Sustainable Energy Utility - Financial Assessment

Prepared for the City of Ann Arbor

Executive Summary

The City of Ann Arbor has committed to a just transition to community-wide carbon neutrality by the year 2030. The City's plan, known as A^2ZERO, centers around six core strategies, including a 100% renewable electricity goal, the electrification of end uses, increased energy efficiency, reducing vehicle miles traveled, improving waste management, and enhancing resilience, as well as one catch-all strategy (other).

To achieve its goal, and specifically the strategy of using 100% renewable energy by 2030, the City of Ann Arbor will need to mobilize additional deployment of renewable energy resources beyond what is currently pursued by the investor-owned utilities and Ann Arborites independently. As part of this effort, the City is exploring the option of creating, owning, and operating a sustainable energy utility (SEU). The SEU is being designed as an opt-in, supplemental municipally-owned energy utility that will provide 100% renewable energy from local solar and battery storage systems and networked geothermal systems installed at participating homes and businesses. It is intended to help mobilize additional renewable deployment by overcoming the main barriers for distributed renewable resources, namely the up-front capital cost requirement, associated hassle and risk aversion, all while allowing Ann Arborites to benefit from the cost savings and emission reduction benefits of locally-sourced renewable energy. In the first phase of the utility, the SEU will install distributed solar and solar plus storage assets at participating residential and commercial premises.

In exploring the SEU feasibility, Strategen was retained by the City to assess the project's financial viability and the benefits for its potential subscribers. We find that the SEU can be self-sustained in the long term, allowing Ann Arborites to use affordable clean energy, all while increasing resiliency and mitigating the impact of system-wide outages. Importantly, initial grant funding or millage funds can be leveraged to overcome the upfront costs of the first deployment tranche, while additional deployment will be self-sustained through continued SEU revenue. The financing terms under which the City funds this effort (whether through debt or a municipal or green bond) will be of critical importance for ensuring net benefits for subscribers and meeting the financial metrics of the City. Alternatively, the City could use a third-party provider through a power purchase agreement (PPA) to overcome the initial funding challenge at the beginning of the program, with the option of purchasing the assets in later years at a depreciated cost and potentially more favorable interest rates.

Starting from a utility financial model previously developed for the City, Strategen used the most recent public data to understand the utility's performance both from the City's perspective in consideration of its financial requirements, and from the subscribers' perspective under a number of different scenarios. This report describes the expected rates and financial outcomes of the program for a base scenario proposed by the City of Ann Arbor. It also describes the sensitivities explored during the modeling process and the impact of each assumption or "decision variable" considered in the analysis. The main results include the cost-based rates to operate the SEU, the minimum subscription level necessary to initiate the SEU, and the benefits of different funding mechanisms such as debt, grants and a PPA.

Based on our analysis, our findings are:

- The SEU can be financially viable for the City, generate cost savings for Ann Arborites, increase resilience, and reduce emissions.
- The financing terms for the SEU are of critical importance. Higher interest rates would translate to higher SEU rates, shrinking the cost savings that Ann Arborites can achieve. An initial grant or millage funding can be used to kickstart the SEU and ensure that the lag between the initial investment and the time the City could receive the federal Investment Tax Credit does not cause any non-compliance issues with the City's own financial requirements.
- Starting the SEU initially through a partnership with a third party that will own and maintain the solar and solar plus storage assets will provide time and certainty, and potentially improve the financing terms the City can obtain.

Introduction & Model Overview

The City of Ann Arbor is committed to using electricity generated entirely by renewable resources by the year 2030. To reach this goal, the city plans to establish a Sustainable Energy Utility (SEU). This SEU would be a municipally-owned energy utility, initially providing clean electricity from local solar and energy storage systems installed on homes and businesses in the city. At a later stage, the SEU plans can include other clean energy options and the development of microgrids. The analysis referenced in this report assesses the financial viability of establishing an SEU for the City of Ann Arbor and the benefits that the citizens could receive if they subscribed to the proposed SEU.

In assessing the viability of the SEU, Strategen examined two perspectives:

- The perspective of the City, requiring the SEU to be self-sustained in the long term and ensuring compliance with the City's financial metrics and requirements.
- The perspective of a subscriber assuming that, for a household or building owner to subscribe to the SEU, it should be made better off, either based on projected electricity bill savings, increased resiliency (mitigating the impact and duration of outages that Ann Arborites experience), or – ideally – both.

The two perspectives are intertwined through the estimated SEU rate, i.e. the price that subscribers will pay for SEU provided solar generated energy and storage, and that the City will receive to cover the utility costs. The financial viability of the SEU for the City depends on the level of customer adoption and the revenue it will collect. On the other hand, the level of customer adoption depends on whether the SEU rate will enable net benefits (whether in the form of bill savings, increased resiliency) for subscribers.

Strategen reviewed and updated the City's financial model based on inputs from the City, as well as our own industry expertise, projected rates reflecting the costs of the utility, and developed a subscriber model estimating the bill savings and resiliency benefits of a subscriber (residential or commercial) compared to the baseline of receiving service from the incumbent investor-owned utility.

SEU-Perspective Financial Model

The key metrics for the SEU to be viable from the City's perspective include maintaining a positive balance in the operating reserve fund and a minimum level of debt service coverage ratio (DSCR) of 1.25. The DSCR is a financial metric used to assess an entity's ability to generate enough revenue to cover its debt obligations, such as interest and principal payments. The DSCR metric is only relevant for the years when the City will be under a debt obligation (e.g., a municipal, revenue or green bond or even a loan), whether at the beginning of the SEU should the City choose to own the solar and storage assets, or in later years if the City decides to acquire the assets after some initial period during which it partners with a third party for a PPA structure.

