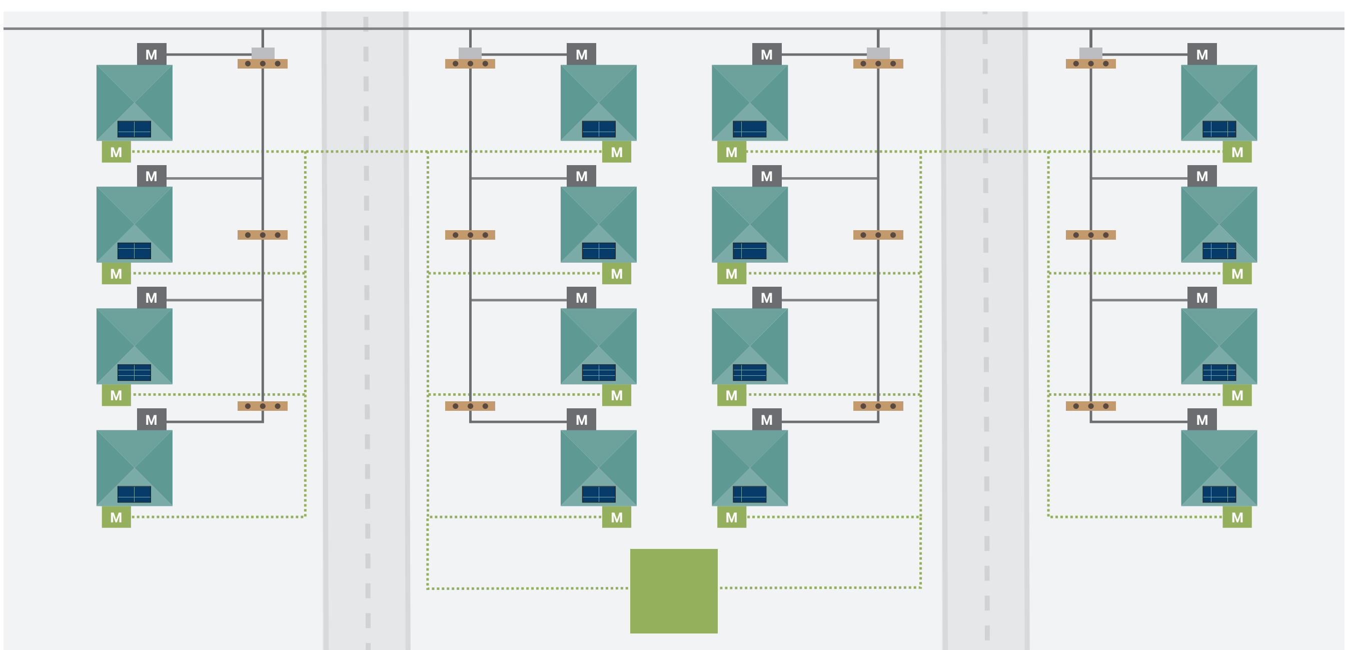
Expanding on the capabilities of a Phase 2 portfolio would be to integrate multiple distribution circuits within one microgrid, as shown in Figure 30. This model might be more beneficial if the portfolio included subscribers with large rooftops with relatively low usage, which would allow for more shared electricity on SEU cables such as Figure 31. For portfolios with moderate distances between connections, the SEU would need to examine the cost-benefit analysis of medium voltage power equipment to effectively manage the long distances that are similarly managed by DTE through multiple distribution circuits.

Figure 31 : Simplified diagram of SEU network across multiple DTE secondary circuits with residential and commercial customers.



A Phase 2 portfolio that covers multiple distribution circuits might require centralized power control equipment, shown as the green box in Figure 32. Thus far each Phase 2 participant has an independent address and independent meter. If the centralized equipment were to include a centralized energy storage unit, additional complexity would emerge. The energy storage unit might require its own interconnection process and impact customer rates. An energy storage unit, or other generating asset, might be considered to operate with a non-export agreement. In this case, the battery would operate only in microgrid mode. This might be conceptually possible, but the economic case for storage is weaker than if the battery could store grid power when it is cheap and feed it back when grid power is more valuable.

Figure 32: Simplified diagram of SEU network across multiple DTE secondary circuit with centralized SEU equipment.



Fundamentally, all diagrams show DTE remains the LSE and would be expected to be available and operational throughout the year, and the microgrids could still operate in parallel with DTE protocols. Further study would be required to outline all operational conditions, technological capabilities, and assumed compliance with DTE operational protocols and procedures. In concert with traditional power plant project finance with significant capital investments, we recommend the City consider utilizing independent engineering experts to review developer plans for overall microgrid design and execution plans.

Comparison of SEU Phases

In Table 29, we compare different visions for SEU phases with the potential maximum size of a subscriber's PV system and the potential consequences for utility outflow rates. The normal course of business if a customer finances BTM PV/PVS is to receive bill credits from the utility for outflow energy. This process does not change if a customer secures a PPA with a TPO, and subsequently would not change in the normal course of business if the SEU were the TPO. It is possible a customer can receive two electricity bills, one from the utility and one from the TPO/SEU. It is equally practical, and practiced across the country, for the TPO to aggregate the utility bill and provide the subscriber with a single bill. In this second model, the SEU would pay DTE for all customers net DTE charges and provide the subscriber a net bill includes of SEU charges and net DTE charges.

Table 29: SEU Phases and Potential Utility Outflow Rates

SEU PHASES AND POTENTIAL UTILITY OUTFLOW RATES		
SEU PHASE AND TYPE	**INDIVIDUAL SYSTEM MAX SIZE**	**POTENTIAL UTILITY OUTFLOW RATE**
Phase 1 Independent Systems	Individual Net-Zero	Contemporary Retail
Phase 2 Microgrid of Independent Systems	Individual Net-Zero	PURPA or Non-Export
Phase 2 Microgrid of Independent Systems	Surplus for other homes	Non-Export
Phase 2 Microgrid of Independent Systems with Central Battery	Subscribers Likely Individual Net-Zero	Non-Export
Phase 2 Microgrid with Community Solar	Subscribers Likely Individual Net-Zero	Non-Export

Further study would be required to validate the concepts in Table 29 with respect to whether under Phase 2 the SEU would be able to secure PURPA benefits or be required to comply with non-export agreements. For portfolios with lower-to-no outflow value the economic constraints challenge financial viability. Typically, microgrid technology also has higher upfront capital requirements. External funds, such as state or federal funding, could provide sufficient economic incentives.

We analyzed the potential limits of SEU operations of microgrid concepts but did not economically model Phase 2 due to the uncertainty in technology selection and the operational criteria necessary to develop cost models. We assume a goal of Phase 2 projects is increased emphasis on reliability, and a valuation on expected improved reliability could be an additional economic driver. There is also an opportunity for Phase 2 operations to potentially qualify as Distributed Energy Resources under FERC Order 2222. This order requires MISO to allow distributed energy resources to bid into the MISO energy market. For example, providers could virtually aggregate distributed battery storage and offer their stored energy as a MISO grid resource during high load periods. Realization of this scenario would measurably improve the financial feasibility of distributed battery storage. At the time of this writing, MISO has a trajectory of providing guidance regarding its implementation of Order 2222 by 2027.

We believe Phase 1 and Phase 2 deployments could occur in parallel in different areas of the city. We would recommend the City consider deploying SEU Phase 1 portfolios where practical to pursue the 100% RE goal by 2030 and not solely focus on Phase 2 deployments.

Establishing the SEU

The SEU would be a new municipal utility and would require significant planning to establish organizational structure, legal documentation, operational direction, financial planning, and many other aspects.

Financial planning

We assume the primary revenue stream for the SEU would be sales of PV generated electricity to subscribing customers. We modeled this revenue stream through BTM volumetric PPAs, though we recognize additional contract methods are available such as leasing options. The SEU would develop large groups of projects, secure financing, and build solar projects on a portfolio basis. Portfolios commonly develop over several years through due diligence and strategic construction planning. Revenue generation for the SEU is expected to increase proportionally with the progression of portfolio deployment.

The SEU has many tools available to finance project deployment. Direct ownership may be possible through 100% City debt financing (such as a SEU revenue bond or City general obligation bond), loans, federal and state grant funding, and City funding such as the climate millage. Indirect ownership may also be possible through TPO solar developers through an additional PPA layer where the SEU facilitates portfolio development and manages customer billing.

Market assessments

If Ann Arbor chooses to pursue the SEU concept further, the City would need to identify a minimum participation threshold to justify the work to form and operate the SEU for the long term. The SEU should also consider prospective customer adoption based on survey research. Participation and development plans could include, and is not limited to, building portfolios with these strategies:

- First-come first-served evaluation throughout the Franchise footprint;
- Regionally focused through shared electrical infrastructure (distribution voltage, shared distribution circuits, etc.);
- Demographic focused through neighborhood organizations, low-income designations such as census tracts, mixtures of residential and commercial participants;

- PV only portfolios, PVS only portfolios, or mixed portfolios with optional energy storage fee;
- Density of interested participants (potentially more helpful for Phase 2 portfolios);
- Parallel development in different areas throughout the City; Desire for backup power (energy storage) considering valuation outside of electricity savings and outflow sales. Parallel development could also leverage different financing options for each portfolio.

Legal issues

Equipment lease terms, including assumption of liability, would be important to design in a manner that preserves the SEU as a market competitor in comparison to commercial solar installers that offer solar leases.

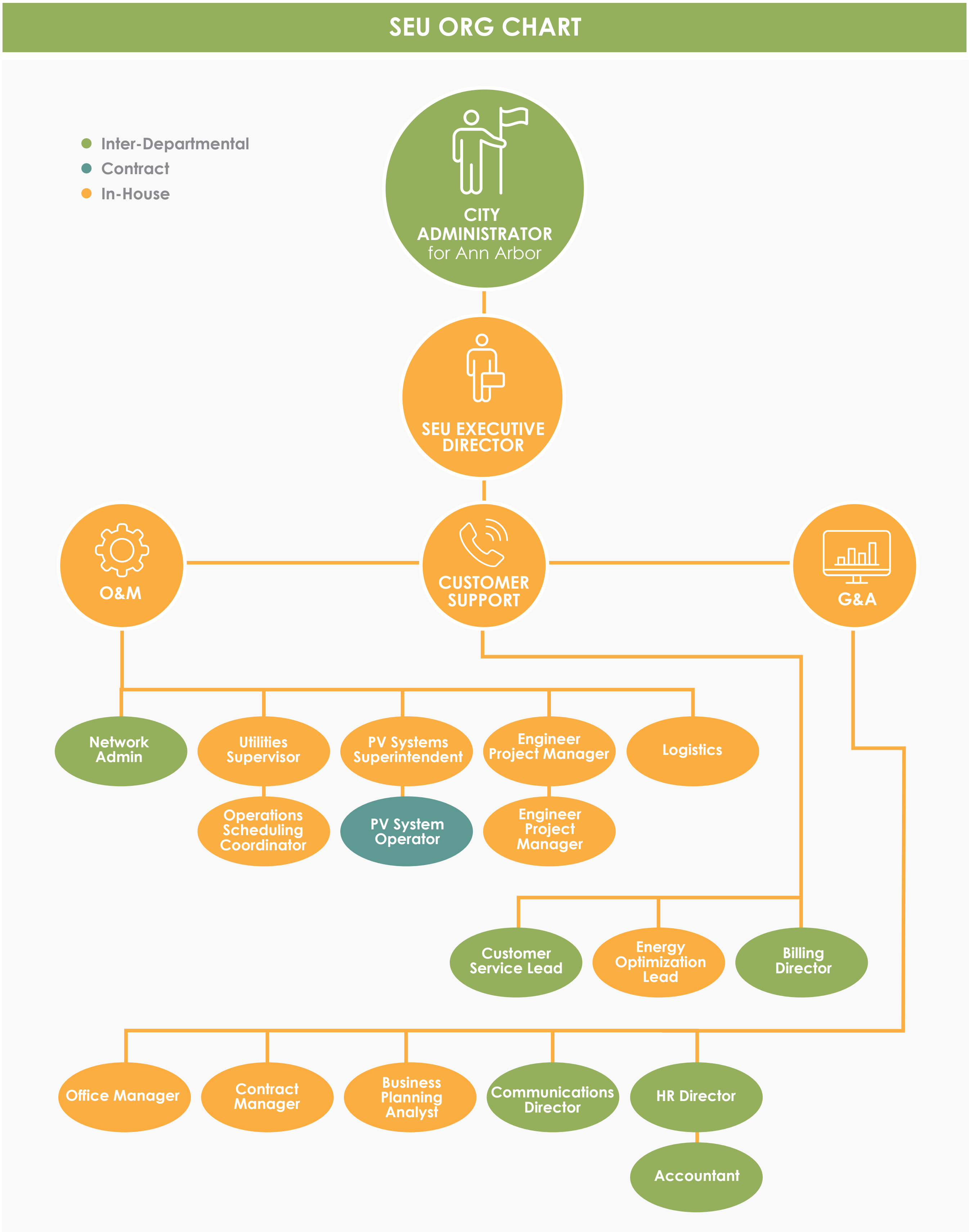
Considering the high number of rental properties present in Ann Arbor, structuring contracts for PV installed on rental properties would be another key area required for success. A traditional challenge for BTM solar developers has been the relationships between landlords and tenants. The SEU would need to resolve contract strategies with both property owners (lease) and identify and secure the precise subscribers and their electric utility obligations (DTE payments and SEU PPAs). This would need to be done for both residential and commercial properties.

Organizational Structure

To develop the SEU structure, staffing plan and levels, we reviewed how other municipal utilities set themselves up, and made adjustments reflecting that the Phase 1 SEU would have only BTM generating assets and no distribution assets. We anticipate a requirement for increased staff over time, but we model flexible staffing approaches to minimize fixed costs. For example, the SEU could pay for City water utility staff to perform customer-relations, account management and billing functions, rather than develop these capabilities itself. For field operations, the SEU would likely contract with private providers, for example to install and maintain BTM equipment; these roles do not show as part of the SEU organization. In the conceptual organizational chart in Figure 33, roles that might be filled by other City staff or under contract are color-coded. However, we did not review City rules regarding outsourcing of jobs so this scheme should be seen as illustrative, not prescriptive. We assume that all SEU functionalities would also require SEU budget, meaning the SEU would be responsible for allocated costs of services provided by other City departments and their personnel.

The anticipated staff growth we examined focused on the solar deployment for Phase 1 and Phase 2 portfolios but could include additional departmental growth based upon other potential areas such as a potential branch for geothermal energy. Staff growth would also depend upon the ratio of expected internal City employees and external contractors hired to fulfill specific enterprise roles. Staff size may vary significantly based on the financing mechanism for solar deployments. For example, operations costs may be lower if the City does not own PV/PVS equipment. Given that significant PV growth would require years to deploy, we estimate significant growth rates are possible while acknowledging challenges with hiring personnel at a rate to meet increased PV/PVS deployment rates.

Figure 33: Conceptual SEU organizational chart.



