TROPOSPHERE LEGAL

To:	Ann Arbor for Public Power
From:	Chris Bzdok
Date:	January 31, 2024
Re:	Response to questions about City of Ann Arbor 100% Renewable Energy Options Analysis

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Executive Summary

This memo responds to your questions about the "City of Ann Arbor 100% Renewable Energy Options Analysis," which I will refer to as a feasibility study. Here is a short summary of the questions and my answers:

1. Is the high end of the feasibility study's total valuation estimate of $1.15 billion for DTE's Ann Arbor assets plausible? No. The report does not provide sufficient information for me to conclude that this high-end estimate is plausible. While theoretically anything is possible, the $1.15 billion is not a realistic outcome. The report says it applies a FERC formula for estimating stranded costs to estimate the high end of an income-based valuation. However, the report does not cite any support for using the FERC formula for this purpose. And even if the FERC formula can be used for this purpose, the report's method departs from the FERC method in several critical ways. Each deviation from the FERC method inflates the resulting estimate.

2. Is the feasibility study report's use of 20 years as the time period to use in calculating the high-end stranded cost obligation realistic? No, that is not realistic in my opinion. The report justifies using 20 years by asserting that Integrated Resource Plans (IRPs) use a 20-year planning period, and cites the IRP statute. However, the IRP statute contains no reference to a 20-year planning period – it refers to 5-, 10-, and 15-year periods. Further, IRPs are plans for electric generation, not electric distribution systems. Most of the cost in the high-end valuation estimate consists of lost distribution revenues. Distribution planning is done on a 5-year time period in Michigan. Finally, even if the IRP planning period was appropriate to use for this purpose, DTE will be replacing far more of its generation capacity over the next 5 and 10 years than the amount used to serve load in Ann Arbor. Therefore, there is no realistic scenario where DTE could strand any generation used to serve Ann Arbor for 20 years.

3. The report's authors assert that Michigan munis cannot do low-income assistance programs (differential rates) due to the *Bolt v. Lansing* precedent. As a result, the MEU option scores "poor to fair" in the equity & justice category, versus "good" for both the DTE+ and SEU options. Is this accurate? While there is an argument that can be made to this effect, others have examined this question closely and determined that municipal utilities can offer low-income rates without running afoul of the *Bolt* case.

4. The report indicates that a muni would be "highly unlikely" to launch before 2030, and the timeline places the muni launch at the year 2035. The report's authors also stated that it will take at least two years to stand up the muni once the contract to acquire DTE's assets is approved. Do you agree with these assessments? I find no information in the report to support the predicted 2035 timeline, and on-line research reveals municipal electric utilities created in less time. I do not have a basis to agree or disagree about the two years to stand up the muni once a contract to acquire DTE's assets is approved. We were able to find case studies in which municipal electric utilities were created in shorter time frames than predicted by the feasibility study report, and one case where the timeline was similar to that predicted by the report.

Author's Note

I am not a technical expert, and I am not offering any expert opinions on technical matters. I have not done a technical review of the workpapers associated with the report. I have done the best I can to offer my opinions based on relevant legal knowledge, my experience evaluating this kind of technical work product as part of my work as a lawyer in this field, and my general familiarity with the subject matter.

1. **Is the high end of the feasibility study's total valuation estimate of $1.15 billion for DTE's Ann Arbor assets plausible?**

Answer: No. The report does not provide sufficient information for me to conclude that this high end of the range of estimates is plausible. While theoretically anything is possible, the $1.15 billion is not a realistic outcome.

As part of estimating the range of asset values for acquiring the DTE distribution system in Ann Arbor, the feasibility study report provides a range of what it calls "FERC Going Concern Valuation Estimates." The report states that the high end of the range of Going Concern Valuation Estimates is $1.15 billion.[1]

The report states that it uses FERC's formula for calculating stranded cost obligations to estimate an income-based valuation for acquiring DTE's distribution system in the City of Ann Arbor. The report presents the FERC stranded cost obligation formula as:

> SCO = (RSE – CMVE)*L
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> where:
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> SCO = Stranded Cost Obligation
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> RSE = Revenue Stream Estimate: the average annual revenues from the departing generation customer over the three years prior to the customer's departure.
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> CMVE = Competitive Market Value Estimate, determined one of two ways, at the customer's option: Option (1) is 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. Option (2) is 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).
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> L = Length of Obligation: refers to the period of time the utility could have reasonably expected to continue to serve the departing generation customer.