Strategen developed a model that takes as inputs the size and portfolio composition of the SEU, as well as the financing method, and calculates the associated costs and revenues of the program. Costs include program costs, capital expenses, operating and maintenance costs, as well as financing costs. The SEU revenue is collected through energy rates from its subscribers. The model also includes an input to specify tax credits and grants; in our runs we assumed only the base 30% Investment Tax Credit (ITC) available through the Inflation Reduction Act (IRA) in the debt scenario.

Financing methods available in the model are: (1) debt to buy and own the energy assets, and (2) a third-party energy service through a power purchase agreement (PPA). The debt method assumes that the SEU gets one loan for the full program cost in the first year, covering both technology and program costs minus any grant or tax exemption assumed in each scenario. The model can accommodate different interest rate assumptions ranging from a commercial loan with a higher interest rate to a municipal, revenue or green bond, which likely would have more favorable rate levels.

Through a separate calculation, the model estimates a cost-based subscriber rate, which then is used to inform SEU's annual revenues. The subscriber rate is expressed in $/kWh produced for solar electricity, and $/kW-month for energy storage. It is meant to recover capital costs, operating and maintenance costs, financing costs, program costs, and other cost inputs (like future investments) needed for the continued operation and expansion of the utility. Although the calculation of the SEU rates will be more detailed when implemented, this simple calculation captures the fact that the rates will be cost based and gives an estimate of what the City and SEU subscribers should expect for this initial phase. The legal environment in the State of Michigan requires that municipal service providers construct rates that adhere strictly to proportionality and cost of service principles. The calculated rates are used as inputs in the customer and SEU financial models. The model then calculates the operating reserve fund and DSCR to ensure that the SEU will be a viable option for the City given the specified inputs.

On the other hand, the PPA method assumes that all development costs are paid by a third-party provider and that the SEU pays that provider for the energy that is produced on its subscribers' premises. In this scenario the model takes a cost per megawatt-hour as an input for each technology and customer class; this input should be taken from the PPA providers' quotes. The PPA method includes an option where the SEU buys the depreciated energy assets from the third-party provider once it has a proven financial record and access to lower interest rates; the analysis assumes this happens after 10 years of PPA service. At that point, the debt method is used, and new cost-based subscriber rates are calculated for the reminder of the assets' useful life. During the PPA period, the subscriber rate is composed by the third-party PPA rate (input) plus a cost adder that aims to recover operational and deployment costs incurred by the utility.

Customer-Perspective Financial Model

From the customer perspective, the analysis investigates whether the customer receives a net benefit for opting into the SEU relative to the base case scenario of continuing to receive service exclusively from the investor-owned utility (DTE). Some Ann Arbor residents and customers may have a particularly high willingness to pay for solar energy and the resiliency that storage can provide (valuing the resulting emissions reductions), but a certain amount of savings – or at least cost parity – is likely required to see the adoption levels needed for a robust SEU customer base. Net savings for solar only and solar plus storage adoption is assessed on an annual basis based on the rates that customers would pay the SEU, the rates they would otherwise be paying DTE, the outflow rates for excess solar generated and distributed to the grid, and the value of resilience customers would receive from battery storage.

Customer benefits from subscribing to the SEU were assessed relative to a baseline residential customer paying DTE rates. A number of assumptions were made to conduct this analysis. A typical load profile for a residential customer was taken from NREL's ResStock analysis tool, specifically from the data pool's End Use Load Profiles for the U.S. Building Stock. The load profile was disaggregated from energy data for single family homes in Michigan's Washtenaw Country. To determine a baseline DTE scenario, this annual load profile was applied to two DTE rate structures: D1.11 Standard Time of Use (TOU) and D1.2 Enhanced TOU.

This baseline scenario was compared against two SEU scenarios, where potential customers adopted (a) solar and (b) solar plus storage from the SEU and paid the associated SEU rate. The analysis was conducted for the year 2028, focusing on the near-term annual bill savings, but could be extrapolated assuming that DTE rates would escalate with inflation. Although utility rates increase only after approval from the Michigan Public Service Commission through a General Rate Case (except for the riders that are updated regularly, like power cost adjustments), it is reasonable, if not conservative, to assume that on average rates will escalate at the rate of inflation. Thus, higher savings can be expected in later years, as utility rates will keep increasing due to incremental capital and fuel costs, while SEU rates will probably escalate at lower rates.

DTE's distributed generation program follows an inflow-outflow mechanism. Inflow is defined as the electricity that is taken from a utility distribution system by the customer. Outflow is defined as the energy generated by the customer's assets but not used by the customer that is sent out to the general electric grid. When solar is generating, it reduces grid consumption, while if the consumer does not need all the solar energy generated, the excess is sent out to the grid. The TOU tariff, and the Enhanced TOU tariff have higher prices during midday hours and lower rates during the early morning and night. This means that SEU subscribers reduce consumption from the grid during times of high prices. As the outflow rate is lower than the inflow rate and potentially lower than the SEU rate, the SEU and its subscribers should ensure the right sizing of their systems; oversized system can generate a significant portion of energy which needs to be sent back to the grid, resulting in net losses for the subscribers during those hours.

Installing energy storage further increases bill savings for SEU subscribers, but comes with an additional subscriber fee, which we have calculated as a fixed fee on the annual bill. In DTE's distributed generation program, inflow rates are higher than outflow rates, so installing an energy storage device (i.e., a battery) allows a household or business to store the solar energy that it does not need at the time of generation (instead of sending it to the grid at the outflow rate) and use that energy later to reduce its consumption (reducing the inflow cost). Under a net metering mechanism in which the inflow and outflow rates would be the same, energy storage would not result in additional bill savings (other than shifting energy to avoid peak hours in a TOU tariff). On the other hand, under a mechanism in which excess energy was not compensated, energy storage would result in increased bill savings (but a solar-only option would result in lower savings than under this mechanism).