SEU Deployment

BTM PV/PVS deployment portfolios

To achieve fast and effective RE implementation the SEU will need to be agile with the size of PV installations and the overall portfolio technology. Phase 1 deployment as PV-only could evolve later to incorporate energy storage for a PVS portfolio, albeit at a higher storage installation cost due to construction crews working multiple times. Neighborhoods that integrate Phase 1 portfolios may prove more challenging to later evolve into Phase 2 portfolios, given the potential for technology variation and rework at the same site. Therefore, the SEU may want to minimize Phase 1 deployments in areas with the greatest Phase 2 potential. We would recommend the City consider the balance of whether Phase 2 potential would impact the goals of achieving 100% RE by 2030. We note Phase 1 portfolios are likely to achieve better economic opportunities (without considering grant opportunities), while Phase 2 may have improved reliability potential, which we did not explicitly value in our modeling.

PV technology has increasingly become cost-competitive across U.S. geographic markets. The SEU would be considered a new market entrant and would need to clearly establish its branding and target market audience. Some Ann Arbor residents and businesses would likely continue to independently finance PV on their property. Additional residential and commercial customers already subscribe to MIGP at its marginal costs, though some would be likely to subscribe to the SEU. The SEU may persuade MIGP customers to join, but we have the impression the SEU would not attempt to purchase existing BTM PV and PVS systems.

One remarkable advantage of PV panel technology is its modularity. We considered two methods for establishing a typical subscriber's amount of PV to install. One method assumed average electricity usage of 10,000 kWh, and assuming a typical rooftop PV yield, the resulting project size (over time and some with storage) was 8 kW-dc. We also considered modeling installation sizes as "blocks" of energy equivalent to the average annual energy output of 5 kW-dc of PV panels. This size aligns well with growth and with interconnection standards and utility size categories. This block may be sufficient for some (residential) customers, while other customers could subscribe to 2 blocks (10 kW-dc equivalent) or larger depending on the customers' premises' potential for PV and their electricity consumption profile. We note many community solar programs offer customers "blocks" of energy as low as a single panel's annual energy output. We have found that greater flexibility (i.e., smaller "blocks") offer increased locational opportunities and customer interest.

A straightforward approach for deploying Phase 1 portfolios would be to design project sizes at or below the estimated annual electricity usage offset of that particular property. Each subscriber would be the signatory for standard DTE interconnection processes and the projects would be most likely to secure the contemporary DTE outflow rates.

Asset Ownership

The baseline assumption for SEU deployments would be direct SEU ownership. Alternatively, the SEU could contract with existing solar developers to own and finance SEU systems. Assets owned by the SEU may have fewer layers of TPO and associated profit margins, while TPO also enables the SEU to deploy a greater quantity of assets with lower upfront capital costs. Interestingly, from a SEU subscriber's perspective, both direct SEU ownership and SEU management with another owner would be perceived as TPO since in both cases the subscriber would receive an energy-based bill from the SEU. We recommend the SEU organization consider deploying both direct ownership and TPO options in parallel.

Customer contracts

In Phase 1, the SEU would establish a long-term lease contract for utilizing SEU subscriber property, with rooftops as the most applicable space. The SEU may directly own the PV panels and all associated equipment or arrange a master contract with a TPO on a bulk purchasing PPA.

We believe the City would prefer that the SEU's default offering to customers in principle match their 100% net-zero quantity, prior to site-specific due diligence and potential rooftop constraints. Final portfolio pricing would not be known until a certain level of development due diligence has been achieved, so there would remain flexibility to decide whether the portfolio can afford 100% annual net-zero or, due to DTE outflow rates, would need to reduce the RE footprint closer to 60%-80% of electricity consumption using a traditional economic optimization for the customer's best return. We recommend SEU planning balance the pros and cons of allowing individual customers to select their preferred strategy versus a stream-lined process that dictates the customer's sizing strategy while reducing customer choice.

Commercial rooftop PV represents a large market with currently low penetration that could become a favorable source of customers for the SEU. Small commercial customers have more favorable outflow rates and may be more straightforward subscribers, while large commercial and industrial customers have less favorable inflow and outflow rates for PV electricity generation economics, due in part to the 150-kW size limitation under DTE's Rider 18 tariff. The Phase 2 customer audience could include large rooftop customers connected to smaller usage customers who could offset their higher inflow rates. Given that PV projects design life is 25 years or greater, this is also a long duration for commercial customer contracts. The SEU may consider shorter contract term lengths to increase commercial subscriber adoption.

The initial scope of work for this study referenced a standard PV size of 7 kW-dc. For further SEU development we recommend Ann Arbor consider refining the subscription size to accommodate the wide range of rooftop sizes and orientations and to maximize participation. Defining a fixed system size per site may appear to streamline permitting and construction but could result in limited deployment and subscriptions. We would recommend the SEU consider establishing technology standards that consider interchangeable equipment and could be replicable for variable roof conditions, which also enables size variability.

As noted in the BTM PV/PVS Energy Option, energy storage prices are generally anticipated to decline significantly over the upcoming decade. PVS use cases in Michigan at the time of this writing are predominantly justified by resiliency objectives. Unlike a traditional diesel or gas backup generator, energy storage can potentially recover a portion of investment costs through energy arbitrage, but not currently at a rate that would be likely to fully recover the investment. The use cases may be subject to change in future years if residential energy storage costs decrease sufficiently to justify storage as a way to arbitrage time-of-day rates. Consequently, we recommend PV-only portfolios be considered for potential lowest cost strategies to achieve this study's primary goal of 100% RE electricity by 2030.

2030 PV deployment projections

An operational SEU could consider BTM PV/PVS deployment as continuous for many years, where 2030 is a milestone year in the middle of long-term deployment. Nonetheless, given the City's goal of obtaining 100% RE by 2030, our study has focused on determining just how much PV a SEU could practically deploy by 2030. Given the many constraints, we modeled a 50 MW portfolio as the SEUs contributions to the reference Energy Options scenarios. Table 30 shows a range of deployment sizes, up to 200 MW. Our 2023 estimates of PV/PVS deployment rates in Ann Arbor are approximately 1.6 MW/year, and an average rate of 28 MW/year from 2024 through 2030 would be required to achieve 200 MW. We believe there would be logistical challenges achieving 28 MW/year for BTM projects, which represents a growth rate 18 times faster than current deployment rates. Contracting for reliable, experienced, and consistent, high-quality installations is paramount and speed should not be the sole metric. Table 30 shows that 200 MW represents 25,000 typical residential subscribers, and while the City scope for this study requested up to 50,000 subscribers, we believe that 200 MW likely exceeds the upper limit of achievable deployment by 2030. We also note, the year 2030 is a milestone date and if there is sufficient subscriber interest then the SEU could keep growing past 2030.

Table 30: SEU Subscribers by Deployment Size

SEU SUBSCRIBERS BY DEPLOYMENT SIZE		
PV DEPLOYED (MW-dc)	CAPACITY/SUBSCRIBER (kW-dc)	SUBSCRIBERS
10	8	1,250
25	8	3,125
50	8	6,250
100	8	12,500
200	8	25,000

We did not strictly define a minimum portfolio size for the SEU. We assumed no less than several MWs would be required to achieve economies of scale for equipment and labor, as well as Ann Arbor investment in SEU creation. Generally, we believe the financial condition of smaller portfolios could match or improve SEU financial conditions over larger portfolios. We assume bond financing would require interest to be paid within a year of bond issuance, which creates a disconnect between the potential deployment rate of large portfolios and how quickly revenue could be realized through completed projects and electricity sales.

For selected financial modeling summaries we considered a potential SEU customer size as available to install and utilize approximately 8 kW-dc of PV. While we observed significant variation in customer energy usage through Ann Arbor's demographics, from smaller residences to larger commercial buildings, this is a reasonable proxy to study. Later in this section we present financial results for deployment sizes between 10 MW-dc to 100 MW-dc.

Any portfolio shown in this table would most likely require years to deploy. We recommend planning several years of deployment in order to maximize the opportunities for solar installers to provide a stable, consistent work force, ideally with the most local labor possible.

Project Finance

We studied several financing options including SEU direct ownership through 100% debt financing, SEU direct ownership through complex capital structures, and indirect ownership through PPA contracts with third-party owners where the SEU could purchase the operating asset at the end of the contract term, such as 10 years after the asset's commercial operation date.

We believe this three-pronged financing approach could be applied in different portfolios, provides learning opportunities and represents the best opportunity to catalyze RE adoption and establish successful startup and long-term SEU sustainability. We now discuss the basic concept of each of these financing options.

Financial Incentives

Renewable power generation technologies have historically received short-term federal financial incentives that resulted in uncertainty for long term planning. Multiple recent new laws have significantly altered the long-term trajectory of federally financed incentives and have increased the number of market participants able to monetize these incentives. Two significant laws were the Infrastructure Investment and Jobs Act (IJA) and the Inflation Reduction Act (IRA). Several examples of new incentives for the scope of this study include the U.S. Department of Energy's Grid Resilience and Innovation Program (GRIP), which is authorized to administer over $10 billion dollars towards improving grid resiliency through federal grants. The IRA offers many financial incentives including a ten-year incentive plan for solar power deployment and energy storage deployment that can range from 5%-70% of project costs, including the new capability for local governments to monetize savings previously only available through tax credits. An example incentive in the IRA is dedicated to regions with census tracts greater than 20% estimated poverty level. The SEU may be able to apply for this subset of IRA incentives to further improve social justice and equity for lower income areas (and subsequently charge less for electricity).

Startup Costs

Typical startup items would include organizational contracts, documentation that aligned with Ann Arbor values, insurance, office space, telecommunications, and many other items. This report's section on Initial Municipal Electric Utility Operation further explains start-up costs for the MEU that would also be relatable to the SEU.

Startup costs for direct ownership such as 100% debt can be amortized over the length of the debt, while alternatively are possibly covered by one-time contributions, such as from the City climate millage. Within a reasonable range of financial parameters and assumptions, we do not see a financial impediment for the SEU to commence operations through several different initial financial pathways.

PPA financing

Signing a PPA with a third-party owner is an avenue for scaling up the initial SEU to provide solar capacity to a significant customer base. We assumed a default 10-year PPA term length, during which the third-party PPA provider would own the portfolio and the SEU would pay the provider a fee equal to the operating costs of the solar projects plus a competitive markup to compensate the provider. Our modeled results assume that at the end of the contract term, the SEU would execute an option to buy the portfolio from the provider at its depreciated value (a proxy for fair market value) and the SEU would continue operating the assets as the owner through their operational life.

Federal grants

We also considered federal grants as a supplemental financing source that could ease the operating cost and capital expenditure requirements for the SEU, rather than relying on debt financing to begin or continue SEU operations. Treating federal grants as supplemental avoids the SEU significantly depending on the uncertain prospect of receipt of federal grants.

The IIJA's GRIP program presents Ann Arbor with an opportunity to apply for grants to support the capital expenditures for a microgrid portfolio or multiple portfolios. The grant can also support the initial operating costs of the larger SEU. Receipt of a grant from the GRIP program could allow the SEU to add more capacity overall, in an accelerated timeline such as the first five years of operation, while still maintaining a positive cash flow position.

Debt financing

We considered two scenarios where 100% of the SEU's initial capital expenditures are financed by issuing a long-term bond. While this study was agnostic to the type of bond, we generally acknowledge a general city bond or a SEU-specific revenue bond may be the primary bond opportunities. Pragmatically, a new municipal utility will not have an established revenue history, and the SEU's debt financing opportunities at start-up may be limited. A simplified scenario we considered assumed that the SEU could achieve a revenue bond at a market rate for similar-sized cities. If the revenue bond rate turned out to be initially higher than market, the SEU could refinance later for an improved rate.

We also considered a scenario where financing for the initial SEU start-up period is covered through a third-party PPA contract as the primary source of financing, with the SEU purchasing the operating assets by issuing a revenue bond at the end of the PPA term. During this PPA term, the SEU will have proven several years of cash flow-positive operations and demonstrated management of a portfolio of projects. The SEU would then be able to potentially issue a revenue-backed bond to finance the buy-out of assets from the PPA provider as well as future capital expenditures. In the PPA scenario below, we assume a large portfolio, 100 MW, which would likely exceed SEU financing capabilities. This is an example size to demonstrate feasibility. A PPA model could be completed on a smaller scale.

In scenarios where SEU portfolios are fully financed by debt, the duration of deployment and potential for direct pay tax credits play integral roles. There will be a practical limit to the amount of BTM solar that can be installed each year, due to many constraints such as availability of skilled workers. Many debt tools require taking the full amount of debt at one time with interest payments commencing concurrently. If the SEU deploys tens of megawatts over the course of several years, then debt service payments will impose a financial burden prior to full revenue generation. Conversely, the solar industry generally assumes direct tax credit payments are likely to be issued a year after capital is deployed, resulting in large non-electricity revenue asynchronous with spending obligations. For SEU portfolios fully financed by debt, we recommend the City examine its portfolio deployment rate, the timing of principal and interest payments, and total costs to assess all debt opportunities such as smaller, more frequent debt issuances, revolving loans, additional grant opportunities, or stacked debt obligations such as bridge loans.

SEU Operations

Operating Expenses

The overall SEU concept offers significant opportunities for achieving local RE goals. Identifying and maintaining focused services and revenue streams would be critical for long term success. The SEU operational model for Phase 1 and Phase 2 deployment requires flexibility due to the variety of potential financing opportunities for any given portfolio.

For overall general and administrative costs, we assumed the SEU's costs would grow as a function of deployment rates. This may be an oversimplification for the first several years of the SEU's operation due to municipal overhead requirements, but we believe the long-term staffing requirements can be approximated with the proportional size of managed assets.

Phase 1 portfolios financed through TPO PPAs would mean the SEU is not directly responsible for equipment operations, maintenance, and the project finance accounting obligations. As a result, SEU staff and its subcontractors would have less work and responsibility. Alternatively, Phase 1 projects directly financed through the SEU would mean the SEU would be directly responsible for project finance accounting obligations and equipment O&M. While the SEU could subcontract these duties and shift the associated risk and liability, direct ownership would increase the required SEU oversight staff.

We believe Phase 2 portfolios are most likely to be deployed through a direct ownership model that would involve securing debt, equity, and potentially grants. We would anticipate greater staff obligations for the complexity of microgrid equipment, software, and infrastructure. We did not model Phase 2 portfolios in the analysis for 100% RE by 2030 due to the likelihood that there will be small levels of implementation by 2030 and due to larger uncertainty about total project costs, which would be based upon substantial design criteria inputs. We would expect higher Customer O&M costs and the potential for Distribution O&M costs depending on the microgrid structure.

Phase 1 operational costs with direct SEU ownership will likely result in high Customer O&M costs associated with the management of the PV and PVS equipment and associated maintenance. For portfolios that are financed with TPO, Customer O&M costs will likely be significantly lower; however, Power Supply costs will be the majority of operational costs.

We estimate Phase 1 SEU start-up costs at $0.35 million, representing about 20% of the total traditional MEU start-up costs.

Billing and Security

For accounting and billing services, we note some solar TPOs offer direct billing services that enable them to aggregate their bill with the remaining utility bill, so subscribers only receive one electricity bill. This may be a pragmatic approach for subscriber adoption and to facilitate accounting responsibilities.

