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4 Introduction

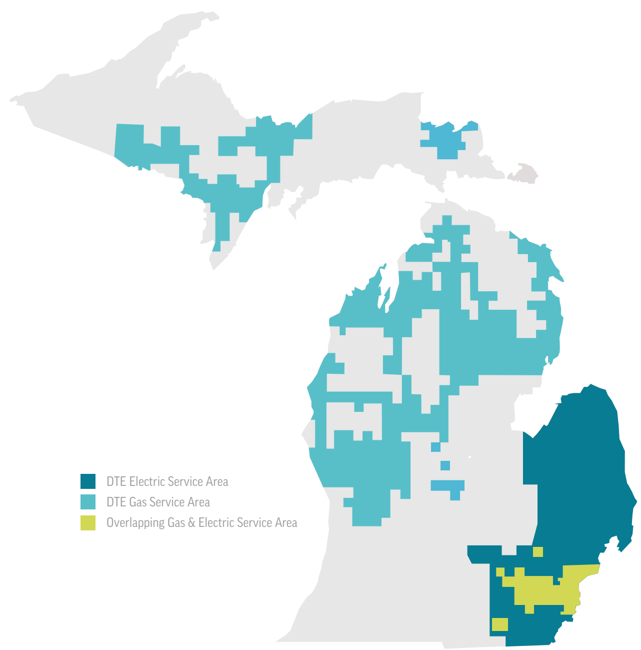
4.1 Company overview

DTE Energy (NYSE: DTE) is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its operating units include an electric company serving 2.3 million customers in Southeast Michigan and a natural gas company serving 1.3 million customers in Michigan. The DTE portfolio also includes non-utility businesses focused on industrial energy services, renewable natural gas, and energy marketing and trading.

As one of Michigan's leading corporate citizens, DTE Energy is a force for growth and prosperity in the 450 Michigan communities it serves in a variety of ways, including philanthropy, volunteerism and economic progress. Information about DTE Energy is available at dteenergy.com, and on Twitter and Facebook.

DTE Energy has more than 10,000 employees in utility and non-utility subsidiaries involved in a wide range of energy-related businesses. The company's growing non-utility businesses are built around the strengths, skills and assets of DTE Energy's electric and gas utilities.

Figure 4.1.1: DTE service area



DTE Electric is investing in a cleaner energy future that our customers can depend on 24/7. We are committed to doing our part to improve and protect the environment, and ensuring that the energy we generate is cleaner, reliable and affordable.

In 2017, DTE Electric was the first energy company in Michigan and one of the first in the country to set carbon reduction goals. In 2019, believing we could do more, we updated those goals and later that year we announced announced our plans to reach net zero carbon emissions by 2050. With our 2022 Integrated Resource Plan (IRP), we're going even further, proposing an acceleration of our interim decarbonization goals through a balanced and diversified approach to transition our generation fleet to cleaner energy.

Founded in 1903, DTE Electric (or Company) is the largest electric utility in Michigan and one of the largest in the nation. With an 11,840 megawatt (MW) system capacity, the Company uses coal, nuclear fuel, natural gas, hydroelectric pumped storage, wind, and solar to generate its electrical output.

Just as the generation fleet is diverse, so too is the customer base the Company serves each hour of the day. DTE Electric's customer mix spans three primary classes: residential, commercial, and industrial. Several business sectors comprise the commercial class, while the industrial class consists of three primary sub-classes: automotive, steel, and other manufacturing. The figures to the right highlight the 2022 forecasted service area sales and allocation of peak load by customer class. Further details regarding the Company's load forecast methodology and customer classes are provided in Section 10.

Figure 4.1.2: Forecasted 2022 service area sales

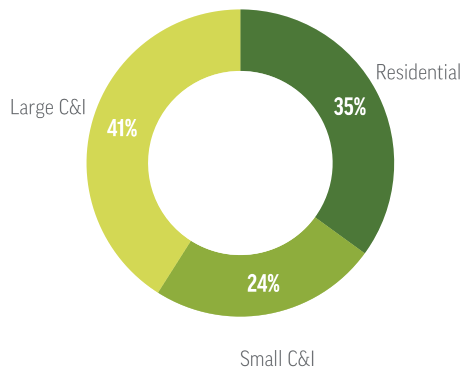
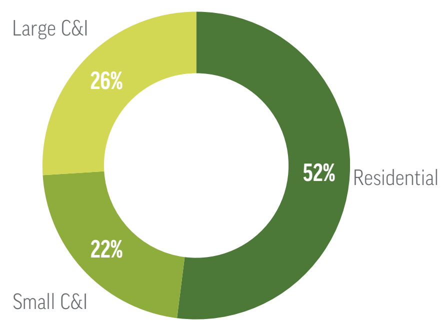


Figure 4.1.3: Forecasted 2022 service area peak



The Company's proposed course of action (PCA) is based on the low- and zero-emission technologies that are commercially available and economical today. The PCA also focuses on demand-side resources, reducing energy demand through reducing energy waste and expanding peak demand response technologies. As the Company developed this plan, it considered how the technologies' feasibility and economics could facilitate this generation transition. In future IRPs, the Company will continue to develop and implement plans to transition its generation fleet in a manner and timeframe that assure reliability and minimize financial impact on customers.

4.2 Existing resource portfolio

DTE Electric's generation assets include a diverse mix of owned and contracted sources of energy. The Company owns and operates a collection of generating units including coal, natural gas, oil, nuclear, wind, solar, and hydroelectric energy-storage facilities. The Company also holds a variety of power purchase agreements (PPAs) with independent power producers throughout Michigan. These PPAs are primarily for renewable energy resources, including wind, hydro, biomass, landfill gas, and waste recovery. (Section 7 provides a breakdown of the Company's existing supply-side resource fleet.) In addition to supply-side resources to meet customer energy needs, the Company offers a wide range of demand-side resources. These resources, described in Section 8, include demand response programs and energy waste reduction programs.

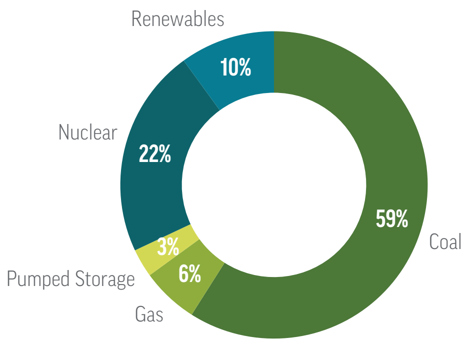
Company-owned generation, based on summer capacity ratings, is 11,840 MW, as shown in Table 4.2.1. This data is accurate as of June 1, 2022, reflecting the startup of the Blue Water Energy Center combined cycle gas plant and the suspension of the St. Clair and Trenton Channel Power Plants. The 2021 generation mix as a percentage based on energy produced is shown in Figure 4.2.2.

Table 4.2.1: 2022 Current owned generation resources

Resource Type	Summer Capacity Rating (MW)[1]
Fossil Steam	6,868 MW
Peaking Plant	2,033 MW
Pumped Storage	1,122 MW
Total Fossil/Hydraulic System	10,023 MW
Nuclear	1,141 MW
Renewables[2]	676 MW (612 MW wind, 64 MW solar)
Total Owned Generation	11,840 MW

1 Revenue requirement of existing generation and power purchase agreements can be found in the IRP Appendix K (Exhibit A-3.2)
2 Renewables based on MWAC installed

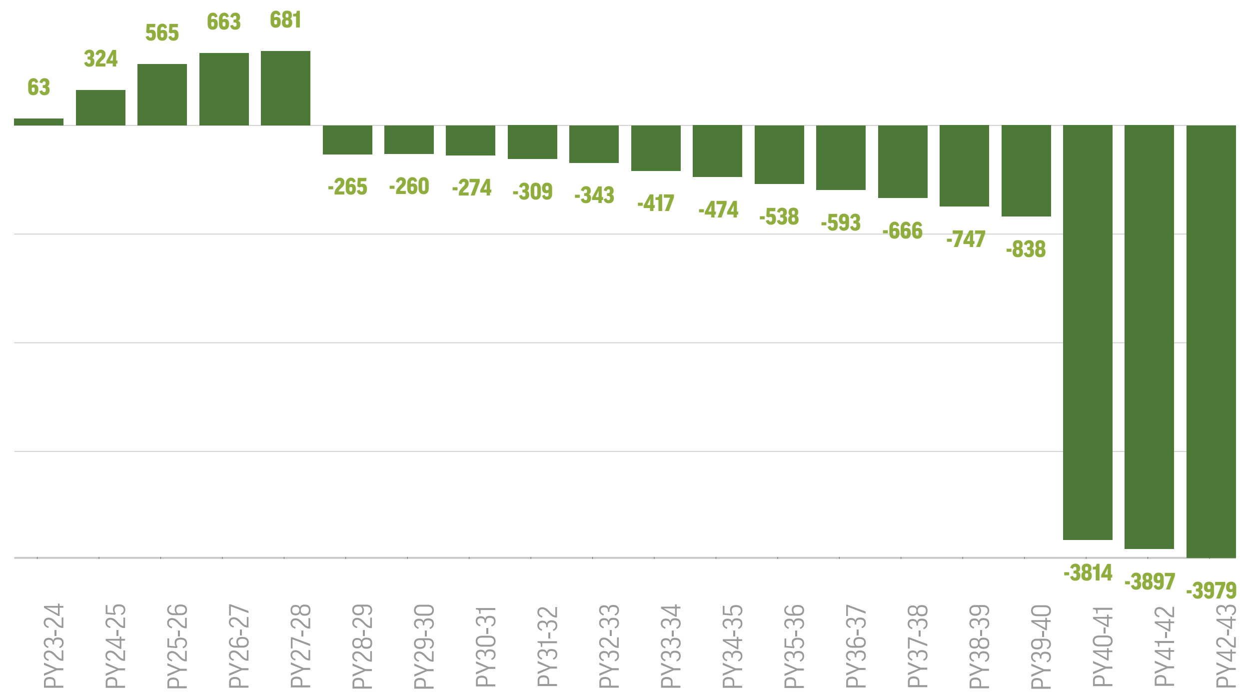
Figure 4.2.2: 2021 Current generation mix



4.3 Capacity outlook

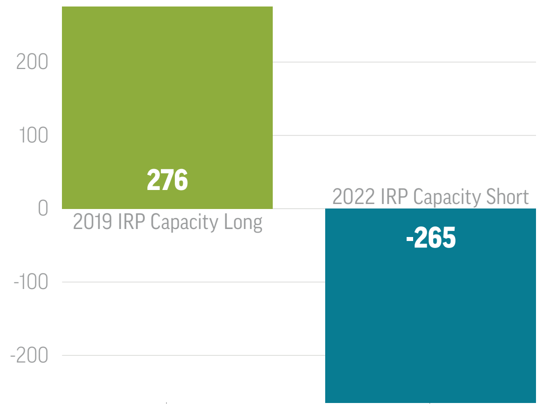
Developing the Company's capacity outlook projection was integral to the IRP process. When the IRP modeling began in December 2021, an assessment of the current state of the Company's capacity position was completed as the optimization modeling's starting point. This included evaluating the balance between load requirements (including reserve margins) and the assumed demand-side and supply-side resources (including planned retirements and planned additions) throughout the study period to determine if, and when, there was a need for additional resources. Figure 4.3.1 illustrates the Company's starting point capacity position throughout the IRP study period of 2023 through 2042.

Figure 4.3.1: Starting point capacity position (MW)



- The Company does not project a capacity need for the five-year period of 2023 to 2027.
- A starting point capacity need was forecasted in 2028 as a result of the assumed retirement of Belle River Units 1 and 2.
- The capacity need forecasted in 2028 was 541 MW less when compared to the need identified in the 2019 IRP, primarily due to an updated load forecast and the retirement of Belle River Units 1 and 2. See Figure 4.3.2.

Figure 4.3.2: 2028 Forecasted capacity need (MW) – 2019 IRP compared to 2022 IRP



4.4 Assumptions across scenarios and sensitivities

The Company used eight scenarios to develop its 2022 IRP. These included three required under the Michigan Integrated Resource Planning Parameters (MIRPP), pursuant to Section 6t of 2016 PA 341: business as usual (BAU), emerging technologies (ET) and environmental policy (EP), a carbon reduction (CR) scenario based on the Feb. 17, 2021 Order in Case No. U-20633 addressing Governor Gretchen Whitmer's carbon emissions goals; Reference (REF); Reference Refresh (REFRESH); and High Electrification (HE) scenarios based on Company assumptions; and an external stakeholder informed scenario (STAKE).

Each scenario assumed that certain market conditions would evolve over time, resulting in differing futures. For example, compared to the BAU scenario, the ET scenario assumes a 35% capital-cost reduction for solar, battery storage, energy waste reduction, demand response, and other emerging technologies. The future state assumed by the REF scenario aligns most closely to the required BAU scenario. However, inputs related to the natural-gas fuel price and carbon-emission costs in the REF scenario differ from the required scenarios. Although currently there are no taxes or cost on carbon dioxide emissions, there is the possibility that in the future there will be some type of CO_2 regulation.

Figure 4.4.1 and Figure 4.4.2 highlight the natural-gas and CO_2-emission cost forecasts for each scenario throughout the study period. Also shown are the forecasts used for the high gas price (200% of 2021 EIA[1]) and CO_2 sensitivities. The consulting company Siemens, formerly known as PACE Global, developed the long-term gas price forecast in the REF scenario. The three required scenarios used the publicly available 2021 EIA long-term gas-price forecast. The methodology utilized to develop the natural-gas fuel forecast is described in Section 13 and further explanation of the CO_2 cost is included in Section 6.

Figure 4.4.1: Annual natural gas price – MichCon Gas Hub ($ per MMbtu)

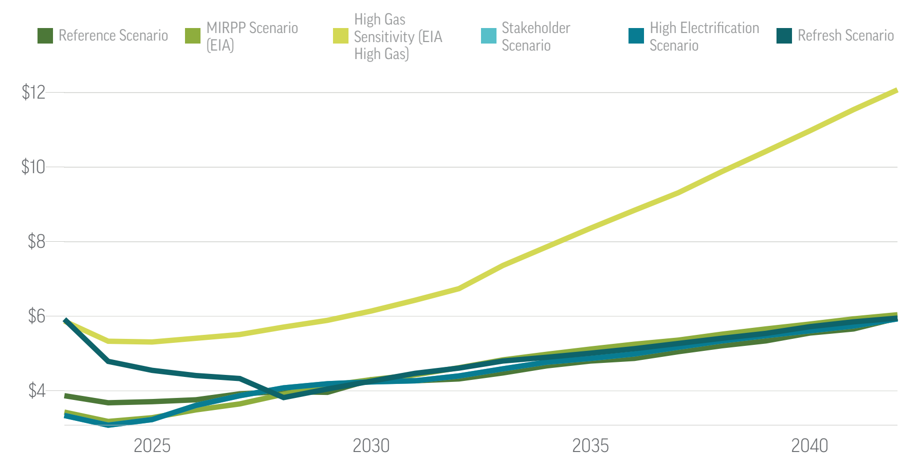
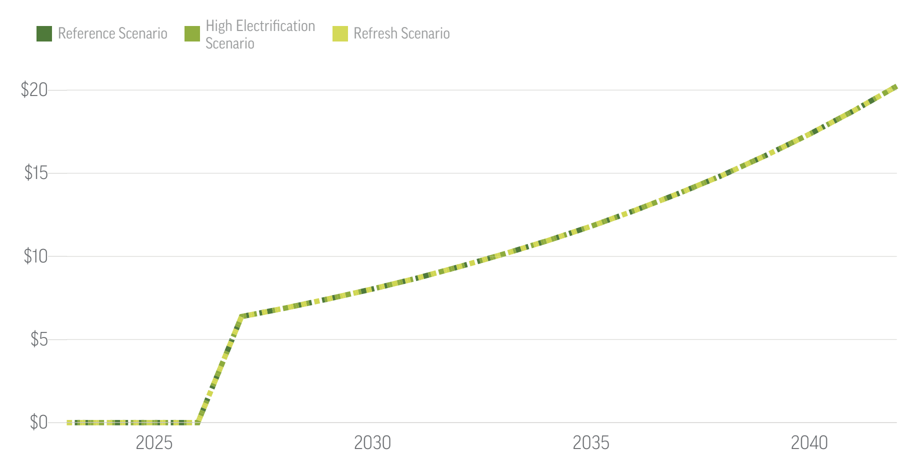
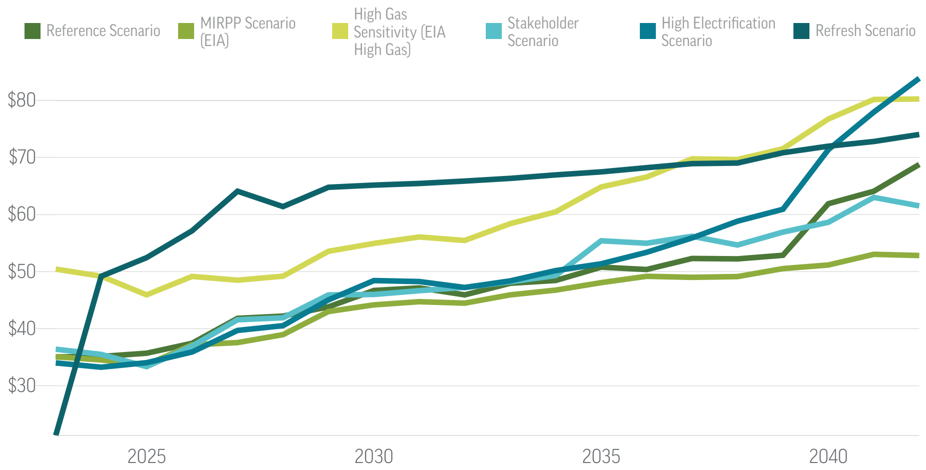


Figure 4.4.2: CO_2 Price forecasts ($ per ton)



Because each scenario and certain sensitivities had different market assumptions, the resulting forecasts for energy prices varied as well. The Company utilized Siemens to develop energy-price forecasts across the scenarios and specific sensitivities. Siemens modeled the Eastern Interconnect to determine markets and interrelationships between energy markets, environmental rules, gas markets, build plans, and capacity price forecasts. Figure 4.4.3 illustrates the resulting energy forecast prices for the Midcontinent Independent System Operator (MISO) Michigan hub.

Figure 4.4.3: MISO Michigan hub power prices



4.5 Regulatory environment and market dynamics

Michigan set course in late 2016, with the passage of Public Act (PA) 341, to revamp the guidelines and requirements for filing IRPs with the MPSC. Throughout 2017, DTE Electric participated in several IRP stakeholder collaborative groups led by the MPSC staff. These groups called for the consideration of a broad range of perspectives as the MPSC staff developed recommendations for IRP modeling parameters and filing requirements. The MPSC issued two orders governing IRPs to be filed under the 2016 law:

1. Michigan Integrated Resource Planning Parameters, Pursuant to Public Act 341 of 2016, Section 6t (Case No. U-18418; issued on Nov. 21, 2017).
2. Integrated Resource Plan Filing Requirements, Pursuant to Public Act 341 of 2016, Section 6t (Case No. U-18461; issued on Dec. 20, 2017).

In response to the Governor's Executive Directive 2020-10, addressing greenhouse gas emissions (GHG), the Commission directed utilities to analyze in IRPs a scenario that maintains the high load growth sensitivity of 1.5% from the Environmental Policy scenario and requires that the Company demonstrate a 28% and 32% reduction in carbon emissions from their 2005 amounts by 2025.[2] This information will be used to support the Department of Environment, Great Lakes and Energy's (EGLE) advisory opinion regarding the plan's compliance with environmental laws as set forth in MCL 460.6t(7).

The Company relied upon these orders, in combination with Section 6t of Public Act 341, to ensure the filed IRP is compliant with the current regulatory construct. The Company has also been participating in the Commission's process to update the Michigan Integrated Resource Planning Parameters and IRP Filing Requirements in Case Nos. U-18461, U-20633 and U-21219 for IRPs filed after 2022 and is using the Commission's updated energy waste reduction and demand response potential studies in this 2022 IRP.[3]

Potential changes in the Midcontinent Independent System Operator (MISO) market

As a load serving entity in MISO Local Resource Zone 7 (LRZ 7), DTE Electric participates in ongoing stakeholder discussions concerning the capacity market's current and future state. Various MISO initiatives are underway in stakeholder forums that may affect future capacity requirements and/or resource accreditation. MISO recently filed a tariff change moving to a seasonal resource adequacy construct, which was approved by FERC on August 31, 2022. This will impact future Planning Years (PY) beginning with PY 2023/24 and will be integrated in future IRPs. It was considered as part of this IRP's risk analysis.

Given the shift in electricity supplies across the Midwest, resource adequacy and transmission planning have been a major priority for MISO and stakeholders. Several ongoing MISO initiatives relevant to resource planning include:

Renewable Integration Impact Assessment (RIIA) – Designed to facilitate a broader conversation around renewable energy-driven impacts on future system reliability, the RIIA is focused on identifying potential integration issues and mitigating solutions. The assessment's primary outputs will include resource adequacy considerations, including potential impacts to the effective load carrying capability (ELCC) assigned to renewable energy resources. The RIIA is being performed in phases, with findings based on increasingly higher levels of renewable energy. To date, the assessment has considered renewable penetration levels up to 40%.

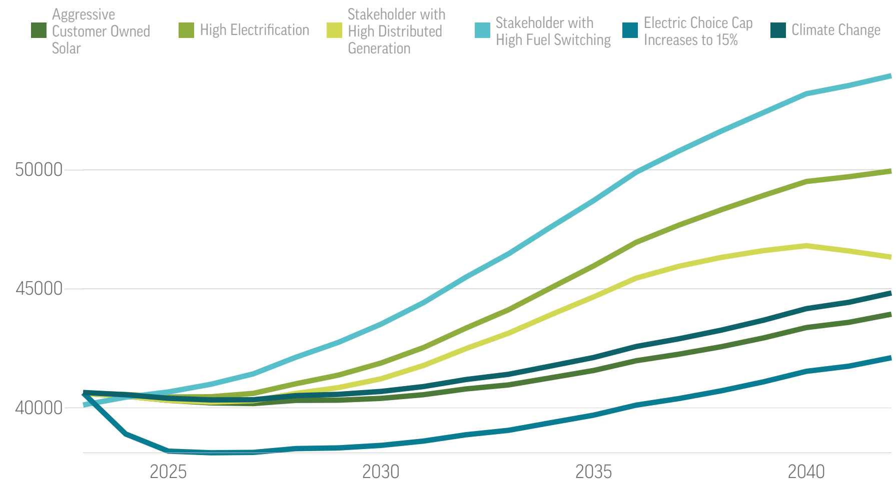
Resource Availability and Need (RAN) – The RAN initiative is focused on developing market-based solutions for the efficient conversion of capacity to energy. It was initiated in response to various observed trends that have resulted in an increased likelihood of capacity emergencies throughout the planning year. Potential outcomes include changes to load modifying resource registration requirements, alteration in outage coordination practices, and the implementation of a seasonal resource adequacy construct (as opposed to the current one-year prompt market). DTE Electric will continue to monitor and evaluate potential changes to resource planning in the future and ensure resource adequacy year-round.

Long Range Transmission Plan (LRTP) – The LRTP is a regional transmission planning initiative within MISO that was developed to address the ongoing industry trends related to the transformation of the generation fleet, increased rate of severe weather events, decarbonization policies and market shifts to electrification. Similar to MISO's Multi-Value Projects that were initiated in 2010, to be included in the LRTP planning process a transmission project must provide improved grid reliability and economic benefits across multiple transmission pricing zones, with a primary focus on improving the transfer capability within the entire MISO footprint. The current portfolio of LRTP projects has been separated into four different tranches, with Tranches 1 and 2 addressing transmission issues in the MISO Midwest subregion (which includes Michigan), Tranche 3 addressing transmission issues in the MISO South subregion, and Tranche 4 addressing the need to increase the transfer capability between MISO Midwest and MISO South subregions. In July 2022, the MISO board of directors approved the Tranche 1 portfolio, which includes 18 transmission projects representing $10.3 billion and over 2,000 miles of transmission lines that are spread across the MISO Midwest subregion.

Electric Customer Choice

The current regulatory construct in Michigan allows 10% of retail load to be served by alternative energy suppliers. Changes to the existing Electric Customer Choice construct would have an impact on the Company's potential long-term resource pathways, as load is a critical component to resource planning. In the majority of the scenarios and sensitivities analyzed, the IRP assumes the current 10% retail load cap remains intact. However, the IRP does consider sensitivities in which the Electric Choice cap is expanded or reduced. Figure 4.5.1 highlights a sample of load sensitivities modeled in the IRP, including varying levels of Electric Choice. Descriptions of the Company's load-forecast methodology and sensitivities evaluated are included in Section 10.

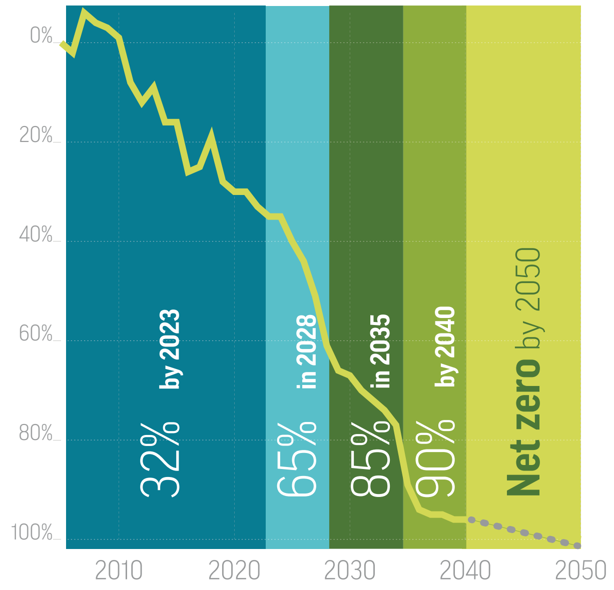
Figure 4.5.1: Load sensitivity bundled sales (GWh)



Environmental

DTE Electric is committed to providing customers with reliable, affordable energy while minimizing its impact on the environment. This includes reducing carbon emissions that affect climate change. In May 2017, DTE Electric was one of the first electric utilities to announce a long-term carbon reduction goal to reduce CO_2 emissions by more than 80% by 2050, positioning the Company as an industry leader in reducing carbon emissions. With the plans laid out in this IRP, the Company is able to take another next step in its clean energy journey, and is proposing acceleration of its carbon reduction goals to 65% in 2028, 85% in 2035, 90% by 2040, and net zero by 2050 as shown in Figure 4.5.2.

Figure 4.5.2: CO_2 emissions reductions



In the 2015 Paris Agreement, the countries participating in the United Nations Framework Convention on Climate Change agreed to hold the rise in global average temperature "well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius." Based on the IPCC's 2018 special report[4] on the 1.5-degree scenario, global CO_2 emissions have to decline by about 40% to 60% by 2030 from 2010 levels, and reach net zero by 2050, to stay within the 1.5-degree scenario. IPCC reports issued in 2021 and 2022 conclude that global warming of 1.5°C and 2°C will be exceeded during the 21st century unless deep reductions in CO_2 and other GHG emissions occur in the coming decades.[5]

Currently in the United States, no federal regulation requires reductions in CO_2 emissions from electric generating units, although in 2022 the Biden administration announced a target for the country to achieve a 50% to 52% reduction from 2005 levels in economy-wide net GHG pollution in 2030 as well as carbon-free electricity by 2035. The U.S. Supreme Court issued a decision on June 30, 2022, that reversed the January 2021 decision by the U.S. Court of Appeals for the District of Columbia that stayed an Environmental Protection Agency (EPA) regulation called the Affordable Clean Energy (ACE) Rule. The Supreme Court remanded the case for further proceedings. The decision may limit the EPA's ability to propose significant GHG reductions for the power industry. The EPA's next steps with respect to regulation of GHGs from energy generating units (EGUs) remain uncertain.

At the state level, in 2020, Governor Gretchen Whitmer signed Executive Directive 2020-10, committing Michigan to a goal of achieving economy-wide carbon neutrality no later than 2050. Pursuant to this commitment, EGLE developed the MI Healthy Climate Plan.[6] The goals set by the plan call for a reduction in economy-wide GHG emissions in Michigan 28% below 2005 levels by 2025, 52% by 2030, and carbon neutrality by 2050. The emission reduction projections set forth in DTE Electric's plan are ahead of the timelines in the MI Healthy Climate Plan and will help support Michigan's economy-wide GHG emissions reductions interim goals. Some states have established CO_2 cap-and-trade programs to reduce GHG emissions from the electric sector, most notably the Regional Greenhouse Gas Initiative and the California cap-and-trade system. These statewide systems require robust CO_2 accounting methods to verify emissions, and stakeholders are driving the development of improved methods of accounting for the CO_2 emissions associated with energy purchases and sales. In Michigan and in MISO, there is currently no accounting required for the CO_2 associated with the purchase and sales of energy. However, this is under consideration in other jurisdictions, subject to emissions trading programs. This type of CO_2 accounting would credit the seller of energy for a calculated average CO_2 mass attributable to the CO_2 intensity of the energy produced at the time of the sale, and similarly the purchaser would incur the CO_2 associated with the purchase. While simple in concept, the calculations are complicated and would require coordination and data sharing across MISO, the sellers and purchasers, and other stakeholders. Energy purchases and sales have been considered in calculating CO_2 reduction in this IRP. It is expected that the role of CO_2 accounting in IRPs will evolve in future filings.