Furthermore, storage systems provide resiliency value to customers by keeping the power on during grid outages. Many residents of Ann Arbor have resorted to purchasing backup generators to power their home due to the frequency and magnitude of power outages they have experienced. Solar plus storage systems can provide similar levels of resiliency as backup generators with less noise and air pollution. The average duration of individual outages in 2023 for Michigan DTE customers was 149 minutes, according to the Michigan Public Service Commission, and the maximum hourly load from the load profile utilized in the analysis was 2.6 kW. A 5 kW, 2.5-hour battery can reasonably cover most outages based on this data. The cost of a whole home generator was used as a resilience value for solar plus storage in the analysis, with the assumption that the system could replace the cost of purchasing said generator. The cost of installing a representative backup home generator was determined based on quoted costs from local heating, ventilation, and air conditioning (HVAC) mechanic shops. Consumers would incur additional costs to maintain and operate generators which would further increase the savings of switching to battery storage systems.

The results of the analysis show annual net savings for the subscribing solar and solar plus storage customer relative to the DTE base case. The results of the analysis were assessed under different assumptions for cost of capital and tax credits, and the resulting rates customers would pay. In all scenarios except assuming higher financing cost in addition to not receiving ITC benefits, the customer sees savings relative to the DTE base case.

Results

This section describes the results of the baseline scenario and includes insights about the sensitivity analysis. For both the baseline scenario, as well as every sensitivity tested, three sets of results are presented:

- Rate Model: projected SEU subscriber rates for the solar and solar plus storage option for residential and commercial customers.
- SEU perspective: DSCR as the main metric of financial viability for the utility.
- Customer model: net customer benefits, comprising of bill savings and resilience benefits.

The following table describes the scenarios tested and their associated variation on the decision variables.

Table 1. Decision variables considered in Strategen's analysis

	Baseline	Sensitivities
SEU Participation		
Program Size	50 MW	10, 20, 100, 150 MW
Resource mix	50% solar only, 50% solar-plus-storage.	100% solar only
Resource location	50% residential, 50% commercial	100% residential 100% commercial
Financing Assumptions		
Funding mechanism	Debt	PPA, Debt + grant, PPA + grant.
Interest rate	4%	5% conservative rate, 3% low rate after 10 years of SEU operations
Grant	$0	30% of initial capital needs
Incentive Tax Credit	30%	0%
System Configuration		
Residential system	8 kW solar, 5 kW K and 2.5 hours battery	none
Commercial system	50 kW solar, 30 kW and 4 hours battery	200 kW solar, 120 kW and 4 hours battery
Grid-forming inverters	none	On all batteries, at 20% cost increase for batteries.

The baseline scenario was informed by initial preferences of the City, targeting a 50 MW, balanced energy mix between customer classes and energy technologies, fully deployed by 2026. The baseline assumes that debt is used to finance the program at a 4% interest rate, without grants and with access to a 30% ITC. The baseline's system configuration assumes that the average residential system has 8 kW-dc of solar and the storage system has a 5-kW capacity and a 2.5-hour duration. The commercial system is assumed to have 50 kW-dc of solar capacity, and 30-kW of 4-hour batteries in paired resources.

This baseline scenario uses the rate model to calculate the subscriber rates based on the cost of the technology, operations and capital, assuming that the systems will also be eligible for the ITC. This cost-based rate also includes a 25% rate of return, which is needed to comply with the 1.25 year-over-year DSCR requirement. The baseline scenario achieves the minimum DSCR requirement after the City receives the ITC (assuming a one-year lag) and applies it to the loan repayment. If the City could secure a grant equal or millage funding (or greater than the ITC), then the DSCR requirement would be met from the first year.

The following table shows the subscriber rates for each customer class and system type in years 2028 and 2038.

Table 2. Projected subscriber rates in baseline scenario (nominal$)

		2028	2038
Residential rates	PV only rate ($/kWh)	$ 0.174	$ 0.193
	Storage Fee ($/month)	$ 87	$ 94
Commercial Rates	PV only rate ($/kWh)	$ 0.133	$ 0.146
	Storage Fee ($/month)	$ 320	$ 351

The baseline scenario results in bill savings for SEU subscribers, although those remain on the low side, presented in the following table. As described in the technical appendix, energy savings are calculated by simulating the annual energy consumption and cost for each customer class and comparing the results for participating and non-participating customers. Resiliency savings are calculated by comparing the net cost of owning storage versus the cost of owning a fossil-fueled back-up generator, and do not take into account any savings from a condition with no back-up generation.

Table 3. Customer benefits in sample years 2028 and 2038 (nominal$)

2028	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ 18	$ 249	$ 1,848	$ 1,713
PVS bill savings ($/year) before storage cost	$ 246	$ 409	$ 1,878	$ 1,715
Bill savings net of storage cost ($/year)	$ (802)	$ (640)	$ (1,962)	$ (2,125)
Resiliency savings ($/year)	$ (353)	$ (190)	$ 245	$ 83

2038	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ 220	$ 504	$ 3,316	$ 3,149
PVS bill savings ($/year) before storage cost	$ 500	$ 700	$ 3,352	$ 3,152
Bill savings net of storage cost ($/year)	$ (624)	$ (423)	$ (857)	$ (1,057)
Resiliency savings ($/year)	$ (174)	$ 26	$ 1,351	$ 1,151

Interesting insights from this sensitivity include:

- In later years, SEU subscribers' benefits will increase, as DTE rates will keep rising, while SEU rates will increase at significantly lower rate (mainly reflecting the increase in operations, maintenance, and program costs). SEU rates will not be exposed to fossil fuel price volatility.
- Subscribing to the SEU only solar option results in net savings after considering the savings in the DTE bill and the SEU payments. Savings increase when the subscriber takes service based on a

TOU tariff, and especially the Enhanced TOU, as solar displaces high price electricity from the grid. As the tariffs change or evolve, it will be important to assess the savings under each tariff to maximize savings.