For the RSE, the report calculates a low-end estimate and a high-end estimate. The low-end RSE is the authors' estimate of the discounted cash flow of generation

[1] Feasibility Study Report, p. 132; p. 133, Table 39; and p. 134, Table 41.

revenue (i.e., excluding distribution revenue) over an L of 20 years. From that low-end RSE, the report subtracts the discounted cash flow of selling that same energy into the wholesale MISO power market (Option 1 of the CMVE). The result is an SCO of $78 million.

The high-end RSE is the authors' estimate of the discounted cash flow of the total retail sales revenue (production and distribution) for DTE in Ann Arbor over an L of 20 years. From that high-end RSE, the report subtracts the discounted cash flow of selling the generation component of that energy into the MISO wholesale power market (Option 1 of the CMVE again). The result is an SCO of $1.15 billion. Table 41 labels this high-end SCO as the high-end Going Concern Value estimate and adds to it the value of the DTE Street Light System in Ann Arbor, for a total "Estimated Value – High End" of $1,158,130,000.

The report makes a number of assumptions for which it does not provide any source or justification. The assumptions may or may not be reasonable, but it is impossible to tell from the information provided in the report.

1. The report does not provide any explanation or authority for using the FERC formula for stranded cost obligations as the income-based valuation estimate. Again, there may be such authority, but the report does not present it.

2. Even if there is authority for using the FERC formula for stranded cost obligations for the income-based valuation estimate, the method used in the report differs in important ways from the FERC stranded cost rule and the sole FERC precedent cited in the report, the *City of Alma* case.[2]

    a. The biggest driver by far of the high-end valuation estimate is the inclusion of DTE's full retail sales revenue – including distribution revenues – in the stranded cost calculation. The report does not cite any authority for including distribution revenues in the calculation of stranded cost obligations.

    b. The FERC stranded cost rule states in a footnote that "[i]n the case of a retail-turned-wholesale customer, subtraction of distribution system-related costs *may* also be appropriate."[3] The report does not address this provision of the rule.

[2] City of Alma, Michigan, 96 FERC ¶ 61,163 (2001).

[3] Order No. 888, Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 75 FERC ¶ 61,080, n. 863 (1996) (emphasis added).

c. The *City of Alma* case held that distribution revenues should not be included in the calculation of the RSE if the city will compensate the incumbent utility for the distribution system, by condemnation or otherwise.[4] It is my understanding that if Ann Arbor forms a municipal electric utility, it plans to acquire the DTE distribution system. The feasibility study report seems to assume that it will, as well.

d. If the rationale is that full retail sales should be input into the FERC stranded cost formula for purposes of estimating going concern value for an acquisition under eminent domain for reasons outside the stranded cost obligation rule, the report does not state that or explain why that would be the case.

e. In the FERC stranded cost formula, Option 1 of the CMVE, the value of the generation at wholesale is netted against the lost retail generation revenues in the RSE. The feasibility study report uses that approach for the generation revenues in the RSE. However, by contrast, the feasibility study report does not recognize any offsets or reductions for the distribution revenues in the RSE. The report does not address that issue at all. As a practical matter, if DTE no longer provided distribution service in the City of Ann Arbor, many of the costs DTE recovers via those distribution revenues would be reduced or eliminated. These reduced or eliminated costs would include income taxes, property taxes, customer-related expenses associated with meters and service drops, and the costs of maintaining and repairing distribution facilities and equipment in the City of Ann Arbor. Other costs – such as administrative and general expenses – would be reallocated across DTE's remaining customer base. Therefore, even if there is a plausible scenario where lost retail distribution revenues would be included in the stranded cost calculation, distribution-related cost reductions and reallocations would need to be included in that estimate. Based on the description of the calculations in the report, it does not appear to have included any such reductions or offsets.

f. The FERC stranded cost rule also places a cap on the SCO. The SCO "can be no greater than the average annual contribution to fixed power supply costs (defined as RSE less variable costs) that would have been made by the departing generation customer had it remained a customer."[5] It is not clear whether the authors considered or included this cap when they estimated stranded costs for the income-based valuation using the

[4] 96 FERC ¶ 61,163, at 61,719.

[5] Order No. 888, 75 FERC ¶ 61,080.