Customer and Investor Expectations

The Company also considered stakeholder and customer feedback expressing support for DTE Electric's transition to a more diverse, balanced and cleaner generation portfolio, as outlined in the Public Outreach Report. This support includes an increased role for renewables and an acceleration of our decarbonization efforts. Moreover, investors are increasingly focusing on environmental, social and governance (ESG) performance.

Renewable portfolio standard

Public Act 342 of 2016 amended Public Act 295 of 2008 by increasing Michigan's renewable portfolio standard (RPS) from 10% by 2015 to 12.5% by 2019 and 15% by 2021. Public Act 342 required electric providers to file amended plans to meet the new standards within one year of its effective date. Compliance with the RPS is addressed through the Company's renewable energy plan (REP) approved by the Commission pursuant to Case No. U-20851 and also in the Company's REP filed on September 30, 2022, under Case No. U-21285. In support of the Company's carbon and clean energy goals, the renewable energy plans outlined in this 2022 IRP take DTE Electric to renewable levels beyond those requirements.

Clean energy incentives and supply chains

The last several years have experienced significant change in markets and policies for clean energy technologies, such as wind, solar and batteries. Disruptions in supply chains and logistics, along with workforce issues that resulted from the COVID-19 pandemic, have impacted products and projects across the country. Specifically, the solar photovoltaic (PV) industry has faced disruptions on the global scale with supply chain constraints and international trade actions. These developments have delayed some solar projects and created uncertainty for utilities and developers related to the pricing and availability of solar panels.

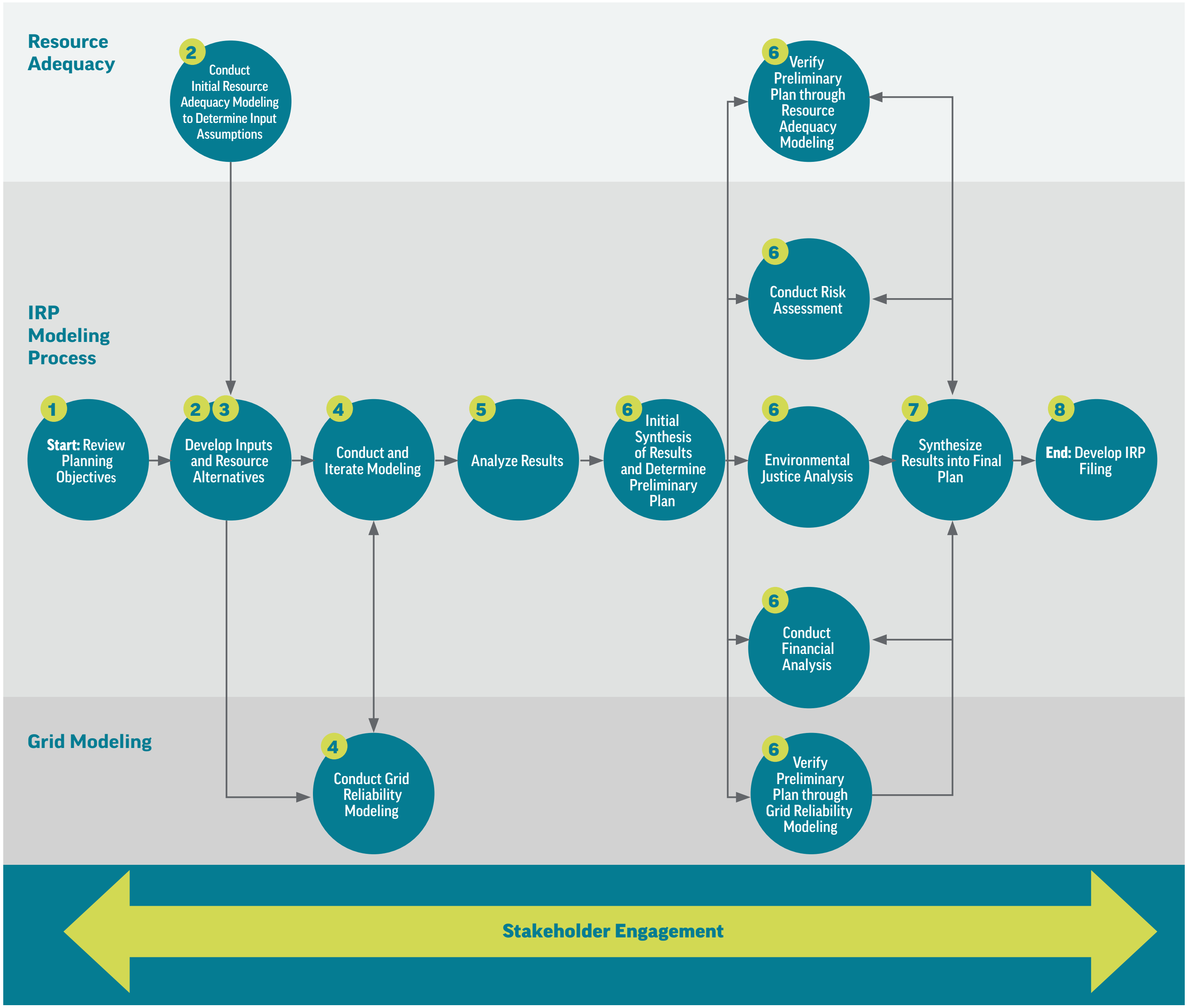
Incentives for domestic production of clean energy technologies, including solar and batteries, in the new Inflation Reduction Act (IRA) are expected to diversify supply chains over time. The IRA, enacted in August 2022, includes unprecedented incentives for energy storage, renewable energy, electric vehicles, and charging infrastructure, energy efficiency, hydrogen, carbon sequestration, nuclear and other clean energy investments. The IRA is expected to further enhances the affordability of our plan. Although all the IRA provisions were not fully implemented at the time of our filing, we took steps during the development of our proposal to analyze its potential benefits for our customers. Specifically, we analyzed a new scenario (REFRESH) to assess the impacts of the IRA's tax credits and adjusted the proposed course of action to include additional wind, solar and battery storage.

4.6 IRP planning process

IRP process

The Company's IRP process contains eight steps to ensure the completion of a comprehensive plan, as shown in Figure 4.6.1. Because assumptions and environmental and regulatory factors change, the integrated resource planning process must be continuous. Prior to filing the IRP with the MPSC, the Company hosted six technical stakeholder workshops to share information regarding the IRP assumptions and preliminary modeling results. These workshops also provided stakeholders the opportunity to provide input into the IRP process, ask questions and submit comments. Further details regarding stakeholder collaboration are included in Section 4.7.

Figure 4.6.1: IRP planning process



Step 1: Review planning objectives

DTE Electric's customer focused planning objectives, Figure 4.6.2, are based on the factors the Company has historically used in making resource decisions and apply to both the Integrated Resource Plan and the Distribution Grid Plan. DTE Electric updated the planning objectives in 2021, building on the planning principles that were used to guide the 2017 Certificate of Necessity and 2019 IRP.. The current planning objectives were refined cross-functionally with the Company's Distribution Operations team and updates were made to standardize the wording to be applicable across both generation and distribution planning. In addition, customer accessibility was added as an objective, based on stakeholder feedback. The planning objectives are used to guide decision-making, including the development of this IRP, as well as the Company's 2021 and future Distribution Grid Plans. The planning objectives are: Safe, Reliable and Resilient, Affordable, Customer Accessibility and Community Focus, and Clean. The Company's 2022 PCA meets customers' future generation and capacity needs with a portfolio of supply and demand-side resources that optimally balances these planning objectives. This was demonstrated in the portfolio metric evaluation described in Section 15.11.

As shown in the first step, before any modeling or analysis is undertaken, the Company reviews its five planning objectives to ensure the IRP will be appropriately balanced.

Figure 4.6.2: Planning objectives

Step 2: Develop inputs

After reviewing the planning objectives, a broad set of scenarios and sensitivities is developed. Scenarios are made up of driving forces that shape and define different paths to the future. They contain key uncertainties that are critical components to help construct and differentiate among the scenarios. These are generally broad market assumptions such as commodity prices, technology costs, load growth and environmental regulations.

Sensitivities, considered smaller changes from a modeling perspective, are specific variables that affect only the DTE Electric service territory and/or Michigan. A sensitivity is designed to test one specific uncertainty or variable. Modelers apply sensitivities to the scenarios. Examples of sensitivities include varying levels of load forecast, EWR, capital costs, market purchases, gas prices, retirement dates, and CO_2 emission adders to name a few.

In addition to scenarios and sensitivities, other inputs are developed for the IRP model, such as load forecasts, fuel prices and transmission impacts.

This step also looks at the existing and approved resources, including known or projected changes, subtracting from it the sum of the customer demand forecast plus planning reserve margin (PRM). The resultant difference would either be a projected capacity surplus or shortfall.

Step 3: Develop alternatives

To develop a reasonable and prudent plan, it is important to consider all feasible resource options to meet customer demand. The IRP process evaluates a multitude of technologies, including natural gas and nuclear units, renewable generation, storage, and demand-side management resources among others. These technologies are considered "alternatives." Some of the alternatives considered are emerging technologies. The costs and operating parameters of each alternative are inputs to the IRP analysis. The Company uses technology cost and operating data from publicly available data from a variety of sources when available.

During steps two and three, the Company held eight public open houses as well as a several technical conferences, one of which included the development of a scenario in conjunction with stakeholders.

Step 4: Conduct and iterate modeling

Different steps within the IRP process use various methods of modeling. The modeling conducted in the IRP analysis is an iterative process between the main IRP optimization modeling, Resource Adequacy modeling and Grid Reliability modeling. The modeling team conducted the IRP optimization modeling using the software tool called EnCompass. The extensive IRP modeling included running various scenarios and sensitivities (called an EnCompass run), each combination resulting in a different portfolio. A portfolio represents the resource plan the model determines to be the optimal plan based on market assumptions and resource alternatives. For this IRP, under the various scenarios and sensitivities, the modeling team completed over 100 EnCompass runs.

Step 5: Analyze results

In step five the Company analyzes the modeling results. Alternative portfolios under certain scenarios can then be compared to each other and conclusions drawn to help design the PCA. Additionally, the model calculates the annual and net present value revenue requirements (NPVRR) for each of those portfolios. Under each scenario, the Company develops a "base" portfolio, which is comprised of the starting point and is the basis for comparison. All sensitivities under the appropriate scenarios are compared to that respective base plan. During this time two additional technical conferences were held.

Step 6: Initial synthesis of results and determine preliminary PCA

Step six examines various considerations following steps four and five and involves the initial synthesis of results, which supports the determination of a preliminary PCA. The preliminary PCA is then further analyzed through a series of additional studies, including resource adequacy modeling, a risk assessment, environmental justice analysis, and financial analysis. ITC also provides verification of the preliminary PCA through grid reliability modeling.

Step 7: Synthesize results into final PCA

If the preliminary PCA does not incorporate or meet one or more of these assessments, then the preliminary PCA will be adjusted and checked again to see if the criteria are met until each assessment is verified. Results are then synthesized into what becomes the final PCA. The PCA is the most reasonable and prudent option to meet the Company's energy and capacity needs at a reasonable cost compared to other alternatives and is aligned with the Company's planning objectives.

Table 4.6.3: IRP assessment criteria for validating the PCA

Step	Assessment Objective
Verify preliminary PCA through resource adequacy modeling	Meets LOLE of 1 day in 10 for critical years
Conduct risk assessment	PCA is determined to be a low risk option compared to other alternative plans
Environmental justice analysis	PCA reduces overall CO_2 and other emissions including identified vulnerable communities
Conduct financial analysis	PCA optimizes financial impacts to customers
Verify preliminary PCA through grid reliability modeling	PCA is not significantly different from initial grid reliability studies performed and meets grid reliability

Step 8: File the IRP and take part in the contested case

The Company then files an application and supporting testimony requesting MPSC approval of its IRP. Per Section 6t of Public Act 341, the MPSC will conduct a contested case proceeding with an initial decision within 300 days and its final decision within 360 days of the date of filing.

4.7 Stakeholder involvement in the IRP

Overview

DTE Electric's IRP was developed through an extensive, year-long analysis process involving complex modeling that considered over 100 potential outcomes based on a range of different inputs.

In addition to comprehensive modeling and analytical studies, the Company spent many months listening and learning from customers and other stakeholders.

The Company sought input from a wide range of individuals and organizations who were involved with DTE Electric's regulatory cases in the past, expressed interest in having input into the Company's planning, or who might be impacted by its plan. Stakeholders included residential, business and industrial customers, community representatives and technical experts. The Company's intent was to discuss the IRP process, listen to their concerns, interests and suggestions, encourage meaningful and informed dialogue on generation planning and gather feedback to consider in the Company's analysis and decision-making.

Key outreach and engagement activities included:

- Eight public open house events hosted at varying times, recorded, transcribed and translated into five languages; all materials and recordings are posted on dtecleanenergy.com.
- More than 300 public questions and comments received and responded to through the IRP email and public comment link on the website.[7]
- Qualitative and quantitative research conducted with approximately 1,300 residential customers, 400 commercial and industrial customers, and 150 community representatives to better understand their views and attitudes toward decarbonization, energy sources and DTE's plan for reaching net zero carbon emissions.
- More than 40 organizations invited to participate in the technical stakeholder workshops.
- Meetings with community representatives from Belle River and Monroe Power Plant communities held to share information about the filing process, answer questions, hear feedback and identify opportunities for collaboration.

The Company appreciates the constructive dialogue and feedback it received across the various outreach channels, as well as the time customers and stakeholders took to provide that feedback. Because of the ongoing, comprehensive dialogue with stakeholders, the 2022 IRP process was robust and led to a proposed plan that reflects diverse feedback and input, including:

- A better understanding of customers' perspectives relative to the generation transition, including the expectation that the Company will continue to adopt clean energy technologies while keeping the energy it provides reliable and affordable.
- The incorporation of feedback from technical stakeholders in the IRP process and analysis, including modeling tool selections, scenario and sensitivity development, and consideration of storage benefits.
- A commitment to partnering with employees impacted by coal plant retirements and transitions by reskilling and retraining for other roles.
- ·The need to proactively partner with Belle River and Monroe Power Plant communities to understand the social and economic impacts of proposed transitions and/or retirements.

Technical workshops

DTE Electric held six virtual technical workshops, as shown in Table 4.7.1, for individuals with a deep understanding of the technical aspects of an IRP and organizations that are often active participants in DTE Electric's regulatory proceeding, and those that expressed interest. In addition, the Company held a two-day technical collaborative to evaluate and identify alternative modeling software for use in developing integrated resource plans. Each workshop was comprised of a presentation and question-and-answer segment led by various subject matter experts from across DTE Electric, including the IRP team, as well as industry experts including Astrapé Consulting, ITC Transmission and Midcontinent Independent System Operator (MISO). In between the workshops, participants were encouraged to email comments and questions to DTE Electric via the IRP email address.

The Company invited participants to the workshops based on parties that participated in DTE Electric's last general electric rate case and IRP, and those that expressed interest. As stakeholders contacted the Company asking to join the technical stakeholder email list, they were added to subsequent meeting invitations. More than 40 organizations were invited to participate in the technical stakeholder workshops, including representatives from the MPSC and the Michigan Department of Environment, Great Lakes, and Energy (EGLE), environmental organizations, ITC Transmission, Midcontinent Independent System Operator (MISO), consumer advocates and trade groups.

Common feedback themes from technical stakeholders included questions around storage and resource adequacy modeling, input on the modeling assumptions for energy waste reduction, renewable energy, load forecasting and modeling assumptions based on the Inflation Reduction Act.

Table 4.7.1: Technical workshop summary

Meeting	Date	Time	Agenda Items
Technical Workshop 1	January 25, 2022	1-2:30pm	• Review of the 2019 IRP • Overview of new modeling software • Changes and enhancements in the 2022 IRP • Discussion on modeling scenarios • Q+A session
Mini Technical Workshop	February 1, 2022	1-2pm	• Presentation and discussion of stakeholder recommendations for the collaborative "stakeholder scenario"
Battery Storage Workshop 1	April 13, 2022	1-3:30pm	• Presentations by industry experts on energy storage • Q+A session
Technical Workshop 2	April 28, 2022	1-2:30pm	• Overview of load forecasting and electrification • Levelized cost of energy and market valuation • Final scenarios and sensitivities • Resource adequacy report out • Q+A session
Battery Storage Workshop 2	June 15, 2022	9-10am	• Review of plans to model benefits associated with storage • IRP capacity expansion modeling • Q+A session
Technical Workshop 3	August 24, 2022	1-3pm	• ITC transmission model overview • MISO presentation • Encompass preliminary modeling results • Q+A session

The Company incorporated feedback from technical stakeholders in several ways, including:

- Selected new modeling software based on feedback received from stakeholders during the 2020 collaborative.
- Developed and ran a specific scenario, called the "stakeholder scenario," based on an open dialogue between technical stakeholders and DTE Electric representatives that incorporated stakeholder feedback on EWR assumptions, load forecasting, and renewable assumptions.
- Developed and ran a specific scenario based on the Inflation Reduction Act to evaluate the legislation's benefits.
- Modeled battery storage ancillary benefits.

Public open houses

DTE Electric hosted eight virtual public open house events, listed in Table 4.7.2, between January and April 2022. The objectives of these events were to inform participants on the IRP process and the Company's generation transformation, and to provide an opportunity for the public to ask questions and provide feedback.

The Company offered afternoon and evening sessions of the public open houses to accommodate participants' schedules. The Company publicized the open houses through news releases; DTE Energy's Empowering Michigan blog; social media posts on LinkedIn, Facebook and Twitter; direct outreach and email invitations to local officials, elected state officials, community-based organizations and other stakeholders; and emails using the MPSC's MI Power Grid IRP workgroup subscriber mailing list.

Table 4.7.2: Public open house summary

Meeting	Date	Time	Agenda Items	Attendees
Public Open House 1	January 18, 2022	1 p.m., 6 p.m.	• Overview of DTE CleanVision Plan • Overview of an IRP • Recap of the 2019 IRP • 2022 IRP planning objectives and participant survey • Q+A session	1pm: 65 6pm: 22
Public Open House 2	February 22, 2022	1 p.m., 6 p.m.	• Renewables • Emerging technology • Q+A session	1pm: 18 6pm: 11
Public Open House 3	March 22, 2022	1 p.m., 6 p.m.	• Customer demand-side management including EWR and DR • Overview of DTE's voluntary renewables program, MIGreenPower • Q+A session	1pm: 28 6pm: 3
Public Open House 4	April 19, 2022	1 p.m., 6 p.m.	• Coal plant retirements and transitions (DTE's Retire with PRIDE initiative) • Grid modernization and reliability • Q+A session	1pm: 20 6pm: 19

To provide inclusivity for all individuals wishing to access and engage in the open houses, we consulted with Abilities in Motion, the Company's employee resource group for persons with a disability. Based on the group's guidance, a number of protocols were incorporated, including: recording all meetings; requiring speakers to use headsets or microphones; making transcripts available online; and using closed captioning. All presentations, event recordings, transcripts and translations of transcripts in multiple languages were posted online for those who were not able to attend the live events. From Jan. 1, 2022, through Sept. 15, 2022, public open house recordings had over 115 views and 670 resource documents were downloaded.

Additional public outreach

In addition to the public open houses, the Company developed an IRP section on its dtecleanenergy.com website, created an online comment submission form and IRP email address, and conducted customer research. As of Sept. 15, 2022, DTE Electric received and responded to more than 300 questions and comments through the online form and IRP email. Public submissions spanned a variety of topics and included general requests for more information. Ultimately, the Company identified several key themes from the public comments received, including interest in DTE Electric progressing its decarbonization goals; support for clean energy like renewables, storage and energy waste reduction; support for a just transition of employees and communities; and a lack of support for new natural gas infrastructure.

DTE Electric also engaged an outside research firm with long-term experience in both the energy and public utility sectors among other industries to conduct a multi-phase, iterative research program to gain a deeper understanding of customer viewpoints on decarbonization, energy generation sources and achieving net zero carbon emissions by 2050. The firm's research included:

- Twenty-eight one-on-one in-depth interviews with commercial and industrial customers and community representatives, providing a broad cross-section of perspectives.
- Seven focus groups with a total of 26 residential customers from a wide range of backgrounds across DTE Electric's service territory.
- A comprehensive survey of 1,293 residential customers, 407 commercial and small business customers and 128 community representatives, conducted online and via telephone.

The research taught the Company a great deal about customer expectations. The Company was encouraged to find that this IRP aligns with those expectations in many ways. Additionally, many customers who participated in the interviews and focus groups expressed appreciation for the dialogue and the opportunity to contribute to DTE Electric's overall planning, and indicated they'd like to learn more about what the Company is considering in the way of future clean electricity generation.

The research demonstrated that customers understand and support the goal of achieving net zero carbon emissions and the goals that DTE Electric is setting. They also believe Michigan's utilities have a role to play in addressing climate change. Most believe the Company will achieve its net zero objectives.

According to the research, customers want a diverse mix of energy generation sources going forward, with renewable energy leading the way, and natural gas supporting reliability. They also want to see solutions including energy storage play a contributing role in the future energy mix, all of which aligns with our proposal.

Affordability is top of mind for customers, especially given recent inflationary pressures. However, they are mindful this transition could impact their bills, and many assume at least a small increase may result from this transition. While concerns about a potential increase exist, the majority of all stakeholder groups - from residential and commercial customers to community representatives- say they would be willing to pay at least a small percentage more annually to support the transition to cleaner sources of energy.

DTE Electric is hopeful that this IRP filing will provide the opportunity for even greater discussion around Michigan's energy future with our customers.Many customers and other stakeholders are not yet fully aware of DTE Electric's plans, but the Company looks forward to engaging with them and hearing more of their feedback about its generation transformation plans.

Community outreach

DTE Electric is committed to partnering with the communities and employees affected by the retirements of its coal-fired plants. These facilities have provided jobs and been an important part of local economies for many years and the Company understands the impact these retirements can have. Because DTE Electric believes it's important that these transitions happen thoughtfully and with dignity, the Company established a vision and process to support employees and communities in this transition.

For employees, it means making sure they have the opportunity to continue their careers at DTE Energy. As with other plant retirements, the Company intends to maintain its no layoff commitment and will work with union leadership to provide employees with support that includes reskilling, retraining and redeployment to other roles in the Company.

The Company also has been working with local elected officials and community representatives in the communities that will be affected by future transitions of the Belle River and Monroe Power Plants to share information, answer questions, hear feedback and identify economic development opportunities. Because the potential transition of the Belle River Power Plant could occur within the first five years of the study period, DTE Electric worked with an economic development consulting firm to conduct a socioeconomic impact assessment on a 2028 retirement and a conversion to a natural gas peaking resource.

Conclusion

Through this engagement, DTE Electric learned that customers would like to see the Company transition to a more diverse, balanced and cleaner generation portfolio. Customers and other stakeholders encouraged the Company to accelerate its carbon reduction goals and emphasized the need to ensure a just transition for employees and communities impacted by the evolution in generation sources. Stakeholders also expressed an interest in continued engagement on DTE Electric's generation transformation plans.

While a variety of outreach methods were utilized during the 2022 IRP process to seek diverse input, ideas and perspectives from a broad range of stakeholders, the Company recognizes that there are barriers which may prevent customers who wish to engage from participating in the IRP process. Further opportunities exist to partner and meaningfully engage with communities, stakeholders and customers as part of the implementation of the approved plan. We will continue to maintain the IRP email address (DTE_Electric_CleanVision@dteenergy.com) and public comment link on the dtecleanenergy.com website through the regulatory filing period for those who wish to provide feedback.

4.8 Coordinated planning

As the electrical system continues to evolve, DTE Electric remains committed to providing clean, safe, reliable, and affordable energy for our customers. Given changes facing the industry, including increased distributed energy resources (DER)[8] and electrification, the MPSC has expressed interest in better aligning transmission, distribution, and resource planning processes. The coordination of planning processes was addressed by the MPSC as part of its order establishing the MI Power Grid initiative (see October 17, 2019, order in Case No. U-20645), as well as subsequent orders.[9]

This section focuses on the Company's efforts to improve coordination between distribution and resource planning. Discussion of the Company's efforts to coordinate studies with the local transmission owner, ITC Transmission, are addressed in Section 12.

The Company submitted its second Distribution Grid Plan (DGP) to the MPSC in September 2021. The plan is based on shared planning objectives for generation and distribution planning and lays out a vision and the investments necessary to enhance reliability, modernize the electric distribution infrastructure, and integrate electric vehicles (EVs) and DERs, such as solar and battery storage.

As outlined in this IRP and the 2021 DGP, the Company has numerous ongoing collaborative efforts related to distribution and generation planning. These efforts include:

- Development and use of shared customer planning objectives to support collaborative processes and decision-making criteria for distribution and generation planning.
- Advancement in load forecasting methodologies and tools to support both distribution planning and IRP processes.
- Identification of investments that could provide resource capacity and distribution benefits such as the Company's proposed investments in CVR/VVO.
- Development of distribution-related inputs to support the IRP process and inform the proposed course of action, specifically:
    - input assumptions for incremental CVR/VVO.
    - deferred transmission and distribution costs associated with energy waste reduction programs.
    - estimated distribution costs associated with new generation resources.
- Coordination among multiple business units including Distribution Operation in the peaking generation study to better understand distribution system and transmission impacts.
- Improved information sharing with external stakeholders related to distribution planning topics including participation by Distribution Operations team in IRP public open houses.

This IRP builds on the developments in distribution planning and incorporates distribution planning assumptions and considerations to support a more holistic planning approach. Continued coordination between the Company's IRP and distribution planning teams and processes will be important to understand and account for the impacts of DER and electrification on both the bulk power and distribution systems.

DTE Electric engaged the local transmission owner ITC Transmission (ITC or ITCT), a subsidiary of ITC Holdings Corp., a Fortis Inc. company. ITC is a fully regulated company under the jurisdiction of the Federal Energy Regulatory Commission (FERC) that operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in the Southeastern part of Michigan's lower peninsula in the IRP process and development of the PCA. ITC Holding's transmission systems in Michigan include the ITCT and Michigan Electric Transmission Company (METC) transmission systems. METC operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in most of Michigan's lower peninsula. Refer to Section 12 for details on coordination with transmission planning.