Sensitivity Analysis

The tables below indicate the variations in the decision variables assessed in the analysis, and the most important learnings from that exercise are described below. The variations include:

1. PPA versus Debt financing (every 5 years).
2. DSCR with and without grant funding.
3. Subscriber benefits if cost of capital changes (3,4,5%).
4. System Size.
5. SEU size

Sensitivity: PPA versus Debt financing

An option that the City is exploring is to partner with a third party and offer the solar and solar plus storage subscriptions though a PPA with that third party. During the PPA years, the City will need to include a cost adder above the PPA rate to recover the program administration costs and create the required reserve to purchase the assets or invest in an expansion. After a number of years (assuming 10 years in this analysis), the City can purchase the assets at a depreciated value and with better financing terms due to the proven track record of the SEU. PPA assumptions are presented in Table 1 and closely follow the assumptions used in the analysis previously conducted on behalf of the City. Rates are slightly lower than the baseline scenario in early years, but escalate at a higher rate and surpass the cost-based SEU rates assumed in the baseline scenario. At the time of acquisition, the City is assumed to pay a depreciated value for the assets. The SEU rates do not change (other than the escalation). With slightly higher rates (or even similar), better financing terms than the baseline scenario, and potentially some operating reserve that the City has built up, the City meets its DSCR requirement. From an implementation standpoint, this partnership has significant benefits as the City gains experience and can secure better financing terms. However, the economics of this option heavily depend on the exogenous assumption of the PPA price. For the residential customer modeled, a PPA price of $0.18/kWh (with a 10% adder to reflect the program costs) for the solar only option would drive the expected bill savings for the SEU subscriber to zero.

Sensitivity 2: DSCR with and without grant funding

The SEU rates have been calculated to allow the SEU to recover all of its costs and comply with the DSCR requirement. However, it is assumed that the solar and storage systems will all be eligible for a 30% ITC, which has also been considered for the development of the rates. The challenge with the ITC is that it could be received one, three, or even more years after the investment has been made, and the City will be subject to debt obligations. In this analysis we assume an ITC delay of one year, which means that the first year the City collects rates that are reflective of the ITC when the ITC has not yet been received, resulting in a DSCR that is lower than 1.25. When the ITC is received, it can be used to repay part of the loan, restoring DSCR to the targeted level of 1.25.

An assumed grant or millage funding equal to the assumed ITC (30%) would reduce the required upfront debt and allow both the City to be compliant with the DSCR requirement and Ann Arborites to receive SEU rates that will make them better off compared to only receiving service from the investor-owned utility. When the City eventually receives the ITC, it could re-pay the millage funding, or apply this (together with the funds received through SEU subscriptions) to the next tranche.

Without a grant or millage funding, the SEU could still be financially viable, but would not comply with the DSCR requirement until the ITC could be used to repay part of the loan. (the ITC is reflected in SEU rates from the beginning, i.e. revenues are recovering costs assuming that the City will receive the ITC which causes the lower DSCR in years prior to the City receiving the ITC. If we assumed no ITC in the SEU rate calculation, the SEU rates would be very high resulting in increased costs for subscribers, i.e. we would address the DSCR but Ann Arborites would not subscribe).

A grant that is greater than the expected ITC could further lower the SEU rates or could be leveraged for financing subsequent tranches.

Sensitivity 3: Subscriber benefits if cost of capital changes.

The financing terms for the SEU are of critical importance. Higher interest rates translate to higher SEU rates, shrinking the cost savings that Ann Arborites can achieve. The table below shows the difference in calculated subscriber benefits under different interest rates.

Table 4. Subscriber benefits under different interest rates

Interest Rate 3%	Residential (TOU)	Residential (Enhanced TOU	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ 145	$ 376	$ 2,459	$ 2,324
PVS bill savings ($/year) before storage cost	$ 373	$ 535	$ 2,489	$ 2,326
Bill savings net of storage cost ($/year)	$ (601)	$ (439)	$ (1,121)	$ (1,283)
Resiliency savings ($/year)	$ (182)	$ (20)	$ 896	$ 734

Interest Rate 4%	Residential (TOU)	Residential (Enhanced TOU	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ 18	$ 249	$ 1,848	$ 1,713
PVS bill savings ($/year) before storage cost	$ 246	$ 409	$ 1,878	$ 1,715
Bill savings net of storage cost ($/year)	$ (802)	$ (640)	$ (1,962)	$ (2,125)
Resiliency savings ($/year)	$ (353)	$ (190)	$ 245	$ 83

Interest Rate 5%	Residential (TOU)	Residential (Enhanced TOU	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ (115)	$ 116	$ 1,205	$ 1,069
PVS bill savings ($/year) before storage cost	$ 112	$ 275	$ 1,234	$ 1,072
Bill savings net of storage cost ($/year)	$ (1,014)	$ (852)	$ (2,850)	$ (3,012)
Resiliency savings ($/year)	$ (533)	$ (370)	$ (443)	$ (605)

Interest Rate 6%	Residential (TOU)	Residential (Enhanced TOU	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ (255)	$ (25)	$ 530	$ 394
PVS bill savings ($/year) before storage cost	$ (28)	$ 135	$ 559	$ 397
Bill savings net of storage cost ($/year)	$ (1,236)	$ (1,074)	$ (3,780)	$ (3,942)
Resiliency savings ($/year)	$ (722)	$ (559)	$ (1,164)	$ (1,327)

Sensitivity 4: System size.