FERC formula. If the authors did consider the cap and decided not to apply it, that decision is not explained in the report.

g. The FERC stranded cost rule also requires the subtraction of transmission revenues from the RSE.[6] It is unknown from the information presented whether the feasibility study report subtracted transmission revenues from the RSE for the high-end stranded costs estimate. On its face, the use of full retail revenues for the RSE would not subtract out transmission revenues, which are recovered as a component of PSCR costs. Or, If the authors did consider whether to subtract transmission revenues and decided not to do so, that decision is not explained in the report.

h. According to the FERC rule quoted in the report, Option 1 for the CMVE includes the value of both the energy *and* capacity on the wholesale market. It is not clear whether the authors included the wholesale value of capacity in the CMVE – the report only refers to energy.[7] The higher the CMVE, the lower the SCO; and so omitting capacity from the CMVE could be another issue that would inflate the high-end valuation estimate.

i. The report uses an L of 20 years, reasoning that DTE's IRP planning horizon is 20 years. That issue is discussed in the next section.

2. Is the feasibility study report's use of 20 years as the time period to use in calculating the high-end stranded cost obligation realistic?

Answer: No, that is not realistic in my opinion.

As noted above, under the FERC stranded cost rule, L is the Length of Obligation. That is "the period of time the utility could have reasonably expected to continue to serve the departing generation customer."[8] Therefore, the larger the L that is assumed, the larger the stranded cost estimate will be. The feasibility study report uses 20 years for L. Said another way, the report assumes that the City of Ann Arbor could be on the hook to DTE for 20 years of stranded costs.

The report states: "Based on FERC precedent, the beginning date of "L" in this case would likely be measured from whatever date DTE ceased incurring costs

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[6] *Id*.

[7] Feasibility Study Report, p. 134 ("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.")

[8] Order No. 888, 75 FERC ¶ 61,080.

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 [Integrated Resource Plan] IRP statute, would be unlikely to exceed 20 years."[9] The use of 20 years for this assumption is problematic, for five reasons.

First, I do not understand the reference to the IRP statute as the basis for 20 years as the longest planning horizon for DTE. The IRP statute requires planning horizons of 5, 10, and 15 years.[10] The statute does not reference a 20-year planning horizon anywhere that I am aware of.

Second, DTE currently has an approved IRP. The settlement agreement approving the IRP approves DTE's plans for 5-year, 10-year, and 15-year time horizons: "The Parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the five-year, 10-year, and 15-year time horizons."[11] The settlement never approves any 20-year plan.

Third, the settlement requires DTE Electric to file its next IRP by December 2026.[12] At that time, DTE will present new or modified plans for the next 5, 10, and 15 years. Thus, DTE is not locked into even its current 5-, 10-, and 15-year IRP plans. At most, DTE is locked into resource commitments it has made for the next three years, from 2023 to 2026.

Fourth, DTE is planning enormous generation resource changes over the next 10 years. Last year, DTE summarized these changes in presentations to investors as follows:[13]

[9] Feasibility Study Report, p. 132, citing IRP statute, MCL 460.6t.

[10] MCL 460.6t(3).

[11] Case No. U-21193, Order Approving Settlement Agreement dated July 26, 2023, Exhibit A, p. 3, paragraph 1.

[12] *Id*.

[13] DTE 2Q 2023 Earnings Conference Call, July 27, 2023, Presentation, slide 12, available at: https://s24.q4cdn.com/970999156/files/doc_financials/2023/q2/2-Q2-23-presentation-final.pdf.

First 5 years (2023 - 2027)

- Ceasing coal use at one Belle River unit in 2025 and remaining unit in 2026; converting to 1,300 MW natural gas peaking resource
- Adding 1,200 MW of solar
- Adding 350 MW of energy storage, increased from 240 MW

Second 5 years (2028 - 2032)

- Retiring two coal units at Monroe in 2028 and accelerating retirement of two remaining units to 2032 from 2035
- Adding 3,200 MW of solar
- Adding 1,000 MW of wind
- Adding 430 MW of energy storage

Next 10 years (2033 - 2042)

- Adding 2,100 MW of solar
- Adding 7,900 MW of wind
- Adding 1,050 MW of energy storage

The magnitude of these changes dwarfs the generation requirements of customers in Ann Arbor. According to the feasibility study workpaper titled "A2 100% Electrified and A2Zero 2030 load projections," in 2030 the authors project a winter peak for the customer base in Ann Arbor (excluding U of M) of about 185 MW and a summer peak of about 107 MW. Relatively modest adjustments in the very substantial resource changes summarized above could avoid stranding any generation costs for DTE.