Data collection will be an important service the SEU will require for both billing services and customer support. A typical, privately owned BTM solar project utilizes the residence's internet service and monitors performance through inverter software or data acquisition system software. Alternatively, a typical utility requires more secure security protocols than a single residential PV system, as well as revenue-grade metering. We expect it to be necessary for the SEU to plan for telecommunications, billing, and security standards, as well as potential additional operating costs if new internet services are required. Additional planning and higher costs would be expected for all SEU products that integrate off-grid reliability services.

Revenue requirements and operating reserve

The revenue requirement is defined as the difference between a) the SEU's annual operating revenue plus any additional revenue (such as receipt of federal tax rebates) and b) annual operating expenses before depreciation plus annual debt service.

In any given year, any revenue that surpasses this revenue requirement is placed in an operating reserve, while any given year where the revenue is insufficient to satisfy this revenue requirement triggers a withdrawal from the operating reserve. Cash from debt issuances is also placed in this operating reserve. It is worth noting that in some years of the modeled results the operating reserve falls to a negative position by relatively small amounts (around $1 million or less). We believe that short-term debt instruments commonly used by utility entities, such as commercial paper, could be used to cover these occasional shortfalls.

Rate analysis and design

The SEU would be a non-profit, supplemental municipal utility starting from scratch and developing a customer base over time. The customer base would be developed through securing a certain threshold of subscribers and installing portfolios of projects that capitalize on equipment economies-of-scale and perhaps consistent construction labor efficiencies. We recommend the SEU ensure that each portfolio (i.e. PV-only, PV/PVS, PVS-only, Microgrid) be set up to achieve economic self-sufficiency by assigning a rate structure that exclusively covers each portfolio's operational and financing costs. SEU overhead could be proportionally allocated to all active portfolios based on a well-defined metric, such as the subscriber quantity or weighted value based on the cost of a portfolio's technology makeup. The SEU would have the ability to pursue outside funding sources to cover some costs of a given portfolio, such as to relieve electricity bill costs for low-income areas.

SEU overhead could be proportionally allocated to all active portfolios based on a well-defined metric, such as the subscriber quantity or weighted value based on the cost of a portfolios' technology makeup. The SEU would have the ability to pursue outside funding sources to cover some costs of a given portfolio, such as to relieve electricity bill costs for low-income areas.

For example, a portfolio of Phase 1 PV-only subscribers may pay one rate while another portfolio of Phase 1 PVS subscribers pay a different rate. A Phase 2 Microgrid portfolio may have an additional rate structure based on high upfront costs that could also be offset by external grant funding. Subscribers would pay for all power generated on site that read through a revenue grade meter. The reason we recommend independent rate structures, for example between PV-only and PVS, is because one product is more expensive and contains higher value. If the SEU offered a PV-only option, we believe it would be perceived as inequitable if the PV-only subscriber were required to pay a portion of another PVS subscriber's battery storage cost that they do not get to utilize.

Typical electricity customers receive monthly utility bills composed of a combination of fixed charges, energy (usage) charges, and demand-based charges. The trend in Michigan at the time of this report is that utility customers with PV power are in the best economic position to be charged with energy-only utility rate structures. Beyond this, BTM PV power is most reliable as an energy-only power generation technology while BTM PVS in the future may be able to better monetize its value for providing capacity. This common energy-only rate charge is known as a volumetric PPA and while historically there has been uncertainty about the specific language of "volumetric PPA" we believe this concept is a satisfactory model. We do note there are additional contracts that seek similar financial returns such as an equipment lease. Variations on the specific contract mechanism do not impact the financial modeling results for the most straightforward modeling method, which is based on the amount of energy produced by PV panels.

Regardless of who owns the PV on a residence, the DTE customer receives the benefit of avoided inflow and receives DTE outflow credits as a direct offset to their bill charges. When a TPO offers a residential customer a PPA, the customer is required to purchase all power generated by PV, and the customer may therefore be economically better off minimizing outflow by installing a system that is smaller than 100% net-zero. For simplicity, we assumed the SEU would expect to bill customers based on contemporary inflow/outflow regulations.

We determined the contemporary DTE tariff of D 1.8 DG was the most economic rate for all residential sized projects as well as most small commercial sized projects. We calculated a SEU could be cost-competitive with DTE for the energy-only portions of a subscriber's bill if the rate were approximately $0.12/kWh for PV-only projects up to 150 kW-ac. We also reviewed historic residential utility rate increases and found an annual escalation rate of 2.5% was well within reason. Comparatively, we note the MEU study found an escalation rate of 3.5% to align with DTE rate increases. If the SEU were to charge an escalation rate of 2.5%, then this could be perceived as increasingly cost-competitive. It is noteworthy that we found a flat rate energy charge of approximately $0.16/kWh over the design life to closely align the SEU's net revenue to the lower initial rate that includes annual escalation.

We studied several financing options to determine if a SEU could be financially viable charging customers at this baseline value, which for the customer would be an approximate break-even case. We note escalation rates can be a debatable topic, so we note this is a reasonable modeling rate and are not declaring this to be an average rate across all years or customer classes. We also note the Phase 1 SEU must operate in a relatively open BTM market, meaning the Phase 1 SEU would need to provide competitive rates (or have additional value propositions) to garner market share.

Separate energy rates are applied to PVS projects since battery storage deployment has higher upfront capital costs and higher operating costs. While we model an energy charge for storage that would represent a simpler billing structure, we believe the higher energy charges would detract from the value of BTM battery storage used as backup power. Most frequently, stand-alone battery storage costs for utility-scale projects are priced on a capacity basis, meaning a fixed price per month over the life of the operating asset. We therefore also provide example capacity payments for PVS projects, which would require PVS subscribers to pay the sum of PV-only energy pricing and the monthly capacity payments. Both pricing options are presented.

Financial model results

In this first phase feasibility study, we arrived at two key metrics for the SEU to define "success." The first metric is that the SEU must maintain a positive balance in the operating reserve fund.[18] Because the additions to (or withdrawals from) the operating reserve are completed after satisfying the revenue requirement, the annual changes to the operating reserve are an indicator of the SEU's ability to maintain a net cash flow-positive position.[19] Thus, the growth in the operating reserve is a strong indicator of the overall income growth of the SEU. To calculate the degree to which the SEU is providing income growth above a reasonable cost of capital, for each scenario discussed below we calculated the net present value of the annual changes in the operating reserve, discounted at the inflation rate. The inflation rate is used as the discount rate to reflect a low cost of capital, given that the SEU is a not-for-profit utility.

The second metric we considered was the target 1.2x debt service coverage ratio (DSCR). This ratio is aligned with the MEU criteria, is consistent with small utility targets, and provides confidence during the credit review period for debt financing. We found the minimum threshold to be challenging in the first years of deployment due to the assumption that the bond issuance year would not wholistically align with IRA tax rebates and the deployment schedule. The deployment schedule was a factor since interest payments were starting before all portfolio assets were generating electricity and revenue. We also balanced the desire to provide as low an electricity rate as possible to customers with a graduated rate of profitability over the deployments' lifetimes. As a simplification, we considered the SEU should maintain the DSCR at 1.2 after the initial variability period, several years into operations. We note, however, that the late years of PV project deployment, after debt is paid, typically results in high returns, which a non-for-profit utility would need to adequately manage.

A number of different scenarios can satisfy these metrics of success, to varying degrees. Key variables that dictate these scenarios include:

- The size of the capital expenditures made to deploy capacity
- The number of years to deploy PV and PVS capacity
- The mix of PV versus PVS capacity
- The cost of power for customers
- Whether the SEU is financed using a PPA and debt or through debt alone.

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[18] Notwithstanding small negative balances that could be addressed through short-term financing.

[19] This includes covering annual debt service and (in cash flow accounting) before depreciation expenses.

We found that the SEU can meet this revenue requirement and maintain a net positive cash flow position in two financing scenarios: First, a scenario that is 100% debt-funded by issuing a bond at the outset ("100% Debt"), and, second, a scenario where the initial SEU operations are launched by signing a third-party PPA, followed by the issuance of a bond at the end of the PPA ("PPA Plus Revenue Bond").

Neither of these scenarios assumed the receipt of federal grants, meaning that any grant awards would serve as supplemental sources to finance additional options.

Financial Model Assumptions

For all three example models shown below we made the following key assumptions:

- SEU charges PV-only subscribers $0.125/kWh in 2024 and pricing escalates at 2.5%/year. If the SEU deploys its first project in 2027, the starting rate would be $0.14/kWh. Pricing is an adjustable financial lever. This baseline rate aligns with an energy-rate competitive with contemporary DTE inflow rate.
- PV-only pricing is benchmarked at $2.65/W for overnight construction costs in 2023 and declines annually by 2.5%.
- PVS pricing is benchmarked at 1.85x the PV-only price (for 5kW, 12.5 kWh) with a 2.5% all-in annual price decline.
- An initial $1 million startup deposit is provided from the City millage to cover initial startup costs and to provide initial operating reserves.
- Bond interest rates are available at 4.5%, bond terms are 22 years to provide several years of cushion before the end of the design life.

100% Debt Scenario, 10 MW and PV-only

The scenario shown in Table 31 assumes that the SEU adds 10 MW of PV-only solar capacity by 2030, representing $24.9 million in capital expenditures. Tax rebates are accounted for in the year(s) following PV deployment and this payment is applied to the loan principal to reduce total debt. We then assume the SEU issues a 22-year, $24.9 million bond.

We consider this a successful model example because any number of variables could help the SEU to further improve financing conditions. For example, with a flat rate PPA price of $0.16/kWh (with no escalation) and all other items held constant, the DSCR increases to 124% and the net present value (NPV) becomes $10.6 million.

We also note, there is no industry comparable reference for a Michigan based, non-profit developer, that can apply economies-of-scale for bulk purchasing while installing residential projects. It is possible the bulk PV CAPEX price can further decrease, total debt can decrease, and economics can be improved.

Table 31: SEU 100% Debt Financing scenario, 10 MW, PV-only

SEU 100% DEBT FINANCING SCENARIO, 10 MW, PV-ONLY			
LINE ITEM	**2024 VALUE ($000)**	**2034 VALUE ($000)**	**2044 VALUE ($000)**
Operating Revenues	$0	$1,768	$2,152
Additional Revenues (e.g. Federal Rebates)	$1,000	$0	$0
PROJECTED OPERATING EXPENSES			
Distribution Expense	$0	$211	$211
Customer Expense	$0	$201	$201
General and Administrative	$0	$10	$10
ALL EXPENSES			
Operating Expenses	$0	$422	$422
Debt Service	$0	$1,485	$1,024
Startup Costs	$175	$0	$0
CAPEX expenses	$0	$0	$0
TOTAL EXPENSES	**$175**	**$1,907**	**$1,446**
Cash Raised from Debt Issuance	$24,877	$0	$0
Net Position (Operating Reserve)*	$825	$76	$811
NPV (Operating Reserve Annual Change)**	$12,957		
Average DSCR***	100%		

* Includes operating revenue, cash on hand, interest on unspent cash

** Any Beginning Operating Reserve Subtracted

*** Average of years 2027-2036 DSCR

AVERAGE RETAIL RATE ANALYSIS			
Total Subscriptions	–	2,000	2,000
Total Customers	–	1,500	1,500
Total Sales (kWh)	0	11,047,970	10,507,836
PV Sales (kWh)	0	11,047,970	10,507,836
PVS Sales (kWh)	0	0	0
PV SEU Rate ($/kWh)	$0.125	$0.160	$0.205
(i) either PVS Energy Rate ($/kWh)†	–	–	–
(ii) or PVS Capacity Rate ($/month)	–	–	–
Reference DTE Energy Rate ($/kWh)††	$0.125	–	–

† Units are kWh for illustrative purposes. We recommend monthly capacity payments.

†† This is not a complete DTE electricity bill, it is a reference energy portion of the total bill based on typical customer usage.

100% Debt Scenario, 50 MW, 50% PV and 50% PVS

We modeled an additional scenario in Table 32 that assumes the SEU deploys a total of 50 MW (50% PV and 50% PVS) from 2027-2030, representing $151.9 million in capital expenditures. Tax rebates are accounted for in the year(s) following PV deployment and this payment is applied to the loan principal to reduce total debt. We then assume the SEU issues a 22-year, $151.9 million bond.

We consider this model a moderate, but manageable, challenge due to the Operating Reserve ebbing temporarily to negative $1 million. We also note the storage cost could be separated into a capacity cost equivalent to approximately $67/mo. per customer instead of blending the energy rate with the PV cost of energy. This scenario shows very high NPV and high average DSCR.

Table 32: SEU 100% Debt Financing scenario, 50 MW, 50% PV and 50% PVS

SEU 100% DEBT FINANCING SCENARIO, 50 MW, 50% PV & 50% PVS			
LINE ITEM	**2024 VALUE ($000)**	**2034 VALUE ($000)**	**2044 VALUE ($000)**
Operating Revenues	$0	$13,015	$15,845
Additional Revenues (e.g. Federal Rebates)	$1,000	$0	$0
PROJECTED OPERATING EXPENSES			
Distribution Expense	$0	$1,379	$1,379
Customer Expense	$0	$1,291	$1,291
General and Administrative	$0	$88	$88
ALL EXPENSES			
Operating Expenses	$0	$2,758	$2,758
Debt Service	$0	$11,810	$8,359
Startup Costs	$175	$0	$0
CAPEX expenses	$0	$0	$0
TOTAL EXPENSES	**$175**	**$14,568**	**$11,117**
Cash Raised from Debt Issuance	$0	$0	$0
Net Position (Operating Reserve)*	$825	$24	$6,929
NPV (Operating Reserve Annual Change)**	$89,753		
Average DSCR***	135%		

* Includes operating revenue, cash on hand, interest on unspent cash

** Any Beginning Operating Reserve Subtracted

*** Average of years 2035-2044 DSCR

AVERAGE RETAIL RATE ANALYSIS			
Total Subscriptions	–	10,000	10,000
Total Customers	–	5,699	5,699
Total Sales (kWh)	0	55,865,459	53,134,204
PV Sales (kWh)	0	28,179,298	26,801,616
PVS Sales (kWh)	0	27,686,160	26,332,588
PV SEU Rate ($/kWh)	$0.13	$0.16	$0.20
(i) either PVS Energy Rate ($/kWh)†	$0.24	$0.31	$0.39
(ii) or PVS Capacity Rate ($/month)	–	$67	$67
Reference DTE Energy Rate ($/kWh)††	$0.125	–	–

† Units are kWh for illustrative purposes. We recommend monthly capacity payments.

†† This is not a complete DTE electricity bill, it is a reference energy portion of the total bill based on typical customer usage.

PPA Plus Revenue Bond Scenario

Assuming a TPO can internally justify the financing, then the SEU signing a PPA with a third party potentially allows the SEU to pursue greater amounts of capacity than in the debt-only scenario. With the PPA, the SEU does not need to issue as much debt to cover the costs of the $359 million of acquiring capacity because it is buying the depreciated value of capacity at the end of the PPA term, rather than the full underpreciated amount.