As already mentioned, DTE's distributed generation program follows an inflow-outflow mechanism. When solar is generating, it reduces grid consumption, while if the consumer does not need all the solar energy generated, the excess is sent out to the grid. As the outflow rate is lower than the inflow rate and potentially lower than the SEU rate, the SEU and its subscribers should ensure the right sizing of their systems. An oversized system can generate a significant portion of energy which needs to be sent back to the grid at a price lower than the SEU rate, resulting in net losses for the subscribers during those hours. An undersized system would be missing savings and emissions reductions potential.

Three different solar and solar plus storage systems are presented below that showcase those dynamics. In the first case, energy storage does not really result in bill savings as the system is small and all of the solar generated energy is used to reduce consumption at the time it is generated. As the solar system increases, the bill savings due to storage also increase as storage shifts electricity to be consumed at higher price hours. The third option, which is the one modeled in the baseline has slightly lower bill savings from solar.

This is because although solar still reduces inflow in the same way as the slightly smaller system, there is more solar generated energy that needs to be sent back to the system at the outflow rate, resulting in a loss for the subscriber.

These examples are only illustrative of the importance of right-sizing the system relative to the load. As already mentioned, the DTE rate is also important in determining the right opportunity. Consequently, the City will need to establish a process to review previous bills and recommend the best tariff and size for each subscriber. This process should be in place even under the PPA scenario, as the PPA provider will probably have an incentive to oversize solar systems.

Table 5. Subscriber benefits for different system size

	Solar: 2kW Storage: 1.25kW/2.5hrs	Solar: 5kW Storage: 3.125kW/2.5hrs	Solar: 8kW Storage: 5kW/2.5hrs
PV savings ($/year)	$ 137	$ 260	$ 249
PVS bill savings ($/year) before storage co	$ 137	$ 323	$ 409
Bill savings net of storage cost ($/year)	$ (125)	$ (333)	$ (640)
Resiliency savings ($/year)	$ (8)	$ (45)	$ (190)

Sensitivity 5: SEU size

Finally, an important question is around the minimum deployment level for the first tranche of the SEU. The capital, operating and maintenance, and financing costs grow linearly with the SEU size. However, the program costs introduce some non-linearity in the SEU's costs, increasing the SEU rates for lower deployment, as the program costs will need to be recovered through a lower number of subscribers. To test this, we assumed the program will include design costs ($200,000), system setup costs ($200,000), acquisition costs ($50/system), and finally annual personnel costs ($500,000). These costs could further increase as the SEU size increases, but for the purposes of this sensitivity, they are assumed to be the minimum program costs for the SEU. The tables below illustrate that although the costs do not significantly impact the expected subscriber benefits beyond a certain threshold, they are indeed driving SEU rates to be prohibitively high when the SEU falls below 20MW.

Table 6. Subscriber benefits under different SEU size

SEU = 10MW	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ (381)	$ (150)	$ (445)	$ (580)
PVS bill savings ($/year) before storage cost	$ (153)	$ 10	$ (416)	$ (578)
Bill savings net of storage cost ($/year)	$ (1,201)	$ (1,039)	$ (4,256)	$ (4,418)
Resiliency savings ($/year)	$ (752)	$ (589)	$ (2,049)	$ (2,211)

SEU = 20 MW	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ (131)	$ 100	$ 988	$ 853
PVS bill savings ($/year) before storage cost	$ 96	$ 259	$ 1,018	$ 855
Bill savings net of storage cost ($/year)	$ (952)	$ (789)	$ (2,823)	$ (2,985)
Resiliency savings ($/year)	$ (502)	$ (340)	$ (615)	$ (777)

SEU = 30 MW	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ (48)	$ 183	$ 1,466	$ 1,331
PVS bill savings ($/year) before storage cost	$ 179	$ 342	$ 1,495	$ 1,333
Bill savings net of storage cost ($/year)	$ (869)	$ (706)	$ (2,345)	$ (2,507)
Resiliency savings ($/year)	$ (419)	$ (256)	$ (137)	$ (300)

SEU = 40 MW	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ (7)	$ 224	$ 1,705	$ 1,570
PVS bill savings ($/year) before storage cost	$ 221	$ 384	$ 1,734	$ 1,572
Bill savings net of storage cost ($/year)	$ (827)	$ (665)	$ (2,106)	$ (2,268)
Resiliency savings ($/year)	$ (378)	$ (215)	$ 102	$ (61)

SEU = 50 MW	Residential (TOU)	Residential (Enhanced TOU)	Commercial - Multifamily	Commercial - School
PV savings ($/year)	$ 18	$ 249	$ 1,848	$ 1,713
PVS bill savings ($/year) before storage cost	$ 246	$ 409	$ 1,878	$ 1,715
Bill savings net of storage cost ($/year)	$ (802)	$ (640)	$ (1,962)	$ (2,125)
Resiliency savings ($/year)	$ (353)	$ (190)	$ 245	$ 83

Technical Appendix

Methodology

In conducting this analysis, Strategen used a spreadsheet-based model owned by Ann Arbor to identify the net financial benefits of a distributed solar and solar-plus-storage program for the proposed Sustainable Energy Utility (SEU) and its customers. Strategen modified this model to include the financial perspective of customers and the use of diverse design assumptions (decision variables) in the analysis of the costs and benefits for the utility. The model is focused on solar and storage as sources to generate or shift energy, but not as potential assets to provide capacity and grid services through the aggregation of distributed systems.