Endnotes

1. EIA = U.S. Energy Information Administration
2. S T A T E O F M I C H I G A N (force.com); S T A T E O F M I C H I G A N (force.com)
3. May 26, 2022, Order, Case No. U-21193.
4. Summary for Policymakers – Global Warming of 1.5 ºC (ipcc.ch); IPCC, 2018: Summary for Policymakers. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty
5. IPCC, 2021: Summary for Policymakers. In: Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, p. 14, available at: Summary for Policymakers (ipcc.ch); see also 2022, Climate Change 2022: Impacts, Adaptation and Vulnerability, Working Group II contributions to IPCC Sixth Assessment Report, Climate Change 2022: Impacts, Adaptation and Vulnerability | Climate Change 2022: Impacts, Adaptation and Vulnerability (ipcc.ch)
6. MI Healthy Climate Plan (michigan.gov)
7. From January, 2022 to Sept. 15, 2022
8. The MPSC's definition of DER is as follows: "A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system." See August 20, 2020, order in Distribution Investment and Maintenance plan Case No. U-20147, page 11. As this definition indicates, these resources could be behind, or in front of, the customer's meter but would be distinguished from utility-scale resources connected to the transmission system.
9. See, September 24, 2021 order in Case No. U-20633

SECTION 5

5 Analytical approach

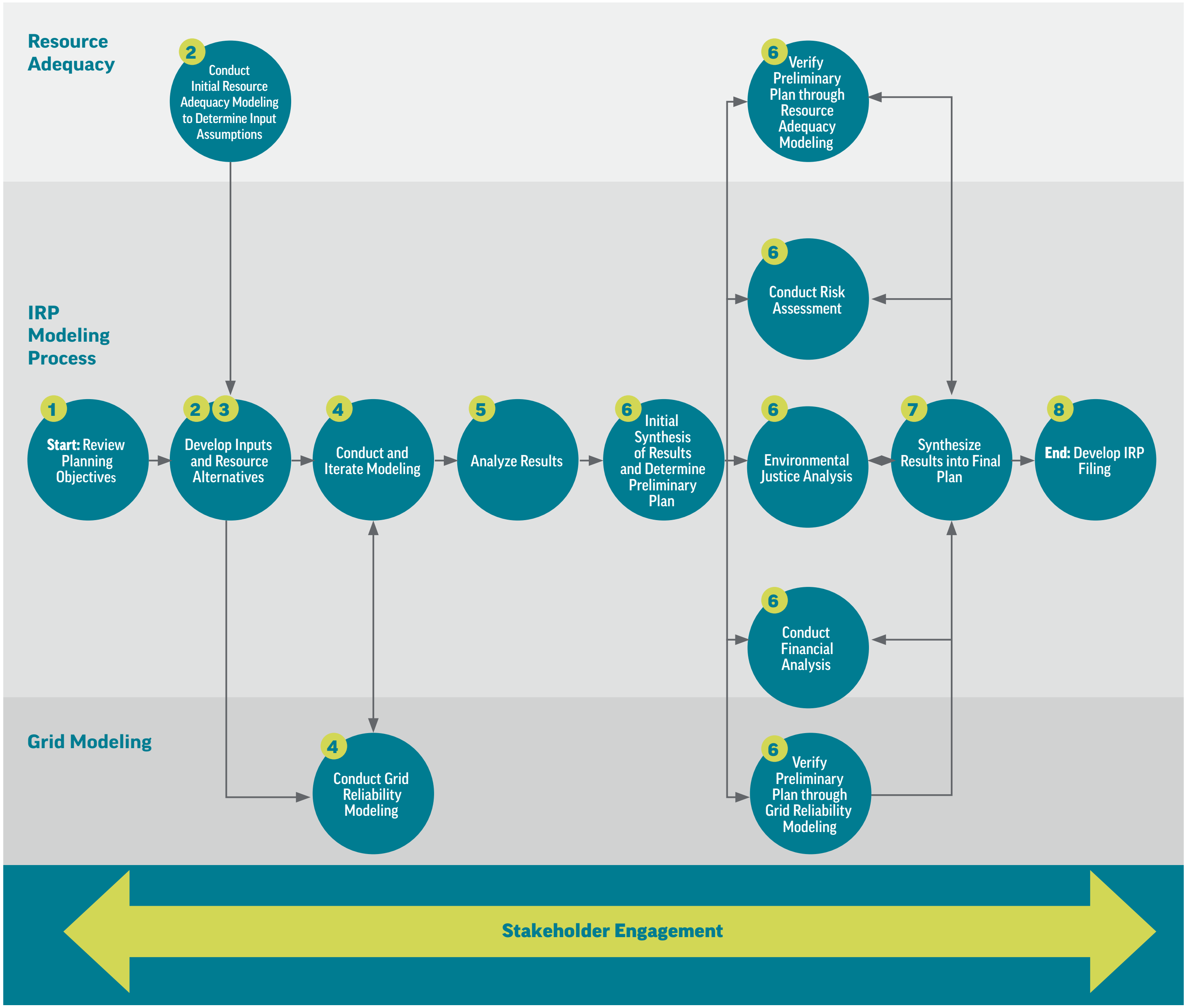
5.1 Overview

Developing the IRP was a detailed, multi-step process that involved many subject matter experts (SMEs) internal and external to DTE Electric. The IRP process, Figure 5.1.1, shows the analytical approach to developing, running and analyzing the models. Steps two through seven provide the modeling steps that were utilized to determine the proposed course of action.

Figure 5.1.1: IRP planning process

1	**Review Planning Objectives**
2	**Develop Inputs**
3	**Develop Resource Alternatives**
4	**Conduct and Iterate Modeling**
5	**Analyze Results**
6	**Initial Synthesis of Results and Determine Preliminary PCA**
7	**Synthesize Results into Final PCA**
8	**Develop IRP filing**

DTE Electric's planning process, step by step



5.2 Modeling process

The modeling process started with determining the data assumptions and developing alternative technologies, which are steps two and three in the IRP process. The data assumptions were gathered utilizing several of the Company's SMEs, as well as Siemens and Astrapé. In addition, as discussed in Section 4.7, the Company shared data assumptions with and offered opportunities to IRP stakeholders to provide input. Company SMEs provided a range of data assumptions including load forecasts, near-term fuel forecasts, renewable energy plans, energy waste reduction levels, and demand response.

To satisfy the modeling requirements put forward in MPSC Case No. U-18418, the SMEs drew upon public data when available, and used industry expertise to develop assumptions that were unique to DTE Electric. Siemens provided data assumptions that included long-term fuel prices[1], market prices, capacity prices and emission prices. Siemens determined these data assumptions by modeling the Eastern Interconnect. The data assumptions changed depending on the scenario. Eight scenarios were run, including three required by the Michigan Integrated Resource Planning Parameters, Section 6t of 2016 PA 341, one required under the CO_2 Executive order, pursuant to the Commission's order in Case No. U-20633, three scenarios developed by the Company, and one developed through collaboration with stakeholders, as well as several sensitivities.

This step also looks at the Company's capacity outlook. This is discussed further in Section 4.3.

In step three of the IRP process, alternative technologies were considered to potentially fill the Company's energy or capacity needs, meeting customer demand. The IRP process evaluated a multitude of technologies, including natural gas units, nuclear units, renewable generation, battery storage and demand-side management resources. These were called “alternatives.” Each alternative’s costs and operating parameters were inputs to the analysis. The Company used technology cost and operating data from publicly available data from a variety of sources (see Exhibit A-3.2 Appendix B). Once the data assumptions and alternative technologies were determined, they were then input into the modeling program.

Step four in the IRP process consisted of running the model. The IRP optimization modeling utilized the EnCompass program, an energy-market simulation that calculated the net present value revenue requirement for multiple portfolios that meet customers’ forecasted energy and capacity demand. In this IRP, modeling runs started in 2023 and ran through 2042. All scenarios and sensitivities were run through EnCompass to develop the least-cost portfolio.

Step five of the IRP process analyzed results of the completed EnCompass optimization model runs. Once the least-cost portfolios were generated for each scenario and sensitivity combination, they were reviewed with respect to the resources that made up the portfolio, costs and CO_2 emission reductions. A preliminary PCA was developed in step six of the IRP process by synthesizing the results of each least-cost portfolio output in conjunction with the Company’s planning objectives and other assessments including resource adequacy modeling, a risk assessment, environmental justice analysis, and financial analysis. (Development of the PCA is discussed in more detail in Section 16.) After the final PCA was determined, the EnCompass model was used to model the PCA across the eight scenarios.

Underpinning all of these steps is stakeholder outreach. Stakeholder outreach is discussed in more detail in Section 4.7.

5.3 Risk assessment methodology

The PCA needs to be a most reasonable and prudent plan in the face of an uncertain future, especially given the dynamic nature of the energy industry and emerging technologies. Risk analysis helps to hedge the uncertainties by performing an evaluation of how different build plans would perform given a range of unexpected possible futures. Five risk assessment methodologies were used to review the feasibility of the PCA: stochastic economic risk analysis, stochastic reliability analysis (resource adequacy), evaluation of key inputs, portfolio metric evaluation, and scenario and global sensitivity analysis. Each of the risk assessment methodologies are described below, while results from the risk assessment methodologies are included in Section 15.9.

Stochastic economic risk assessment

A stochastic analysis is an advanced modeling technique that uses probability distributions of key assumptions to evaluate portfolios. It is a highly quantitative analysis that uses multiple draws of different variables to test different factors such as economics or reliability under a variety of conditions. Siemens performed the stochastic analysis for the Company and utilized the Aurora model (a capacity expansion model with the added capability to run stochastic studies) to generate results from 200 different draws from the key drivers’ probability distributions. For each of the portfolios analyzed, the portfolio’s average present value was determined as well as its economic risk. The present value is similar to the NPVRR reported from the optimization runs. It represents the portfolio’s costs over the study period. The economic risk, which represented the risk of having a high-cost portfolio, was calculated by taking the average cost of the highest 5% of the draws for each resource plan. The stochastic analysis’ goal was to minimize both the average portfolio cost and the economic risk. The key drivers were characterized as probability distribution functions using a combination of historical measures of volatility, market correlations, and expected future relationships between the assumptions. In our stochastic modeling, load growth, natural gas and coal prices, the price of carbon used for analytic purposes and the cost of generating technologies all were evaluated with probability distributions. More details are shown in Section 15.10.

Resource adequacy

Resource adequacy modeling ensures that DTE Electric has enough resources to serve its customers in all hours of the year with the Company’s fleet specified in the PCA. The resource adequacy modeling is a form of stochastic modeling. Resource adequacy is related to reliability and ensuring the Company’s fleet has enough resources to meet its customer’s needs. If the DTE Electric fleet was not “resource adequate” to a target reliability standard, there is a higher probability of customer interruptions i.e., load shed, due to lack of supply. Resource adequacy is measured in units of Loss of Load Expectation (LOLE). The MISO standard for LOLE as well as the standard of many other Independent System Operators (ISO) in North America is one day in 10 years, or 0.1 LOLE. In addition, an extreme weather adjustment was made to quantify the changes in LOLE that would result from increasing the number of hot days per year. The resource adequacy analysis used 6,150 draws to thoroughly test the resource adequacy of the PCA under a variety of load and resource availability combinations. More details are shown in Section 15.11

Evaluation of key IRP inputs

The IRP inputs (e.g., capital costs, market prices, fuel price forecasts, etc.) were adopted between November 2021 and February 2022, before the optimization models were built. Before the filing, in August 2022, most of the inputs were reviewed to determine if they had changed materially since the initial adoption. In addition, there were a few emerging industry issues that were considered, such as the IRA tax credits on renewables technologies, batteries, and carbon capture and sequestration. The decision on whether to update an input was based on how materially different the input was, and whether the scenarios and sensitivities that had been run could address the identified change and known challenges to updating the IRP modeling. This process is described in detail in Section 15.12.

Portfolio metric evaluation

The portfolio metric evaluation was a quantitative evaluation of several alternative portfolios considered that were evaluated for the PCA, using four different quantitative measures. In the Company's analysis, portfolios were analyzed in the areas of:

- Capacity position with and without a 500 MW uncertainty band.
- Diversity.
- Economic stochastic with and without the IRA tax credits.
- Total CO_2 reduction.

The portfolios selected for analysis consisted of the same plans evaluated in the economic stochastic risk analysis. Results of this method are included in Section 15.13.

Scenario and global sensitivity analysis

Scenario and global sensitivity analysis is a method of risk assessment. This is covered at length in Section 6, with results provided in Sections 15.1 through 15.8.

5.4 Environmental justice analysis

The purpose of the environmental justice (EJ) analysis is two-fold. First, the EJ analysis evaluates the environmental and health impacts of certain portfolios, thereby informing DTE Electric's modeling and planning process by providing a comparative view of the potential environmental and public health impacts on certain communities under various alternatives studied. Second, the EJ screening and analysis ensure the advisory opinion of Department of Environment, Great Lakes, and Energy (EGLE) in the utility IRP cases is supported by an environmental and health impact analysis. Results are provided in Sections 18.5 and 18.6.

5.5 Financial analysis

The financial analysis consists of several modeling efforts. The first is a rate impact analysis. The revenue requirement associated with the Company's proposed PCA will be recovered in DTE Electric's future general rate cases, related energy waste reduction and renewable energy program proceedings, and power supply cost recovery filings. The analysis demonstrates the total impact of the Company's PCA on customer rates for residential, secondary, primary and other. The second modeling effort relates to an updated financial compensation mechanism (FCM) for future power purchase agreements (PPAs) and the appropriateness of the after-tax weighted average cost of capital within the incentive. The third analysis relates to different approaches including accelerated depreciation, securitization or a regulatory asset to address the net book value of coal-fired assets that are retiring during the study period. Refer to Section 16 for additional information.

5.6 Grid reliability modeling

DTE Electric engaged ITC Transmission, the local transmission owner, to collaborate on the IRP's grid reliability studies. DTE Electric requested an analysis of the ITCT and METC transmission systems due to the potential changes to DTE Electric's generation fleet, based on alternative retirement dates for the Monroe and Belle River power plants and other known changes in the state. The analysis was designed to include both generation and transmission considerations in the IRP process and identify potential transmission implications to support the alternative retirement dates. The analysis by ITC was also designed to determine the nature and extent of transmission planning violations (e.g., voltage levels not meeting specified criteria) associated with changes in the generation resources (within Zone 7), as well as estimates of the costs to resolve such violations and to interconnect new generation sources. In addition, the Company asked ITC to study potential transmission options that could impact the utility's IRP by increasing import or export capability.

Endnotes

1. With respect to the gas price forecasts, Siemens developed the long-term gas price forecast in the reference and high electrification scenarios. The required scenarios as well as the stakeholder-developed scenario used the publicly available 2021 EIA long-term gas price forecast, and the REFRESH scenario used the 2022 EIA long-term gas price forecast.

SECTION 6

6 IRP scenarios and sensitivities

6.1 Scenarios

Scenarios are made up of driving forces that shape and define different paths to the future. They contain key uncertainties that are critical to help construct and differentiate among the scenarios. These are generally broad market assumptions such as commodity prices, technology costs, load growth and environmental regulations. While scenarios help us to frame a particular future, the true future still remains uncertain and difficult to predict. The Michigan Integrated Resource Planning Parameters (MIRPP), Section 6(t) of 2016 PA 341, provided three required scenarios, all of which utilize the 2021 EIA gas-price forecast: business as usual (BAU), emerging technologies (ET) and environmental policy (EP). Based on the CO_2 Executive order, pursuant to the Commission's order in Case No. U-20633, the carbon reduction (CR) scenario was also completed. The Company developed additional scenarios - Reference (REF), Reference Refresh (REFRESH) and High Electrification (HE), that incorporated the Company's viewpoint of the future based on research and forecasts. The Company also provided stakeholders the opportunity to develop a scenario (STAKE). Exploring these eight scenarios, incorporated with numerous sensitivities, ensured that the resulting DTE Electric 2022 IRP would provide the optimal solutions to the Company's future demands for electricity in a range of potential futures.

All alternative technology costs for the scenarios were taken from publicly available sources. In terms of unit-retirement assumptions, the starting point for each scenario used DTE Electric's announced coal-retirement plan from the 2019 IRP, and any updates since that time, which included the Belle River Power Plant retiring in 2028 and the Monroe Power Plant by 2040. The starting point for renewable energy builds, energy waste reduction, and demand response levels across all scenarios is described in Sections 8 and 9. Finally, in each scenario the starting point assumed renewal of all existing Public Utility Regulatory Policies Act of 1978 (PURPA) contracts.

Reference (REF): This scenario most closely matched the Company's internal planning assumptions, forecasts and goals/aspirations. It utilized the Company's gas forecast and incorporated its CO_2 and clean-energy goals as a starting point. It included a CO_2 price starting at approximately $5 per ton in 2027, continuing up to $11 per ton in 2040 (real $2020).

Business as usual (BAU): In this scenario, thermal and nuclear generation retirements in the modeling footprint were driven by a maximum-age assumption, public announcements or economics. Demand and energy remained at low growth rates. The BAU gas forecast was based on the 2021 Annual Energy Outlook from the U.S. Energy Information Administration, "Natural Gas: Henry Hub Spot Price: Reference Case." (2021 EIA gas forecast). No CO_2 price was applied.

Emerging technology (ET): This scenario assumed that technological advancements and economies of scale would result in a 35% reduction in capital costs for demand response, energy waste reduction, storage and solar. Retirements of Belle River and Monroe coal units were considered. The 2021 EIA gas forecast was used for this scenario. No CO_2 price was applied.

Environmental policy (EP): This scenario assumed tighter carbon regulation by targeting a 30% CO_2 reduction by 2030. Coal units were retired based first on carbon emissions, then economics. The wind and solar capital costs were assumed to decline by 35%. All other technologies costs were unchanged from the BAU scenario. The 2021 EIA gas forecast was used, as well as no CO_2 price, to achieve the specified 30% CO_2 reduction.

Carbon reduction (CR): This scenario was based on the environmental policy scenario and high load growth. It tested two sensitivities for specific CO_2 reductions in 2025 at 28% and 32%.

High electrification (HE): This scenario assumed EV sales are consistent with the MI Healthy Climate Plan (50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales are electric by 2030).

Stakeholder (STAKE): The Stakeholder scenario reflected the draft Michigan Healthy Climate Plan and various other assumptions including:

- 2% per year EWR through 2042.
- 100% carbon neutrality by 2050; approximately 80% CO_2 reduction by 2030 in Michigan.
- 50% Michigan Renewable Portfolio Standard (RPS) by 2030.
- All coal retired by 2035 for the entire Eastern Interconnect.
- Retirement of Belle River Units 1 and 2 in 2025 and 2026, respectively.
- Retirement of Monroe by 2035 (Units 3 and 4 in December 2028 and Units 1 and 2 in December 2034)
- No new gas units, including RICE, combustion turbines, and combined cycle gas turbines with carbon sequestration and storage (green Hydrogen (H_2) fueled peakers were available in the optimization for selection) (both DTE Electric and rest of Zone 7).
- High electric vehicle demand including 50% of light-duty sales, 30% of medium duty sales, and 100% of bus sales are electric by 2030 in Michigan.
- NREL advanced costs for renewables and batteries.

Reference Refresh (REFRESH): This scenario was completed to update various assumptions that changed since the REF scenario was developed in December 2021. With the increase in gas prices, this scenario reflected more recent natural gas forward pricing and associated energy market prices. In August 2022, the recently approved Inflation Reduction Act (IRA) extended and created new tax credits for clean energy resources such as wind, solar, storage and carbon capture. This scenario incorporated the investment and production tax credits for the respective technologies included in the IRA.

Table 6.1.1: Scenario summary

Scenarios	Reference (REF)	MIRPP (BAU, ET, EP, and CR)	Stakeholder (STAKE)	High Electrification (HE)	Reference Refresh (REFRESH)
Description	Uses DTE Electric's forecast on fuel costs. Assumes current retirement schedule and Company's environmental goals	Utilizes 2021 EIA as gas forecast and no CO_2 price. Existing fleet is largely unchanged.	Uses advanced NREL capital costs of renewables and storage	Same as REF, but assumes higher growth of electric vehicle demand	Incorporates updated natural gas prices and associated wholesale energy prices as well as tax credits from the IRA
CO_2 Assumption	CO_2 price based on DTE Electric CO_2 goals. \$5/ton starting in 2027.	No CO_2 price applied	No CO_2 price applied	Same as REF	Same as REF
Gas Prices	Uses DTE Electric fuel forecast and transitions to Siemens forecast.	Uses DTE Electric fuel forecast and transitions to 2021 EIA gas-price forecast	Uses DTE Electric fuel forecast and transitions to 2021 EIA gas-price forecast	Same as REF	Uses DTE Electric's current fuel forecast and transitions to 2022 EIA gas-price forecast
Capital Costs	Public sources	Sensitivities utilizes optimistic views on capital costs of wind, solar, battery, EWR, and DR	Public sources, utilizes advanced NREL capital costs of renewables and storage	Same as REF	Same as REF
EWR Cost Assumptions	Consistent with Potential Study	Consistent with Potential Study; sensitivity with capital costs decreased by 35% from the Potential Study	2% EWR	Same as REF	Same as REF
Renewables	50% clean energy goal (renewable and EWR)	35% clean energy goal (renewable and EWR)	50% Michigan RPS by 2030	Same as REF	Same as REF

Because each scenario had different market assumptions, the resulting forecast for energy and capacity prices varied. Described on the following pages is the methodology utilized to determine the energy and capacity-price forecasts associated with each scenario.

Energy price

The energy market prices used in the IRP model were determined by blending the energy market forward pricing with the fundamental forecast in years 2023-2025 to smoothly shift to the fundamental energy price forecast in 2026. The blending methodology applied a ratable adjustment between the forward prices and the fundamental forecast. The forwards are a short-range outlook that represents what is happening in markets today and for two to three years into the future. Energy price fundamental forecasts typically take a longer-term view and are more representative of what is forecasted to happen in the mid-to-long term (2026-2042). Siemens based the long-range fundamental forecast market prices on projected gas prices and changes in the generation fleet in various regions, based on economics and forecasted regulations for each scenario. The resulting prices on an annual basis are shown in Table 6.1.2.

Table 6.1.2: Annual energy price forecasts ($/MWH)

		Reference Scenario	MIRPP Scenarios (EIA)	High Gas Sensitivity (EIA High Gas)	Stakeholder Scenario	High Electrification Scenario	Refresh
2023	Transition	39.80	39.75	42.36	39.98	39.64	50.20
2024	Transition	38.97	38.54	45.80	38.94	38.13	43.65
2025	Transition	37.77	36.07	46.06	35.84	36.42	41.34
2026	Siemens	37.45	37.17	49.16	36.96	35.92	42.32
2027	Siemens	41.82	37.57	48.50	41.57	39.70	44.01
2028	Siemens	42.21	38.96	49.20	41.91	40.53	41.62
2029	Siemens	43.83	43.01	53.56	45.92	45.05	44.85
2030	Siemens	46.70	44.18	54.94	46.00	48.43	46.88
2031	Siemens	47.15	44.73	56.07	46.66	48.26	49.20
2032	Siemens	45.93	44.48	55.46	47.24	47.22	48.40
2033	Siemens	47.96	45.93	58.40	48.21	48.38	49.95
2034	Siemens	48.45	46.76	60.47	49.31	50.18	49.44
2035	Siemens	50.78	48.07	64.83	55.40	51.37	51.89
2036	Siemens	50.37	49.18	66.57	54.97	53.38	52.30
2037	Siemens	52.30	49.00	69.75	56.19	55.90	52.73
2038	Siemens	52.23	49.13	69.63	54.66	58.83	54.34
2039	Siemens	52.86	50.53	71.52	56.92	60.92	54.94
2040	Siemens	61.89	51.16	76.73	58.64	71.37	64.11
2041	Siemens	64.08	53.03	80.15	63.00	77.94	66.10
2042	Siemens	68.77	52.82	80.23	61.51	83.86	69.03

(REFRESH did not use transition method)

Capacity prices

Siemens calculated the capacity-price forecast as part of the fundamental modeling for each scenario, or high-gas and high-CO_2 market sensitivity. In the IRP optimization modeling, no credit was given when excess capacity was available to theoretically sell into the market. For more details, see Appendix F, Exhibit A-3.2. Table 6.1.3 represents nominal $/kW capacity prices.

Table 6.1.3: Capacity-price forecasts ($/kW)

Year	Reference Scenario	MIRPP Scenario (EIA)	High Gas Sensitivity (EIA High Gas)	Stakeholder Scenario	High Electrification Scenario	Refresh Scenario
2023	18.93	29.73	18.93	32.05	18.93	21.30
2024	43.29	48.32	43.29	49.96	43.29	49.18
2025	45.56	47.87	45.56	51.43	45.56	52.45
2026	49.43	57.00	49.43	61.44	49.43	57.15
2027	55.52	57.18	55.52	61.62	55.52	64.08
2028	53.76	54.79	53.76	50.80	53.76	61.39
2029	56.30	58.08	56.30	61.92	56.30	64.77
2030	56.30	58.44	56.30	55.14	56.30	65.15
2031	55.66	57.73	55.66	54.46	55.66	65.44
2032	56.00	58.75	56.00	49.56	56.00	65.86
2033	56.23	59.09	56.23	48.81	56.23	66.33
2034	56.17	60.59	56.17	47.21	56.17	66.94
2035	56.37	61.16	56.37	62.58	56.37	67.47
2036	56.98	61.58	56.98	63.16	56.98	68.20
2037	57.49	62.36	57.49	64.07	57.49	68.91
2038	57.39	61.61	57.39	64.71	57.39	69.02
2039	58.85	63.76	58.85	64.68	58.85	70.82
2040	59.29	64.55	59.29	66.35	59.29	71.97
2041	60.05	65.27	60.05	67.33	60.05	72.79
2042	60.83	66.26	60.83	68.16	60.83	74.02

6.2 Sensitivities

Sensitivities, as compared to scenarios, are generally designed to test one specific uncertainty. The Michigan Integrated Resource Planning Parameters, Section 6t of 2016 PA 341, provided several required sensitivities. Each scenario has a starting point with no sensitivities applied. Then, each sensitivity was applied to the appropriate scenarios. A sensitivity typically changes one variable from the starting point. The sensitivities are described below.

Load: The starting point was the Company's forecasted load. Nine alternative load forecasts were developed including:

1. High load growth: Required based on the Michigan Integrated Resource Planning Parameters (MIRPP) requirements to assess the impacts of either double the growth present in the starting point or a 1.5% growth rate on energy and peak demand.
2. Return of 50% Retail Choice load: Required based on the MIRPP requirements to model the return of 50% of the retail choice load to the utility's capacity service by 2023.
3. Aggressive customer-owned distributed generation: Performed to assess the impacts of higher penetration levels of behind-the-meter solar photovoltaics.
4. High electrification: Modeled to understand the impacts of higher adoption rates of electric vehicles and heat pumps in the Company's service area.
5. Stakeholder: Developed through the stakeholder collaboration process to assess the impacts of higher adoption of electric vehicles.
6. Stakeholder with 25% distributed generation growth through 2030: Developed through the stakeholder collaboration process to assess the impacts of higher adoption of electric vehicles as well as aggressive customer owned behind-the-meter solar adoption.
7. Stakeholder with high fuel switching: Developed through the stakeholder collaboration process to assess the impacts of higher adoption of electric vehicles as well as high levels of fuel switching in residential and commercial buildings from natural gas end-uses to electric.
8. Electric Choice cap increases to 15%: Developed through the stakeholder collaboration process to assess the impacts of increasing the retail open access cap from 10% to 15%.
9. Climate change: Performed to assess the impacts rising trends in temperature would have on energy and peak demand.

Energy waste reduction: Several levels of energy waste reduction were tested as sensitivities. The starting point assumption was based on the 2021 Statewide Potential Study, with sensitivities representing 1.50%, 2.0%, 2.0% until 2033, 2.50%, and 3.0%.

EWR cost levels: In the REF scenario, EWR costs were assumed to reflect the costs in the 2021 Statewide Potential Study. The ET scenario assumed a 35% reduction in EWR incentive levels from the Potential Study, regardless of what level of EWR is targeted.

Gas prices: The BAU, ET, EP and CR scenarios all used the 2021 EIA forecast as their starting point. A sensitivity for the three MIRPP scenarios was to increase the EIA forecast by 200% to determine the impact of gas prices. The reference and high electrification scenarios used the Company's forecast as its starting point, with no additional sensitivity on gas prices. Additionally, the natural gas price was updated to reflect recent forward pricing in the REFRESH scenario.

Retirement: Seven scenarios used the announced DTE Electric retirement plan as their starting point. Several early retirement analyses were modeled as sensitivities on various scenarios, but mainly the REF scenario. (Results of these sensitivities are covered in Section 15.)

Lithium-ion battery: A sensitivity that was performed on the ET scenario included additional benefits for storage. Additionally, there was a sensitivity requested by stakeholders to include a battery standard, bringing a certain amount of storage online throughout the study period.

Carbon price: The REF scenario's starting point has a $5/ton price for carbon in 2027, which reaches ~$11/ton in 2040 (real $2020). The BAU, ET and EP scenarios' starting points have a constant $0/ton carbon price across all years. There was a carbon-price sensitivity that increases the carbon price by $2.50/ton.

Available replacement: The BAU scenario included a sensitivity where only combustion turbines (CT) were allowed as the replacement resource.

Additional sensitivities: Additional sensitivities were run on relevant scenarios, including the impact of market purchases, ancillary services and thermal ELCCs. The details and the results of all these runs are in Section 15.

6.3 Sensitivities submitted by stakeholders

Along with developing a consensus around the assumptions within the stakeholder scenario, the Company's external stakeholders also developed sensitivities to be performed on this scenario. There were 12 sensitivities requested by stakeholders which included:

1. Retire two Monroe units by Dec. 31, 2028, and the remaining two units by Dec. 31, 2030.
2. Offer all gas technologies to the model (EIA assumptions).
3. Update reciprocating internal combustion engine (RICE) technology capital costs to ~$890/kW and offer all gas technologies to the model.
4. Constrain to 80% CO_2 reduction by 2030.
5. 3% per year EWR.
6. 3% per year EWR and additional building heat fuel switching.
7. 25% annual growth of DG from 2023-2030; 15% annual growth 2031-2042.
8. Double voluntary green pricing by 2025.
9. Battery installation standard of 482 MW by 2025; 1,205 MW by 2030; and 1,928 MW by 2040.
10. Combine sensitivities 1 and 9 and include 10% DG solar by 2030.
11. Retire two Monroe units by December 31, 2028 and the remaining two units by December 31, 2030, and include four hydrogen-fueled CTs in 2031
12. Retire two Monroe units by December 31, 2028, and the remaining two units by December 31, 2030, convert Belle River to natural gas and include two hydrogen-fueled CTs in 2040.

Additionally, during its first technical conference, the Company asked its stakeholders for input on sensitivities to run. A total of four sensitivities were submitted incorporating a range of variables:

1. Retail Choice cap increasing from 10% to 15% by June 1, 2024. (Performed on the BAU scenario).
2. Evaluate different levels of capacity prices. (The Company determined this sensitivity was unnecessary as the model does not allow capacity market purchases nor does it allow excess capacity to sell into the market.)
3. 50% decrease in gas prices. (The Company determined this sensitivity was unnecessary, as gas-fueled units are economic in its scenarios.)
4. CO_2 prices of $2.50/ton in 2025, increasing by $2.50/ton each year. (Performed on the REF and STAKE scenarios).