This scenario envisions the SEU eventually owning 100 MW, the greatest amount of capacity yet. One difference in Table 33 compared the tables for the scenarios above is that the average DSCR is for years 11 to 21, rather than for years 4 to 14. This difference was made to reflect the fact that in this scenario, the SEU does not issue a bond until after the 10-year PPA term is over.

Table 33: SEU Financial Model Results for Year 1: PPA Plus Revenue Bond

SEU FINANCIAL MODEL RESULTS FOR YEAR 1 PPA Plus Revenue Bond			
LINE ITEM	**2024 VALUE ($000)**	**2034 VALUE ($000)**	**2044 VALUE ($000)**
Operating Revenues	$0	$21,755	$23,034
Additional Revenues (e.g. Federal Rebates)	$1,000	$0	$0
PROJECTED OPERATING EXPENSES			
Distribution Expense	$0	$2,758	$2,758
Customer Expense	$0	$2,583	$2,583
General and Administrative	$0	$175	$175
ALL EXPENSES			
Operating Expenses	$0	$5,515	$5,515
Debt Service	$0	$9,822	$16,140
Startup Costs	$175	$0	$0
CAPEX expenses	$0	$218,260	$0
TOTAL EXPENSES	**$175**	**$233,596**	**$21,655**
Cash Raised from Debt Issuance	$0	$218,260	$0
Net Position (Operating Reserve)*	$825	$6,419	$1,526
NPV (Operating Reserve Annual Change)**	$31,881		
Average DSCR***	107%		

* Includes operating revenue, cash on hand, interest on unspent cash
** Any Beginning Operating Reserve Subtracted
*** Average of years 2035-2044 DSCR

AVERAGE RETAIL RATE ANALYSIS			
Total Subscriptions	–	20,000	20,000
Total Customers	–	11,399	11,399
Total Sales (kWh)	0	108,965,438	103,638,132
PV Sales (kWh)	0	54,963,651	52,276,485
PVS Sales (kWh)	0	54,001,787	51,361,647
PV SEU Rate ($/kWh)	$0.13	$0.16	$0.20
(i) either PVS Energy Rate ($/kWh)†	$0.24	$0.30	$0.37
(ii) or PVS Capacity Rate ($/month)	–	$67	$67
Reference DTE Energy Rate ($/kWh)††	$0.125	–	–

† Units are kWh for illustrative purposes. We recommend monthly capacity payments.
†† This is not a complete DTE electricity bill, it is a reference energy portion of the total bill based on typical customer usage.

Policy Decision

Will the SEU incentivize Large Commercial and Industrial businesses with a tariff structure that results in better economics than DTE inflow and outflow rates? If the SEU or the City purchased RECs from projects larger than 150 kW-ac we anticipate increased local PV adoption.

SEU Scenario Deployment Summary

The following summary table provides comparative analysis for the three presented SEU deployment sizes. In general, we recommend SEU financing closely align deployment rates with debt repayment obligations (principal and interest). For large portfolios, we would recommend potentially securing a series of annual funding opportunities versus one large debt raise that would require interest repayment prior to the deployment of all assets.

Table 34: Technical and Financial Description of Three SEU deployment scenarios

SEU DEPLOYMENT Three Example Scenarios			
SEU DEPLOYMENT DETAILS	1,250 SUBSCRIBERS*	6,250 SUBSCRIBERS	12,500 SUBSCRIBERS
Portfolio Capacity (MW)	10	50	100
PV-Only Capacity (MW)	10	25	50
PVS Capacity (MW)	–	25	50
Overnight Cost ($000)	$ 24,900	$ 151,900	$358,980
1st Finance Structure	100% Debt	100% Debt	10-yr PPA (TPO)
2nd Finance Structure	–	–	Year 10 – 100% Debt
SEU Debt Obligations ($000)	$ 24,900	$ 151,900	$233,000
Deployment Year(s)	2024-2027	2027-2030	2025**
PV-Only Starting PPA Rate***	$0.125/kWh	$0.135/kWh	$0.128/kWh
(i) PVS Starting PPA Rate****	–	$0.258/kWh	$0.246/kWh
Or (ii) PVS Capacity Payments	–	$67/month	$67/month

* The subscriber count is based on a generalized 8 kW-dc per subscriber. The subscriber count would be higher with residential subscribers that have smaller loads or lower with commercial subscribers that have larger loads. In addition to the information in the above table, our analysis finds that the IRA expands the economic impact of the state policies we modeled.

** 2025 is reference pricing year and deployment would require many years.

*** This is not a complete DTE electricity bill, it is a reference energy portion of the total bill based on typical customer usage.

**** Units are kWh for illustrative purposes. We recommend monthly capacity payments.

Alignment with A²ZERO Energy Criteria and Principles

A narrow assessment of the SEU's alignment with the A²ZERO Energy Criteria and Principles would recognize that, in 2030, it is distinguished from the DTE model by somewhat greater deployment of BTM PV/PVS. This might be too blinkered an assessment, however, because the SEU can provide a variety of resources that we recognize but have not evaluated here. For example, the SEU could provide significantly greater support and financing to advance A²ZERO Goals beyond Strategy 1 – 100% renewable electricity. The SEU, for example, could broaden and accelerate energy efficiency programs; assist property owners in switching from gas-fired appliances to electric; organize and support deployment of EV chargers around town; and lead trip-reduction efforts. Without a SEU the City is much more limited in the resources it can bring to bear on these commitments. Our quantitative projections take for granted that all these A²ZERO 2030 goals will be achieved, but the resources and institutional focus of a SEU would provide much greater assurance that they would be attained.

Our ratings here focus only on the Energy Options the SEU would deploy, without regard for stacking with DTE resources or private PV/PVS deployment.

Table 35: Alignment of Phase 1 SEU with A²ZERO Energy Criteria and Principles

ALIGNMENT OF PHASE 1 SEU with A²ZERO Energy Criteria

CRITERION	RATING	COMMENTS
Reduce GHG	YES	BTM PV/PVS programs of the SEU would displace fossil-fuel sources from the grid.
Additionality	YES	BTM/PV/PVS programs of the SEU would be new.
Equity & Justice	EXCELLENT	BTM PV rates of the SEU would be competitive with or better than DTE rates, easy to access, with strong local participation opportunities.

ALIGNMENT OF PHASE 1 SEU with A²ZERO Energy Principles

PRINCIPLE	RATING	COMMENTS
Enhance Resilience	FAIR	We model SEU scenarios with increased PVS deployment but relatively few households in Ann Arbor would have PVS by 2030.
Start Local	EXCELLENT	All Phase 1 SEU Energy Options would deploy within Ann Arbor.
Speed	FAIR	We project that BTM PV/PVS provided through the SEU would provide no more than 15% of load carrying capacity in 2030.
Scalable & Transferable	GOOD	Creating an SEU requires political will and financing, but has little net fiscal impact over time, is legal and is technically straightforward in Phase 1.
Cost Effective	EXCELLENT	We project that SEU rates for PV would be lower than rates for DTE power.

MUNICIPAL ENERGY UTILITY ANALYSIS

Municipal utilities vary in form, but the most common is a public utility that owns the electrical distribution infrastructure and sells electricity from third-party generators to its customers who are physically connected to "the grid." When an entity tries to municipalize in this way, it must use a court process to determine the value of the incumbent utility's assets and purchase that infrastructure from the utility. If Ann Arbor were to form a municipal utility, it would likely source electricity through a combination of PPAs and solar PV sited around the city and owned by property owners, the municipal utility itself, or energy developers.

The intent of our Preliminary Municipalization Feasibility Study was to provide initial financial estimates for evaluation by Ann Arbor to help the City determine if it should continue with its investigation of a locally controlled MEU. This Phase I Feasibility Study utilized publicly available data and other information sources to determine potential cost impacts associated with a MEU for the City. We develop a revenue requirement for the potential MEU, which is divided by the total energy sold to develop an "all-in" energy rate. We compare the MEU energy rate to a blended rate developed for continued service by DTE within the City boundaries (defined as "DTE in Ann Arbor" for the purposes of this Report) and based, in part, on an estimated blend of existing and projected retail rates.

The Phase I Feasibility Study assumes an "overnight" transfer of the DTE assets to the City for the purposes of evaluating financial feasibility, as further explained herein. Other data sources for this Study include estimates for "start-up costs," field investigation by members of the NewGen Project Team, and projections for power supply provided by 5 Lakes Energy, as well as estimates of "going-concern" valuation. The projections for power supply assume that the City would achieve its goal of having 100% renewable energy to meet its projected electric load by 2030 with service from the MEU or DTE.

Timeline and Risks

Municipalization is a complex legal process that has historically been vigorously opposed by the incumbent utility. We see no reason to expect this would be different in the case of Ann Arbor. Historical experience has been that the process takes many years and involves considerable legal expense.[20] We assess that it would be unlikely that a decision to municipalize could be made, clear all obstacles and prerequisites, and be implemented as early as 2030. We have therefore recommended above that if Ann Arbor determines to proceed to create a municipal utility using distribution assets from DTE, arrangements to reach 100% renewable electricity by 2030 should be made outside of that construct but with defined options to move any generation or power purchase agreements to the municipal utility at the appropriate time.

The legal costs likely to be incurred in the process of attempting to municipalize are uncertain and could be substantial. Estimates of the assets and going concern values in this report are preliminary, and updated and more thorough analyses would be required for use in formal legal proceedings. These additional legal and engineering/technical costs are not included in our estimates below, which are intended to provide preliminary assessments of the costs of acquiring, operating, and maintaining distribution assets for a MEU. As described below, the costs we estimate are "overnight" costs in the immediate future and will change by the time that a municipalization transaction could occur.

Phase I MEU Feasibility Study Elements

The following highlights the Phase I Feasibility Study elements and key assumptions:

- Define the potential MEU service area as the existing customers within the City limits served by DTE from the distribution equipment emanating from the various electric substations within and surrounding the City. It is assumed that the City would develop its own substation facilities and take service directly from ITC, the regional transmission service provider, at the high side of the transformers within the new substations. The City would not acquire any DTE substations, sub-transmission, or transmission assets in the City.
- Determine estimates for the direct cost to the City of acquiring DTE assets serving customers within the City utilizing publicly available data, information from the City, and the types and condition of the delivery assets determined during a limited onsite field review.
- Incorporate high-level load forecast analyses developed by 5 Lakes Energy based on available data and expectations for increased electrification of various applications and appliances utilized by citizens and businesses in the City.
- Incorporate power supply projections (including delivery) developed by 5 Lakes Energy which assume the City would achieve its goal of 100% renewable energy. These estimates include procurement of renewable energy resources by the City as well as comparison estimated costs for DTE to provide 100% renewable energy to the projected City load (based on current and estimated future market costs). It is assumed that DTE will apply its rate of return (8.9%) to the wholesale market purchases in its retail production costs.
- Determine preliminary estimated start-up, financing, operations and maintenance (O&M), and administrative and general (A&G) costs utilizing publicly available data and NewGen Project Team professional experience.

[20] "An Analysis of Municipalization and Related Utility Practices," prepared for the District of Columbia Department of Energy and Environment, September 30, 2017.

- Project estimated costs (rate revenues) of providing MEU service (i.e., revenue requirement) compared to the costs (rate revenues) under continued DTE service (referred to as DTE in Ann Arbor).
- Provide an estimate of future capital replacement costs for the MEU to upgrade historic and antiquated equipment (those estimated to be over approximately 40 years old) on an annual cash basis over the Study period. The future capital replacement costs (referred to as renewals and replacements) were not developed to specifically address current reliability concerns.
- Provide an estimate of costs for new substations and transmission assets which would allow City customers to be served by the MEU through the regional transmission service provider, ITC. These new systems would allow current and future DTE customers beyond the City municipal boundaries to continue to be served by DTE.
- Present the Phase I Feasibility Study results to the Ann Arbor City Council upon request.

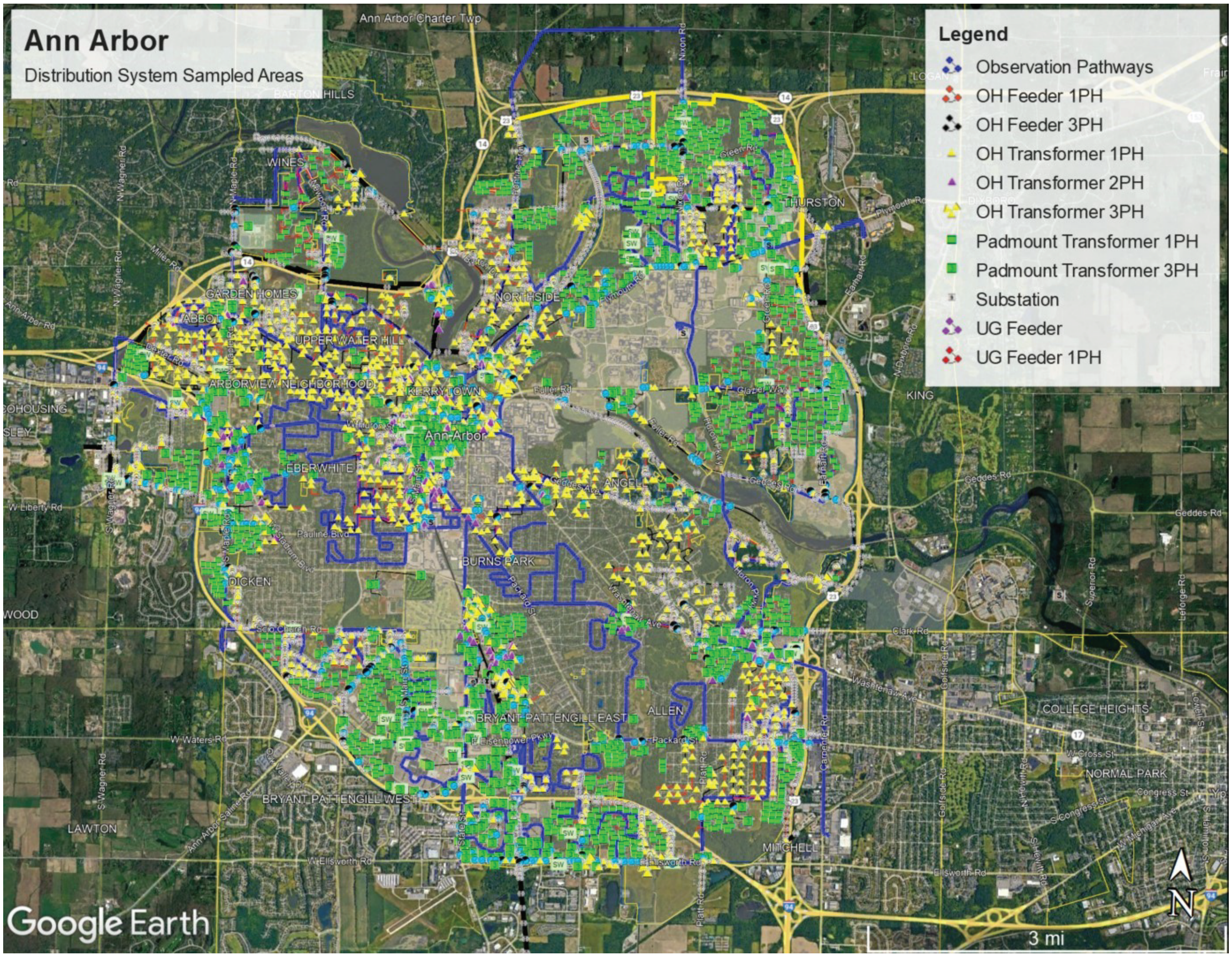
Feasibility Study Process

Detailed information on the electric system within the City was requested from DTE by the City; however, it was not provided for this Study. The NewGen Project Team conducted field investigation activities from November 28–December 2, 2022.