The modified utility financial model takes multiple inputs. Those are separated into two main categories: decision variables and input assumptions.

- Decision variables are program design choices that the City could control to optimize the program design, including program size, target customers, deployment schedule, financing options, and the configuration of energy systems. Strategen has explored different scenarios to inform the City and assist with its decision making.
- Input assumptions include all other assumptions that cannot be modified by the City as part of the program design. Those include mainly cost assumptions, like the capital and operations cost of solar and storage in different years, which can be updated as the City gets increased visibility into what its actual costs will be. Furthermore, the model is set up so that the City can run sensitivity analysis changing one of the inputs at a time to understand how sensitive the results are to certain changes.

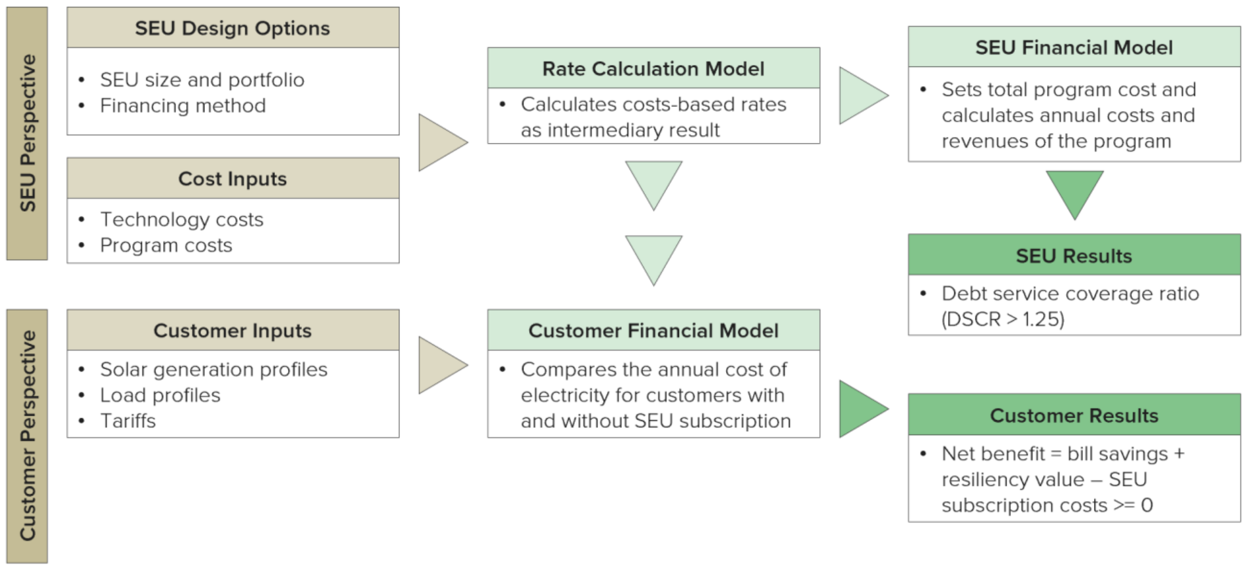
The main results of this model are the year-by-year SEU rates for solar only and solar-plus-storage customers (for both residential and commercial customers), financial metrics including the debt service coverage ratio (DSCR), as well as the net benefits to the subscribers.

The rate (cost per solar kWh produced and fixed fee per storage kW per month) that each customer class would pay for the energy purchased from the SEU is calculated as the total annualized cost of the resources (capital and operating expenses, as well as financing and other costs) divided by the total energy produced by the energy systems, accounting for system degradation. The rates also incorporate program costs, and other cost inputs (like future investments) needed for the continued operation and expansion of the utility. Although the calculation of the SEU rates in practice will be more detailed, this simple calculation is meant to capture the fact that the rates will be cost based and give an estimate of what the City and SEU subscribers should expect for this initial phase. The calculated rates are used as inputs in the customer and SEU financial models.

The SEU financial model estimates the program's cash flow versus its debt obligations (if financed through debt) and calculates the debt to service ratio (DSCR) on an annual basis dividing the net revenues of the SEU (total revenue using the calculated SEU rate minus operating expenditures) by the total annual debt (both principal and interest through the duration of the loan). Importantly, external sources of income such as tax credits or grants, are not considered as revenues that impact the DSCR of the program, but as capital expense reductions. Similarly, additional or early payments of the debt principal are not considered as debt obligations, thus not affecting the annual DSCR values.

To include the financial perspective of the customers, Strategen built a second model that uses the SEU cost-based rates to identify potential savings from opting in to the solar program as compared to the customer's current electric service bill. The comparison bill used for this analysis simulates the cost of energy for the customer if they do not subscribe to the program. The baseline bill is estimated using a representative energy load profile for distinct customer classes in Michigan and the applicable power rate for each class. The main results from the model are the potential annual savings from opting in to the SEU and the potential economic savings from adding storage to provide resiliency to the customer. The annual savings are calculated as the delta between the customer's annual cost of electric service with and without SEU participation. Both bills are calculated on an hourly basis and are highly impacted by the sizing of the solar and storage systems relative to the customer's load. The resiliency savings refer to the customer's economic benefit of installing storage instead of an alternative fuel-based generator, and don't include potential reliability improvements for the grid. These are calculated as the difference between the annualized cost of owning a fuel-based generator and the net cost of owning and operating the storage system. In reality, maintaining and operating a fossil fuel generator would result in additional fuel and other ongoing costs that have not been included, resulting in a conservative estimation of net benefits for the SEU storage option.