SECTION 7

Existing supply-side resources

7.1 Overview

DTE Electric has a diverse fleet of generation consisting of 24/7 baseload coal and nuclear power plants, natural-gas and oil-fired peaking units, pumped storage, and wind and solar parks. In addition, DTE Electric has entered into several power purchase agreements, most sourced with renewable generation. The following sections provide detail on the Company's existing supply-side resources.

7.2 Fossil-fueled generating units

Belle River Power Plant sits near the St. Clair River in both East China Township and China Township, Michigan. DTE Electric co-owns the plant with the Michigan Public Power Authority (MPPA), a consortium of 22 municipalities that aggregate to provide for the electrical needs of their customers. Belle River is a two-unit plant; Unit 1 was placed into service in 1984 and Unit 2 began commercial operations in 1985.

MPPA has an ownership position equal to 18.61% of the plant and so is entitled to 18.61% of the total plant electrical capacity and energy output. It pays 18.61% of all costs.

Each unit has a Company-owned net demonstrated capacity rating of 517 MW. The 2017-2021 average capacity factor for Unit 1 was 54% and 59% for Unit 2. Both units

Table 7.2.1: Coal-Fired Units

Generation unit name	Commercial operation date	Age (Years)	Starting point planned retirement year	Starting point planned remaining life (Years)	NCF (%) 2017 - 2021	Summer capacity rating (MW)
Belle River Power Plant - Unit 1	1984	38	2028	6	54	517
Belle River Power Plant - Unit 2	1985	37	2028	6	59	517
Monroe Power Plant - Unit 1	1971	51	2039	17	56	758
Monroe Power Plant - Unit 2	1973	49	2039	17	53	773
Monroe Power Plant - Unit 3	1973	49	2039	17	59	773
Monroe Power Plant - Unit 4	1974	48	2039	17	56	762

1. Converted Belle River Power Plant is projected to retire by 2040.
2. Monroe Units 1 and 2 are projected to retire in 2035.
3. Monroe Units 3 and 4 are projected to retire in 2028.

are coal-fired and utilize low-sulfur western (LSW) coal as their primary fuel source. Fuel oil is also utilized for unit startup and can serve as a supplemental fuel source during peak load conditions. The units are equipped with multiple emission-control technologies, including low NO_2 burners, over-fire air (OFA) systems, electrostatic precipitators (ESPs), dry sorbent injection (DSI) and activated carbon injection (ACI).

Monroe Power Plant is in Monroe, Michigan, along Lake Erie. It is a four-unit, supercritical coal-fired steam plant whose units were sequentially placed into service between 1971 and 1974. Unit net demonstrated capacity ratings for Units 1-4 are 758 MW, 773 MW, 773 MW and 762 MW, respectively. The 2017-2021 average capacity factor for Unit 1 was 56%, 53% for Unit 2, 59% for Unit 3 and 56% for Unit 4. The units' primary fuel source is coal. They also use fuel oil for unit startup and as a supplemental fuel source during peak load conditions.

Monroe blends various coal types based on electrical and fuel-market pricing dynamics. The units are equipped with multiple emission-control technologies, including low NO_2 burners, over-fire air (OFA) systems, electrostatic precipitators (ESPs), flue gas desulphurization (FGD) scrubbers and selective catalytic reduction systems.

DTE Electric owns both oil- and gas-fired generating units, which are shown in Tables 7.2.2 and 7.2.3.

The 2017–2021 average capacity factor for the peaking units was approximately 7%.

Blue Water Energy Center (BWEC) is located near the St. Clair River in East China Township, Michigan, on property adjacent to the Belle River Power Plant. BWEC is a combined cycle natural gas turbine power plant that began operation in June 2022. The plant is designed to have a net demonstrated capacity of 1,127 MW and is designed to have an availability exceeding 95%.

The plant is comprised of two state-of-the-art, highly efficient

Table 7.2.2: Oil-fired units

Generation unit name	Fuel	Commercial operation date	Age (Years)	Number of units	Summer capacity rating (MW)
Belle River Power Plant Peaker 11-1 / 11-5	Oil	1981	41	5	14
Colfax Peaker 11-1 / 11-5	Oil	1969	53	5	14
Enrico Fermi Power Plant - Peaker 11-1	Oil	1966	56	1	13
Enrico Fermi Power Plant - Peaker 11-2	Oil	1966	56	1	13
Enrico Fermi Power Plant - Peaker 11-3-[1]	Oil	1966	56	1	13
Enrico Fermi Power Plant - Peaker 11-4-[1]	Oil	1966	56	1	12
Monroe Power Plant - Peaker 11-1 / 11-5	Oil	1969	53	5	14
Northeast Peaker 13-1	Oil	1971	51	1	19
Northeast Peaker 13-2	Oil	1971	51	1	20
Oliver Peaker 11-1 / 11-5	Oil	1970	52	5	14
Placid Peaker 11-1 / 11-5	Oil	1970	52	5	14
Putnam Peaker 11-1 / 11-5	Oil	1970	52	5	14
River Rouge Power Plant Peaker 11-1 / 11-4-[1]	Oil	1967	55	4	11
Slocum Peaker 11-1 / 11-5-[1]	Oil	1968	54	5	14
St. Clair Power Plant - Peaker 12-1 / 12-2-[1]	Oil	1970	52	2	5
Superior Peaker 11-1	Oil	1966	56	1	13
Superior Peaker 11-2	Oil	1966	56	1	13
Superior Peaker 11-3	Oil	1966	56	1	12
Superior Peaker 11-4	Oil	1966	56	1	14
Wilmot Peaker 11-1 / 11-5	Oil	1968	54	5	14

1. Fermi 11-3 / 11-4, River Rouge 11-1 / 11-4, Slocum 11-1 / 11-5, and St. Clair 12-1 / 12-2 are projected to retire in 2024.
All other units were assumed to remain operational throughout the study period.

natural-gas-fired H-Class turbines to produce electricity. Waste heat from the gas turbines is captured in heat recovery steam generators (HRSG) and used to power a steam turbine that produces additional electricity. Emissions will be mitigated using a multi-pollutant catalyst and low NOx producing gas turbine design features. BWEC is the most efficient power plant in the state producing reliable, low-emission electricity.

Greenwood Energy Center is located in Avoca Township, Michigan. It is a single unit natural gas-fired steam plant that was commissioned in 1979 with a net demonstrated capacity of 785 MW. The unit utilizes natural gas as its primary fuel source for electrical generation and is used in a peaking capacity by the Company due to its design characteristics and fuel cost. The 2017-2021 average capacity factor for Greenwood Unit 1 was 10%. Oil fuel is utilized for unit startup. The unit is equipped with low NOx burners and over-fire air OFA systems for emissions control.

7.3 Nuclear generating units

DTE Electric owns and operates the Enrico Fermi 2 Power Plant in Frenchtown Township, Michigan. It is a boiling water reactor with a net demonstrated capacity rating of 1,141 MW. The plant was

Table 7.2.3: Gas-fired units

Generation unit name	Fuel	Commercial operation date	Age (Years)	Number of units	Summer capacity rating (MW)
Belle River Power Plant Peaker 12-1	Gas	1999	23	1	75
Belle River Power Plant Peaker 12-2	Gas	1999	23	1	75
Belle River Power Plant Peaker 13	Gas	1999	23	1	74
Blue Water Energy Center	Gas	2022	0	2 CT, 1 ST	1,127
Dean Peaker 11-1	Gas	2002	20	1	78
Dean Peaker 11-2	Gas	2002	20	1	78
Dean Peaker 12-1	Gas	2002	20	1	78
Dean Peaker 12-2	Gas	2002	20	1	78
Dearborn Energy Center	Gas	2019	3	2 CT, 1 ST	34
Delray Peaker 11-1	Gas	2000	22	1	64
Delray Peaker 12-1	Gas	2000	22	1	63
Greenwood Energy Center - Peaker 11-1	Gas	1999	23	1	75
Greenwood Energy Center - Peaker 11-2	Gas	1999	23	1	75
Greenwood Energy Center - Peaker 12	Gas	1999	23	1	74
Greenwood Energy Center - Unit 1	Gas	1979	43	1	785
Hancock Peaker 11-1	Gas	1967	55	1	11
Hancock Peaker 11-3	Gas	1967	55	1	17
Hancock Peaker 12-1	Gas	1970	52	1	32
Hancock Peaker 12-2	Gas	1966	56	1	33
Northeast Peaker 11-1[1]	Gas	1966	56	1	15
Northeast Peaker 11-2	Gas	1966	56	1	15
Northeast Peaker 11-3	Gas	1966	56	1	14
Northeast Peaker 11-4	Gas	1966	56	1	15
Northeast Peaker 12-1	Gas	1971	51	1	18
Renaissance 1	Gas	2002	20	1	163
Renaissance 2	Gas	2002	20	1	163
Renaissance 3	Gas	2002	20	1	163
Renaissance 4	Gas	2002	20	1	163
St. Clair Power Plant - Peaker 11-1	Gas	1968	54	1	19

1 Northeast 11-1 is projected to retire in 2023. All other units were assumed to remain operational throughout the study period.

commissioned in 1988 and received a 20-year license renewal in 2016, allowing the unit to continue operating through at least 2045. During 2017-2021, the plant operated at an 81% average capacity factor.

7.4 Hydroelectric generating units

DTE Electric owns 49% of the Ludington Pumped Storage facility, which is discussed in more detail in Section 7.6. The Company also has contracts in place to purchase power from four small hydroelectric facilities within the state. Information regarding these facilities and the respective contracts are included in Section 7.7.

7.5 Renewable generating units

As of 2022, DTE Electric's portfolio of owned and contracted renewable generating assets exceeds 1,862 MW, including assets to meet the renewable portfolio standard (RPS) and serve Voluntary Green Pricing (VGP) programs. Renewable energy resources owned by the Company are described in this section and those under contract are described in later sections. All company-owned renewable assets were assumed to remain in operation throughout the study period (2023-2042).

The Company owns 12 wind parks in Michigan, with a combined capacity of 1,236 MW, including assets for the RPS and those serving VGP programs. The parks' nameplate capacities range from 14 MW to 200 MW, and the fleet consists of 567 wind-turbine generators. Meridian Wind Park, expected in service at the end of 2022, completes the Company's RPS portfolio with an installed capacity of 225 MW and 77 installed wind turbines. Table 7.5.1 provides detailed information about DTE Electric-owned wind parks.

DTE Electric also has entered into six wind Power Purchase Agreements (PPAs) with renewable projects, with a combined capacity of 458 MW. (The agreements are in Section 7.7). DTE

Table 7.5.1: DTE Electric-owned wind

Park Name	Location	Commercial operation date	Wind turbines	Turbine size	Capacity factor (%)	Installed capacity (MW)
Gratiot Wind Park	Central, MI	2011	64	1.6	27.7	102.4
Minden	Thumb, MI	2013	20	1.6	40.3	32
McKinley	Thumb, MI	2013	9	1.6	41.3	14.4
Sigel	Thumb, MI	2013	40	1.6	44.5	64
ECHO	Thumb, MI	2014	70	1.6	39.6	112
Brookfield	Thumb, MI	2014	44	1.7	38.7	74.8
Pinnebog	Thumb, MI	2016	30	1.7	38.4	51
Pine River	Central, MI	2019	65	2.3 / 2.5	28	161.3
Polaris	Central, MI	2020	68	2.3 / 2.5	31.5	168.6
Isabella 1	Central, MI	2021	71	2.822[1]	28.2[2]	200.2
Isabella 2	Central, MI	2021	65	2.82[2]	28.2[2]	183.3
Fairbanks	Garden, MI	2022	21	3.45	39	72.5

1 Based on historical performance
2 Forecasted capacity factor with no curtailment

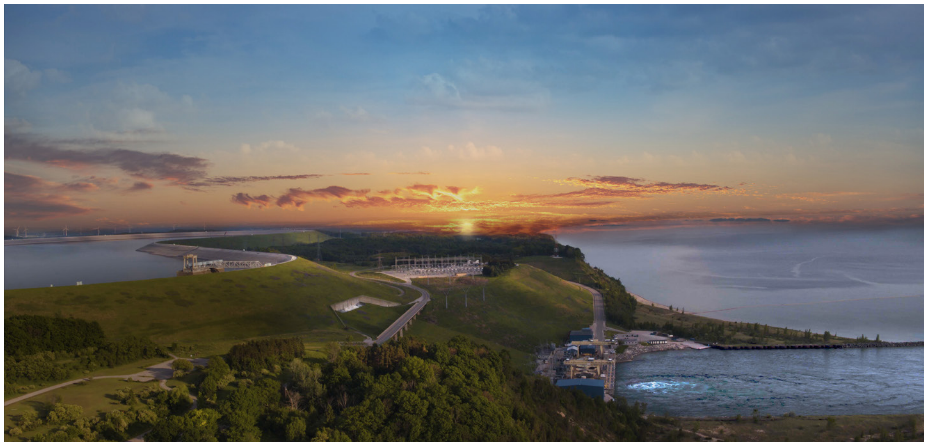


Table 7.5.2: DTE Electric-owned solar

Park Name	Location (county)	Commercial operation date	Capacity factor[1] (%)	Capacity (MWAC)
SCIO Solar Array	Washtenaw	2010	14.2	0.056
Blue Cross Blue Shield	Wayne	2011	11.6	0.2
Monroe County Community	Monroe	2011	11.1	0.5
Ford Solar Array	Wayne	2011	12.3	0.5
DTE Training and Development Center	Wayne	2011	13	0.38
General Motors Solar Array	Wayne	2011	13.3	0.5
DTE Headquarters (DECo Project #3)	Wayne	2012	11.3	0.081
Mercy High School	Oakland	2012	12.1	0.375
Warren Consolidated Schools	Macomb	2012	10.5	0.189
General Motors Orion Assembly	Oakland	2012	14.9	0.3
Huron Clinton Indian Springs Metro Park	Oakland	2012	12.6	0.495
Wil-Le Farms	Huron	2012	10.8	0.484
Immaculate Heart of Mary	Monroe	2012	13.6	0.5
University of Michigan - North Campus Center	Washtenaw	2012	13.4	0.43
University of Michigan - Institute of Science	Washtenaw	2013	13.1	0.241
Riopelle Farms	Huron	2013	13	0.503
St. Clair RESA	St. Clair	2013	13.4	0.503
Leipprandt Orchards	Huron	2013	13.2	0.503
Hartland Schools	Livingston	2013	12.6	0.444
McPhail	Oakland	2014	13.8	0.75
Domino Farms	Washtenaw	2015	14.1	1
Thumb Electric Cooperative	Tuscola	2015	14.5	0.603
Ford World Headquarters	Wayne	2015	11.9	0.75
Ashley / Romulus	Wayne	2015	12.4	0.684
Brownstown	Wayne	2016	14.2	0.5
Greenwood Energy Center	St. Clair	2016	17.8	1.392
Ypsilanti	Washtenaw	2016	16.6	0.672
General Motors Transmission Plant	Macomb	2016	16.2	0.744
Demille Rd	Lapeer	2017	15.2	28
Turrill Rd	Lapeer	2017	15.2	20
O'Shea Park	Wayne	2017	14.8	2
Ford Rooftop Solar	Wayne	2021	17.2	0.75

1 Based on historical performance

Electric receives the renewable energy credits produced by these parks for use in complying with Michigan's renewable portfolio standard.

In addition to the wind portfolio, the Company owns and operates a diverse set of solar assets across Michigan totaling 65 MWac. Since 2010, DTE Electric has experimented with various technologies and approaches to building solar, and has worked with its partners at array host sites to educate the community about solar energy. The sites in the Company's portfolio range in size from less than 100 kWac to 29 MWac. The sites' designs vary and include ground-mount, roof-mount and carport panels. Company-owned solar parks are shown in Table 7.5.2.

7.6 Energy storage facilities

The Ludington Pumped Storage facility is in Ludington, Michigan, alongside Lake Michigan. It is a six-unit hydroelectric power plant. The plant is co-owned by DTE Electric and Consumers Energy (CE); DTE Electric owns 49% and CE owns 51%. CE, as the majority owner, is also the operating authority. The power plant was commissioned in 1973 and received a 50-year license renewal in 2019. Ludington Power Plant's 2017-2021 average capacity factor was 12%. The net demonstrated capacity of the plant portion owned by DTE Electric is 1,122 MW.

Ludington can act as a 1,122 MW storage system and provides a great opportunity to support the announced renewable energy resources that will grow in Michigan's bulk electric system. Ludington operates by pumping water up from Lake Michigan into a reservoir when power prices are low, and then generates energy by releasing the water through turbines back into Lake Michigan when customer demand increases or generation from intermittent resources decreases and electricity prices increase. When weather conditions disrupt renewables generation, Ludington can ramp up to provide generation quickly, thus smoothing the impact of renewable resources and providing a flexibility benefit.

7.7 Power purchase agreements

In addition to owned resources, DTE Electric has entered into various power purchase agreements (PPAs) that have been approved by the MPSC under Public Act (PA) 2/PURPA and PA 295/342:

- The Public Utility Regulatory Policies Act of 1978 (PURPA) requires electric utilities to purchase power from qualifying facilities (QFs) at the utilities' avoided cost, provide back-up power to QFs, interconnect with QFs, and operate with QFs under reasonable terms and conditions.
- PA 2 of 1989, enacted by Michigan, requires utilities with greater than 500,000 customers to enter into PPAs for both energy and capacity from certain landfill gas and solid waste QFs.
- PA 295 of 2008, enacted by Michigan, required utilities to meet certain renewable energy standards by 2015, and requires 50% of renewable energy credits used for compliance to be sourced from third parties.
- PA 342 of 2016, enacted by Michigan, increases the renewable energy standards from 10% by 2015 to 15% by 2021.

The Company currently has nine PA 2/PURPA contracts and eleven PA 295/342 contracts for both energy and capacity. The Company also receives capacity credit for customer-owned generation in the amount of 2 MW. The Company has capacity rights from both PA 2/PURPA and 2008 PA 295/342 renewable-energy contracts, which are distinct from DTE Electric-owned renewable-energy systems. The Company will receive a total of 159 zonal resource credits in the 2022-23 planning year associated with PPAs (including customer-owned generation). If an existing contract term was set to mature prior to the end of the IRP study period (2042), for modeling purposes, it was assumed to be renewed and continues through 2042, at the respective contract price. The contracts are listed in Tables 7.7.1 and 7.7.2 with their corresponding expiration dates and UCAP values.

Table 7.7.1: PA2 and PURPA contracts

PA 2/PURPA facility	Expiration date	Generation type	UCAP (MW)
Ann Arbor - Barton Dam	4/1/2036	Hydro	0
Ann Arbor – Superior	5/1/2036	Hydro	0
STS French Landing	1/30/2039	Hydro	0.2
Charter Township Ypsilanti	1/1/2028	Hydro	0.5
Riverview Energy Systems	8/13/2027	Landfill gas	4.9
Sumpter Energy Associates (Station #1)	7/13/2033	Landfill gas	19.1
Lyon Electric Generating	9/21/2030	Landfill gas	Combined with Arbor Hills
Turbine Power Limited Partnership - Arbor Hills	6/12/2031	Landfill gas	15.3
Ann Arbor Landfill	4/29/2033	Landfill gas	0.8

Table 7.7.2: PA 295 agreements

PA 295 agreement	Expiration date	Generation type	UCAP (MW)
Heritage Stoney Corners Wind Farm I, LLC	1/1/30	Wind	2.6
Heritage's Garden Wind	1/1/30	Wind	1.1
L'Anse Warden Electric Company, LLC	1/1/32	Biomass	16.9
WM Renewable Energy, LLC	1/1/32	Landfill gas	3
Gratiot County Wind, LLC	1/1/33	Wind	11.7
Blue Water Renewables, Inc.	1/1/32	Biomass	3
Tuscola Bay Wind, LLC	1/1/33	Wind	13.5
Tuscola Wind II, LLC	1/1/34	Wind	12.8
Pheasant Run Wind, LLC	1/1/34	Wind	11.1
Big Turtle Wind Farm, LLC	1/1/35	Wind	2.6
Assembly III Solar, LLC	1/1/47	Solar	40

7.8 Regional Transmission Operator unit capacity credits

In addition to energy, a key benefit of the Company's generating units and PPAs is the provision of capacity. MISO, a Regional Transmission Operator (RTO), grants the Company's generating units and PPAs with capacity credits, also known as zonal resource credits (ZRCs). A summary of the current PY 2022/23 capacity credit for Company-owned generating units is provided in Table 7.8.1.

Table 7.8.1: RTO capacity credits, company-owned

Resource	RTO capacity credits (ZRCs)
Fossil (coal)	3,891
Fossil (gas & oil peakers)	3,606
Nuclear	1,055
Pumped storage	1,030
Owned renewables/ Premium Power	160

7.9 Spot market purchases and off-system sales

DTE Electric operates within the MISO energy market. As part of its function as a load-serving entity within MISO Local Resource Zone 7, the Company purchases wholesale energy from the MISO energy market, as required. The Company also sells energy to the MISO energy market when generating in excess of its customer demand.

SECTION 8

8 Demand-side resources

8.1 Overview

Demand response (DR) programs help reduce or shift enrolled customers' energy use during periods of peak or high demand. The reduction or shift in customer usage from DR programs can provide value to both the utility and all customers by reducing the need for additional generation, resulting in lower energy costs. Customers participating in DR programs can benefit from lower bills and/or incentives when utilizing the programs. If the DR programs are less costly than other capacity resources, the utility and all customers can benefit from displacing or deferring the need for new generation resources.

The Company currently receives capacity credit from MISO for its established DR portfolio, which is a diverse set of programs for residential, commercial, and industrial customers. In addition, the Company continues to invest in various pilots to enhance the current portfolio offerings, as well as leverage new technologies. The goal of the Company's DR programs is to deliver measurable peak demand reduction by engaging customers to manage and shift their energy consumption.

Table 8.1.1 summarizes the DR programs currently available to DTE Electric customers and the associated MW (UCAP[1]) each program claimed in the last capacity demonstration case No. U-21099 as a load modifying resource. Each program is described in more detail in Section 8.2.

Table 8.1.1: Summary of current demand response programs

Demand Response Program	MW (UCAP)
R10 – Interruptible Supply Rider	353
D1.1 – Interruptible Space Conditioning	218
D8 – Interruptible Supply Rate	118
R1.2 – Electric Process Heat	72
Smart Savers (BYOD)	61
R12 – Capacity Release	45
D3.3 – Interruptible General Service	22
D1.8 - Dynamic Peak Prcing	11
R1.1 – Alternative Metal Melting	4
Total	**904**

8.2 Existing DR programs

The following are descriptions of each program within the DR portfolio that are registered as Load Modifying Resources (LMRs) that receive MISO capacity credit.

Interruptible Space Conditioning Rate (D1.1): Commonly referred to as "IAC" or Cool Currents, this program consists of a separately metered service connected to the customer's central air conditioner (A/C) or heat pump and is available to residential and commercial customers. DTE Electric will cycle the A/C condenser by remote control on selected days for intervals of no more than 30 minutes in any hour and no more than eight hours in any day. Company interruptions may include interruptions for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons or when available system generation is insufficient to meet anticipated system load.

Dynamic Peak Pricing (DPP) Rate (D1.8): Residential and commercial customers can choose to take service under this whole-home rate and receive a discounted per kilowatt rate during certain hours of the day and week in exchange for paying a higher rate of $0.95 per kilowatt hour for energy used during Critical Peak Pricing (CPP) event hours. The CPP event attribute of this rate is what is given capacity credit by MISO. The Company can implement CPP events for several factors including, but not limited to, economics, system demand or capacity deficiency. The SmartCurrents[2] program provides additional savings to the customer by providing them with a Wi-Fi enabled thermostat that can be adjusted during CPP events. CPP events are limited to 14 per year and only available on nonholiday weekdays from 3 p.m. to 7 p.m.

Interruptible General Service Rate (D3.3): Commercial secondary customers can elect to have separately metered service that is subject to interruption or establish a portion of their load as firm through the product protection feature. This rate is not available to customers whose loads are primarily off-peak. Company interruptions may include interruptions for but not limited to, maintaining system integrity, making an emergency purchase, economic reasons or when available system generation is insufficient to meet anticipated system load.

Interruptible Water Heating Service Rate (D5): This program is available to customers (both residential and commercial) using hot water for sanitary purposes or other uses subject to the approval of the Company. A timer or other monitoring device controls the daily use of all controlled water heating service. Company interruptions may include interruptions for but not limited to, maintaining system integrity, making an emergency purchase, economic reasons or when available system generation is insufficient to meet anticipated system load. Events can be called for no longer than 4 hours per day.

Interruptible Supply Base Service Rate (D8): Primary voltage customers who desire separately metered service for a specified quantity of demonstrated interruptible load of not less than 50 kW at a single location can take service under this rate. Customers may be ordered to interrupt only when the Company finds it necessary to do so either to maintain system integrity or when the existence of such loads will lead to a capacity deficiency.

Alternative Electric Metal Melting (Rider 1.1): Customers who operate electric furnaces for the reduction of metallic ores and/or electric use consumed in holding operations who provide special circuits can have that load separately metered, making it subject to interruption. The Company may order an interruption to maintain system integrity.

Electric Process Heat (Rider 1.2): Customers who use electric heat as an integral manufacturing process, or electricity as an integral part of anodizing, plating or a coating process, and who provide special circuits, can have that load separately metered, making it subject to interruption. The Company may order an interruption to maintain system integrity.

Interruptible Supply Rider (Rider 10): Rider 10 allows customers to elect the amount of interruption they are willing to take under a separate meter. Program participation is capped at a total of 650 MW of enrolled load. Rider 10 is designed for customers of greater than 50 MW at a single location, but at the Company's discretion, and with available capacity, the minimum site requirements can be waived. The Company may order an interruption to maintain system integrity.

Capacity Release (Rider 12): Customers are provided a capacity release payment by subscribing at least 100 kW of load per site location for interruption The Company may order an interruption to maintain system integrity. The program is only available from June 1 – Sept. 30.

Smart Savers (Bring Your Own Device/ BYOD): Customers who have a Wi-Fi enabled smart thermostat installed can opt to have the Company adjust the thermostat up to 4 degrees during an event in exchange for an annual incentive. The Company can implement Smart Saver events for several factors including, but not limited to economics, system demand or capacity deficiency. Only 14 events can be called between June 1 and Sept. 30 and events are limited to nonholiday weekdays from 12 p.m. to 8:00 p.m. Events are limited to no more than 4 hours at a time.

All dispatchable DR resources are currently registered with MISO as load modifying resources, which are used to help meet capacity requirements for the peak period. Most of the programs maintained by the Company may only be utilized to maintain system integrity (which would include MISO capacity shortages), thus preventing them from economic dispatch in the energy market. Four programs (D1.1, D1.8, D3.3 and Smart Savers) in the Company's DR portfolio can also be deployed when interruption is economically preferable to purchasing energy.

8.3 Demand response pilot programs

DTE Electric is conducting additional DR pilots that follow the MPSC Pilot Guidelines provided in MPSC Case No. U-20645 and encompass residential, commercial, and industrial customers. Based on the results of these pilots and of utility benchmarking efforts, the Company expects to identify other alternative DR programs that may become economic and technically viable alternatives to generation capacity, have an appropriate level of customer adoption potential and are cost-effective for customers. While the Company intends to learn as much as possible through benchmarking of other pilots and programs and leverage the knowledge of vendors who have experience in implementing DR programs, it is considered best practice to conduct actual pilots before launching a new full-scale program. These pilots seek to identify how the Company's unique customer base will react to specific marketing efforts, program design features and other characteristics that are dependent on DTE Electric's unique combination of systems, equipment, tariffs, programs and processes.

The Company designs and executes DR programs to help customers reduce their peak energy use, which provides value to participating customers in the form of savings or other compensation; the utility through reduced capacity needs and lower capacity costs; and all customers through reduced overall system costs. The Company has several successful, long-term programs that support its peak-reduction objectives, and many other pilot efforts through which the Company explores diverse opportunities to engage customers and reduce peak load. However, the Company's DR offerings and customer engagement should not remain static over time, and the continued development of pilots is critical to ensure a pipeline of learnings to support future programs and to present customers with the best program offerings. To support ongoing pilot efforts, the Company needs to remain agile enough to efficiently redeploy DR pilot spending and resources as capacity needs change, customer behaviors evolve, program acceptance is assessed, or other more cost-effective technologies and opportunities arise in the near future. This flexibility will ensure DTE Electric is well positioned to expand existing or future programs to respond to changing market conditions and customer behavior. The Company continues to evaluate alternative programs that may emerge as a result of insights from pilots or utility benchmarking efforts. In the coming years, the Company expects to continue developing new pilots and programs that may become economic alternatives to capacity and have an appropriate level of customer adoption potential.

Current pilots that are currently being evaluated by the Company include an electric vehicle (EV) DR pilot, a residential whole-home generator pilot, a commercial and industrial (C&I) battery storage pilot, peak time savings (PTS) and a C&I dashboard pilot.

8.4 IRP starting point: demand response

DTE Electric has been able to grow the DR portfolio that consists of approved programs above what was forecasted in the 2019 IRP. The starting point is consistent with the 2021 Capacity Demonstration Case No. U-21099, which shows DR MWs growing from 920 MWs (UCAP) in 2023 to 949 MWs (UCAP) in 2026. (See Table 8.4.1.)