Finally, IRPs are plans for *generation* (and related demand-side resources such as energy efficiency). IRPs do not include planning for distribution. As noted in response to question #1, the biggest driver of the high-end valuation estimate is 20 years of stranded *distribution* revenues. DTE files distribution plans in a different MPSC docket, U-20147. The time horizon for DTE's distribution plan is 5 years.[14] I do not understand why the report did not consider that 5-year planning horizon at least for distribution costs – or if it was considered, why it was not used.

3. **The report's authors assert that Michigan munis cannot do low-income assistance programs (differential rates) due to the *Bolt v. Lansing* precedent. As a result, the MEU option scores "poor to fair" in the equity & justice category, versus "good" for both the DTE+ and SEU options. Is this accurate?**

[14] Case No. U-20147, Doc. No. 0095, DTE Electric Company's 2023 Distribution Grid Plan.

Answer: While there is an argument that can be made to this effect, others have examined this question closely and determined that municipal utilities can offer low-income rates without running afoul of the *Bolt* case.

The question considered in *Bolt* was whether a stormwater fee was a tax or a user fee.[15] Michigan courts determine whether a given charge is a tax or a user fee by applying three criteria:

1. A user fee must serve a regulatory purpose, rather than a revenue-raising purpose.

2. A user fee must be proportionate to the necessary costs of the service.

3. A user fee must be voluntary. "Voluntary" in this sense means a price paid for a commodity or service – such that a person may refuse, or limit their use of, the commodity or service.[16]

Applying these criteria, courts have found that the following charges – among others – are user fees and not taxes:

- Water and sewer rates;[17]

- Commercial access fees imposed on shuttle service providers by an airport authority;[18]

- Annual occupancy permit fees for multi-family residential properties;[19]

- Fees for copies of recorded real estate documents, even if the fee exceeds the register of deeds' copy cost.[20]

No case that I can find has specifically applied these criteria to determine whether a municipal utility low-income rate is a user fee or a tax. However, this issue was evaluated extensively in connection with the creation of the City of Detroit's Water Affordability Plan (WAP). The WAP is an income-based plan that offers qualifying customers a fixed, reduced monthly rate and erasure of past debt. City of Detroit Legal

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[15] *Bolt v City of Lansing,* 459 Mich 152 (1998). *Bolt* was a Headlee Amendment case, but these criteria are used to distinguish between user fees and taxes in other contexts too.

[16] *Id*.

[17] *Shaw v City of Dearborn,* 329 Mich App 640 (2021).

[18] *A&E Parking v Detroit Metropolitan Wayne County Airport Authority*, 271 Mich App 641 (2006).

[19] *Midwest Valve & Fitting Co v City of Detroit*, __ Mich App __, 2023 WL 3766730; 2023 Mich App LEXIS 3915 (for publication) (2023).

[20] *Lapeer County Abstract & Title Co v Lapeer County Register of Deeds*, 264 Mich App 167 (2004).

Department determined that if a per-meter charge to fund WAP was designed to be proportionate to the cost of water service to all customers, and served the regulatory purpose of making water service reasonably available to all customers while raising adequate revenue to pay the cost of the services, it should be found to be a user fee and not a tax.[21]

I am not aware of any court cases that have challenged WAP on the grounds that it is a tax. There are certainly design elements that would help armor a low-income municipal electric rate against such a challenge. I am happy to discuss those further if helpful.

4. **The report indicates that a muni would be "highly unlikely" to launch before 2030, and the timeline places the muni launch at the year 2035. The report's authors stated that it will take at least two years to stand up the muni once the contract to acquire DTE's assets is approved. Do you agree with these assessments?**

Answer: I find no information in the report to support the predicted 2035 timeline, and on-line research reveals municipal electric utilities created in less time. I do not have a basis to agree or disagree about the two years to stand up the muni once a contract to acquire DTE's assets is approved.

I am not able to locate any source or basis cited for these predictions. If the source is experience and judgment, then we would want to know whether any of the authors who made the predictions have themselves participated in municipalization efforts.

We were able to find case studies in which municipal electric utilities were created in shorter time frames than predicted by the feasibility study report, and one case where the timeline was similar to that predicted by the report.