Field Investigation

The field investigation included approximately three and one-half days of onsite visual review of the Ann Arbor MEU service territory. The existing DTE distribution system serves the City and surrounding areas from multiple (between nine and eleven) substations within and without the City limits. DTE's typical substation includes two transformers and four to six feeders. Some substations appear to exclusively serve customers within the City limits; others also serve customers outside the City boundary. The NewGen Project Team created base level GIS maps from satellite and aerial photography and field reconnaissance. These maps were utilized to catalogue the field inventory as well as to produce an overview of the Ann Arbor MEU service territory, as provided in Figure 34 (shaded in blue). Figure 34 shows a high-level Google Maps depiction of the Ann Arbor municipal boundaries.

Figure 34: Ann Arbor MEU Service Territory Schematic (Approximate)



The field review resulted in the development of an initial estimate of the size, type, and estimated age of assets within the potential Ann Arbor MEU area. A summary of the findings from the field review is provided in Table 36 below.

Table 36: Asset Inventory – Estimated from Field Investigation

ASSET INVENTORY – ESTIMATED FROM FIELD INVESTIGATION		
FERC ACCOUNT	DESCRIPTION	QUANTITY (1000 ft or units)*
364 – Poles, Towers, Fixtures	Support for Overhead Distribution Lines	1,670
365 – Overhead Conductors and Devices	3 Phase/1 Phase Overhead Distribution Lines	1,670
365 – Overhead Conductors and Devices	Fused Cutouts, Reclosers	8,150
366 – Underground Conduit and Direct Burial Installations	Buried Conduit – 3 Phase/1 Phase	610
367 – Underground Conductors and Devices	Buried Conductor – 3 Phase/1 Phase in Conduit	610
368 – Transformers	3 Phase/1 Phase Overhead/Pad mount	8,900
369 – Services	Overhead Secondary and Service, conductor, support equipment, 3 Phase/1 Phase	1,935
369 – Services	Underground Secondary and Services, support equipment, 3 Phase/1 Phase	3,440
370 – Meters	Customer meters, hardware	60,200

* Estimated linear feet from GIS mapping. Accounts 364,365 Fuses/Reclosers, 368, and 370 in units.

As indicated, the NewGen Project Team conducted a limited field investigation to estimate the amount, condition, and age (within a reasonable 10-year category) of the distribution facilities within Ann Arbor's MEU area. It should be noted that the asset inventory estimate above excludes DTE's electrical substations; however, it does include the overhead and underground conductors that originate in the DTE-owned substations. As noted herein, this analysis assumes that the City would need to build new substations and transmission assets to connect to the ITC grid. Therefore, the delivery assets acquired from DTE would need to be electrically connected to these new substations. Because these new substations are not part of the existing DTE infrastructure, they have been included separately below.

Additionally, it should be noted that the above asset inventory estimate does not include any future investments to either replace aging assets (typically referred to as "Renewals and Replacements") or to address existing issues with system reliability. For the purposes of this Study, we have included an estimate of Renewals and Replacements but have excluded any estimates of future costs specifically to address existing reliability concerns.

Asset Value Estimates

The NewGen Project Team developed two types of estimated values for this Study: cost-based estimates and income-based estimates. These two types of estimated values are then used to arrive at overall estimates of direct costs to the City of acquiring DTE's distribution system. The cost-based value estimates were developed from the information obtained from the field investigation and GIS inventories. The income-based value estimates were developed from projections of DTE retail rates and MISO wholesale rates, following the FERC Stranded Cost formula. The income-based value estimates are referred to collectively as the "FERC Going Concern Valuation Estimates." Further discussion of these asset value estimates and how they are incorporated into this Study is provided below.

Because of the uncertainty associated with the valuation of DTE's distribution assets, particularly given the dearth of comparable contemporary examples, we have endeavored to provide the City with what we are comfortable presenting as reasonable low and high value estimate scenarios for the system. Further discussion of these value estimates and how they are incorporated into this Study is provided below.

Cost-Based Asset Value Estimate

In general, the cost-based asset value approach results in a range of values from Original Cost Less Depreciation (OCLD) to a Replacement Cost New Less Depreciation (RCNLD) approach. OCLD is an industry term for estimating the value associated with the original cost of existing assets, adjusted to reflect accumulated physical depreciation. RCNLD is an industry term for estimating the value associated with replacing existing assets with the same or similar new equipment, adjusted to reflect accumulated physical depreciation.

The NewGen Project Team utilized the preliminary field inventory and obtained budgetary information for the various new equipment, devices, and associated labor for installation. Cost estimates are based on 2023 values. The NewGen Project Team also developed an estimate of the age of the assets reviewed for the purposes of determining the amount of depreciation or useful life left within the system. The results of the field investigation indicate that, on average, the equipment currently serving the Ann Arbor MEU area has incurred approximately 67% of accumulated depreciation relative to its useful life.

In general, the NewGen Project Team believes that the RCNLD approach overstates the fair market value of the assets to be acquired. This is because the incumbent utility (investor-owned utility) receives a return (profit) from the OCLD value, also referred to as book value, of the assets. This type of utility model encourages investment from the utility owner by tying the profit allowed to the amount spent on equipment and systems. However, the OCLD approach typically results in a lower value than the RCNLD, as it is not contingent on pricing new equipment, but rather the cost of the equipment when it was originally installed.

If the City chooses to move forward with this project, the NewGen Project Team recommends that the City take the position that OCLD value is a more representative cost-based valuation of the assets to be acquired for the MEU than RCNLD. The OCLD is derived from a Replacement Cost New (RCN) analysis developed by the NewGen Project Team. Often, multiples of OCLD have been utilized to determine a fair-market value for assets to be acquired. For the purposes of this analysis, we have utilized a value of 1.5 times OCLD (1.5x OCLD) as the low cost-based value for the acquired DTE assets.

Estimates of accumulated depreciation were derived from industry survivor curves and applied to each class or group of assets as applicable. It is important to emphasize that the values developed for this Study are estimates based on limited field observations and represent a "best estimate" given the limitations of available data. A detailed review of DTE's continuing property records (the basis on which net plant in service is determined for purposes of establishing utility rates) may yield substantially different results.

Table 37 provides a summary of the replacement costs, the accumulated depreciation, and the RCNLD and OCLD values for each asset class by Federal Energy Regulatory Commission (FERC) account. The total RCN estimate is approximately $889 million whereas the RCNLD estimate is approximately $300 million and the OCLD is approximately $130 million. The estimated accumulated depreciation (for the Ann Arbor MEU system) is approximately 67% (33% of the RCN value is remaining).

It is important to emphasize that the values developed for this Study are estimates based on limited field observations and represent a "best estimate" given the limitations of available data. A detailed review of DTE's continuing property records (the basis on which net plant in service is determined for purposes of establishing utility rates) may yield substantially different results.

Table 37: Cost Based Asset Valuation – RCNLD and OCLD

COST-BASED ASSET VALUATION – RCNLD & OCLD				
FERC ACCOUNT	RCN	DEPRECIATION %	RCNLD	OCLD
Assets To Be Acquired*				
364 – Poles, Towers, Fixtures	$106,605,002	70%	$31,744,601	$17,779,049
365 – Overhead Primary	$36,413,118	70%	$10,843,017	$5,284,165
365 – Overhead Equipment (not including transformers)	$40,527,963	70%	$12,068,327	$5,881,300
366 – Underground Conduit and Direct Burial Installations	$28,604,634	56%	$12,560,035	$6,670,668
367 – Underground Conductor and Devices	$41,548,084	64%	$15,003,475	$7,154,462
368 – Transformers	$474,604,091	69%	$148,790,719	$42,122,656
369 – All Services	$106,500,314	69%	$32,651,800	$15,919,586
370 – Meters	$64,521,328	44%	$36,454,551	$29,328,695
Total	**$899,324,535**	**67%**	**$300,116,523**	**$130,140,581**

* As indicated, no DTE electrical substations would be acquired, see text for discussion. Further, assets' costs do not include investments in increased eliability, as noted in text.

Income-based/FERC Going Concern Valuation Estimate

As indicated above, high and low scenarios for the FERC Going Concern Valuation Estimate were developed for this Study. Going concern refers to a valuation approach based on the difference between the revenue received by DTE under "retail" rates compared to potential sales of the same electricity under "wholesale" rates. Two valuation scenarios were developed for this Study because the values in the FERC equation are potentially subject to challenge and interpretation. Additionally, because there are very few cases addressing the issue, it is not clear how a court or FERC might rule on such disputes.[21] As a result, the two values described below are strictly estimates, and firm numbers cannot be provided at this time.

The FERC method is a deceptively simple equation:

Table 38: FERC Going Concern Valuation methodology

FERC GOING CONCERN VALUATION METHODOLOGY

$$SCO = (RSE - CMVE) \times L$$

SCO = Stranded Cost Obligation

RSE = Revenue Stream Estimate—average annual revenues from the departing generation customer over the three years prior to the customer's departure (with the variable cost component of the revenues clearly identified).

CMVE = Competitive Market Value Estimate—determined in one of two ways, at the customer's option:

> **Option (1)**—the utility's estimate of the average annual revenues (over the reasonable expectation period ''L'' discussed below) that it can receive by selling the released capacity and associated energy, based on a market analysis performed by the utility; or
>
> **Option (2)**—the average annual cost to the customer of replacement capacity and associated energy, based on the customer's contractual commitment with its new supplier(s).

L = Length of Obligation (reasonable expectation period)—refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer.

[21] For one example, see City of Alma, Michigan, 96 F.E.R.C. ¶ 61,163 (2001).

Even for utilities with ostensibly perpetual Michigan Foote Act franchises (like DTE possesses in Ann Arbor), FERC has generally used a utility's planning horizon as of the date the "reasonable expectation period" began as a value for "L." Based on FERC precedent, the beginning date of "L" in this case would likely be measured from whatever date DTE ceased incurring costs specifically to serve Ann Arbor, and the length of L would depend on DTE's planning horizon as of that date, which, in keeping with the IRP statute, would be unlikely to exceed 20 years.[22]

For the high FERC Going Concern Valuation Estimate, the RSE is the estimated discounted cash flow for the total retail sales estimated for DTE in Ann Arbor over a 20-year period (a reasonably possible L Value), using the Weighted Average Cost of Capital as filed by DTE in their most recent rate case (8.9%). The CMVE is the estimated discounted cash flow of the value of the energy that would have been sold to retail customers in Ann Arbor, if it were instead sold into the wholesale MISO power market, as estimated by 5 Lakes Energy. The difference between these two values is the potential Stranded Cost Obligation (SCO) associated with the DTE delivery assets and business within the City. For the "full retail" scenario, SCO represents a high estimate of the potential valuation of the assets within the City. This is not to say that DTE might not seek a higher valuation or that a court or FERC may not order a lower valuation.

For the low FERC Going Concern Valuation Estimate, the RSE is the estimated discounted cash flow of the retail production only sales (excluding delivery retail revenue), using the same DTE discount rate of 8.9%. The CMVE is the estimated discounted cash flow of the energy that would have been sold to retail customers in Ann Arbor, if it were sold into the wholesale power market (a similar value as the high value estimate). However, for the purposes of this analysis, the "production only" FERC Going Concern Valuation Estimate is added to the asset cost estimate discussed above (OCLD x 1.5), because it assumes that DTE no longer owns the distribution assets (sold to the City) but may have some claim on the value of lost production sales in the City (which may represent potential stranded costs).

The results of the FERC Going Concern Valuation Estimate show a high value scenario estimate of approximately $1.15 billion and a low value scenario of approximately $78 million. Table 39 provides a summary of the two values for the FERC Going Concern Valuation Estimates developed for this Study.

Table 39: FERC Going Concern Valuation Estimates

FERC GOING CONCERN VALUATION ESTIMATES		
VALUATION COMPONENT	LOW VALUE ESTIMATE ($000)	HIGH VALUE ESTIMATE ($000)
Revenue Stream Expected ($000)	$956,000	$2,028,000
Commercial Market Value ($000)	$878,000	$878,000
L Value (Years)	20	20
Discount Value (WACC DTE)	8.9%	8.9%
Stranded Cost Obligation ($000)	$78,000	$1,150,000

[22] MCL 460.6t.

Because the low value scenario of the FERC Going Concern Valuation Estimate is predicated on the City's separately acquiring the distribution assets based on a Cost-Based Asset Valuation, the low value estimate of the payment to DTE for municipalization would be the sum of the low value of the FERC Going Concern Valuation Estimate ($78 million) and the 1.5x OCLD estimate above ($130 million), or a total of $208 million, plus the value of the street lighting system, addressed below.

Valuation of Street Lighting Systems

As previously indicated, Ann Arbor currently owns a portion of the street lighting systems within the City. For the purposes of the feasibility study, we assumed that the City would purchase the remainder of the street lighting systems from DTE. Further, the City would provide ongoing O&M services on the street lighting systems within the City as part of the MEU. It should be noted that the analysis of the street lighting systems was excluded from the field investigation conducted by the NewGen Project Team. However, 5 Lakes Energy provided this analysis based on data acquired from DTE's most recent regulatory filings. For the purposes of the financial feasibility analysis, it is assumed that the City could acquire the remaining street lighting systems from DTE for approximately $8.1 million and would finance this purchase with 30-year taxable debt. Ongoing maintenance costs for the incremental street lighting purchase are estimated to be approximately $250,000 per year, which is estimated to increase at the rate of inflation.

The estimated debt service and ongoing annual O&M costs for Year 1 of the analysis are summarized in Table 40 below.

Table 40: Street Light Acquisition Annual Cash Expense (Year 1)

STREET LIGHT ACQUISITION ANNUAL CASH EXPENSE (Year 1)	
DTE Street Light System in Ann Arbor ($)	$8,130,000
Debt Term (Years)	30
Taxable Debt Interest Rate (%)	5.50%
Annual Debt Service*	$604,000
Annual O&M Expense (Year 1 $)	$250,000
Total Annual Cash Expense (Year 1 $)	$854,000

* Assumes 30-year bonds at 5.5% interest rate.

Acquisition Costs for Financial Feasibility Analysis Study

For both DTE's distribution and street lighting assets, we developed low and high value estimates to determine the financial feasibility analysis for this Study. The low value estimate is the OCLD value times 1.5 (1.5 x OCLD), which is a reasonable estimate for the costs that are often seen in asset transactions. The low value estimate also includes costs for the incremental street light acquisition, as well as the low value estimate of the FERC Going Concern Valuation Estimate (the previously discussed "production only" valuation estimate). This equals a total low value estimate of approximately $281 million (see Table 41 below). The high value estimate is the high FERC Going Concern Valuation Estimate calculated from the difference between expected retail revenues (including distribution-related revenues) and potential wholesale sales in the MISO market (the previously discussed "full retail" approach).