Table 8.4.1: Starting point demand response (2023 to 2042)

Year	MW (UCAP)
2023	920
2024	929
2025	929
2026	949
2027	949
2028	946
2029	944
2030	944
2031	944
2032	944
2033	944
2034	944
2035	944
2036	944
2037	944
2038	944
2039	944
2040	944
2041	944
2042	944

8.5 PCA: demand response

No additional DR beyond the current portfolio's growth that the Company is forecasting was selected.

8.6 Energy waste reduction

DTE Electric's energy waste reduction (EWR) program launched in June 2009 as a result of the Clean, Renewable, and Efficient Energy Act, also known as 2008 Public Act (PA) 295. In 2016, PA 342 was signed into law, amending PA 295. The EWR standards in PA 342 maintained the minimum energy savings standards of 1% of total annual retail electric sales per year through 2021. Beginning in 2019, the subsequent Commission Order in Case No. U-18262 directed EWR plans to substantially conform to the results of statewide energy efficiency potential studies and to a provider's IRP.

The Company's EWR programs help reduce customers' energy usage by increasing awareness and adoption of energy saving technologies. This is accomplished by providing products and services such as rebates, tips, tools, strategies and energy efficiency education to help customers make informed energy saving decisions.

The Company has continued to build momentum for its EWR program every year since the initial 2009 launch by expanding the scope of existing programs and adding new program options to the portfolio. DTE Electric's EWR program has historically exceeded the energy saving standards defined in PA 295 and PA 342, as shown in Table 8.6.1.

Table 8.6.1: Summary of annual EWR savings (GWh)

Year	0% to Legislative Target (1% after 2011) (GWh)	Legislative Target to Actuals (GWh)	Total
2009	146	57	203
2010	227	176	403
2011	339	180	519
2012	455	156	611
2013	471	143	614
2014	480	202	682
2015	485	136	621
2016	481	150	631
2017	485	276	762
2018	471	257	728
2019	468	249	717
2020	462	308	770
2021	457	487	944
2022*	443	443	886
2023*	444	444	889

*2022/2023 savings are based on projections from the DTE Electric 2022/2023 EWR Plan Filing, Case No. U-20876

8.7 General benefits of EWR

EWR programs help reduce the Company's reliance on fossil-fueled generation from existing plants, mitigate the need to build new generation resources in the future, help reduce reliance on power purchases from other suppliers and ease utility bill pressures by providing benefits to consumers and the DTE Electric system. They also provide environmental benefits, economic stimulus, job creation, risk reduction and energy security.

At the consumer level, energy-efficient products often cost more than their standard counterparts, but the higher upfront cost is balanced by lower energy consumption, resulting in lower energy bills. Over time, the money saved on electric bills as a result of energy-efficient products may pay consumers back for their initial investment. Although some energy-efficient technologies are complex and expensive, such as installing high-efficiency windows or a high-efficiency boiler, many are simple and inexpensive. Installing light-emitting diode (LED) lighting or low-flow water devices, for example, can be done by most individuals.

8.8 EWR program offerings

The Company's EWR offerings include residential, income-qualified, commercial and industrial, pilot, and education and awareness programs. The programs are managed by DTE Electric managers and operated by expert implementation contractors, primarily utilizing local labor and products.

Each program offers a combination of EWR products, services, customer incentives, rebates, and education. The following is an overview of each program category:

- Residential programs offer customers products, services and rebates encompassing appliance recycling; heating, ventilation, and air conditioning (HVAC); weatherization; lighting; home energy assessments; energy education; behavioral programs; school programs; online marketplace; and direct install programs.
- Income-qualified programs offer eligible customers recommendations, direct installation of qualified energy efficiency measures, major appliance replacements, weatherization measures, and education to assist in reducing their energy use and managing utility costs.
- ·Commercial and industrial programs offer businesses products; services and prescriptive rebates for specific equipment replacement such as lighting, boilers, pumps, and compressors; custom programs providing rebates per kilowatt hour (kWh) of electricity savings for a comprehensive system or industrial process improvement; small business programs; operational programs; energy education, and distributor engagement.
- Pilot programs focus on new and emerging experimental programs to fit longer-term portfolio needs; test the cost-effectiveness of new technologies; and assess customer adoption of new technologies and market acceptance of existing technologies using new approaches.
- Education and awareness programs raise customer EWR awareness to help save energy and to reduce energy costs. A secondary objective is to raise awareness of the various channels for customers to engage in specific EWR programs offered through the Company's website and other social media platforms.

EWR programs require independent verification of the utility claimed energy savings. This work is completed by an independent evaluation, measurement and verification (EM&V) contractor in accordance with industry standards. The EM&V process is also guided by input from the Evaluation Workgroup of the MPSC EWR Collaborative.

Figure 8.8.1 shows current programs offered. A complete description for each program may be found in the Company's 2021 Energy Waste Reduction Annual Report [1]

Figure 8.8.1: Current energy-waste reduction program offerings

Current energy-waste reduction program offerings

Residential Programs	Commercial & Industrial Programs	Income-Qualified Programs	Education & Awareness Programs	Pilot Programs
APPLIANCE RECYCLING	PRESCRIPTIVE	ENERGY EFFICIENCY ASSISTANCE	RESIDENTIAL	RESIDENTIAL
MULTI-FAMILY	NON-PRESCRIPTIVE	INCOME-QUALIFIED MULTIFAMILY	COMMERCIAL & INDUSTRIAL	COMMERCIAL & INDUSTRIAL
HVAC & WATER HEATING	SELF-DIRECT	INCOME-QUALIFIED HOME ENERGY CONSULTATION	DTE INSIGHT	ENERGY MANAGEMENT TOOLS
ENERGY STAR	BUSINESS ENERGY CONSULTANTS		EMPLOYEES	HEALTH & SAFETY
AUDIT & WEATHERIZATION	RETROCOMISSIONING			
HOME ENERGY CONSULTATION	MID-STREAM LIGHTING			
SCHOOL	MID-STREAM FOOD SERVICE			
HOME ENERGY REPORTS	MID-STREAM HVAC			
NEW HOME CONSTRUCTION	FIND AND FIX			
	SMALL BUSINESS FOCUS			
	STRATEGIC ENERGY MANAGEMENT			
	ENERGY STAR RETAIL LIGHTING			
	MULTIFAMILY COMMON AREAS			

1 https://geg2a4cqgdz35lnem46az2tb-wpengine.netdna-ssl.com/wp-content/uploads/DTEEEAnnualReport2021.pdf

8.9 Historical EWR performance

Since their inception in 2009, the Company's EWR programs have resulted in the first-year energy savings, first-year capacity savings, and spend detailed in Table 8.9.1.

Table 8.9.1: Annual energy savings, capacity savings and spend (2009-2022)

Year	Incremental annual energy savings (MWh)	Annual % energy savings	Incremental annual capacity savings (MW)	Spend ($MM)[3]	$/MWh
2009	202,718[1]	0.42%	19[1]	$23	$114
2010	402,995[1]	0.89%	45[1]	$47	$118
2011	519,262[2]	1.15%	69[1]	$65	$125
2012	610,655	1.34%	83[1]	$80	$131
2013	613,527	1.30%	84[2]	$86	$140
2014	681,638	1.42%	96[2]	$97	$143
2015	620,850	1.28%	81[2]	$100	$161
2016	630,920	1.31%	106	$102	$162
2017	761,630	1.57%	116	$110	$145
2018	727,907	1.55%	115	$128	$176
2019	717,072	1.53%	127	$130	$182
2020	769,790	1.67%	120	$155	$201
2021	944,217	2.06%	152	$217	$230
2022[4]	886,360	2.00%	173	$207	$233

1 Audited gross savings 2 Verified gross savings 3 Includes financial performance incentive 4 2022-2023 EWR Plan values from Case No. U-20876

From 2009 through 2021, DTE Electric customers saved more than 8,200 gigawatt hours (GWh) and $5.4 billion in avoided-cost savings. The savings achieved so far will continue into future years.

8.10 Starting point and proposed course of action: EWR

IRP Starting Point and PCA: EWR

In 2021, the Michigan Public Service Commission issued the Michigan Energy Waste Reduction Statewide Potential Study as a roadmap for identifying the amount of achievable energy savings potential in the Company's service territory. Public Act 341 of 2016 requires the MPSC to periodically conduct EWR potential studies to support modeling scenarios and assumptions used by electric utilities in IRPs. The Company's PCA maximizes the achievable potential identified in the 2021 Michigan Energy Waste Reduction Statewide Potential Study. The level of EWR savings in the PCA includes 2.0% in 2023 and average annual savings of 1.5% throughout from 2024 through 2042. This is the same as the starting point for the IRP and is the most economic EWR scenario modeled. The annual energy and capacity savings for the Company's 2023-2042 EWR programs includes the forecasted amounts shown in Table 8.10.1.

Table 8.10.1: EWR PCA annual MWh savings, capacity savings and spend (2023-2042)

Year	PCA: Potential Study Forecasted incremental annual energy savings (MWh)	Forecasted spend ($MM)
2023	888,874	$210
2024	784,021	$253
2025	711,645	$233
2026	652,472	$220
2027	601,778	$213
2028	538,660	$194
2029	492,455	$187
2030	452,788	$183
2031	654,715	$290
2032	733,225	$364
2033	716,853	$356
2034	832,907	$444
2035	795,323	$386
2036	904,158	$520
2037	835,049	$505
2038	830,658	$523
2039	768,342	$511
2040	717,150	$508
2041	717,150	$508
2042	717,150	$508

Cumulative energy savings: MWh

Table 8.10.2 displays the forecasted cumulative MWh savings for the EWR PCA. Cumulative energy savings represent both the overall savings occurring in each year from new participants and savings continuing to result from past participation with EWR measures that are still in place. Cumulative annual savings does not always equal the sum of all prior year incremental values as EWR measures have finite lives and their savings decline over time. The cumulative energy savings is forecasted to be more than 8.6 million MWhs from 2023 through 2042 at a cost of $7.1 billion to DTE Electric's customers.

Table 8.10.2: Forecasted cumulative MWh savings (2023-2042)

Year	Forecasted cumulative MWh savings (2023-2042)
2023	991,560
2024	1,818,398
2025	2,545,693
2026	3,212,845
2027	3,820,673
2028	4,316,912
2029	4,787,941
2030	5,119,216
2031	5,768,017
2032	6,322,886
2033	6,451,663
2034	7,124,944
2035	7,494,693
2036	7,823,754
2037	8,119,422
2038	8,148,473
2039	8,294,070
2040	8,350,223
2041	8,577,437
2042	8,628,004

Cumulative capacity savings: MW

Although peak demand reductions are not the EWR programs' primary focus, the cumulative capacity savings is forecasted to be 1,182 MW by the end of 2042. Table 8.10.3 shows that the Company's EWR programs are projected to achieve significant cumulative MW savings from 2023 through 2042.

Table 8.10.3: Forecasted cumulative MW savings (2023-2042)

Year	Forecasted cumulative MW savings (2023-2042)
2023	152
2024	273
2025	381
2026	481
2027	571
2028	646
2029	713
2030	763
2031	863
2032	943
2033	963
2034	1,063
2035	1,111
2036	1,151
2037	1,138
2038	1,135
2039	1,149
2040	1,144
2041	1,180
2042	1,182

The Company performed an analysis ensuring that the PCA for EWR is cost-effective. Cost-effectiveness is measured by the results of the Utility System Resource Cost Test (USRCT) as established in PA 342. Specifically, if the savings can be delivered at a USRCT benefit-cost ratio greater than 1.0, then the EWR plan is considered cost-effective. The resulting USRCT benefit-cost ratio for the EWR PCA is 1.42.

In summary, the Company is well-positioned to continue providing value to its customers and other stakeholders through a robust and well-run EWR program. Based on its experience implementing EWR programs since 2009 and the results of the 2021 Michigan Energy Waste Reduction Statewide Potential Study, the Company believes the PCA's EWR assumptions are likely to deliver the projected energy savings.

8.11 Volt-VAR optimization and conservation voltage reduction

DTE Electric has researched and piloted Volt-Var Optimization (VVO) over the last few years.

Volt-Var Optimization (VVO) manages system-wide reactive power flow to achieve one or more specific operating objectives. The objectives can include reducing losses, managing circuit level voltage, optimizing operating parameters and/or optimizing power factors, etc.

Conservation Voltage Reduction (CVR), as one of the VVO options, is designed to maintain customer voltage down to the circuit level in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand or energy consumption. CVR/VVO provides both a benefit to the distribution system as well as a generation alternative through reduced demand and energy consumption.

CVR is achieved by utilizing various electrical equipment including transformer load tap changers (LTC), overhead line regulators, and capacitor banks. In addition, supervisory control and data acquisition (SCADA) monitoring devices and line sensors are used to ensure customer voltage levels are maintained in allowable voltage ranges; advanced telecommunication and optimization tools can also be used to achieve optimal savings in the system.

8.12 CVR/VVO Pilot

The Company has been evaluating CVR/VVO as an option to reduce peak demand and energy consumption as a generation alternative as part of the Company's implementation of the 2019 IRP. The pilot implemented a series of upgrades on selected circuits to allow voltage reduction at substation transformers using a time-based schedule. In addition, the pilot included measurement and analysis of the expected benefits. The technology upgrades needed to implement CVR/VVO on selected circuits include two major components.

The first technology enhancement is to enable real time remote monitoring and control capability at substations and on circuits. The technology upgrades could take the form of:

- Installing Remote Terminal Units (RTU) and SCADA at substations to enable remote voltage and current monitoring and to enable remote control of transformer load tap changers when needed.
- Installing advanced voltage sensors on circuits to enable remote monitoring of circuit primary voltage.

The second technology enhancement is to install or upgrade line capacitor banks to improve voltage conditions. The technology upgrades could take the form of:

- Installing remote controllable capacitor banks in new locations to improve circuit voltage profile during peak hours.
- Upgrading capacitor banks at existing locations with remote control to improve circuit voltage profile during peak hours.

The exact technology installed at substations and on circuits could vary depending on detailed engineering and technology analysis prior to CVR/VVO implementation on individual circuits. As the Company scales up CVR/VVO beyond the pilot, the goal is to verify the CVR/VVO implementation on a portfolio of circuits to better understand program costs and benefits as well as any field execution constraints.

8.13 CVR/VVO program

The Company continues to engage with industry experts and peer utilities that have implemented CVR/VVO to identify new approaches to achieve energy and demand savings for customers.

Based on the promising results of the pilot, the Company intends to continue investments in CVR/VVO in 2022 and beyond as a program. The Company has engaged with industry experts and peer utilities that have implemented CVR/VVO around approaches to achieve energy and demand savings for customers. Specifically, the Company plans to move beyond the pilot and to invest in a more advanced approach to CVR/VVO, where set points for substation transformer LTCs, capacitor banks and regulators are coordinated and adjusted dynamically to optimize the voltage levels on a real-time basis to maximize demand and energy savings. Substations for CVR/VVO implementation are prioritized based on their energy reduction potential and synchronized with the substations selected for the Company's substation automation program This advanced approach to CVR/VVO would leverage the Company's Advanced Distribution Management System (ADMS) to manage the real-time control of the equipment involved. This new CVR/VVO approach is expected to produce higher demand and energy savings than the pilot and provide flexibility in adjusting voltages to better accommodate distributed energy resources. For instance, with the pilot approach of CVR/VVO, if a voltage reduction on substation transformer led to low voltage conditions during any time period, the substation transformer would not be selected for CVR/VVO implementation, thus limiting its applicability. In contrast, using the updated approach, the substation transformer could still be selected for the advanced approach of CVR/VVO because the substation transformer voltages will be adjusted to automatically maximize voltage reduction and avoid low voltage conditions. ADMS control of CVR/VVO through the ADMS Volt-Var control (VVC) module is expected to be implemented in 2024.

8.14 IRP starting point: CVR/VVO

The Company continues to implement the CVR/VVO investments approved in the 2019 IRP. This includes approximately 28.7 MW of cumulative CVR/VVO through 2025. See Table 8.14.1

Table 8.14.1: Starting point CVR/VVO - annual and cumulative peak and annual and cumulative energy reduction (MW and MWh)

Year	Annual Peak Demand Saving (MW)	Cumulative Peak Demand Saving (MW)	Annual Energy Reduction (MWh)	Cumulative Energy Reduction (MWh)
2020	0.9	0.9	1,398	1,398
2021	0.9	1.8	1,398	2,796
2022	5.7	7.6	8,854	11,650
2023	6.8	14.3	10,485	22,135
2024	7.1	21.4	10,951	33,086
2025	7.4	28.7	11,417	44,503

8.15 Proposed course of action: CVR/VVO

The Company continues to implement the CVR/VVO investments approved in the 2019 IRP and reflected in the starting point of the 2022 IRP as discussed above. The PCA includes approximately 7.5 MW per year from 2026 through 2030 for a total of 37.5 MW through that period. The program is maintained at a demand savings level of approximately 66.2MW through the end of the study period. See Table 8.15.1.

Table 8.15.1: CVR/VVO PCA - annual and cumulative peak and annual and cumulative energy reduction (MW and MWh)

Year	Annual Peak Demand Saving (MW)	Cumulative Peak Demand Saving (MW)	Annual Energy Reduction (MWh)	Cumulative Energy Reduction (MWh)
2026	7.5	36.2		56,153
2027	7.5	43.7	11,650	67,803
2028	7.5	51.2	11,650	79,453
2029	7.5	58.7	11,650	91,103
2030	7.5	66.2	11,650	102,753
2031		66.2		102,753
2032		66.2		102,753
2033		66.2		102,753
2034		66.2		102,753
2035		66.2		102,753
2036		66.2		102,753
2037		66.2		102,753
2038		66.2		102,753
2039		66.2		102,753
2040		66.2		102,753
2041		66.2		102,753
2042		66.2		102,753

Endnotes

1. Unforced capacity

2. A customer can take service under the Dynamic Peak Pricing rate and not be enrolled in SmartCurrents but a customer who is enrolled in SmartCurrents must take service under the Dynamic Peak Pricing rate.

SECTION 9

9 Future renewable and storage planning

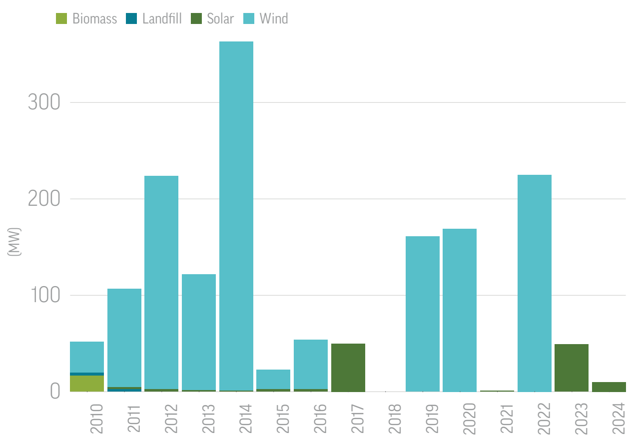
9.1 Overview

Renewable energy and energy storage are a critical part of DTE Electric's plan to achieve its generation and carbon-reduction goals. As the Company transitions its fleet to meet its commitment to achieve net zero emissions by 2050, it also is helping customers reach their clean energy goals. The Company's MIGreenPower program provides customers options to manage their own carbon footprints on their own timelines. Customer demand for and participation in the MIGreenPower program demonstrate the cost-effectiveness and ease of enrollment of this voluntary green pricing offering. The future of renewable energy and storage is unfolding at a rapid pace and the Company stands ready to lead the change.

9.2 Existing renewable portfolio standards

Pursuant to Public Act 342, the Company's August 2020 amended Renewable Energy Plan (REP), included a renewable energy portfolio to meet the updated renewable energy targets. Those targets are 12.5% in 2019 and 2020, and 15% by 2021 through August 2029, the end of the REP's timeframe. The previous 12-month period of weather-normalized retail sales will be used to calculate the number of megawatt hours of electricity in the renewable energy credit portfolio. The Company's ability to comply with the renewable portfolio standard through the end of the REP is dependent upon the actual performance of the renewable assets closely matching the capacity factor projections, among other assumptions. The total incremental cost of compliance forecasted in the Company's last approved amended REP, filed in August 2020 for the period 2023 through August 2029, is approximately $14.2 million. The August 2020 REP filing included a summary of the planned renewable energy credit portfolio, including incentive renewable energy credits, as well as the forecasted expected compliance levels by year to meet the renewable portfolio targets. The Company recently filed an amended REP filing on Sept. 30, 2022. The existing renewable energy fleet and the build plan shown in Figure 9.2.1 are forecasted to meet and sustain the updated renewable portfolio standard targets and are forecasted to have approximately 1.6 million renewable energy credits remaining at the end of the plan.

Figure 9.2.1: PA 342 compliance renewable energy build plan



Public Act 342 also includes a clean-energy goal, encompassing a renewable energy and energy waste reduction (EWR) goal of 35% in 2025. The Company is currently in compliance and expects to maintain at least 15% of electricity from renewable energy via renewable energy credit (REC) retirements. In addition, the Company will have over 24% energy waste reduction by 2025. The Company's EWR targets anticipate approximately 20% in 2022, approximately 22% in 2023, approximately 23% in 2024 and approximately 25% in 2025. The combined effect of at least 15% renewable energy and annual energy waste reduction targets will achieve the 35% goal prior to 2025.

9.3 Voluntary green pricing programs

In addition to the renewable portfolio standard, the Company is growing its voluntary green pricing (VGP) programs to support customers who are pursuing their own carbon-reduction efforts. The Company plans to actively market these programs and accommodate customer demand without setting program participation caps.

Enrollments below 2,500 MWh

DTE Electric offers MIGreenPower, a VGP program, to all its 2.3 million full-service customers. Launched in April 2017, MIGreenPower provides interested customers with an easy and affordable way to reduce their carbon footprint by increasing the percentage of their energy usage that is attributed to specific renewable projects. Customers who subscribe to MIGreenPower can elect to increase the amount of renewable energy they use in 5% increments, up to 85%, with the ability to cancel at any time. Participating customers will see a line item for a subscription fee as well as lines for two credits on their monthly bill, calculated based on the level of renewable energy they select, knowing they are helping to support Michigan's clean energy future.

Enrollments above 2,500 MWh

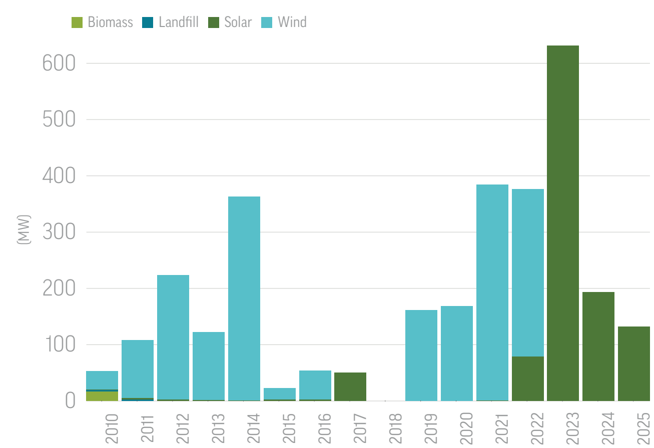
In an effort to expand the Company's voluntary offerings, the Company received MPSC approval in January 2019 for a large customer VGP pilot program. Enrollment in the program is voluntary and allows full-service large customers to engage in a contract to increase the portion of their electric usage attributable to renewable resources in 5% increments at a level beyond the renewable energy all customers receive from the Company's generation fleet, up to 85%. This allows customers to choose a participation level that aligns with their specific preferences and objectives.

The program and associated tariff are designed to grow with customer demand in phases. New assets will be added to ensure the program grows with customers' needs. Program assets will be approved though the existing REP contract-approval process, ensuring fairness and cost competitiveness. Understanding that it would not be prudent to bring on excess resources without adequate demand, the Company aims to manage both forecasted demand and renewable energy construction timelines to ensure there is no extended gap in program availability to new subscribers. The build plan is flexible and accommodates growing demand over time for the Company's VGP programs. Issues related to resources used to meet MIGreenPower demand and VGP program design are addressed as part of Section 61 cases and corresponding REP amendment cases, such as the current Case Nos. U-21172 and U-21285.

9.4 IRP starting point: renewable energy

The IRP starting point for renewable energy encompasses the renewable portfolio standard mandated by PA 342 and approved VGP projects. The starting point build plan in Figure 9.4.1 encompasses the additional amount of renewable energy needed to meet and sustain these commitments through the IRP study period of 2042.

Figure 9.4.1: Starting point: renewable energy build plan



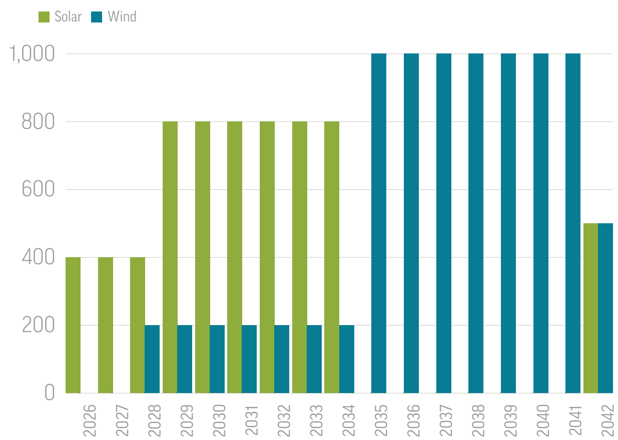
9.5 Proposed course of action: renewable energy

The PCA contains 15,400 MW of renewables including:

- First five years – 800 MW of solar.
- Second five years – 3,600 MW of solar, and 1,000 MW of wind.
- Second 10 years – 2,100 MW of solar and 7,900 MW of wind.

See Figure 9.5.1 for additional details on the renewables included in the PCA

Figure 9.5.1: PCA: renewable energy build plan



9.6 Energy storage technologies

With higher levels of renewable energy, energy storage will be increasingly important in the Company's supply mix and can provide numerous benefits to the grid, as discussed in Section 14. The Company collaborated with stakeholders on new analytical approaches to capture flexibility benefits of energy storage as part of the IRP modeling (see Section 4). In this IRP, the Company is focused on gaining experience with commercially available lithium-ion batteries in the near term, while continuing to monitor mid- to long-duration storage technologies that can support high levels of intermittent resources under a net zero future.

The Company's first pilot battery energy storage system (BESS) is the 14 MW lithium-ion battery system at the Slocum peaker site. This project was proposed in the Company's 2022 electric rate case (Case No. U-20836). The project will provide the Company with experience engineering, procuring, constructing and operating its first grid scale battery. Subject to MPSC approval, the Slocum BESS pilot project is currently scheduled to be completed in 2024 and will replace the current five diesel peaker engines, totaling 14 MW. The BESS will have 56 MWh of energy storage and charge utilizing lower cost off-peak energy. It will discharge that energy during higher value on-peak hours to capture market energy value for customers. The plant is expected to operate (charge and discharge its stored energy) on a daily basis. A BESS is an energy storage system and not a generating unit, and as such will not consume fuel and will not itself produce any environmental emissions. The operation of a BESS is silent and current technology supports round-trip efficiencies exceeding 85%.

The Company plans to build on the experience at the Slocum site and scale up lithium-ion battery storage applications beginning in the mid-2020s as more renewables are added to the system as part of the proposed course of action. Other applications may also provide reliability support to the distribution system, as discussed in Section 14.

As the Company increases the level of renewable energy in the 2030s with additional thermal generation retirements, mid- and long-duration storage technologies are expected to come into play with advancements in performance and cost profiles. Mid- and long-duration technologies include thermal, electrochemical (batteries with new, different, potentially low-cost chemistries), mechanical (gravitational, pumped storage) and chemical (includes hydrogen). These types of storage are generally more modular installations and, aside from pumped hydro, are generally less mature than lithium-ion batteries that provide up to four hours of storage.

Long-duration energy storage is not new to the Company. The Ludington pumped storage facility is an important long-duration energy storage resource in the Company's existing supply portfolio, providing 1,120 MW of capacity (DTE Electric's share of the facility, which is co-owned by Consumers Energy). This facility, coupled with new applications of energy storage technologies, will help balance supply and demand with the increased decarbonization of the grid. See Section 7 for additional information.

9.7 IRP starting point: energy storage

The IRP starting point for modeling does not include BESS energy storage technologies because the Company's pilot project for lithium-ion batteries have not been previously approved by the MPSC. The Company's existing portfolio does include the Ludington pumped storage facility.

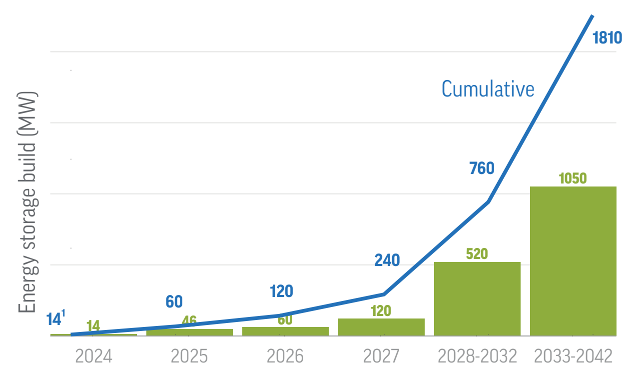
9.8 Proposed course of action: energy storage

The PCA contains 1,810 MW of energy storage in the form of lithium-ion batteries including:

- First five years – 240 of MW (includes 14 MW battery storage pilot at Slocum site).
- Second five years – 520 of MW.
- Second 10 years – 1,050 of MW.