Figure 1. Updated SEU model



Inputs and assumptions

The analysis used public data from diverse sources including initial assumptions from the City of Ann Arbor (decision variables), technology costs from NREL's annual cost of energy benchmark, program costs from Strategen's assessment, localized electricity demand profiles from NREL's Restock and Comstock models, and local electricity tariffs from DTE, as well as adjustments to the original model based on the Strategen team's expert judgement on the calculation of financial metrics.

Decision Variables

These initial assumptions were set in the model following the City's preferences on the SEU participation, financing assumptions, and preferred system configuration. Preferences on the SEU participation include inputs defining the size of the program in megawatts, the share of solar and storage capacity, the share of capacity deployed in residential and commercial sites, and the annual schedule of capacity deployments.

Another decision variable is the choice of a financing method, with debt (municipal or green bond could also be simulated using the same input) and power purchase agreement (PPA) as available options. The debt option assumes that the SEU gets one loan for the full program cost in the first year of the program at an assumed nominal interest rate. The PPA option assumes that all development costs are paid by a third-party provider and that the SEU pays only for the energy that is produced. In this scenario the model takes a cost per megawatt-hour as an input for each technology and customer class. The PPA option also assumes that the assets are sold to the SEU at a depreciated value after 10 years of operations and that the purchase is funded through debt at a lower interest rate. The new rate is assumed to be lower as the financial rating of the new utility could enable lower rates in the future. Under the PPA option, the SEU rate includes an adder on top of the third-party PPA rate that aims to recover program and other associated costs. Both financing options can be complemented with tax credits and grants; in our runs we conservatively assumed a 30% Investment Tax Credit (ITC) available through the Inflation Reduction Act (IRA) in the debt scenario.

Finally, the preferred system configuration refers to the size of each component of the residential and commercial, and solar and storage systems. The original model was modified to accommodate different configurations of solar and storage as inputs but, given the technology prices linked to these inputs, Strategen recommends using residential solar systems in between 4-12 kW, and commercial systems below 500 kW. The system input options include a cost multiplier meant to represent grid forming inverters across the portfolio, should the City want to explore the cost impact of such a scenario.

Table 7. Decision variables considered in Strategen's analysis

	Baseline	Sensitivities
SEU Participation		
Program Size	50 MW	10, 20, 100, 150 MW
Resource mix	50% solar only, 50% solar-plus-storage.	100% solar only
Resource location	50% residential, 50% commercial	100% residential 100% commercial
Deployment schedule	All assets deployed in 2026	Linear deployment 2026-2029 All assets deployed 2029
Financing Assumptions		
Funding mechanism	Debt	PPA, Debt + grant, PPA + grant.
Interest rate	4%	3% after 10 years of SEU operations
Grant	$0	30% of initial capital needs
Incentive Tax Credit	30%	0%
System Configuration		
Residential system	8 kW solar, 5 kW and 2.5 hours battery	none
Commercial system	50 kW solar, 30 kW and 4 hours battery	200 kW solar, 120 kW and 4 hours battery
Grid-forming inverters	none	On all batteries, at 20% cost increase for batteries.

Cost Inputs

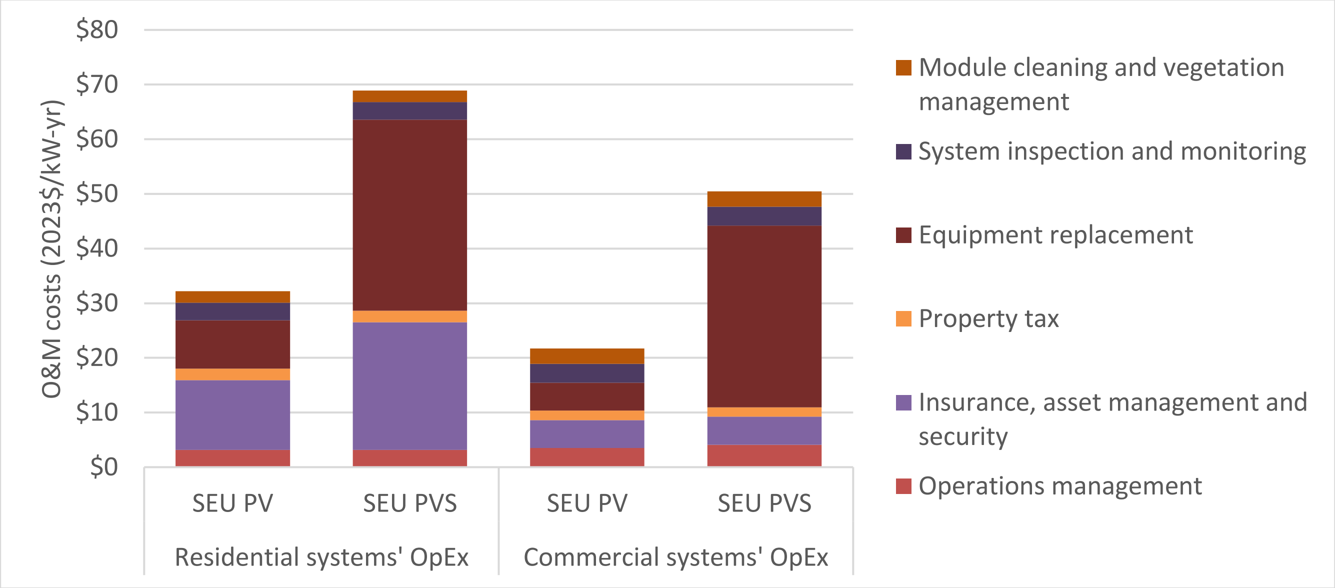
The cost inputs are publicly available from industry recognized sources. Technology costs for solar and storage systems were taken from the annual cost benchmarks by the U.S. National Renewable Energy Laboratory (NREL). Specifically, the cost of residential systems corresponds to NREL's 2023 benchmark of modeled market prices,[1] while the cost of commercial systems come from NREL's 2022 benchmark.[2] The 2022 benchmark was used for commercial systems as the systems described in the study are representative of the expected size range of commercial SEU assets. The costs in both studies are representative of solar and storage assets with useful lives of 25 years and are inclusive of the maintenance and replacement costs required to achieve such duration.