As previously indicated, the high value estimate of the FERC Going Concern Valuation Estimate includes revenues DTE expected to receive from operating its distribution assets, so their asset value is not separately added to the value below. For the purposes of determining the total asset costs and subsequent financial feasibility, both values have been adjusted to include the estimated value of the additional streetlighting systems (approximately $8.1 million), as described above and included below. Table 41 includes only costs of assets Ann Arbor would acquire from DTE, not assets it would develop itself, such as substations.

Table 41: Low and High Valuation Estimate

LOW & HIGH VALUE ESTIMATE		
ITEM	**LOW VALUE ESTIMATE ($000)**	**HIGH VALUE ESTIMATE ($000)**
OCLD (rounded $)	$130,000	$130,000
OCLD x 1.5	$195,000	$195,000
Additional Street Lighting Systems	$8,130	$8,130
Going Concern Value (Rounded)	$78,000	$1,150,000
Total Value Estimate	$281,130	$1,158,130

Estimation of MEU Load

The estimation of the MEU electric load by class was determined from publicly available sources and the City. The population of Ann Arbor was estimated to be approximately 123,000 in 2022 according to the United States Census. It is assumed that during the Study period, load growth in the City will increase at a compounded annual growth rate of approximately 3.3% per year, to reflect the City's goals for electrification. However, the growth is not linear over the entire Study period. For the period from 2024–2030, the compounded annual growth rate is approximately 0.4%; however, from 2031–2044, the growth rate increases to 4.4% annually to reflect the impact of the City's electrification goals.

A summary of the customers and loads by customer class is provided in Table 42 below.

Table 42: Customer Numbers and Load Estimates

CUSTOMER NUMBERS & LOAD ESTIMATES			
CUSTOMER CLASS	**NUMBER OF CUSTOMERS***	**kWh/MONTH/ CUSTOMER**	**TOTAL ANNUAL AVERAGE MWh SALES**
Residential	52,000	1,517	728,211
Commercial	8,200	6,468	488,149
Total	**60,200**	**7,985**	**1,216,360**

* Estimated customers/load based on information developed by 5 Lakes Energy for the Study period (see text).

DTE Benchmark Rates

The average retail rate for customers within the Ann Arbor area served by DTE was determined from an analysis of average rates published by DTE by residential and commercial rate class for January 2019 through April 2023, the average load on an annual basis from the data provided by DTE, and adjustments for published rate increases by DTE for Year 1 (for delivery services). For the purposes of this Study, DTE delivery rates were assumed to increase annually at an estimated rate of 3.6% for Year 1 and beyond. Table 43 below provides a summary of the analysis developed for the DTE average retail rate for the Ann Arbor service territory for Year 1 of the Study period.

Table 43: Average Retail Rate for DTE Customers in Ann Arbor

AVERAGE RETAIL RATE FOR DTE CUSTOMERS IN ANN ARBOR			
CUSTOMER CLASS	AVERAGE ANNUAL LOAD (kWh)	AVERAGE RATE 2019–2023 ($/kWh)	AVERAGE RATE YEAR 1 ($/kWh)
Residential	728,210,932	$0.1813	$0.1920
Commercial*	488,148,927	$0.1354	$0.1400
Total**	**1,216,359,858**	**$0.1629**	**$0.1748**

* The average rate for 2019–2023 is based on historical information filed by DTE and the average rate for Year 1 is based on recently published rate increases for DTE for 2024 (see text).

** Total average rate is weighted by sales by class (by average annual load for the historic period and by 2024 load, not shown, for the average 2024 rate).

Retail Rate Structures – Power Supply and Distribution

Currently, DTE provides services under two "unbundled" retail rate offerings: power supply and distribution. Power supply rates recover DTE's power-related costs incurred to procure, manage, and deliver electricity from the wholesale power market (MISO) to the retail customers within its service territory. These costs include the costs for DTE to own and dispatch their generation resources into the MISO market and for purchasing power from the MISO market. Additionally, these costs include delivery of the power from MISO to DTE-owned substations within the City (at transmission-level voltage).

Distribution retail rates recover delivery, customer-related (not covered by customer service charges), and administrative and general (A&G) costs. Distribution rates for DTE are regulated by the Michigan Public Service Commission (MPSC) and are determined through the regulatory rate review process. For the purposes of this Study, distribution rates are assumed to be equal to the proposed rates in the 2024 DTE general rate case (U-21297) and are increased at a historical rate of 3.6% annually throughout the Study period.

MEU Financial Modeling

As previously indicated, the financial model develops an estimated cash flow for the MEU based on a series of inputs, as described below. The operating revenues are assumed to equal the sum of the operating expenses, the non-operating expenses, and a margin required to fund operating reserves. The total revenue requirement is divided by the total sales to determine an "average system rate" for the MEU. Similarly, an average system rate was determined from an analysis of DTE rates within the Ann Arbor area (DTE in Ann Arbor) as provided in Table 44. The financial model compares the annual average system rates over the 20-year Study period (Year 1 through Year 21).

The financial model assumes an "overnight" conversion to a MEU and does not recognize the time required for a municipalization effort, which is likely a long process that could take a decade or more to complete. However, for the purposes of this preliminary feasibility study, the start date of the MEU is assumed to be "Year 1" of the Study period. If the City decides to move forward with its municipalization effort, a reasonable time frame for establishment of a MEU would be developed for subsequent analyses.

As previously discussed, the financial model for the MEU does not include specific investments to increase the reliability of the system. Development of an estimate of the capital necessary to specifically address reliability issues was beyond the scope of this Phase I municipalization effort. However, the financial model does assume a typical annual capital program to replace distribution assets over a 30-year time frame with new assets (renewals and replacements), which could improve the reliability of the system. The capital investments are further described below. Without a detailed distribution system improvement plan, the assumption of a 30-year renewals and replacement plan is reasonable. Additionally, the model assumes that the City will install new substations and transmission facilities, as described herein, which could increase system reliability. However, without the development of a specific distribution improvement plan and/or additional detailed information regarding the status of the distribution system from DTE, we cannot quantify the impact of these improvements on system reliability.

The average retail rate for DTE in the City is the result of the average rates developed in Table 44. The average MEU rate is the result of the total operating expenses and reasonable annual debt service coverage to meet financial requirements divided by projected load. The table shows results for the first 20 years of MEU operations, but debt service is modeled assuming a 30-year term with assets acquired from DTE financed at 5.5% and new transmission assets financed at 4.5%. Operating expenses are derived from public DTE financial filings with federal agencies and are generally assumed to increase at the rate of inflation, except as noted herein. Expenses are reflected in thousands of dollars ($000) and rates are provided in $/kWh.

Table 44: MEU Financial Model Results for Year 1 (Low and High Value Estimates)

MEU FINANCIAL MODEL RESULTS FOR YEAR 1 (Low & High Value Estimates)		
LINE ITEM	**LOW VALUE ESTIMATE YEAR 1 ($000)***	**HIGH VALUE ESTIMATE YEAR 1 ($000)***
Operating Revenues	$148,993	$227,158
PROJECTED OPERATING EXPENSE		
Power Supply and Delivery	$78,094	$78,094
Power Supply Management	$100	$100
Streetlight O&M	$250	$250
Distribution Expense	$7,249	$7,249
Customer Expense	$3,513	$3,513
General and Administrative Expense	$7,229	$7,229
Renewals and Replacements	$14,857	$14,857
TOTAL OPERATING EXPENSES	**$111,291**	**$111,291**
DEBT SERVICE		
System Acquisition	$20,291	$85,429
Startup Costs	$769	$769
Streetlight Acquisition	$604	$604
Additional Capital Investments**	$9,754	$9,754
TOTAL EXPENSES	**$142,709**	**$207,847**
Margin/Operating Reserves	$6,284	19,311
AVERAGE RETAIL RATE ANALYSIS (YEAR 1)		
Total Sales (kWh)	939,750,718	939,750,718
Average MEU Rate ($/kWh)***	$0.1585	$0.2417
Average DTE in Ann Arbor Rate ($/kWh)****	$0.1748	$0.1748

* Numbers may not add due to rounding.
** Additional Capital Investments includes substations and transmission lines to be developed by the City. See Text.
*** Assumes 30-year bonds at either 4.5% or 5.5% interest rate (see text).
**** DTE average retail rate developed in Table 43.

Financial Model Assumptions

A series of assumptions has been utilized in the development of the financial feasibility model. These assumptions have been categorized as those related to the distribution assets, the initial operation of the MEU, and the continued operation of the MEU over the Feasibility Study Period. A summary is provided below.

Distribution Assets

As indicated, the distribution assets to be acquired for the creation of the Ann Arbor MEU include the distribution systems and associated equipment necessary to serve the various customers within the City. The distribution assets to be acquired were valued at a low valuation scenario (1.5x OCLD plus the low value of the FERC Going Concern Valuation Estimate) ("production only") and the high valuation scenario of the FERC Going Concern Valuation Estimate ("full retail"), as presented in Table 45. As part of establishing the MEU electric system, the City would need to develop transmission assets and associated equipment to take service directly from the regional transmission provider and distribute power to the MEU. The City would acquire all the remaining equipment that conveys, transforms, or otherwise manages the power at the distribution level within the City. A summary of the equipment to be acquired from DTE is provided in Table 36 above. A summary of the estimated transmission assets to be developed by the City to support the MEU is provided in Table 45 below.

Table 45: Transmission Assets to be Developed by Ann Arbor

TRANSMISSION ASSETS TO BE DEVELOPED BY ANN ARBOR			
DESCRIPTION	**QUANTITY**	**MATERIAL/ LABOR COST PER UNIT ($000)**	**COSTS ($000)**
SUBSTATIONS			
69kV-13.2kV Transformer 10/15/25MVA	2	$2,500	$5,000
69kV Breakers	4	$135	$540
15kV Breakers	8	$50	$400
Substation Deadends and Steel	1	$50	$50
Disconnect Switches (69kV, 15kV)	1	$360	$360
Control Enclosure	1	$300	$300
Construction Labor	1	$800	$800
Cost before Contingency and Engineering			$7,450
Contingency	20%		$1,490
Subtotal			$8,940
Engineering	8%		$596
TOTAL COST PER SUBSTATION			**$9,536**
# of Substations/Total for Substations	10		$95,360
69kV SINGLE CIRCUIT TRANSMISSION LINE PER MILE			
Transmission Material and Construction Costs			$499
Contingency			$100
Engineering			$40
TOTAL COST PER MILE OF TRANSMISSION LINE			$639
Miles of Transmission Lines/Total Transmission Cost	30		$19,175
SUB TOTAL COST FOR NEW SUBSTATIONS AND TRANSMISSION LINES			$114,535
Owners Overhead	30%		$34,361
TOTAL ESTIMATED COST WITH OWNERS OVERHEAD			**$148,896**

For the purposes of the feasibility analysis, it has been assumed that the MEU will be able to finance the acquisition cost of the DTE assets over a 30-year period utilizing taxable debt. The taxable debt interest rate utilized for this analysis is 5.5% per year. It is anticipated that the MEU can issue non-taxable debt as a municipal entity for ongoing cash needs. However, for this Study, it has been assumed that for the purposes of acquiring the privately held assets, the use of non-taxable debt would provide an unfair advantage for the MEU. Further, it is assumed that required bond counsel would not allow tax-free debt to be issued for this specific purpose, as it potentially results in a taxpayer subsidy for the acquisition of private assets. Therefore, for this Study, taxable debt is utilized as a funding mechanism for this purpose.

Initial Municipal Electric Utility Operation

The initial operation of the MEU will require a source of cash to fund various activities prior to, and within, the first six months of operations. After this initial period, it is assumed that the rate revenue from energy sales will support the cash needs of the MEU. For the purposes of the financial analysis, two categories of initial operation costs have been included: those associated with regulatory/professional services and those associated with system/labor and other cash needs of the MEU. The regulatory and professional services are assumed to include attorney fees, consultant fees, regulatory fees, and other fees/charges, including those associated with preparing for and complying with the North American Energy Reliability Corporation (NERC) requirements. The total cash necessary for the regulatory/professional services is estimated to be approximately $10 million. This estimate is based on industry experience and is not based on quotes from professional service providers or investigated potential costs for licensing or other fees with local, state, or federal governmental entities for these services.

The other cash needs for the MEU prior to and during the start-up period include a requirement for one year of estimated A&G labor costs, estimated costs to improve existing software/billing systems (adding to the City's existing system), spare equipment costs (based on the asset inventory) and working capital (cash) for purposes of power supply costs. The NewGen Project Team assumed that these start-up costs could be amortized with the issuance of debt by the MEU over a 30-year period at a tax-exempt rate of 4.5%. This is a simplifying assumption as there may be limitations with the use of bond funds for operations. As noted, if the City is successful in developing a MEU, it is anticipated that the estimated start-up costs would be repaid to the City from the proceeds of the debt issue. The debt service for these bonds would be recovered through the rates charged for providing electric service to its customers. The cash needs related to startup costs were estimated to be equal to 12.5% (1/8) of one year's operating expenses, or approximately $1.7 million. It is assumed that the City will issue tax-free debt to finance these costs.

Continuing MEU Operation

The continued operation of the MEU will require cash for operations, including power purchases (and delivery via the transmission system), utility operating expenses, and maintenance of operating reserves. The following provides a summary of the assumptions regarding the costs for each of these items.

Wholesale Power Market – Renewable Power

Table 46 provides a summary of the projected power supply costs developed by 5 Lakes Energy for this Study. Specifically, 5 Lakes Energy developed an annual average of power supply costs, which includes delivery to the City (at transmission level voltage) and estimates of inflation during the Study period. The power supply costs assume that the City and DTE in Ann Arbor will provide 100% renewable energy by 2030 (to meet the City's renewable energy requirement). The difference between the two power supply cost projections represents the costs of capacity resources between the MEU and DTE in Ann Arbor. It is assumed for the MEU that the City would need to purchase renewable capacity resources to support its energy needs. It is also assumed that these capacity purchases would be made by the City from MISO. However, for the DTE in Ann Arbor power supply projection, it is assumed that DTE will be able to provide capacity from existing and projected resources, which include a blend of renewable and non-renewable generation (mixed capacity). This allows DTE to procure renewable energy at a lower rate than the MEU. The difference in power supply costs results in higher production-related costs for the MEU included in the retail rate analysis. The MEU Power Supply Projections (Table 31) are used to support the MEU operations and included in the revenue requirement calculations for the MEU. The DTE in Ann Arbor Power Supply Projections are used to support the DTE in Ann Arbor operations and are included in the revenue requirement calculations for the DTE in Ann Arbor scenario.