The incremental energy storage build is included in Figure 9.8.1.

Figure 9.8.1: PCA: energy storage build plan



1 The 14 MW build in 2024 represents the Company's Slocum battery energy storage system pilot

SECTION 10

10 Peak demand and energy forecasts

10.1 Overview

An accurate load forecast for the planning period is a key input into the Integrated Resource Plan. The Company developed its load forecast by analyzing historical data to identify the statistically significant factors in energy sales for each customer class. The resulting models included economic variables, changes in end-use efficiency and saturation, adoption of new technologies and projected increases in energy waste reduction to forecast the Company's annual service-area sales, bundled sales and peak demand.

A bottom-up methodology, using an hourly electric load model, developed the annual service-area and bundled peak-demand forecast. The Company also used this model to determine monthly peak demands in the forecast period. Historical hourly advanced metering infrastructure (AMI) data is the basis for the hourly electric load model, which aggregates hourly demand profiles from various customer classes and end uses into a system annual load shape. The annual forecast sales and hourly demand profiles for each end use are inputs to this model.

Normal temperature on the day of the annual peak is assumed to be 82.8 degrees Fahrenheit, which is the mean temperature from Detroit Metropolitan Airport. The value is based upon an average peak-day mean temperature for a 15-year period (2006 through 2020). The mean temperature is calculated as the average of hourly temperatures for the day. The peak day is assumed to occur on a weekday in July.

The energy forecast was developed by using a model for each customer class. The models' results were added together to obtain the total service-area sales forecast. The Electric Choice sales forecast was subtracted from the service-area sales forecast to obtain the bundled sales forecast. The residential class accounts for approximately 34%, small commercial and industrial class 24%, and large commercial and industrial class 42% of the service area forecast sales. Service area forecast contributions to peak are approximately 51% residential class, 23% small commercial and industrial class, and 26% large commercial and industrial class. The allocation of customer classes for both sales and peak demand is shown in Figures 10.1.1 and 10.1.2.

Figure 10.1.1: Forecasted 2023 service area sales by customer class

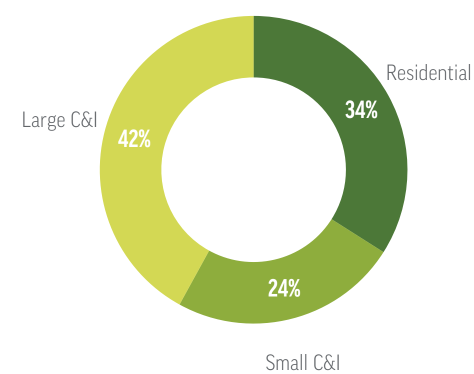
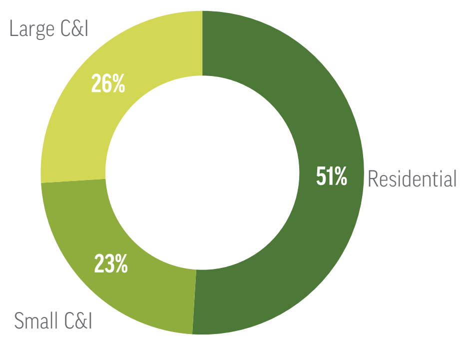


Figure 10.1.2: Forecasted 2023 service-area peak by customer class



10.2 Customer classes

Most customer class sales and customer forecasts are built from linear regression models that relate monthly sales to economic activity, weather, changes in end-use ownership, and energy efficiency. The forecast is developed separately for each major rate classification: residential, commercial and industrial (C&I) and other. The residential sales forecast is derived by combining a use-per-customer forecast, and a statistically adjusted end-use (SAE) specification, with a customer forecast. Separate models are estimated for small and large C&I customers. Small C&I is modeled similarly to residential, while large C&I is forecast using generalized econometric models unique to seven supersectors. Other, which consists of streetlighting and traffic signals, is forecast based on growth in customers and adoption of more energy efficient lighting.

Residential

Electricity sales in the residential class were forecast using the SAE model, which specifies energy use as a function of 22 end uses, including customer-owned solar and electric vehicle demand, along with factors that affect the end-use requirements, such as economic activity and weather. The residential class forecast begins with a basic end-use model with appliance saturation projections and average electricity usage per end use provided by a Company-conducted residential appliance saturation survey and the Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) for the East North East Central region in which DTE Electric operates. Residential energy waste reduction (EWR) programs are applied directly to the corresponding end uses in the SAE model. The combination of appliance saturations and average electricity per end use is indexed and calibrated to the Company's usage per customer for the base year to create an electricity forecast for each end use. Figure 10.2.1 and Figure 10.2.2 show aggregated classifications of these end uses and how the consumption mix is projected to change over time.

Figure10.2.1: Forecasted 2023 residential consumption by end use

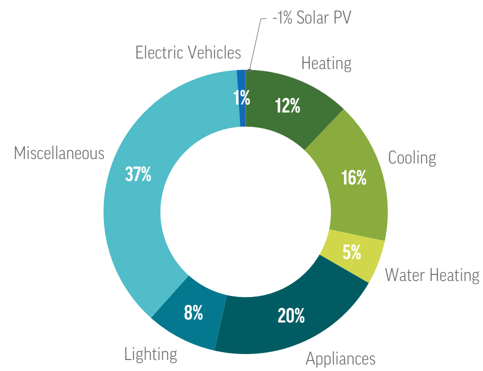
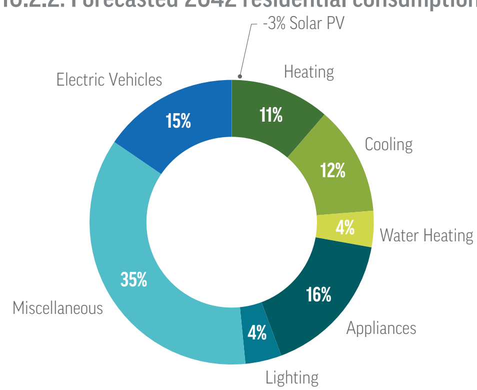


Figure10.2.2: Forecasted 2042 residential consumption by end use



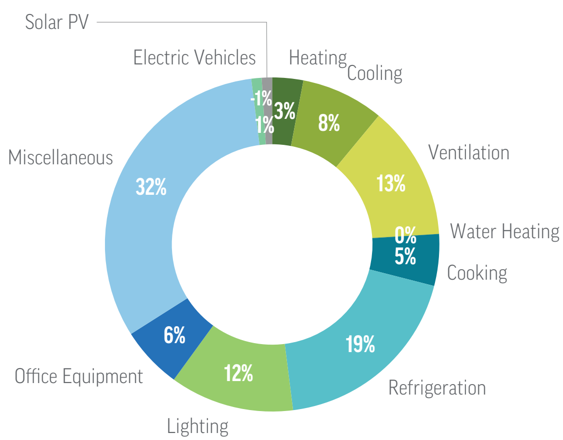
End-use intensities are combined with utilization variables which reflect how much the end use is utilized. For residential, the primary variables used to explain utilization are weather, real personal income, population and households. Additionally, resulting from the COVID-19 pandemic, Michigan mobility data was integrated into the model due to the shift in electricity consumption patterns caused by shelter-in-place and social distancing policies. The utilization variables are then combined with the end-use intensities to compute an explanatory variable. Along with seasonal factors, the resulting explanatory variable is then regressed against the Company's residential monthly use per customer sales. The model acts as the statistical adjustment and calibrates the end-use forecast to the Company's historical sales.

The number of residential customers was forecasted using historical and projected households for Southeast Michigan provided by IHS Markit. Customer counts are modeled using a regression, with households as the primary explanatory variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total residential class sales forecast.

Small commercial and industrial

Similar to the residential class forecast, small C&I class sales are also forecast using the SAE model, utilizing 11 end uses, including customer-owned solar and electric vehicle demand. Additionally, small C&I EWR programs are incorporated directly into the SAE model. The small C&I sales forecast begins with a basic end-use model with saturation projections and average electricity usage per end use derived from the EIA's Commercial Building Energy Consumption Survey (CBECS) for the East North Central region. Since small C&I buildings within the DTE Electric service territory consume electricity differently, the projections are weighted by intensity and prevalence of 11 different building types as defined by the EIA. To better calibrate these projections to the Company's service area, employment values are used to weight the saturations, and average electricity usage per end use is enhanced with the Company's service area employment data. The combination of saturations and average electricity per end use is indexed and calibrated to the Company's usage per customer for the base year to create an electricity forecast for each end use. Figure 10.2.3 shows the forecasted small C&I consumption by end use.

Figure 10.2.3: Forecasted 2023 small C&I consumption by end use



For small C&I, the primary variables used to explain utilization are weather, gross state product, non-manufacturing employment and households. The utilization variables are then combined with the end-use intensities to compute an explanatory variable. Along with seasonal factors, the resulting explanatory variable is then regressed against the Company's small C&I monthly use per customer sales.

Small C&I customers are modeled using a regression with residential customers as the primary variable. The customer forecast is then multiplied by the use per customer from the SAE model to produce the total small C&I class sales forecast.

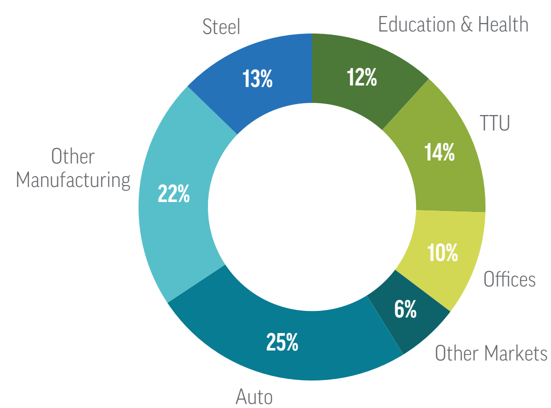
Large commercial and industrial

The large C&I forecast begins by disaggregating all primary service sales into seven distinct supersector markets. Granular market segments defined by the customer's North American Industry Classification System (NAICS) code are aggregated into supersectors defined by the Bureau of Labor Statistics. The seven supersectors include: medical and education; transportation, trade and utility (TTU); offices; other markets; automotive; other manufacturing; and steel.

Econometric models, a commonly used technique among utility forecasters, are used to forecast sales for the Company's service territory at the supersector level. Individual regression equations are applied to all supersectors, using various explanatory variables, such as corresponding supersector employment and gross state product, automotive production, weather and cumulative energy waste reduction savings, to drive the forecast. The regression results are evaluated for reasonableness and validated through various model statistics.

Regression modeling does not account for incremental growth of emerging technologies (photovoltaics and electric vehicles). Therefore, it is necessary to make post-regression adjustments to the forecast to incorporate future technology and customer specific closings or expansions. The three main post regression adjustments include distributed generation growth, fleet electrification growth and large customer projects that are informed by customer account managers.

Figure 10.2.4: Forecasted 2023 large C&I sales



10.3 Demand-side management and emerging technologies

Future demand-side management and emerging technologies, including EWR, distributed generation, building electrification and electric vehicles, were incorporated into the long-term load forecast. Demand-response programs were not explicitly included in the forecast peak. However, demand-response programs were included in determining the Company's required amount of unforced capacity needed to meet the MISO adequacy requirements for the forecast MISO coincident peak demand for the DTE Electric bundled load.

EWR

The starting point forecast assumes EWR savings levels consistent with the 2021 Energy Waste Reduction Statewide Potential Study and was modeled for each of the three customer class forecasts. Since historical and forecast EWR savings are available at the end-use level for residential, those savings were applied directly to the corresponding end uses in the residential SAE model, resulting in lower end-use intensity projections. C&I EWR savings were applied in both the small C&I and large C&I forecast models as an explanatory variable in the respective regression models.

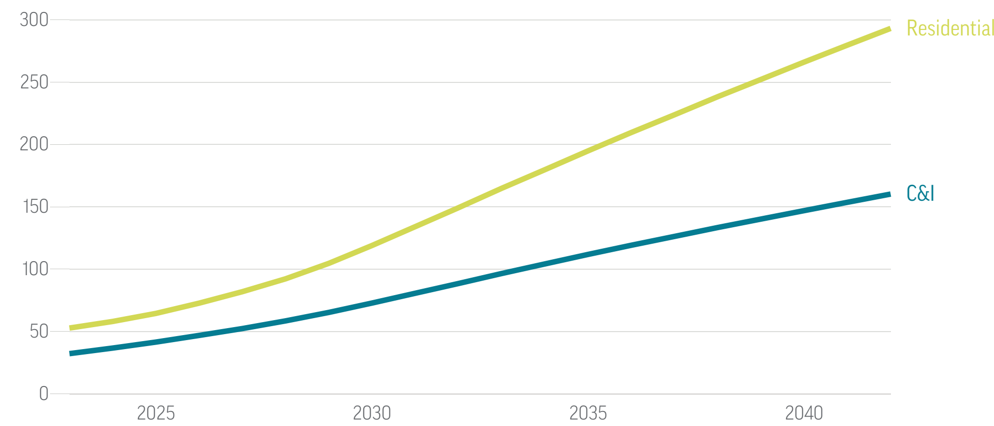
Distributed generation

Unlike traditional power supply sources, distributed generation (including behind-the-meter solar photovoltaics) affects DTE Electric's load forecast. Solar energy generated is either consumed onsite or exported back to the grid, lowering the overall demand for electricity. Since 2007, through legacy net-metering programs and the new distributed-generation program, the Company has partnered with customers to help create a clean energy future for Michigan. Given the pace of distributed-generation installations, the load forecast assumes that those patterns will continue moving forward as costs for the technology come down.

The distributed-generation outlook was developed utilizing the Company's residential and nonresidential interconnection history. The Company engaged with ICF Resources LLC (ICF), a global consulting service company, to conduct a market study. ICF produced forecasts of photovoltaic (PV) economics for both residential and C&I customers and estimated the customer PV capacity and electricity output that will be added in DTE Electric's service territory.

In the residential and small C&I models, the historical and forecast distributed generation is input directly as an end use into the model. In the large C&I models, the incremental distributed generation is subtracted as a post-regression adjustment. Figure 10.3.1 shows the forecasted cumulative capacity for residential and C&I markets.

Figure 10.3.1: Distributed generation forecast (installed capacity MW)



Electric vehicles

As of December 2021, there are over 33,000 EVs in Michigan, or about 0.5% of total vehicles on the road. While the market is relatively small today, industry experts expect that to change rapidly over the coming years. Despite supply chain issues, specifically around semiconductor chips, vehicle sales within the overall automotive market finished up 3% last year. The EV market outperformed the overall market significantly, with plug-in hybrids (PHEVs) up almost 150% and battery electric vehicles (BEVs) up over 80%. In Michigan, 2021 EV sales more than tripled those from 2020.

In 2019, DTE Electric established the Charging Forward program, with current key goals of reducing barriers to EV adoption, efficiently integrating EV load with the grid, enabling equitable access to EVs and piloting new technologies. Additionally, Charging Forward seeks to support the state's Michigan Healthy Climate Plan. Given the growing interest from consumers, and continued increases in EV adoption, the forecast assumes EV adoption will continue to grow. As costs for these vehicles come down, and more models become available, EVs will continue to become a way for Michiganders to reduce their carbon footprint and lower their fuel and maintenance costs.

The forecast for EVs begins with a cumulative vehicle stock forecast for both light-duty vehicles and fleet vehicles within the Company's electric service territory, as seen in Figures 10.3.2 and 10.3.3, respectively. The EV volume is multiplied by the KWh/mile and the assumed vehicle miles traveled unique to each vehicle segment to arrive at the load associated with the forecasted vehicle volumes.

Figure 10.3.2: Light-duty vehicle stock forecast (cumulative number of units)

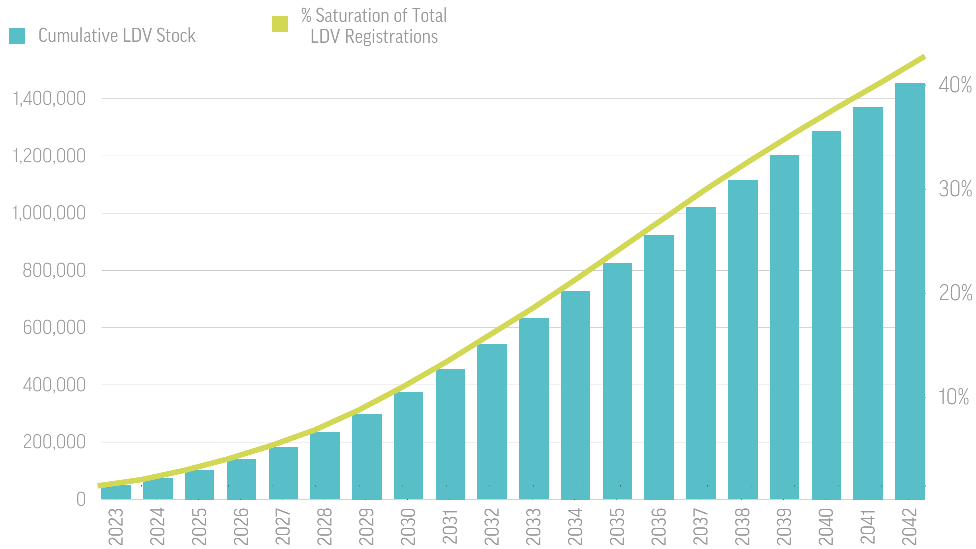
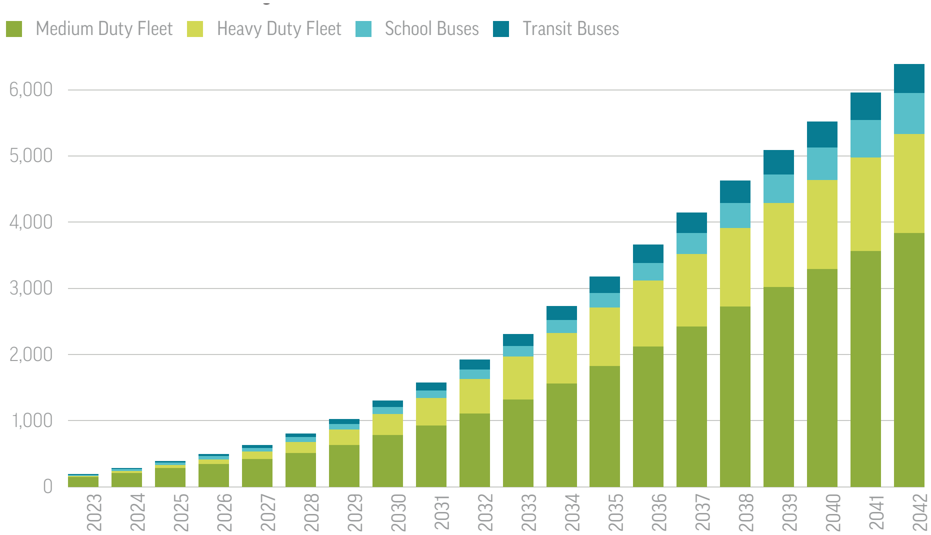


Figure 10.3.3: Fleet vehicle stock forecast (cumulative number of units)



While Figures 10.3.2 and 10.3.3 are EV forecasts for the Company's service territory, the Company's statewide EV volume forecast is shown under different sensitivities in Figure 10.3.4.

Figure 10.3.4: Michigan EV volume forecast (cumulative number of units)

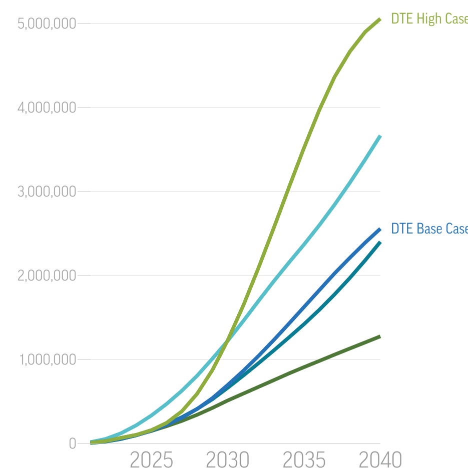
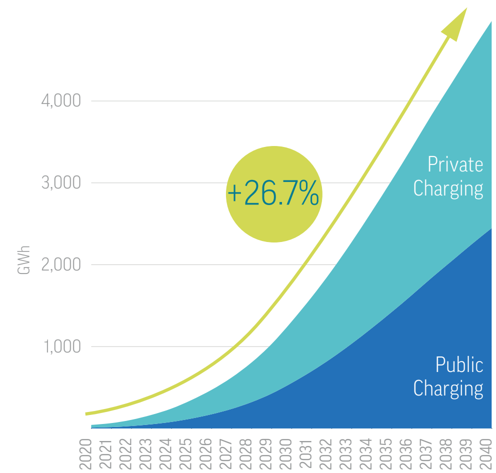


Figure 10.3.5: Projected EV load (cumulative volumes)



For light-duty vehicles, the Company's appliance saturation survey suggests approximately 75% of EV charging happens at personal residences while the other 25% takes place at nonresidential locations, such as workplace or public charging stations. Therefore, approximately 75% of the light-duty EV sales forecast was applied to the residential model as an additional end use, while the remaining was applied to the small C&I model as an additional end use as a starting point. Over time, as EV adoption becomes more mainstream, the forecast assumes these dynamics will shift in favor of more nonresidential charging. As public infrastructure is built to support DC fast charging and consumers without access to home charging begin to adopt EVs, the boundary between home and public charging is projected to overlap.

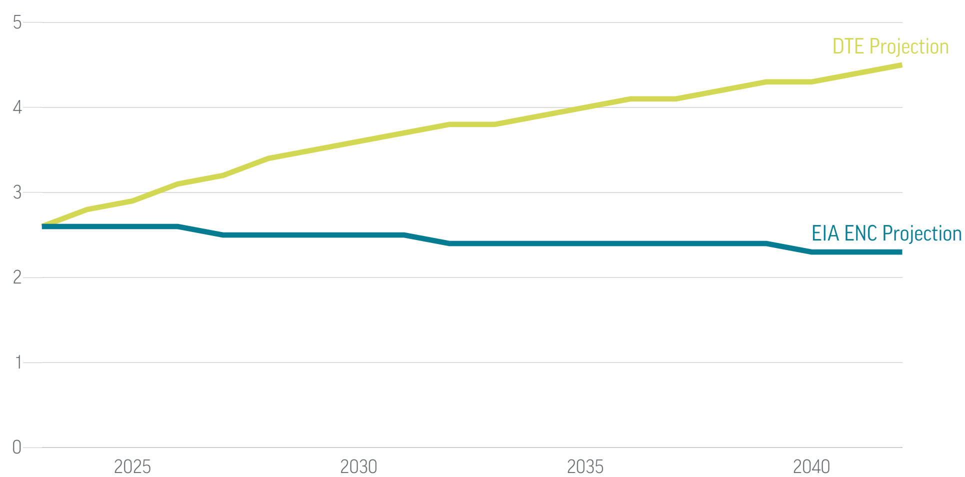
For fleet (medium-duty and heavy-duty) vehicles, 100% of the fleet EV sales forecast was applied to the large C&I model as an incremental adjustment to the forecast.

Based on the EV adoption forecasts and expected charging patterns, Figure 10.3.5 presents the resulting projected EV load with cumulative volumes shown over time.

Building electrification

While still in the early phases of adoption, air-source (ASHP) and ground-source (GSHP) heat pumps have recently become a more viable solution for some residential customers to help reduce their carbon footprint and lower their heating costs compared to baseboard, propane, or fuel oil heating systems. Beginning in 2009, heat pump adoption began to gain modest traction in DTE Electric's service area. For most other end uses, the residential model utilizes saturation projections from the EIA's Annual Energy Outlook for the East North Central (ENC) region. Given the growth in heat pumps experienced over the last 10 years in DTE Electric's service territory, EIA's heat pump projection was discarded due to EIA projecting a declining heat pump saturation for the East North Central Region. The forecast assumes growth in heat pump adoption will persist as customers with baseboard, propane or fuel oil heating systems turn over and adopt a more efficient and cost-effective technology to heat their homes. Historical and forecast heat pump adoption is modeled as an additional end use in the residential forecast. The projected saturation of residential heat pumps for DTE Electric and the East North Central region can be seen in Figure 10.3.6.

Figure 10.3.6: Residential heat pump saturation forecast



10.4 Historical sales growth

The compounded annual growth rate for 2017-2021 is -1.1%. Table 10.4.1 includes the previous five-year service-area actual weather-normalized sales.

Table 10.4.1: Historical growth in electric sales

year	Service Area TN Sales	
2017	47,519	
2018	47,295	-0.5%
2019	46,636	-1.4%
2020	44,390	-4.8%
2021	45,482	2.5%
	2017-2021 CAGR	**-1.1%**

10.5 IRP starting point: sales and demand forecast

The starting points for service-area sales and peak demand, over the forecast period 2023 through 2042, are expected to increase annually an average of 0.5% and 0.3% respectively. The growth rate for bundled sales was the same as the service area due to a steady Electric Choice sales forecast. Figures 10.5.1 and 10.5.2 show the starting point forecast sales and peak demand. The Electric Choice sales forecast was based on 10% of retail sales.

Figure 10.5.1: Annual sales (GWh)

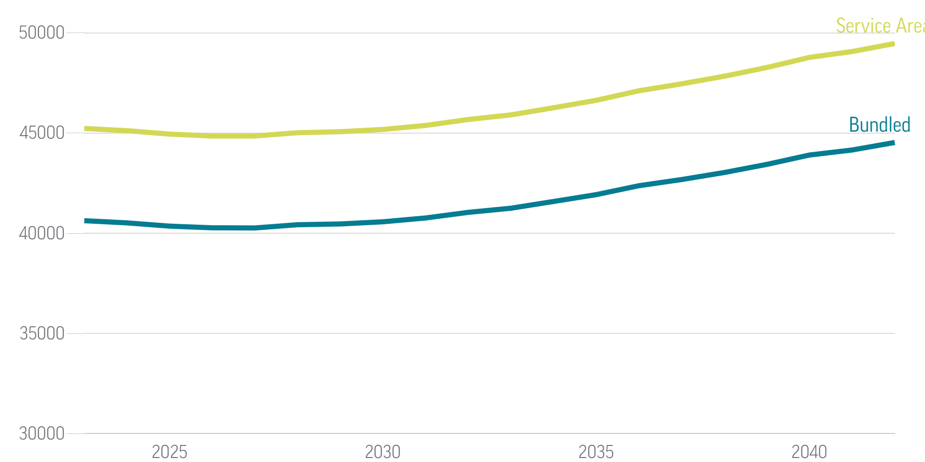


Figure 10.5.2: Annual peak sales (MW)

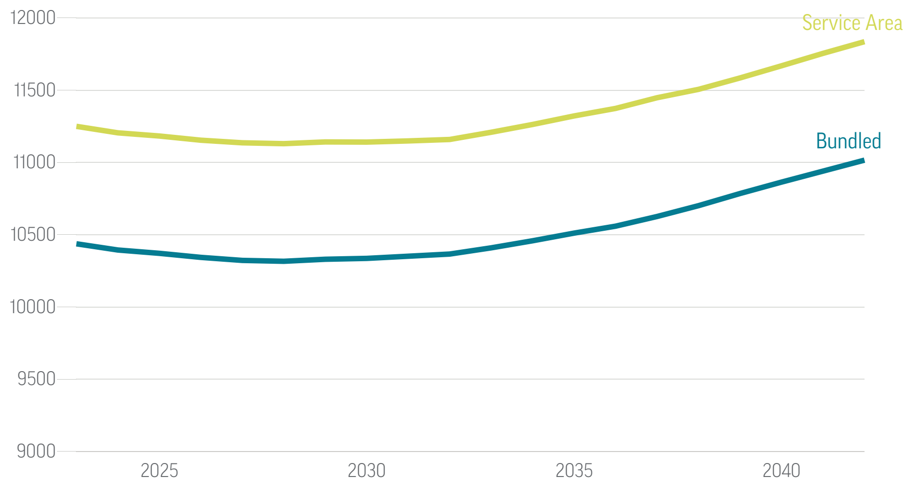


Table 10.5.3 shows DTE Electric's service area sales, net system output, load factor and peak demand for the starting point. Data for 2017-2021 is actual, not weather normalized. 2022 is four months of weather-normalized actuals and eight months of forecast. The forecast for 2023-2042 assumes normal weather.

Table 10.5.4 shows DTE Electric's service area sales by customer class for the starting point. Data for 2017-2021 is actual, not weather normalized. 2022 is four months of weather-normalized actuals and eight months of forecast. The forecast for 2023-2042 assumes normal weather. The total growth rate for 2023-2042 is 0.5%.