- **Jefferson County, Washington (2-5 years):** In 2008, the citizens of Jefferson County approved a ballot measure authorizing the PUD to pursue the acquisition of the county's electrical grid from the privately held Bellevue-based Puget Sound Energy (PSE). In 2010, after 2 years of negotiations, the PUD and PSE came to a purchase agreement of $103 million dollars for Jefferson County's electrical system and all of its assets in 2010. In order to pay for that purchase, the PUD applied for and received funding from the USDA's Rural Utility Service (RUS) program, borrowing $115 total to cover capital improvements and start up expenses as well as the agreed purchase price. In April of 2013 the PUD took over operation of the grid, becoming the first public agency to take over a private

[21] I can provide more materials from the WAP evaluations upon request.

system in WA in more than 65 years. Source: https://www.jeffpud.org/mission-vision/.

- **Winter Park, Florida (2 years):** On September 9, 2003, the citizens of Winter Park voted in favor to purchase the electric utility system from then, Progress Energy® Florida. This vote came in response to tremendous customer dissatisfaction reports and significant reliability issues. On June 1, 2005, the city celebrated the official "flipping of the switch" from an investor-owned utility to municipal ownership. The city does not generate power, so it purchases approximately 100 Megawatts (MW) of power on the open market. Long-term contracts are in place with the Florida Municipal Power Association (FMPA) and also agreements with the city's neighbor, Orlando Utilities Commission (OUC). Source: https://cityofwinterpark.org/departments/electric-utility/

- **Hermiston, Oregon (5.5 years):** In Feb. 1996, Hermiston city officials met with Pacific Power's (PP&L) district manager to discuss what they perceived as a deteriorating level of service from the utility. The city also asked if PacifiCorp would sell its Hermiston operations to Umatilla Electric Cooperative (UEC), which served surrounding areas. Discussions between Pacific Power and UEC occurred sporadically through the next several months. In June 1998, after PacifiCorp decided it would neither sell to UEC nor to the city, the city council called for a September 15 advisory vote on whether Hermiston should acquire PacifiCorp's facilities. The city began paperwork to condemn PacifiCorp's properties but said it would withdraw its condemnation effort if PacifiCorp agreed to provide Hermiston residents with service equivalent to what it anticipated with UEC. The following July, under the threat of condemnation of its assets by the city, PP&L agreed to sell the system to the city. (Source: https://northeastoregonnow.com/a-history-of-hermiston-energy-services/).
  PP&L's facilities in Hermiston were acquired and began operating as Hermiston Energy Services on Oct. 1, 2001. (Source: https://www.hermiston.or.us/energy)

- **Long Island Power Authority (12 years):** The Long Island Power Authority (LIPA) was established in 1986 by the Long Island Power Authority Act, which was enacted to control electricity costs within the service area of the Long Island Lighting Company (LILCO). In 1998, LIPA acquired LILCO's electrical transmission and distribution system, as well as certain other assets, and became the primary supplier of electricity on Long Island. That same year, LILCO's remaining assets, including its electrical generating facilities, were merged with Brooklyn Union Gas, creating a new publicly-traded utility corporation called KeySpan Corporation. In Oct. 2007, National Grid LLC (National Grid) purchased KeySpan and legally assumed KeySpan's contracts with LIPA. Most of LIPA's current day-to-day operations are performed by

National Grid, a private utility, under three major contractual agreements. (Source: https://www.osc.ny.gov/files/reports/special-topics/pdf/public-authorities-lipa-2012.pdf)

- **Clyde, Ohio, Light & Power (4 years):** In May 1984, the City Manager Nelson Summit decided that the city is paying too much for its retail electric service; he began to investigate the possibility of establishing a municipal electric system. The city council completed a preliminary feasibility study on establishing a municipal electric system in Clyde in July 1985. In July 1987, the study projected that a municipal system would result in savings of about $62 million over a 10-year period for Clyde customers. In November, a final feasibility study on establishing a municipal system was completed. In July 1987, the citizens of Clyde approved the start-up of a municipal electric system by a 70-30 percent margin. The next July, city officials offered to buy back the local power system from TE and are quoted a price of nearly $40 million. Clyde officials received bids indicating they can construct a new system for around $3.5 million, so they decided to build their own. In August 1988, the city sold more than $4 million in bond anticipation notes to allow construction of a new municipal system. The new municipal system will compete by allowing Clyde residents the choice of staying with TE or switching to municipal service. In November, city officials adopted an ordinance setting the municipal system's residential rates at a level approximately 25% lower than TE's.
  (Source: https://clydeohio.org/DocumentCenter/View/360/The-Clyde-Electric-Story)