Table 46: Power Supply Rate Comparison ($/MWh)

POWER SUPPLY RATE COMPARISON ($/MWh)			
YEAR	MEU POWER SUPPLY PROJECTIONS (100% RE AND CAPACITY)*	DTE IN ANN ARBOR POWER SUPPLY PROJECTIONS (100% RE, MIXED CAPACITY)**	DIFFERENCE
Year 1	$83.10	$83.10	$0.00
Year 2	$80.93	$76.30	$4.64
Year 3	$78.77	$69.49	$9.28
Year 4	$76.60	$62.69	$13.91
Year 5	$74.44	$55.89	$18.55
Year 6	$72.27	$49.08	$23.19
Year 7	$70.11	$42.28	$27.83
Year 8	$73.37	$44.04	$29.33
Year 9	$76.63	$45.79	$30.84
Year 10	$79.90	$47.55	$32.34
Year 11	$83.16	$49.31	$33.85
Year 12	$86.42	$51.07	$35.35
Year 13	$89.75	$52.73	$37.02
Year 14	$93.09	$54.40	$38.69
Year 15	$96.42	$56.06	$40.36
Year 16	$99.75	$57.73	$42.03
Year 17	$103.08	$59.39	$43.69
Year 18	$106.42	$61.05	$45.36
Year 19	$109.75	$62.72	$47.03
Year 20	$113.08	$64.38	$48.70
Year 21	$116.41	$66.05	$50.37

* MEU Power Supply assumes 100% Renewable Energy and Capacity.
** DTE in Ann Arbor assumes 100% renewable energy and a mix of renewable and non-renewable capacity.

Utility Operating Costs

The MEU operating costs include distribution expenses (associated with O&M of the locally owned distribution system), customer expenses (associated with billing and managing customer accounts), A&G expenses (A&G cost associated with management and other expenses), and other charges. The costs for these operational requirements were estimated based on an analysis of costs incurred by DTE for similar services. This analysis included the development of ratios of costs reported by DTE divided by the total energy sales in kWh. The resulting ratios were multiplied by the total energy sales assumed for the City and were increased annually at the annual inflation rate of 3.6%. The total utility non-power related operating costs were estimated to be approximately $18 million in Year 1 of the Study.

Investments in the system are referred to as "renewals and replacements" or normal capital expenditures and are assumed to be equal to approximately 1/30 of the RCN costs for the system for assets estimated to be installed prior to 1985 (roughly the midpoint of the age of assets estimated from the field analysis). This equates to approximately $14.8 million in Year 1 of the Study. This value is assumed to be paid annually in cash, and the value increases with the annual rate of inflation.

Debt Service and Reserve Deposits

The financial model also includes annual reserve deposits and debt service expenses for system acquisition, startup, streetlight acquisition, and additional capital investment costs.

Annual reserve deposits are assumed to be equal to the difference between the annual cash available for debt service after operating expenses and the debt service expenses for system acquisition, startup, streetlight acquisition, and additional capital investment costs. The reserve deposits are assumed to be 20% of the debt service expenses, which is consistent with a desired debt coverage ratio of at least 1.2 (1.2 times the debt service requirement or 1.2x).

Capital Improvement Expenses

The "capital improvement" expense is intended to allow funds for the MEU to build facilities necessary to connect from the transmission system to existing distribution facilities acquired from DTE and to serve City customers. Table 45 provides a preliminary estimate of the costs associated with these capital improvements. Specifically, this includes the development of approximately ten new electrical substations, sized for redundancy and estimated future load. Additionally, these costs include approximately thirty miles of transmission-level conductor (68 kV) in a loop configuration around the City, as well as dedicated transmission lines to feed the substation.

Estimated construction costs for these capital improvements are estimated to be approximately $150 million for the transmission facilities which recognizes the high costs of current construction in the industry today. It is assumed that these costs will be funded with tax-free debt issued by the City over a period of 30 years.

Total Revenue Requirement/Average System Rate

The financial model determines the revenue requirement (the total dollars needed to support the MEU) based on the individual expenses identified above. The revenue to be recovered from rates is equal to the revenue requirement of the utility. The average system rate is equal to the revenue requirement divided by the total energy (kilowatt-hour [kWh] sales) to determine a $/kWh. This rate would not necessarily be equal to the rates charged by the MEU for its customer classes, as rates would be based on a detailed cost of service analysis developed upon creation of the MEU. Because different customers place different demands and use power at different times, the rate design of the MEU would need to be tailored to assure that rates were cost based for each customer class or adjusted to fit specific policy requirements of the City.

The average system rate is a metric utilized to compare the potential costs of operating the MEU to the costs of continuing to obtain service from DTE. The average system costs for DTE were estimated based on our assessment of information from existing customers, including those in the commercial and residential classes, as previously described. The total bill analysis included adjustments for estimated composition of customers within the City (between customer classes). The average system distribution retail rate for Ann Arbor customers was estimated to increase at an annual rate of 3.6% over the Study period based on an analysis of historical DTE rate changes.

Low Valuation Estimate Rate Analysis

A summary of the projected average system retail rates for the MEU compared to those estimated for DTE in Ann Arbor is provided in Table 47 below for the low valuation estimate (1.5x OCLD plus the low FERC Going Concern Valuation estimate). The analysis results in an annual revenue requirement for the MEU that is approximately 9% lower than the estimated revenue requirement for DTE in Ann Arbor in the first year of the Study. This is primarily due to the debt service expenses estimated to be incurred by the MEU. This difference changes over time, as the estimated revenue requirement for the MEU increases relative to DTE in Ann Arbor due to the underlying power supply costs and changes in the projected retail rates. In Year 7, the difference in the estimated all-in average rates reaches its lowest point (approximately 1% greater for the MEU than DTE in Ann Arbor), then the difference continues to increase over the remaining years of the Study. This is because the DTE in Ann Arbor retail rates continue to increase at their estimated annual rate; however, the majority of the costs for the MEU are fixed debt expenses (although some costs are projected to increase at the rate of inflation). Both the low valuation estimate rate analysis and the high valuation estimate rate analysis include projection of costs for the MEU and DTE to obtain 100% renewable energy for the City by Year 7.

Table 47: Average System Retail Rate Comparison ($/kWh) – Low Valuation Estimate

AVERAGE SYSTEM RETAIL RATE COMPARISON ($/kWh) Low Valuation Estimate				
YEAR	MEU ALL-IN AVERAGE RATE ($/kWh)	DTE IN ANN ARBOR ALL-IN AVERAGE RATE ($/kWh)	DIFFERENCE $	DIFFERENCE %
Year 1	$0.1585	$0.1748	($0.0163)	(9%)
Year 2	$0.1572	$0.1703	($0.0130)	(8%)
Year 3	$0.1556	$0.1658	($0.0102)	(6%)
Year 4	$0.1540	$0.1615	($0.0075)	(5%)
Year 5	$0.1525	$0.1573	($0.0048)	(3%)
Year 6	$0.1510	$0.1532	($0.0022)	(1%)
Year 7	$0.1495	$0.1477	$0.0018	1%
Year 8	$0.1520	$0.1528	($0.0008)	(1%)
Year 9	$0.1547	$0.1579	($0.0032)	(2%)
Year 10	$0.1576	$0.1630	($0.0054)	(3%)
Year 11	$0.1606	$0.1681	($0.0076)	(5%)
Year 12	$0.1636	$0.1733	($0.0096)	(6%)
Year 13	$0.1664	$0.1789	($0.0125)	(7%)
Year 14	$0.1694	$0.1845	($0.0151)	(8%)
Year 15	$0.1725	$0.1901	($0.0176)	(9%)
Year 16	$0.1758	$0.1957	($0.0199)	(10%)
Year 17	$0.1792	$0.2013	($0.0221)	(11%)
Year 18	$0.1821	$0.2076	($0.0255)	(12%)
Year 19	$0.1852	$0.2138	($0.0286)	(13%)
Year 20	$0.1886	$0.2200	($0.0314)	(14%)
Year 21	$0.1921	$0.2261	($0.0340)	(15%)

Incremental Annual Costs

As indicated in Table 47 above, the estimated MEU all-in average retail rate is lower than the estimated all-in average retail rate for all but one year of the Study period in the low asset valuation estimate scenario. Table 48 provides a summary of the estimated annual sales, average rate, revenues, and power supply costs for the MEU providing 100% renewable electricity compared to DTE in Ann Arbor for selected Study years: Year 1, Year 7, Year 11, and Year 21.

Table 48: Annual Savings Analysis – Low Valuation Estimate

ANNUAL SAVINGS ANALYSIS Low Valuation Estimate				
ITEM	YEAR 1	YEAR 7	YEAR 11	YEAR 21
Total Annual Sales (kWh)	939,751,000	959,561,000	1,082,136,000	1,745,666,000
Ann Arbor MEU Average Rate ($/kWh)	$0.1585	$0.1495	$0.1606	$0.1921
Ann Arbor MEU Total Revenue ($000)	$148,993	$144,001	$180,091	$354,068
Ann Arbor MEU Power Supply Costs ($000)	$78,000	$68,000	$93,000	$215,000
DTE in Ann Arbor Average Rate ($/kWh)	$0.1748	$0.1477	$0.1681	$0.2261
DTE in Ann Arbor Total Revenue ($000)	$164,269	$142,312	$188,587	$416,769
DTE in Ann Arbor Power Supply Costs ($000)	$85,000	$44,000	$60,000	$133,000
Difference between Ann Arbor MEU and DTE Revenue (Savings) ($000)	($15,276)	$1,689	($8,496)	($62,701)
% Difference	(9%)	1%	(5%)	(15%)

High Valuation Estimate Rate Analysis

A summary of the projected average system retail rates for the MEU compared to those estimated for DTE is provided below in Table 49 for the high valuation estimate (which is equal to the high FERC Going Concern Valuation estimate). The analysis results in an annual revenue requirement that is approximately 37% higher for the MEU than DTE in Ann Arbor in the first year of the Study. This is primarily due to the debt service expenses estimated to be incurred by the MEU to acquire the system.

This difference in the average system retail rates between the MEU and DTE in Ann Arbor changes over time. In Year 7 the difference is approximately 56%, as the revenue requirement for DTE in Ann Arbor drops with the reduction in power supply costs and the power supply costs for the MEU increase. The difference is projected to be 37% in Year 11, as the DTE in Ann Arbor rates increase and the fixed costs (debt service) for the MEU stay the same. The difference is reduced to 4% in Year 21, as the resulting costs for DTE in Ann Arbor and the MEU become more similar. The power supply costs are assumed to increase for the MEU as the City achieves its objectives for 100% renewable energy in Year 7 (assuming 100% renewable capacity resources), whereas the power supply costs for the DTE in Ann Arbor case decrease in the initial years, then increase at a lower rate than those for the MEU (due to reliance on a mix of renewable and non-renewable capacity resources).

Table 49: Average System Retail Rate Comparison ($/kWh) – High Valuation Estimate

AVERAGE SYSTEM RETAIL RATE COMPARISON ($/kWh) High Valuation Estimate				
YEAR	MEU ALL-IN AVERAGE RATE ($/kWh)	DTE IN ANN ARBOR ALL-IN AVERAGE RATE ($/kWh)	DIFFERENCE $	DIFFERENCE %
Year 1	$0.2417	$0.1748	$0.0669	38%
Year 2	$0.2401	$0.1703	$0.0698	41%
Year 3	$0.2381	$0.1658	$0.0723	44%
Year 4	$0.2362	$0.1615	$0.0747	46%
Year 5	$0.2343	$0.1573	$0.0770	49%
Year 6	$0.2324	$0.1532	$0.0792	52%
Year 7	$0.2306	$0.1477	$0.0829	56%
Year 8	$0.2299	$0.1528	$0.0772	50%
Year 9	$0.2297	$0.1579	$0.0718	45%
Year 10	$0.2298	$0.1630	$0.0668	41%
Year 11	$0.2302	$0.1681	$0.0621	37%
Year 12	$0.2310	$0.1733	$0.0577	33%
Year 13	$0.2305	$0.1789	$0.0516	29%
Year 14	$0.2305	$0.1845	$0.0460	25%
Year 15	$0.2310	$0.1901	$0.0409	22%
Year 16	$0.2318	$0.1957	$0.0361	18%
Year 17	$0.2330	$0.2013	$0.0316	16%
Year 18	$0.2325	$0.2076	$0.0249	12%
Year 19	$0.2327	$0.2138	$0.0188	9%
Year 20	$0.2334	$0.2200	$0.0134	6%
Year 21	$0.2345	$0.2261	$0.0084	4%

Incremental Annual Costs

As indicated in Table 49 above, the estimated MEU average retail rate is higher than the estimated DTE in Ann Arbor average retail rate for all years of the Study period for the high valuation estimate. Table 50 provides a summary of the estimated annual sales, average rate, revenues, and power supply costs for the MEU providing 100% renewable electricity compared to DTE in Ann Arbor for selected Study years.

Table 50: Annual Savings Analysis – High Asset Valuation Estimate

ANNUAL SAVINGS ANALYSIS High Valuation Estimate				
ITEM	YEAR 1	YEAR 7	YEAR 11	YEAR 21
Total Annual Sales (kWh)	939,751,000	959,561,000	1,082,136,000	1,745,666,000
Ann Arbor MEU Average Rate ($/kWh)	$0.2417	$0.2306	$0.2302	$0.2345
Ann Arbor MEU Total Revenue ($000)	$227,158	$222,167	$258,256	$432,234
Ann Arbor MEU Power Supply Costs ($000)	$78,000	$68,000	$93,000	$215,000
DTE in Ann Arbor Average Rate ($/kWh)	$0.1748	$0.1477	$0.1681	$0.2261
DTE in Ann Arbor Total Revenue ($000)	$164,269	$142,312	$188,587	$416,769
DTE in Ann Arbor Power Supply Costs ($000)	$85,000	$44,000	$60,000	$133,000
Difference between Ann Arbor MEU and DTE Revenue (Savings) ($000)	$62,890	$79,854	$69,669	$15,464
% Difference	38%	56%	37%	4%

Alignment with A^{2}ZERO Energy Criteria and Principles

We provide ratings of the MEU model with several caveats.

First, our ratings for the MEU follow from the energy modeling we performed, which assumed all energy would be sourced from the grid and not from local or distributed sources. We did not model stacking of other Energy Options in the MEU scenario, because our stacking scenarios model 2030 and we judge there is no plausible scenario in which the MEU could launch by 2030. Thus, while it might be reasonable to assert that the MEU would layer in additional Energy Options, our modeling gives us no basis for assigning speculative ratings to such possibilities. The City might explore policy-driven MEU programs and Energy Options in coordination with a Phase 2 MEU Feasibility Study, which we recommend below.

Second, and likewise, we do not assign 2030 ratings to the MEU because we assume the MEU could not be operational by then. Instead, our evaluation of the MEU provides a snapshot at some indeterminate moment after 2030, in the MEU's hypothetical launch year. Through 2030 and until the MEU launches, we recommend that Energy Options in the MEU pathway should substantially mirror the SEU pathway. Rather than simply repeat our SEU ratings for 2030 here, then, we provide our assessment of MEU performance in its launch year. We again stress that our ratings are based on a single snapshot in time. Several of our MEU ratings would likely improve over time: for example, we project the MEU would purchase a large amount of non-local and costly RECs at the outset, but these purchases would decline over time, improving the Cost Effectiveness rating.

Third, financial outcomes for the MEU are heavily contingent on the methodology used to model the cost of acquiring DTE's distribution assets. We express this uncertainty by assigning a range of ratings to the Equity and Justice criterion and Cost Effectiveness principle.