Table 10.5.3: IRP starting point: service area electric sales and demand

Year	Sales (GWh)	% Change	Losses (GWh)	System Output (GWh)	% Change	Load Factor	Peak (MW)	% Change
2017	47,142		3,202	50,345		54.5	10,554	
2018	48,527	2.9%	3,645	52,172	3.6%	52.2	11,418	8.2%
2019	46,623	-3.9%	3,493	50,116	-3.9%	53.8	10,630	-6.9%
2020	44,381	-4.8%	3,470	47,851	-4.5%	49.6	11,005	3.5%
2021	45,839	3.3%	3,541	49,380	3.2%	51.3	10,992	-0.1%
2022	45,343	-1.1%	3,772	49,115	-0.5%	49.2	11,390	3.6%
2023	45,230	-0.2%	3,527	48,757	-0.7%	49.5	11,250	-1.2%
2024	45,121	-0.2%	3,526	48,647	-0.2%	49.6	11,205	-0.4%
2025	44,949	-0.4%	3,515	48,464	-0.4%	49.5	11,183	-0.2%
2026	44,855	-0.2%	3,514	48,369	-0.2%	49.5	11,154	-0.3%
2027	44,856	0.0%	3,518	48,374	0.0%	49.6	11,136	-0.2%
2028	45,017	0.4%	3,534	48,550	0.4%	49.8	11,130	-0.1%
2029	45,069	0.1%	3,540	48,609	0.1%	49.8	11,142	0.1%
2030	45,182	0.3%	3,556	48,738	0.3%	49.9	11,141	-0.0%
2031	45,381	0.4%	3,577	48,958	0.5%	50.1	11,149	0.1%
2032	45,678	0.7%	3,608	49,286	0.7%	50.4	11,159	0.1%
2033	45,907	0.5%	3,631	49,539	0.5%	50.4	11,209	0.5%
2034	46,264	0.8%	3,667	49,931	0.8%	50.6	11,263	0.5%
2035	46,634	0.8%	3,704	50,338	0.8%	50.8	11,322	0.5%
2036	47,110	1.0%	3,752	50,862	1.0%	51.0	11,374	0.5%
2037	47,456	0.7%	3,787	51,243	0.8%	51.1	11,448	0.7%
2038	47,835	0.8%	3,824	51,659	0.8%	51.3	11,506	0.5%
2039	48,272	0.9%	3,866	52,138	0.9%	51.4	11,585	0.7%
2040	48,777	1.0%	3,914	52,691	1.1%	51.5	11,669	0.7%
2041	49,069	0.6%	3,943	53,013	0.6%	51.5	11,755	0.7%
2042	49,469	0.8%	3,983	53,451	0.8%	51.6	11,836	0.7%
Compound Annual Growth Rate 2023-2042								
	0.5%			**0.5%**			**0.3%**	

10.6 Forecast sensitivities

To manage future uncertainties, sensitivities were developed exploring a range of higher and lower sales and peak demand levels. The alternative sensitivities, excluding those completed in accordance with the Commission's final order in Case No. U-18418, include aggressive customer-owned distributed generation, high electrification, stakeholder, stakeholder with high distributed generation, stakeholder with high fuel switching, Electric Choice cap increasing to 15%, and climate change.

Aggressive customer-owned distributed generation

The aggressive customer-owned distributed generation sensitivity was based on the reference scenario and utilized an aggressive assumption for solar photovoltaic adoption produced by ICF Resources LLC. Solar system capital costs were set to align with the National Renewable Energy Laboratory's (NREL) 2021 Annual Technology Baseline aggressive scenario.

Table 10.5.4: Service area weather-normalized electric sales by class (GWh)

Year	Residential	Small C&I	Large C&I	Other	Total	%
2017	14,883	11,083	20,919	258	47,142	
2018	15,939	11,271	21,093	224	48,527	2.9%
2019	15,066	10,948	20,382	226	46,623	-3.9%
2020	16,316	10,086	17,759	220	44,381	-4.8%
2021	16,387	10,768	18,469	216	45,839	3.3%
2022	15,799	10,817	18,519	208	45,343	-1.1%
2023	15,491	10,813	18,721	205	45,230	-0.2%
2024	15,528	10,835	18,555	203	45,121	-0.2%
2025	15,523	10,799	18,426	202	44,949	-0.4%
2026	15,580	10,781	18,293	200	44,855	-0.2%
2027	15,651	10,787	18,219	199	44,856	0.0%
2028	15,767	10,832	18,220	198	45,017	0.4%
2029	15,838	10,846	18,187	198	45,069	0.1%
2030	15,974	10,887	18,123	198	45,182	0.3%
2031	16,123	10,949	18,110	199	45,381	0.4%
2032	16,303	11,069	18,107	199	45,678	0.7%
2033	16,447	11,155	18,107	199	45,907	0.5%
2034	16,654	11,290	18,121	199	46,264	0.8%
2035	16,864	11,439	18,131	199	46,634	0.8%
2036	17,129	11,630	18,151	199	47,110	1.0%
2037	17,307	11,779	18,170	199	47,456	0.7%
2038	17,480	11,951	18,204	199	47,835	0.8%
2039	17,695	12,127	18,252	199	48,272	0.9%
2040	17,954	12,324	18,300	199	48,777	1.0%
2041	18,100	12,454	18,316	199	49,069	0.6%
2042	18,305	12,623	18,342	199	49,469	0.8%
Compound Annual Growth Rate 2023-2042						
	0.9%	**0.8%**	**-0.1%**	**-0.1%**	**0.5%**	

High electrification

To align with the draft MI Healthy Climate Plan, this scenario assumes 50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales are electric by 2030. Additionally, it is assumed that there are increased incentives around existing programs to turn over baseboard, propane and fuel oil heating systems and quickly replace them with heat pumps.

Stakeholder

This scenario was developed through the stakeholder collaboration process to assess the impact of higher penetrations of electric vehicles. The assumptions are the same as in the high electrification case as it relates to electric vehicles with 50% of light-duty vehicle sales, 30% of medium-duty and heavy-duty sales, and 100% of bus sales being electric by 2030.

Stakeholder with high distributed generation

This sensitivity was also developed through the stakeholder collaboration process to assess the impacts of both aggressive DG adoption and increased penetration of electric vehicles. The stakeholder scenario was used as the starting point and included 25% annual growth of rooftop solar from 2023-2030 and 15% annual growth from 2031-2042.

Stakeholder with high fuel switching

This sensitivity was also developed through the stakeholder collaboration process to assess the impacts of both increased electric vehicle penetration and high levels of fuel switching from natural gas end uses to electric. The stakeholder scenario was used as the starting point and included aggressive building electrification assumptions. It is assumed residential customers adopt heat pumps for heating as well as heat pump water heaters at a rate of 30% saturation and 50% saturation by 2030 and 2042 respectively. It is also assumed small commercial and industrial customers are fully electrified at a rate of 20% saturation and 50% saturation by 2030 and 2042 respectively.

Electric Choice cap increases to 15%

An additional sensitivity was also developed through the stakeholder collaboration process to assess the impact of increasing the retail open access cap from 10% to 15% by June 1, 2024. New Choice customer enrollments begin in March, which is when the new Choice load was assumed to begin in 2024. The full year of 15% Choice is reflected in 2025.

Climate change

The climate change sensitivity was performed to assess the potential impacts on electricity consumption through trends in temperatures and uses the reference case as the starting point. Trends in temperature from 1960-2021 were applied to the normal weather assumed in the starting point. The increasing temperature trend was applied in the form of cooling degree days (CDDs) and heating degree days (HDDs) to project changes in load. The results indicated annual increases in CDDs and annual decreases in HDDs, which results in higher summer loads and lower winter loads.

Figure 10.6.1: Load sensitivity bundled sales (GWh)

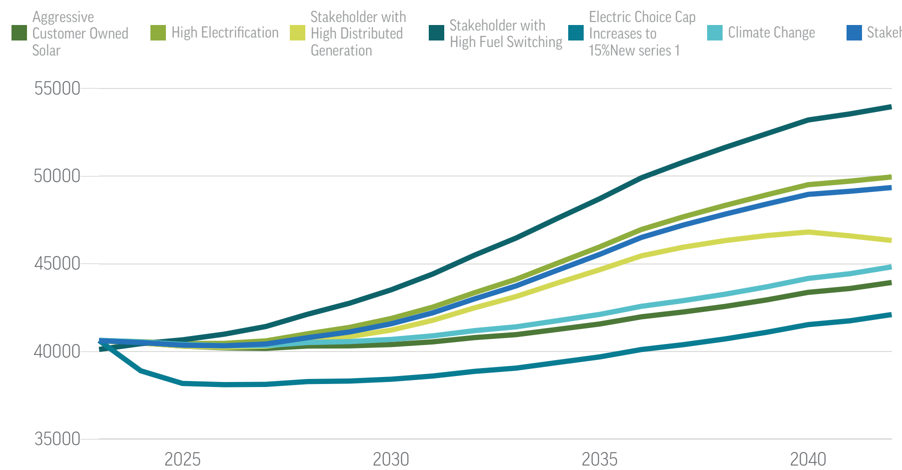
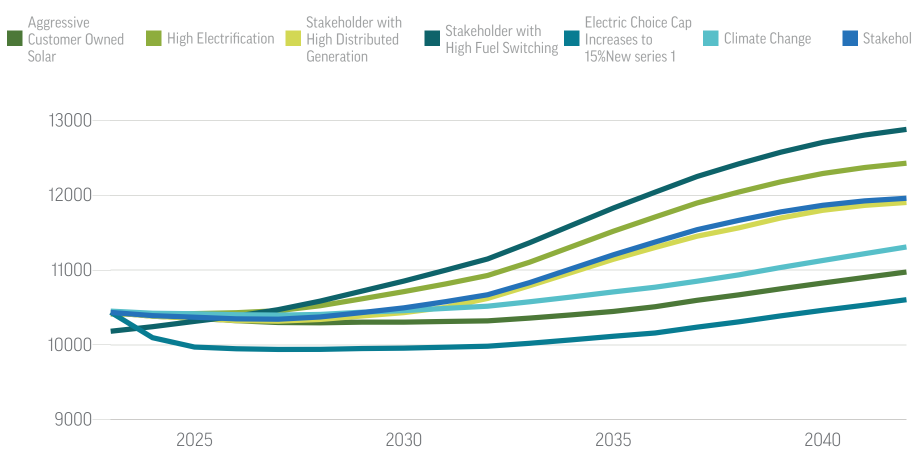


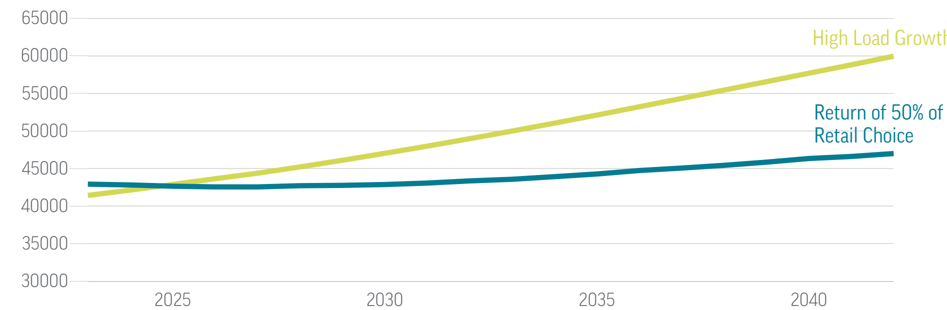
Figure 10.6.2: Load sensitivity bundled peak sales (MW)



High load growth and 50% Electric Retail-Choice return

The Commission's final order, Case No. U-18418, specified the IRP modeling parameters and requirements. It also specified sensitivities within the parameters regarding the load projection. Under the business-as-usual scenario, two sensitivities were required: (a) High load growth: Increase the energy and demand growth rates by at least a factor of two above the business-as-usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the business-as-usual load projection and the high-load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity. (b) If the utility has retail-choice load in its service territory, model the return of 50% of its retail-choice load to the utility's capacity service by 2023[1]. The alternative forecast sensitivities, in accordance with Case No. U-18418, are displayed in Figure 10.6.3.

Figure 10.6.3: U-18418 Alternative forecast sensitivity sales (GWh)



A comparison of the growth rates for all the sensitivities is shown in Table 10.6.4.

Table 10.6.4: Load sensitivity growth rates

From 2023-2042	Service Area Sales	Bundled Sales	Service Area Peak	Bundled Peak
Starting Point	0.5%	0.5%	0.3%	0.3%
Aggressive Customer Owned Solar	0.4%	0.4%	0.3%	0.3%
High Electrification	1.1%	1.1%	0.9%	0.9%
Stakeholder	1.0%	1.0%	0.7%	0.7%
Stakeholder with High Distributed Generation	0.7%	0.7%	0.7%	0.7%
Stakeholder with High Fuel Switching	1.6%	1.6%	1.2%	1.2%
Electric Choice Cap Increases to 15%	0.5%	0.2%	0.3%	0.1%
Climate Change	0.5%	0.5%	0.4%	0.4%
High Load	2.0%	2.0%	1.7%	1.8%
Return of 50% of Choice	0.5%	0.5%	0.3%	0.3%

Endnotes

1. Exhibit A, Order issued 11/21/2017 in MPSC Case No. U-18418, page 16.

SECTION 11

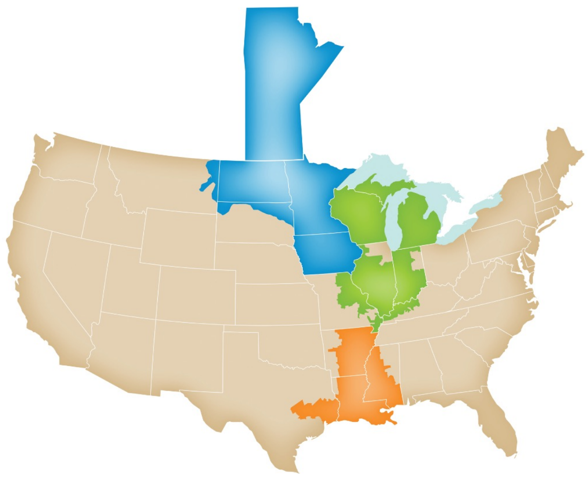
11 Capacity and reliability

11.1 Overview

Midcontinent Independent System Operator

DTE Electric is a market participant in the Midcontinent Independent System Operator (MISO), a Regional Transmission Organization (RTO) established to ensure reliability and grid stability across 15 U.S. states and Manitoba.

Figure 11.1.1 - MISO service territory



MISO energy market

DTE Electric sells generation and purchases energy from the wholesale power market in both the day-ahead and real-time energy markets and participates in the MISO Resource Adequacy process. These markets are regulated by the Federal Energy Regulatory Commission (FERC). As a market participant, the Company must comply with the FERC-approved MISO tariff.

Market prices are determined on an hourly basis through day-ahead and real-time markets. The day-ahead market is a financially binding market that is used to schedule generation to meet a projected demand for the next operating day. The real-time market settles differences between day-ahead positions and actual operations in real time. The Company can sell power from its generation assets and purchase power to serve its customer load more reliably and economically participating in these markets, compared to using only its own generation. The Company expects to continue to operate in the MISO markets for the foreseeable future.

MISO enables open access to transmission for new generation and performs reliability studies to determine whether transmission upgrades are needed. The allocation of costs associated with transmission upgrades are set forth by the MISO tariff. DTE Electric operates within the International Transmission Company (ITC) transmission area and is subject to specific tariff language for generation interconnection. Unlike other transmission owners in MISO, ITC reimburses new generators for the interconnection costs associated with transmission upgrades.

MISO ancillary service market

MISO administers day-ahead and real-time markets for operating reserves where each of the three operating reserve products

– regulating, spinning and supplemental – are bought and sold. Regulating reserve is the ability to generate resources to raise or lower output to respond to the moment-to-moment changes in demand and frequency. Spinning reserve is synchronized unloaded resource capacity set aside to be available to immediately offset deficiencies in energy supply that result from a resource contingency or other abnormal event. Supplemental reserve is unloaded (possibly offline) resource capacity set aside to be fully available within the contingency reserve deployment period (typically 10 minutes) to offset deficiencies in energy supply that result from a resource contingency or other abnormal event.

Reactive supply and voltage control supplied by facilities that can be operated to produce or absorb reactive power to control voltage on the system. MISO/ITC administers this service, ensuring it is sold by qualified generators and purchased by transmission customers. These products' current value in the MISO market is relatively small. However, their value may increase in the future as renewable-generation penetration increases.

MISO capacity market

MISO has a hybrid voluntary annual capacity construct that requires all available generation in the MISO region to participate in an annual planning resource auction (PRA) and be available for all 8,760 hours of the following MISO planning year (PY). Load-serving entities can either participate in the auction (bid their load into annual auction) or pay a capacity deficiency charge. The MISO planning year runs from June 1 to May 31. The forward capacity market is designed to ensure sufficient resources are in place to reliably serve load on a forward-looking basis. Load-serving entities can meet their Planning Reserve Margin Requirement (PRMR) by offering or self-scheduling capacity resources and bidding load demand into the auction. Alternately, they can opt out of the auction by submitting a fixed resource adequacy plan, which offsets capacity resources and load demand.

11.2 Resource adequacy construct

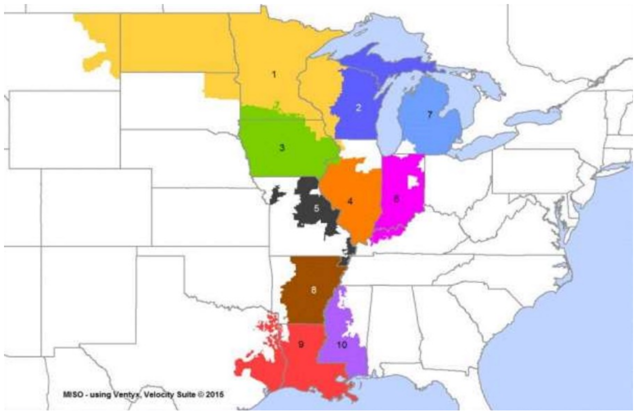
Planning Reserve Margin Requirement

Under the MISO Resource Adequacy construct, MISO sets an annual capacity requirement for the following planning year – the PRMR – for load-serving entities based on their peak demand forecast coincident with the MISO peak, plus a planning reserve margin. The Planning Reserve Margin is established to confirm there is sufficient generation resource capacity to ensure that interruption of firm customer demand – known as "loss of load expectation" – occurs no more frequently than one day in 10 years. MISO requires all market participants to secure resources to meet the PRMR and thus achieve the loss of load expectation.

In simpler terms, demand (load) must be balanced with supply (resources). If the two are unbalanced, there is either an excess of capacity and supply is greater than demand, or there is a capacity shortfall and demand is greater than supply. A market participant with a capacity shortfall to its PRMR is required to purchase sufficient zonal resource credits for the entirety of the MISO planning year to avoid paying a capacity-deficiency charge. In addition, MCL 460.6w (PA 341) requires the Company to annually demonstrate that it will have sufficient resources to meet its projected planning reserve margin on a four-year forward basis. This Michigan requirement is intended to ensure proper longer-term planning for resource adequacy, which is different from MISO's annual planning cycle, which focuses on one year.

MISO has divided its region into 10 sub-regions known as local resource zones to support regional transmission and system constraints. DTE Electric's load demand rests entirely within Zone 7; all company-owned and contracted generation-capacity resources with the exception of L'Anse Warden PPA, Garden Wind PPA, and Fairbanks Wind (Zone 2), are also in Zone 7. Zone 7 PRMR for the 2022-2023 MISO planning year is 21,886 MW using MISO PRA data published April 4, 2022.

Figure 11.2.1: MISO local resource zones



Local reliability requirement

The MISO local reliability requirement is the minimum amount of unforced capacity (the amount of installed capacity available at any time, after accounting for unit forced-outage rate) that must be physically located in a local resource zone to maintain a loss of load expectation of one day in 10 years, without consideration of the benefit of imports from other zones by use of the electric transmission system. The MISO Loss of Load Expectation Working Group (LOLEWG) analysis determines the minimum local reliability requirement by either adding or removing planning resources (electric generation) until the loss of load expectation reaches the target of interruption of firm demand no more frequently than one day in 10 years.

Capacity import limit and capacity export limit (LOLEWG)

The LOLEWG determines the capacity import limit and capacity export limit to and from each MISO local resource zone. The limits are the electric transmission import and export capability that can be reliably depended upon to transport power between zones. The LOLEWG updates the limits annually to capture changes in these capabilities as a result of modifications to the electric system.

MISO has determined a Zone 7 capacity import limit of 3,749 MW and export limit of 2,392 MW for the 2022-2023 PY.

Local clearing requirement

To ensure adequate supply and reliability, each zone has a local clearing requirement, or the minimum amount of resources that must be physically located within the zone taking electric transmission import capability into consideration. The local clearing requirement is equal to the local reliability requirement less the capacity import limit for the zone and less non-pseudo tied exports for the zone. The past few years, this requirement has averaged approximately 97% of the resources having to be sourced within MISO Zone 7. The PRMR for the zone less the local clearing requirement equals the effective capacity import limit (ECIL) for that zone. Non-pseudo tied exports are those exports in which MISO maintains dispatch control of the generating resource.

DTE Electric capacity meets PRMR

For the 12-month period beginning June 1, 2022 (MISO PY 2022-2023), MISO determined an unforced capacity planning reserve margin (PRMUCAP) of 8.7%. Applied to the Company's adjusted peak demand (plus transmission losses) of 9,924 MW, this results in a Company PRM of 863 MW. As discussed in Section 7, DTE Electric's generation assets include a diverse mix of owned and contracted sources of energy to ensure reliable and economical capacity adequacy for its customers. The Company is meeting its 863 zonal resource credits (ZRCs) of PRM using a combination of baseload, cycling, peaking, intermittent, short-term purchases, demand-side and storage resources.

Resource adequacy changes

MISO filed with the Federal Energy Regulatory Commission (FERC) tariff changes to alter its resource adequacy construct from an annual to a seasonal approach (spring, summer, fall and winter) and incorporate planned outages performance under tight system hours as part of the capacity resource accreditation. The seasonal approach will be similar to the annual construct with a single planning reserve auction that solves for each season. This will likely impact resource outage planning and provide a more granular focus on resource adequacy across the entire planning year. The Seasonal Accredited Capacity filing (Docket No. ER22-495) was approved by FERC on August 31, 2022, with MISO requesting the implementation starting with PY 2023/2024. Due to the timing of the FERC approval and the limited information the Company has received from MISO, the Company does not have an accurate Zone 7 capacity forecast under the new construct prior to this case filing. However, capacity position under a range of scenarios was considered as part of the risk analysis as discussed in Sections 5.3 and 15.12.

MISO has recently started to discuss, through the stakeholder process, further changes to how accreditation is done for nonthermal (including intermittent and DR) resources. Preliminary discussions indicate a potential negative accreditation impact on these types of resources in the future, though impact will vary by resource-type and season.

11.3 Capacity accreditation of resources

Each resource modeled in the IRP has a "firm capacity" associated with it. For most resources, this is identical to the MISO historical attribution of the Effective Load Carrying Capability (ELCC). The 2022 MISO attributions of the existing resources except for existing solar were used in all years. All solar ELCCs, including existing and approved solar in the starting point were assumed to be the same as new installed solar selected by the model. For new thermal resources, the MISO class average was used. For new wind resources, the Zone 7 class average was used. For new solar and storage resources, a study was completed by Astrapé Consulting using the Strategic Energy Risk Valuation Model (SERVM) model to establish the ELCC of those resources to be used in the EnCompass model.

Thermal units are considered to be firm dispatchable units, which means aside from random outages, these resources are available when they are needed to produce energy to serve customer loads. On the other hand, solar and storage units are both considered energy limited – that is, these units' output depends on the weather conditions or the state of charge of the storage units, to be available to serve customer loads when called upon. As more and more solar units are built in the region, they will all have similar generation profiles and the solar generation will be very plentiful at certain times.

Solar units and storage units are synergistic with respect to firm capacity or being available on peak. This is known as a diversity benefit. If there is more solar generation for the storage to shift to when it's needed, this benefits the ELCC solar + storage resource. Similarly, if there are more storage resources on the system, more excess solar generation can be shifted to when it is needed.

The Company used the initial results from the Astrapé Resource Adequacy study to determine tiered solar and storage ELCCs to use in the EnCompass model. Two factors impact the firm capacity of the solar value:

1. The amount of solar that has been installed in the rest of Zone 7 (non-Company controlled).
2. The total amount of storage that has been installed in Zone 7 (Company and non-Company).

Assumptions must be made about these two factors when developing the tiered firm capacities of DTE Electric solar to use in the EnCompass model.

The Company assumed the rest of Zone 7 builds mirrored its assumptions for solar and storage build. This was because market forces across Zone 7 would be similar; if solar and storage was being selected in DTE Electric's section of the zone, those same market forces would drive a similar selection in the rest of the zone.

The resulting ELCCs assumed in the IRP modeling are shown in figures 11.3.1 and 11.3.2.

Figure 11.3.1: Solar ELCC based on Astrapé RA model

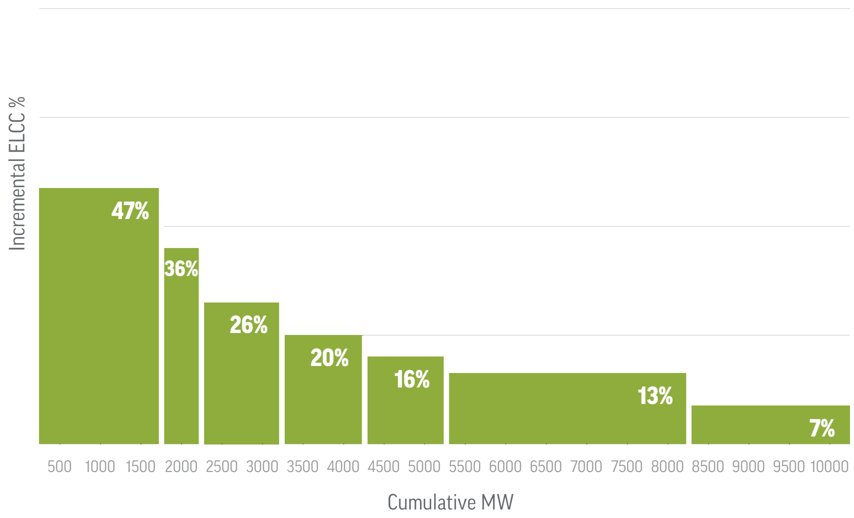
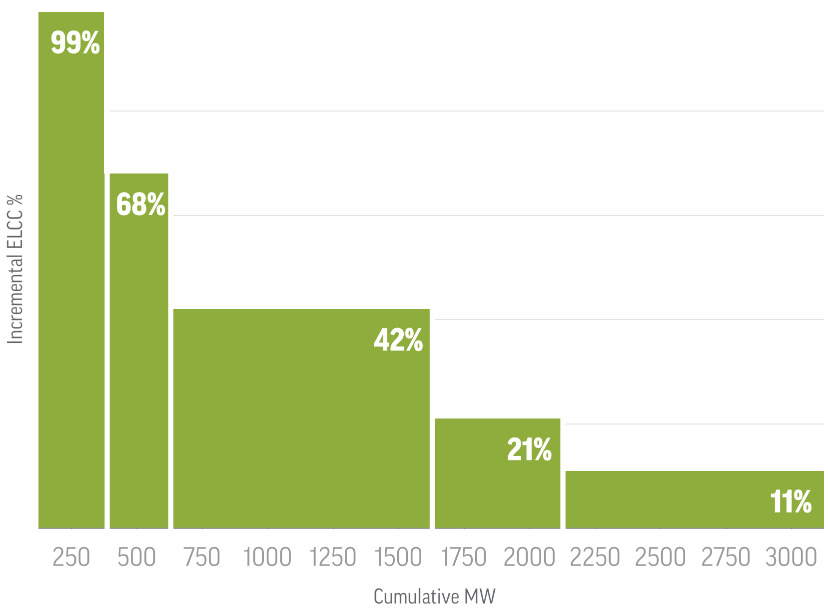


Figure 11.3.2: Storage ELCC based on Astrapé RA model



SECTION 12

12 Transmission and distribution analysis

12.1 Overview

In 2003, DTE Electric sold its transmission system to ITC Holdings Corp, which became responsible for the ownership, operation, maintenance and planning of the transmission system in the Company's service territory. ITC subsequently joined MISO and thereby became bound by its tariff provisions and business practice manuals, which define processes through which the transmission system is operated and planned. Thereafter, MISO became responsible for providing transmission service to the Company.

MISO is a Regional Transmission Organization (RTO) that manages the electric power system in several U.S. states and one Canadian province and its regulated by the Federal Energy Regulatory Commission (FERC). This management includes transmission system planning. The MISO Transmission Expansion Plan (MTEP) process evaluates the need for upgrades to the transmission system for reliability, economic or policy-driven purposes and establishes a framework for MISO stakeholder input. Although transmission owners are obligated to propose solutions to identified reliability issues on the transmission analysis, MISO will consider other stakeholder input in its determination of the final project implemented. After stakeholder review, MISO's board of directors approves justified projects in Appendix A of MTEP, at which point the appropriate transmission owner must make a good-faith effort to construct the project.