Strategen disaggregated the energy storage costs from NREL's benchmarks in terms of capacity, energy, and siting costs using the 2023 NREL annual technology baseline (ATB) as a reference for the cost composition of a lithium battery. This step allows the user to try different capacity and duration configurations for the battery, along with configurations for the ratio of solar to storage of the representative systems for commercial and residential customers.

Table 8. Capital cost of technology (2023 nominal$)

	Residential system	Commercial system
Cost of solar ($/kW-dc)	$2,843	$2,212
Storage cost of energy ($/kWh)	$514	$165
Storage cost of power ($/kW)	$625	$632
Storage base cost ($/system)	$7,577	$14,481
Annual CapEx decline rate	2%	2%

Figure 2. Operations and maintenance costs (2023 nominal$)



Other cost inputs are those from starting and operating the program. Strategen considered program design and system startup expenses as fixed costs, and incentives, participant acquisition and personnel expenses as variable costs linked to the size of the program. The initial program cost setup in the model was based on references to similar programs in the country.

Table 9. Program costs assumptions

Program design	$ 200,000
System startup	$ 200,000
IT systems	$ 100/year
Personnel	$ 500,000/year
Participant acquisition	$ 50/customer
Incentives	$ 0/customer

PPA rates

The analysis also examines a scenario in which the City partners with a third party for a PPA during this initial phase. The power purchase agreement (PPA) price is a direct input assumed to be competitive with local utility rates. The cost of energy under the PPA scenario is assumed to be passed on to customers with a cost adder that is meant to capture the program costs, as well as recover other SEU related costs (like the need to create a reserve for future acquisitions or investments). This input was set at 10% of the PPA rates and is not included in the values below.

Table10. PPA rate inputs used in base scenario

Solar-only residential rate	$0.15 /kWh
Solar-plus-storage residential rate	$0.23 /kWh
Solar-only commercial rate	$0.08 /kWh
Solar-plus-storage commercial rate	$0.14 /kWh
Annual escalation rate	1.5%
PPA term	10 years, followed by SEU purchase
SEU adder (%)	10%

DTE rates

To calculate the bill savings for SEU subscribers, we estimated the bill of a typical household based on local time-of-use (TOU) tariffs from DTE for average residential customers as well as the general service tariff applicable to multifamily buildings, and the tariff corresponding to schools. For solar only systems, these tariffs were used under the assumption that the customer pays for the energy produced by the solar system instead of DTE energy. For hours when solar production is lower than the load the customer buys its remaining needed energy from DTE at the TOU rate; when solar generation is higher than the load, the customer sells the excess energy to DTE at the outflow rate.

For solar-plus-storage systems, the DTE tariff is also used to guide the charging and discharging of the batteries. The model assumes that storage only charges during off-peak periods and is discharged during on-peak periods on top of solar to avoid the higher DTE hourly rates. If in any hour solar energy is produced above load and charging capacity, the energy is exported to the grid at the DTE outflow rate; and if energy is needed beyond the solar and the battery output in any hour, the needed energy is purchased from DTE at the TOU rate.

Table 11. DTE tariffs considered in customer financial model

Tariff	Rate type	Period	Price ($/kWh)
Standard Residential Time-of-Use (TOU) Rate	Inflow	Summer peak	24.36
		Summer off-peak	18.69
		Rest-of-year peak	20.05
		Rest-of-year off-peak	18.69
	Outflow	Summer peak	15.39
		Summer off-peak	9.72
		Rest-of-year peak	11.08
		Rest-of-year off-peak	9.72
Enhanced Residential TOU Rate	Inflow	Summer peak	25.61
		Summer off-peak	15.24
		Rest-of-year peak	23.18
		Rest-of-year off-peak	14.54
	Outflow	Summer peak	16.77
		Summer off-peak	6.39
		Rest-of-year peak	14.34
		Rest-of-year off-peak	6.19
General Service Rate	Inflow	Summer peak	15.22
		Summer off-peak	15.22
		Rest-of-year peak	15.22
		Rest-of-year off-peak	15.22
	Outflow	Summer peak	9.23
		Summer off-peak	9.23
		Rest-of-year peak	9.23
		Rest-of-year off-peak	9.23
Secondary Educational Institution Rate	Inflow	Summer peak	14.96
		Summer off-peak	14.96
		Rest-of-year peak	14.96
		Rest-of-year off-peak	14.96
	Outflow	Summer peak	9.00
		Summer off-peak	9.00
		Rest-of-year peak	9.00
		Rest-of-year off-peak	9.00

** All rates have an annual escalation rate of 2.1% following assumed inflation.*

Solar generation profiles

The generation profile for the solar system was taken from NREL's System Advisor Model (SAM) using a blend of 6 different locations throughout the Ann Arbor area for a typical meteorological year (TMY). The assumed DC to AC ratio is 1.23 to 1.

Customer load profiles

The financial model uses hourly data from NREL's end-use load profiles for the U.S. building stock. These profiles are built by NREL using statistical methods and samples of the energy consumption from multiple building classes across the country. The datasets used are representative of the average electricity consumption for single-family homes, multifamily buildings, and schools in Michigan during a typical meteorological year.