Table 51: MEU Alignment with A²ZERO Energy Criteria and Principles

MEU ALIGNMENT with A²ZERO Energy Criteria

CRITERION	YEAR ONE RATING		COMMENTS
Reduce GHG	YES		MEU would use both local and grid resources that displaced GHGs and were additional.
Additionality	YES		MEU would use both local and grid resources that displaced GHGs and were additional.
Equity & Justice	POOR	FAIR	Improved access to grid-sourced RE depends on MEU rates, which may be higher or lower than DTE rates. Grid-sourced power allows for little participation of marginalized groups in decision making.

MEU ALIGNMENT with A²ZERO Energy Principles

PRINCIPLE	YEAR ONE RATING		COMMENTS
Enhance Resilience	POOR		100% grid-sourced electricity would add nothing to local resiliency.
Start Local	FAIR		100% grid-sourced RE would likely be sourced within Michigan.
Speed	POOR		MEU is highly unlikely to launch before 2030.
Scalable & Transferable	FAIR		Utility municipalization is rare in the US, and requires time, money, and dedication that few communities are currently willing to dedicate.
Cost Effective	POOR	FAIR	Significant cost uncertainty owing to range of plausible valuations.

Municipal Energy Utility Analysis Conclusion

The NewGen Project Team investigated the technical and financial feasibility of creating a locally owned municipal electric utility (MEU) for the City. This would require the City to acquire the existing electric distribution assets of the incumbent utility, DTE, within the municipal boundaries. Further, the City would potentially need to build approximately ten substations and associated transmission assets to serve its load from an interconnection to the transmission grid. This would also require the City to procure wholesale power, manage and maintain the local distribution system, and bill customers for their power usage.

The analysis suggests that the formation of a MEU for the City may be financially feasible if the asset acquisition value is equal to the low valuation estimate provided herein. Specifically, this valuation estimate assumes the City could acquire the assets at a value of 1.5x OCLD, plus the low FERC Going Concern Valuation Estimate (which limits DTE's going concern compensation to recovery of lost production revenues, as described herein). However, if the City were required to acquire DTE's distribution assets at the high valuation estimate provided herein (which is equal to the high FERC Going Concern Valuation Estimate), the analysis suggests that the formation of a MEU for the City is not financially feasible.

CONCLUSIONS & RECOMMENDATIONS

CONCLUSION AND RECOMMENDATIONS

In order to achieve 100% renewable electricity by 2030, the City of Ann Arbor will need to undertake steps beyond current reliance on DTE for most utility services supplemented by City of Ann Arbor renewable energy programs already underway. Absent additional measures, we project that renewable electricity supply to Ann Arbor will be at best about 59% of electricity consumption in 2030.

BTM resources and community solar are superior Energy Options for the principles of starting local and improving resilience. BTM and community solar resources can ultimately contribute significantly to Ann Arbor's electricity supply, but available space ultimately limits the contribution of solar within the City. Further, because these resources require voluntary adoption by many people, adoption tends to be gradual. A SEU or MEU can encourage faster adoption of these community-based resources; we recommend that Ann Arbor continue to develop the SEU Phase 1 concept to accelerate adoption of local resources.

Although BTM resources and community solar are favored by many of the A^{2}ZERO Energy Criteria and Principles, because the long-term potential for these renewable resources falls short of the City's total electricity requirements and the pace at which these can be developed will likely be gradual, the City must use a significant amount of utility-scale renewables that are remote from the City in order to reach 100% renewable energy by 2030.

All utility-scale generation delivers power to the transmission grid where it is physically integrated with power flows from all other utility-scale generation on the same grid. In this region, all utility-scale power is sold into a wholesale market from which all power for delivery to customers is purchased by the utility that distributes power to them. Consequently, renewable power loses identity in the power markets. Also importantly, only a utility can purchase actual power from the transmission system and if Ann Arbor purchases power from a specific wind farm or solar system connected to the transmission grid, all it can do with that power is sell it into the wholesale market. Utility-scale renewable power does not flow to designated customers, but instead credit goes to those customers who are financially responsible for renewable generation.

To facilitate tracking the production and use of renewable generation, markets have been created for renewable energy credits (RECs) that can be purchased separately from the actual power so that the buyer can claim exclusive rights to the renewable characteristics of the power. The purchase of RECs provides an economic incentive for renewable generation by adding revenue on top of the energy and capacity sales that the facility can make. Each REC corresponds to one megawatt-hour (MWh) of power generated from a renewable resource. There are national markets for RECs. Ann Arbor can reasonably meet its 100% RE goal by purchasing RECs to supplement RE resources provided by DTE and PV resources installed in or by the City. Since every other source of renewable energy that the City could use is either available only in small quantities relative to the City's requirements, or will be slow to develop, or both, the City can meet its 100% RE goal only by significant purchases of RECs produced from utility-scale renewable generation.

RECs vary in quality with respect to the City's principles. RECs sourced from existing renewable energy facilities will not provide additionality. RECs sourced from Texas do not provide benefits local to Ann Arbor. In general, higher quality RECs will be costlier and require longer lead times.

In short, we recommend that the City meet its initial requirements for renewable generation of electricity by purchasing RECs, with attention to the quality of those RECs, with some purchases being for recurring purchases over long periods of time and others being for short periods so that they can be displaced through other strategies that will mature after 2030. In the evaluation of other strategies, over time, the avoided cost of purchased RECs will be one of the quantifiable benefits of the other strategies.

Since lead times for RECs that score well on Ann Arbor's principles can be significant, Ann Arbor should proceed with a request for proposals in the near future to obtain RECs in 2030 and thereafter.

The utility structure within which Ann Arbor pursues 100% renewable electricity qualitatively and quantitatively affects the options that are available. Our analysis of the structural options available to Ann Arbor suggests that to reach 100% renewable electricity by 2030, Ann Arbor will need to initially work within the DTE+ structure we described above. However, this can be supplemented by a SEU or Ann Arbor can acquire resources within the DTE+ construct that can be transitioned later to the MEU.

The MEU option is promising in its potential alignment with the A²ZERO Energy Criteria and Principles, but our financial analysis indicates it is a risky pathway – without excluding the possibility that it will be cost-competitive with other options. The SEU option is financially feasible, less risky and serves the A²ZERO Energy Criteria and Principles well, but likely has less long-term potential than the MEU to advance the A²ZERO goals. The DTE+ scenario can also achieve 100% RE by 2030 with more-predictable outcomes, but almost certainly costs the city budget more over time because of the mix of Energy Options it would rely on and evaluates somewhat less favorably against the A²ZERO Energy Criteria and Principles.

We suggest that our analysis of the MEU scenario holds enough promise that the City should authorize a Phase 2 Feasibility Study to characterize more precisely the costs and risks of this approach. Because launch of a MEU is not assured and would likely take many years if it were pursued, the City ought concurrently to consider implementation of a SEU to heighten assurance of meeting its 2030 goals. If subsequent study supported launch of a MEU, when the time came the SEU assets and programs could be transferred over; if not, the SEU could continue apace. In short, we see development of a SEU as consistent with, and advantageous to, the longer-term development of a MEU. If the City embraces that concept, the question becomes how to start stacking the Energy Options to attain the 2030 goal, while also laying groundwork for a MEU.

In addition to a standard Phase 2 Feasibility Study, the City should seek an estimate of the costs to improve distribution system reliability, because acquiring DTE's deteriorated assets and replacing them on a normal schedule would not promptly address the urgent reliability problems many customers in the City are regularly facing. Thirdly, the City should seek an estimate of costs to upgrade the system capacity from 4.8kV to 13.2kV wherever necessary, to handle increased loads we project over the coming 20 years and integrate the many distributed energy assets that should grow enormously over that period.

APPENDICES

APPENDICES

APPENDIX 1 A^{2}ZERO ENERGY CRITERIA AND PRINCIPLES

To support our work in achieving the energy-related goals in A^{2}ZERO goals, a series of core criteria and guiding principles were adopted by City Council in early 2021. These criteria and principles are rooted in the A^{2}ZERO plan and stem from the overall ethos of the Office of Sustainability and Innovations. The energy criteria are requirements for all investments, meaning that any energy-related activity needs to meet these criteria or clearly articulate why it was not possible to meet these criteria to be considered. The energy principles represent values the City holds, which should be maximized, to the fullest extent possible, in decision making related to energy. Principles may, at times, be in conflict with one another.

The core criteria include:

- Reducing greenhouse gas emissions.
- Additional to what is already being generated.
- Grounded in equity and justice.

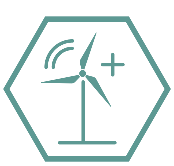
The principles include:

- Enhancing the resilience of our people, our community, and our natural systems.
- Start Local.
- Speed.
- Scalable and transferable to other locations.
- Cost effective.

Criteria

The City of Ann Arbor will evaluate potential investments based upon 3 Core Criteria: the investment will 1) reduce greenhouse gas emission; 2) add to the available renewable energy within the electric system; and 3) will be grounded in equity and justice. The Criteria will be, at times, in tension with each other during decision making, but this tension can be necessary to create a balanced investment approach.

Reducing greenhouse gas emissions. The first criterion seeks solutions that reduce energy demand and/or power Ann Arbor's electricity needs with carbon neutral renewable energy solutions. This includes investments in energy efficiency, HVAC improvements, and investments in technologies such as solar photovoltaic, hydroelectric turbines, and biodigesters. This does not include certain forms of generation that have been labeled "renewable" such as biofuels, solid waste incineration, and wood-burning since these fuel sources are associated with operations that continue to release large quantities of greenhouse gas emissions and other harmful byproducts.



Additional to what is already being generated. The second criterion is about ensuring that renewable energy or energy efficiency projects are new and, to the extent possible and quantifiable, displacing fossil fuel energy sources. We want to ensure that our investments are leading to additional renewable energies being developed or additional energy efficiency investments being made; avoiding having our projects fulfill state mandates (i.e., RPS). This is true for physical new renewable energy builds, new energy efficiency investments, as well as if we choose to invest in power purchase agreements (PPA), virtual power purchase agreements (vPPAs), renewable energy credits (RECs), virtual power reductions (VPRs), or carbon offset initiatives.

Grounded in equity and justice. The third criterion is about ensuring our strategy is grounded in procedural and distributive equity. This means that the solutions we find to reducing energy consumption and powering our grid with renewable energy should center low-income and minority populations in both decision making as well as in the benefits of solutions. It also means piecing together different solutions that are respective of the different capacities Appendix 1 and lived experiences of members of our community and finding solutions that support fair and just compensation for those helping to create a renewable energy future.

Principles

In addition to the Core Criterion, a set of value-added principles will support the decision making process. Situations will exist where these principles are in conflict but addressing that conflict helps ensure the City achieves a balanced approach to carbon neutrality in the energy sector.

Enhancing the resilience of our people, our community and our natural systems. Through the eyes of our energy work, this principle focuses on ensuring that individuals, especially at-risk individuals, emergency services and emergency service personnel, have power during and after a disaster. Solutions may include implementing local renewable projects with battery storage, investing in microgrids, or creating a more reliable and resilient physical grid infrastructure. The driving factor is ensuring that, during a disaster, loss of power does not compound an existing crisis.

Start Local. The second principle emphasizes location. There is a desire to focus investments locally, including generating as much new local renewable energy as possible. When not possible, stakeholders have emphasized a desire for Michigan generation. When renewable energy solutions are not viable in Michigan, we propose prioritizing projects that are developed in partnership with environmental justice communities that have been disproportionately burdened by the extractive nature of the fossil fuel-based economy. Only when communities such as these are not interested in partnering, are we proposing to actively seek other locations for new renewable energy developments.

Speed. The third principle is about time. This principle focuses on finding solutions that can be deployed rapidly in order to quickly reduce greenhouse gas emissions. At the center of this principle is a desire to reduce emissions, fast.

Scalable and transferable to other locations. The fourth principle is about finding solutions that are scalable and transferable to other locations. At the core of this principle is ensuring that we find solutions to achieving carbon neutrality in Ann Arbor that other Michigan municipalities (and, potentially, municipalities in other states) could replicate, thereby increasing the impact of our actions.

Cost Effective. The final principle is about finding solutions that are cost effective. This means finding solutions that are as affordable as possible while also aligning with the core criteria outlined above and in support of as many principles outlined in this section.

APPENDIX 2 INPUT VALUES FOR MISO ZONE 7 POWER COST MODELING

SCENARIOS MODELED IN STEP8760	**NAME ABBREVIATION** (SEEN IN STEP FORWARD A2 MODELING)	**PACE OF ELECTRIFICATION**	**TECH SCENARIO** (NREL ATB)	**ACCELERATED GENERATOR RETIREMENTS**	**PORTFOLIO STANDARD**	**WIND CONSTRAINT**
Green Future 100 (Run for 2040 Only)		Fast	Advanced	Yes	Success of Biden Goals 100%	None
Green Future 95		Fast	Advanced	Yes	Success of Biden Goals 95%	None
MICHP - Fast		Fast	Advanced	Yes	Business as Usual	None
BAU - Slow		Slow	Conservative	No	$78,000	None
MICHP - Moderate		Slow	Moderate	No	MI Healthy Climate Plan	None
MIHCP - High Electrification	mihcp_high_ electrification	Fast	Moderate	No	MI Healthy Climate Plan	None
MIHCP - Early Retirement		Slow	Moderate	Yes	MI Healthy Climate Plan	None
BAU - Moderate Tech Costs		Slow	Moderate	No	Business as Usual	None
BAU - Advanced Tech Costs		Slow	Advanced	No	Business as Usual	None
BAU - EV - Conservative - Constrained	bau_ev_ conservative_ constr	Updated Emissions Standard	Conservative	No	Business as Usual	6.5GW
MIHCP - EV - Conservative - Constrained	mihcp_ev_ conservative_ cons	Updated Emissions Standard	Conservative	No	MI Healthy Climate Plan	6.5GW
BAU - EV -	**bau_ev_**	**Updated Emissions Standard**	**Conservative**	**No**	**Business as Usual**	**2.2GW**

Bold text denotes models that were evaluated in STEP Forward A2 modeling.

APPENDIX 3 INPUT VALUES FOR MICHIGAN POWER COST MODELING

YEAR	METRICS	BUSINESS AS USUAL	MI HEALTHY CLIMATE PLAN	SUCCESS OF BIDEN GOALS
2025	RPS	15% Renewable	15% Renewable	15% Renewable
2030	RPS	15% Renewable	15% Renewable	15% Renewable
2035	RPS	15% Renewable	60% Renewable	100% Clean
2040	RPS	15% Renewable	60% Renewable	100% Clean

YEAR	METRICS	SLOW	FAST	UPDATED EMISSIONS STANDARDS
2025	% EVs on Road	1%	4%	4%
2030	% EVs on Road	2%	20%	18%
2035	% EVs on Road	4%	44%	45%
2040	% EVs on Road	5%	66%	75%
2025	% Buildings Electrified	6%	6%	6%
2030	% Buildings Electrified	10%	15%	10%
2035	% Buildings Electrified	18%	32%	18%
2040	% Buildings Electrified	30%	58%	30%