12.2 Collaboration with ITC

ITC Transmission (ITC), a subsidiary of ITC Holdings Corp, a Fortis Inc. company. ITC or ITCT is a fully regulated company under the jurisdiction of the Federal Energy Regulatory Commission (FERC) that operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in DTE Electric's service territory. ITC Holding's transmission systems in Michigan include the ITCT and Michigan Electric Transmission Company (METC) transmission systems. METC operates high-voltage systems that transmit electricity from generating stations to local electricity distribution facilities in most of Michigan's lower peninsula.

DTE Electric engaged ITC to discuss the IRP and requested an analysis of the ITCT and METC transmission systems due to the potential changes to DTE Electric's generation fleet. The analysis was designed to include both generation and transmission considerations in the IRP process and includes cost estimates for new generation interconnections and associated transmission upgrades required to support different potential retirement scenarios. The Company met with ITC on a regular cadence to establish and discuss the studies' scope, the specific scenarios most relevant to the IRP, and the studies' results and significance. ITC also performed an analysis of the transmission upgrade costs needed to accommodate the Company's PCA and an analysis of the capacity import limit (CIL) under conditions similar to those contemplated in the Company's IRP.

Transmission analysis

In order to identify likely transmission system challenges and opportunities related to its IRP, the Company requested that ITC study scenarios with varying assumptions. ITC analyzed three different scenarios over a 20-year time horizon with various retirement and generation assumptions. Additionally, ITC performed a simplified analysis[1] on a fourth scenario with increased renewable additions in the 10-year horizon.

The analysis by ITC was designed to determine the nature and extent of transmission planning violations (e.g., voltage levels not meeting specified criteria) associated with changes in the generation resources (within in Zone 7) as well as estimates of the costs to resolve such violations and to interconnect new generation resources. In the analyses, ITC modeled snapshots of the transmission system representing summer peak and summer shoulder peak load conditions to evaluate key risk items. The factors evaluated within the transmission system impacts include generation retirement, generation interconnection, generation attributes, load forecasts, and planned transmission changes. The analysis was based on ITC's published planning practices and criteria in accordance with the National Electric Reliability Council (NERC) TPL (Transmission Planning) Standards.

The key analyses performed by ITC included the following:

- Steady state analysis – Thermal and voltage violations on the transmission system.
- Stability analysis – Testing electrical system's ability to maintain generation and load balance (stay in synchronism) after major disturbances given the scenario impacts due to the retirement of major generating units.
- Transmission system upgrade cost estimation – Costs to mitigate violations to the transmission planning criteria associated with both retirement of existing generating units and additions of new resources.
- New generation interconnection direct attachment facility cost estimation.
- Capacity import limit (CIL) analysis – Impacts from DTE Electric's PCA to the capacity import capability of the lower peninsula of Michigan.

12.3 ITC's transmission evaluation

ITC's analysis showed that substantial enhancements to the transmission system will be required to support all four scenarios with the difference between them being the timing of the transmission enhancement and associated costs. The transmission enhancements would accommodate the retirement of the Company's coal generation and the interconnection of new generation. Except for the simplified analysis, the evaluation that ITC performed included steady-state thermal and voltage analysis, along with transmission stability analysis for each scenario. The analysis also included a summary of the corrective action plans, including transmission upgrades and the interconnection facilities required for each case. The required enhancements included upgrades to station equipment, underground cable systems and overhead lines, as well as static and dynamic reactive devices. As shown in Table 12.3.1, ITC estimated that the cost of the transmission enhancements would range between $1 billion and $1.3 billion over the 20-year time horizon. There were several additional considerations, not included in the analysis, that could also impact the results. These included the study being limited to the generation expansion plans within Zone 7 only, single contingency events, and a limited scope of the long-range transmission plan (LRTP) projects (Zone 7 only). More mitigation will be needed as the transmission system is studied for multiple contingency events as MISO completes their studies. Lastly, cost estimations were based on today's dollars with no inflation rate and were premised upon numerous assumptions; consequently, the actual costs will vary depending on the actual timing and amount and location of generation additions, retirements, and the corresponding system power flows as well as the cost of land, materials and equipment.

Table 12.3.1: ITC Estimated Scenario Costs[1]

Scenario	Model Year	Retirement	Incremental Replacement	Total Costs1 ($M)
ITC Scenario-1				
	5 year	Belle River 1-2	665 MW Solar	$130 - $210
	10 year	Monroe 1-4	5654 MW Solar 1450 MW Storage 1350 MW CCGT w/CCS/SMNR	$850 - $1,120
	15 year	No New Retirements	No New Additions	$870 - $1,140
	20 year	No New Retirements	1000 MW Solar 550 MW Storage 150 MW CCGT w/CCS	$1,000 - $1,270
ITC Scenario- 2a				
	5 year	Belle River 1-2	665 MW Solar	$130 - $210

Scenario	Model Year	Retirement	Incremental Replacement	Total Costs1 ($M)
	10 year	Monroe 3-4	2654 MW Solar 300 MW Storage 700 MW CCGT w/CCS	$630 - $800
	15 year	Monroe 1-2	3000 MW Solar 1150 MW Storage 650 MW SMNR or CCGT w/CCS	$870 - $1,140
	20 year	No New Retirements	1000 MW Solar 550 MW Storage 150 MW CCGT w/CCS	$1,000 - $1,270
ITC Scenario- 2b				
	5 year	Convert Belle River 1-2		0
	10 year	Monroe 3-4	1619 MW Solar 125 MW Storage	$360 - $450
	15 year	Monroe 1-2	3000 MW Solar 875 MW Storage 750 MW SMNR or CCGT w/CCS	$570 - $790
	20 year	Belle River 1-2	2700 MW Solar 1000 MW Storage 750 MW CCGT w/CCS	$1,000 - $1,270
ITC Scenario- 3				
	5 year	Belle River 1-2	665 MW Solar	N/A
	10 year	Monroe 1-4	8335 MW Solar 2500 MW Storage 2000 MW Wind 250 MW DR	

1. All values are cumulative"

The IRP process used key insights from the ITC study, along with other studies, to balance customer affordability with reliability to support local generation flexibility and help maintain a stable voltage. Reactive power (VARS) is required to maintain the system voltage to deliver real power (watts) through transmission lines. The grid reliability modeling performed by ITC was part of a comprehensive modeling process by which the Company incorporated learnings into the IRP process and PCA development to ensure reliability and affordability were incorporated into the PCA. The PCA was similar to one of the scenarios modeled by ITC, with a conversion of Belle River to a natural gas peaking resource, a phased approach to the retirement of Monroe, and the deployment of a new dispatchable resource, resulting in fewer reliability impacts and associated costs in the earlier years of the study. ITC's study also revealed the need for 650 MVAR of reactive resources for the system to be reliable once Belle River and Monroe fully retire. The PCA defers the need for this 650 MVAR of reactive resources.

Capacity import analysis

Import capacity is a measure of the transmission system's ability to transfer power from another zone. In MISO's Resource Adequacy construct, the Capacity Import Limit (CIL) and Capacity Export Limit (CEL) represent the amount of power that can be transferred between zones during the system coincident peak load. The Company's assumptions about the CIL and CEL were based upon public reports from MISO. Specifically, the Company assumed the 2022-2023 values of 3,749 MW for the CIL and 2,392 MW for the CEL contained in MISO's Loss of Load Expectation (LOLE) Study Report for Planning Year 2022-2023.

The Company requested that ITC perform an analysis of capacity imports into Michigan to understand the effects that generation additions and retirements contemplated in the Company's IRP may have on future CIL values. ITC performed this analysis using a methodology consistent with MISO's annual LOLE analysis for the Company's preliminary PCA. Results from ITC's analysis are provided in Table 12.3.2.

Table 12.3.2: ITC capacity import analysis

Key Study Year	Preliminary PCA (Without LRTP)	Preliminary PCA (With LRTP Tranche 1 Projects 2030)
2028	4500 MW	6500 MW (after 2030)
2035	4200 MW	6300 MW

As can be seen from this analysis, the Company's PCA would not adversely affect the system's ability to import power from neighboring regions.

12.4 Distribution analysis

The Distribution Operations (DO) team supported several analyses for the IRP, including assumptions related to transmission and distribution. Specifically, DO developed assumptions to reflect the estimated deferred transmission and distribution costs associated with the EWR program.

In addition, a study was performed in 2021 by Sargent and Lundy under DO's direction that quantifies the potential distribution and subtransmission grid upgrade costs that would result from Belle River and Monroe power plant resource retirement scenarios as shown in Table 12.4.1

Table: 12.4.1 Distribution and subtransmission system upgrade estimates for plant retirements

Belle River	Monroe	Distribution/Subtransmission Cost Estimate
Off	2 units off	$60 - $70M
On	2 units off	$60 - $70M
On	4 units off	$90 - $110M

Distributions Operations also supported the analysis of peaking generation in collaboration with the Energy Supply team in support of the IRP. Specifically, peakers were reviewed to identify those with known distribution system impacts. DTE Electric maintains operating practices which document the system load conditions and equipment shutdowns that trigger the use of localized peaking generators. During these known conditions, local generation resources such as peakers that are able to supply reactive power, are utilized to temporarily help support distribution system demands, and can minimize potential overloads and voltage drops. If not mitigated, the retirement of peaking units with known distribution system impacts may produce reliability issues and low voltage violations during both planned and unplanned outages since these units would be unavailable to support the distribution and transmission systems.

To accommodate the loss of peaker benefits, distribution grid mitigation projects will likely be required to minimize the risk of distribution system failure during adverse system conditions. In cases where an impact to the distribution system was identified, DO estimated preliminary mitigation costs associated with upgrading the distribution system as well as potential transmission costs.

Endnotes

1. Due to the simplified nature of the analysis it was limited in scope and did not include dynamic stability analysis

SECTION 13

13 Fuel

13.1 Overview

DTE Electric has several existing fossil-fuel-generating facilities. The largest portion of its current capacity mix is coal generators, including those at the Monroe and Belle River Power Plants. The Company also has gas-fired generating capability at its Blue Water Energy Center (BWEC), as well as at peaking plants, including Greenwood, Renaissance, Dean, Belle River, Delray and others. Furthermore, the Company has oil-fired generating capability at its Monroe and Belle River Power Plants along with a number of oil-fueled peaking units.

13.2 Natural gas

Natural gas overview

DTE Electric currently uses natural gas as the primary fuel at its Blue Water Energy Center, Greenwood, Renaissance, Belle River and Dean peakers, as well as at other smaller peaking units. Depending on the location, natural gas and natural-gas transportation are procured from supply and transportation providers, via third-party marketers or from local distribution companies (LDCs).

The Company entered into an agreement with NEXUS Gas Transmission to provide firm natural-gas transportation from the Utica and Marcellus shale region starting in November 2018. Similar to the Company's approach to coal and coal-transportation procurement, future gas-supply and firm transportation contracts will be secured to ensure reliability.

Delivered natural-gas prices to existing and planned utility-owned generating plants

Forecast methodology

When forecasting natural-gas prices, the commodity costs are added to the applicable transportation costs to determine the delivered cost of natural gas to each generation facility.

Forecasted natural gas prices

The forecast methodology was based on the forecasted prices at the applicable natural-gas hub locations in or around Michigan, including MichCon CityGate and Dawn. For years 2023 through 2025, the near-term futures prices are transitioned to the long-term gas price forecast from Siemens. The long-term Siemens forecast was used exclusively starting in 2026.

Forecasted transportation prices

Next, forecasted transportation costs were added to the forecasted natural gas prices, as applicable, to represent the costs associated with transporting the gas from the relevant hub to the power plant. Depending on the plant and location, transportation costs may have been based on existing agreements or general service tariff rates.

A brief summary of how natural gas is supplied to each of the Company's gas-fired generators is provided next.

BWEC

DTE Electric purchases gas year-round with a combination of short-term and long-term purchases. In order to reduce exposure to spot prices and reduce price volatility for our customers, approximately two-thirds of BWEC's supply will be purchased on a forward basis at fixed prices. The Company has firm transportation agreements with Vector and Enbridge for access to the Dawn hub and with DTE Gas and NEXUS for access to the Utica Marcellus region, providing redundancy in transportation service to diverse locations of gas supply. The Company has firm storage and balancing agreements with Enbridge and Washington 10, which include approximately 7.5 Bcf of storage capacity. These contracts allow for multiple ways to service BWEC reliably, while minimizing costs to its Power Supply Cost Recovery customers.

Renaissance

DTE Electric purchases gas at MichCon CityGate from a third-party gas marketer. The Company has a firm gas-transportation agreement with DTE Gas to transport that gas on its system to the plant. The Company's agreement with DTE Gas includes approximately 1.1 Bcf of firm storage capacity.

Greenwood and Greenwood peakers

Greenwood gas supply and transportation is provided by a third-party gas marketer. The gas is delivered to the ANR Pipeline interconnect with the SEMCO lateral. The Company has a firm gas-transportation agreement with SEMCO to transport gas from the ANR Pipeline interconnect to the plant. The Company pays for gas based on prices at the Dawn hub, plus applicable transportation costs.

Dean

DTE Electric purchases gas at MichCon CityGate and Dawn from a third-party gas marketer. The Company has a firm transportation agreement with DTE Gas to transport that gas to the plant. The Company also has an agreement with DTE Gas for balancing services, which includes approximately 0.3 Bcf of firm storage capacity.

Belle River peakers

DTE Electric purchases gas from third-party marketers at the China Township point on the Great Lakes Gas Transmission pipeline. The Company has a firm transportation agreement with SEMCO to transport gas from Great Lakes Gas Transmission to the Belle River Peakers.

Delray and Dearborn

DTE Electric purchases gas at MichCon CityGate from third-party gas marketers. The Company has a firm transportation agreement with DTE Gas to transport that gas to the plants. The Company's transportation agreements with DTE Gas include approximately 0.35 Bcf of firm storage capacity.

St. Clair peakers

DTE Electric purchases delivered natural gas from SEMCO Energy under LDC tariff service.

Proposed Belle River Power Plant conversion

The Belle River Power Plant is located adjacent to the Company's BWEC site and is located approximately one mile from three major pipeline systems – Vector Pipeline, DTE Gas and Great Lakes Gas Transmission. The Company intends to interconnect with the Vector lateral that currently serves BWEC to provide gas supply to Belle River. The BWEC lateral was prudently designed to have sufficient capacity to accommodate the natural gas requirement of both BWEC and an additional future gas-fired resource such as the Belle River Power Plant when it is converted to natural gas. This interconnect will allow for access to both the DTE Gas and Vector Pipeline systems for transportation services and to Washington 10 and Enbridge Gas for storage and balancing services. In addition, natural gas hubs at MichCon (upstream) and Dawn (downstream) provide liquid markets to procure natural gas supplies.

This IRP assumes that the Company will contract with Vector Pipeline for firm transportation services and with Enbridge Gas for firm transportation, storage and balancing services, and procure gas at the Dawn hub. The Company utilized its contracted rates for BWEC with Vector Pipeline and Enbridge Gas to estimate the cost of these services by scaling the costs based on the capacity of the Belle River Power Plant when it is converted to natural gas. This assumption results in an estimated annual fixed fuel costs of $7.4 million for transportation, $9 million for storage and balancing, and a one-time cost of $6.6 million to interconnect with the existing Vector lateral and to expand metering capacity to accommodate the additional load. Considering that Belle River is expected to operate as a peaking or cycling plant with a relatively low capacity factor, the entirely firm services described above are conservative estimates of the necessary gas supply services to reliably serve the plant. The Company will utilize a request for proposals to facilitate a competitive bidding process for gas supply services, which may result in lower costs than assumed in this IRP.

Assumptions for new gas sites

While no specific plant site has been identified at this time, the Company estimated fuel supply costs for a new combined cycle gas turbine (CCGT) with carbon capture and sequestration (CCS) based on a generic South Area location considering that the plant is forecasted to replace the Monroe Power Plant capacity. Similar to BWEC, the Company would enter into firm transportation and storage agreements for the new CCGT with CCS to ensure supply reliability. The Company estimated the costs of the lateral, transportation, and balancing services, resulting in estimated annual fixed fuel costs of $7.5 million for transportation and $8.7 million for storage and balancing.

Natural gas price forecasts utilized for IRP modeling

Three natural-gas price forecasts, at each relevant gas hub, were used for modeling purposes. Figure 4.4.1 shows these natural-gas price forecasts based on the MichCon gas hub and reflects the commodity price.

The Company's reference natural-gas forecast was used in the Reference and the High Electrification scenarios. As the forecast methodology section states, the first three years were a transition from the forward prices as of late 2021 to the long-term gas price fundamental forecast from Siemens.

The 2021 EIA natural-gas forecast was used in the four required MIRPP scenarios and the STAKE scenario, instead of a Siemens fundamental forecast. The first three years are a transition from these prices to the long-term gas price forecast from the 2021 EIA.

In the high gas sensitivity, the June 2022 forwards were used for years 2023-2032. Following year 2033, the natural gas fuel price projections gradually increased up to 200% of the 2021 EIA gas price forecasts by the end of the study period. The 2022 EIA natural gas price forecast was used for the period 2028 to 2042 in the REFRESH scenario.

Transportation costs were added to the supply costs to represent the costs associated with transporting the gas from the relevant hub to the power plant. Depending on the plant and location, transportation costs may have been based on existing agreements or general service tariff rates.

13.3 Coal

Coal overview

DTE Electric's coal-fueled power plants consume a combination of low-sulfur western coal (LSW) and high-sulfur eastern coal (HSE), along with petroleum coke, as shown in Figure 13.3.1. LSW accounted for approximately 85% of the Company's coal consumption in 2021, due to its favorable pricing and emissions when compared to HSE coal. Although LSW is historically lower in cost on a per-ton delivered basis, the Company's Monroe Power Plant has the ability to blend HSE coal with LSW coal to utilize the higher heat content of HSE coal and maximize production during high-market opportunities. In addition to LSW and HSE coal, petroleum coke (petcoke), a byproduct of the petroleum refinement process, is an economic fuel that provides higher heat content when compared to coal. Petcoke is consumed only at the Company's Monroe Power Plant due to its emissions control equipment.

Delivered coal prices to existing utility generating plants

Forecast methodology

Coal commodity costs were added to transportation rate (including railcar costs) to determine the delivered cost of coal by route to each generation facility. Beyond the forecast's first five years, the Company utilized the escalation rate from the Siemens coal forecast.

Forecasted coal prices

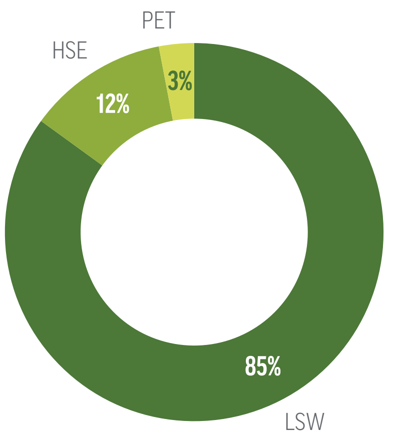
For 2023 and 2024, the coal cost forecast was developed by utilizing existing contract prices and forecasted forward market prices. Forecasted forward market coal prices were based upon market information obtained from an over-the-counter coal broker. For 2026 and 2027, the forecasted coal cost was derived by applying an inflation index factor to the 2025 forward market coal prices. Beyond 2027, the Company utilized the Siemens forecast escalation applied to the forward market coal prices.

Forecasted transportation prices

The near-term transportation rates were computed by applying adjustments to the existing contract rates using either prescribed periodic rate increases, or rate increases based upon contractually defined indices. In the latter case, historical data was utilized to project future rate adjustments.

A brief summary of how coal is supplied to each of the Company's coal-fired generators is provided below.

Figure 13.3.1: DTE Electric 2021 coal consumption



To ensure reliable supply, reduce exposure to spot prices, and reduce price volatility for our customers, approximately three-quarters of DTE Electric's total coal supply requirement is purchased on a forward basis at fixed prices.

Belle River Power Plant

Belle River exclusively consumes LSW from Montana, which is transported via rail to DTE Electric's subsidiary, Midwest Energy Resources (MERC), in Superior, Wisconsin. MERC provides trans-shipment services to the Company and other third-party customers. The coal is then held in inventory and subsequently loaded into lake freighters for transportation to the power plant.

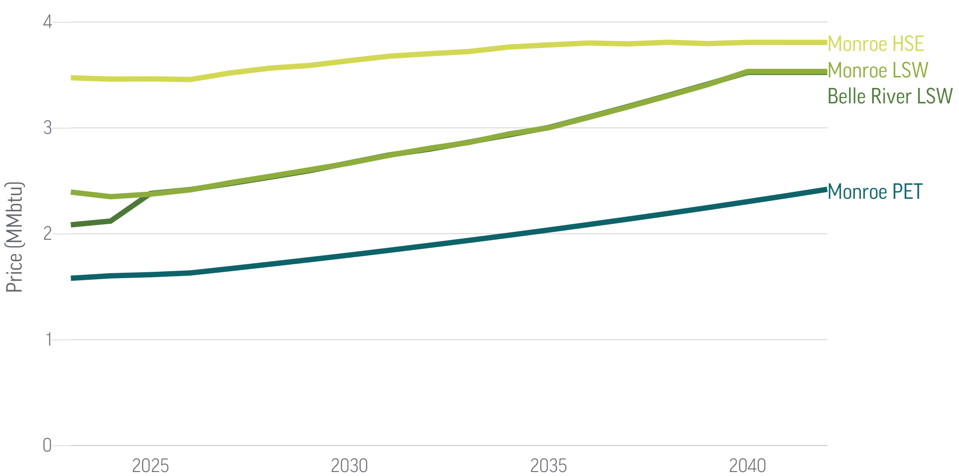
Monroe Power Plant

Monroe consumes a combination of LSW from Wyoming, HSE from the Northern Appalachia region and petcoke. All three of these fuels can be delivered via rail and vessel, although petcoke is delivered primarily via truck. LSW and petcoke vessel shipments utilize MERC as a trans-shipment facility while HSE vessel shipments utilize various Lake Erie docks for trans-shipment. Monroe also blends petcoke with coal.

Coal-price forecasts utilized for IRP modeling

The coal-price forecast utilized for the modeling was the same in all scenarios. Figure 13.3.2 shows coal prices for Belle River Power Plant LSW, Monroe Power Plant LSW, Monroe Power Plant HSE and Monroe Power Plant petcoke.

Figure: 13.3.2 – Annual delivered coal price



13.4 Oil

Oil overview

The Company uses diesel fuel oil for start-up and over-fire capabilities of its coal-fired generating units. Diesel is also the primary fuel at the Company's diesel peaking generator units.

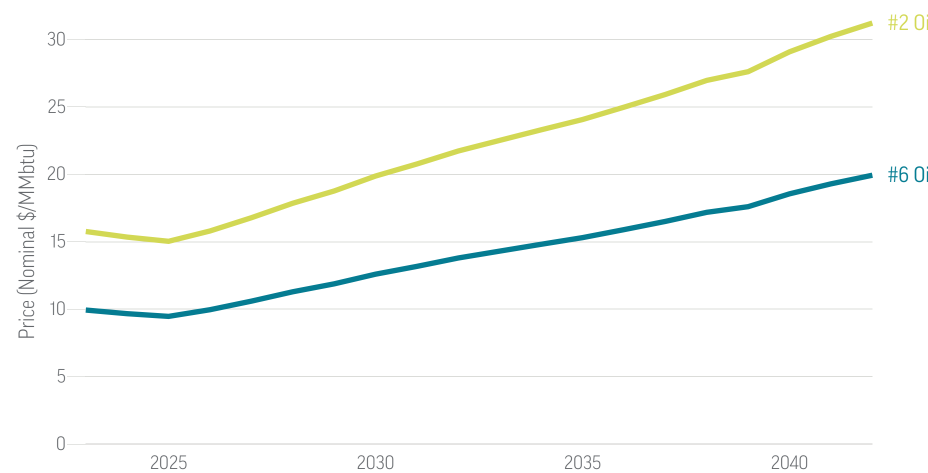
Delivered oil prices to existing utility generating plants

For 2022, fuel oil supply pricing was market index based with a constant markup applied by the supplier. For 2023 through 2025, a transition period is in place between the near-term futures prices and the long-term price forecast from Siemens. Starting in 2026, the Siemens forecast was utilized exclusively for forecasted fuel oil prices.

Oil-price forecasts utilized for IRP modeling

The oil-price forecast used for the modeling was constant across all the scenarios. Figure 13.4.1 shows prices for No. 2 oil and No. 6 oil.

Figure 13.4.1: Delivered annual oil prices



SECTION 14

14 Resource screen

14.1 Overview

The goal of resource screening is to ensure modeling includes technologies that are at a sufficient technical maturity and can provide economical value benefiting customers. The EnCompass model is designed to incorporate various potential resources, which are then run in the full optimization process.

The IRP considered numerous potential supply-side and demand-side resources. The Company performed a screening process consisting of a technical feasibility analysis of emerging technologies first, and then a calculation of the levelized cost of energy to determine the number of alternative technologies included in the EnCompass optimization modeling.

14.2 Existing and planned resources

As described in Sections 7 and 8, the Company has a diverse portfolio of existing supply-side and demand-side resources to meet customers' energy needs. In addition to existing resources, the Company has included specific approved resources in the study period. As discussed in Section 9, approved future solar assets have been included in the IRP modeling starting point.

The 2019 IRP, approved by the Commission in 2020, included the following PCA that reduced the Company's reliance on coal and increased renewable energy and demand-side resources:

Coal retirements (summer capacity rating MW)[1]:

- River Rouge Unit 3 (272 MW) – 2022.
- St. Clair Units 2, 3, 6 and 7 (1,065 MW) – 2022.
- Trenton Channel Unit 9 (495 MW) – 2022.
- Belle River (1,270 MW)[2] – 2029/2030.
- Monroe (3,066 MW) – 2039.

Demand-side Programs:

- EWR at 1.75% in 2020 (prorated based on date of order) and 2% in 2021.
- DR increasing from 709 MW in 2019 to 859 MW in 2024.
- CVR/VVO pilot in 2020 with scaling to 50 MW by 2030.

Renewable Energy investments approved separately as part of the Company's amendments to its Renewable Energy Plan and Section 61 filings:

- PA 342 15% Renewable Portfolio Standard (RPS) - 1,601 MW.
- Voluntary green pricing (VGP) program (MIGreenPower) - 1,432 MW.

14.3 Technical feasibility screening

The Company evaluated the technical feasibility of certain emerging technology alternatives in the first step of technology screening. Maturity was measured by technology readiness level (TRL) as shown in Table 14.3.1. The emerging technologies reviewed are shown in Table 14.3.2. The alternatives were evaluated based on technical feasibility and maturity of technology, which allowed the elimination of alternatives that were not yet commercially available at scale, had high cost or scarce fuel supply at scale, or that had geographic limitations.

Table 14.3.1: Technical readiness level

Technical Readiness Level (TRL)	Definition
1-3	Basic Research
4-5	Technology Development
6	Technology Demonstration
7-8	System Commissioning
9	Commercialized

Table 14.3.2: Emerging technologies feasibility screening

Technology	Technological / Feasibility Pass	Reason for Eliminating
Advance Nuclear Reactors (Gen IV)	No	Maturity (TLR 1-5) vs SMR (TRL 4-6)
Allam Cycle	No	Maturity (TLR 6)
BESS (excluding Li-Ion chemistries)	No	Current estimates of cost, cycle life, size and maturity
Carbon Capture, Sequestration and Utilization	Yes	
Concentrating Solar Thermal	No	Geography: Climate lacking completely cloudless day
Direct Air Capture	No	Does not provide energy or capacity; out of scope for IRP
Flow Batteries	No	Maturity vs Li-ion batteries
Geothermal	No	Lack of geographic sites
Hydrogen Fuels for Generation	Yes	
Hydropower	No	Geography
Kalina Cycle	No	Maturity (TRL 6-8)
Long Duration Storage (e.g. thermal, gravitational)	No	Current estimates of cost, cycle life, size and maturity
Microturbines	Yes	
Offshore Wind	No	Maturity vs Onshore Wind
Organic Rankine Cycle	No	Maturity (TRL 6-8)
Reciprocating Internal Combustion Engines	Yes	
Renewable Diesel	No	Scarcity of economic fuel
Renewable Natural Gas	No	Scarcity of economic fuel
Small Modular Reactors	Yes	
Thermal Storage	No	Maturity at scale vs Li-Ion, lower round trip efficiency vs Li-Ion batteries
Waste Heat to Power	No	Extremely site specific
Water Wave/Tidal	No	Maturity

14.4 Levelized cost of energy screening

The second step in the technology screening was performing an identification process comparing the levelized cost of energy (LCOE) between alternatives on a consistent basis. This step is particularly helpful when comparing technologies that have common attributes. The LCOE was calculated by forecasting the annual costs to operate a technology over its useful life, dividing it by that technology's forecasted generation, and then levelizing the result. Levelizing takes a varying stream of numbers over a period and simplifies them to one value, typically represented in $/MWh. Usually, costs will increase over time; levelization takes these increasing values, discounts them, and expresses the result as one number, usually in current-year dollars. Figure 14.4.1 shows the overnight capital costs for selected technologies used in the LCOE calculation.

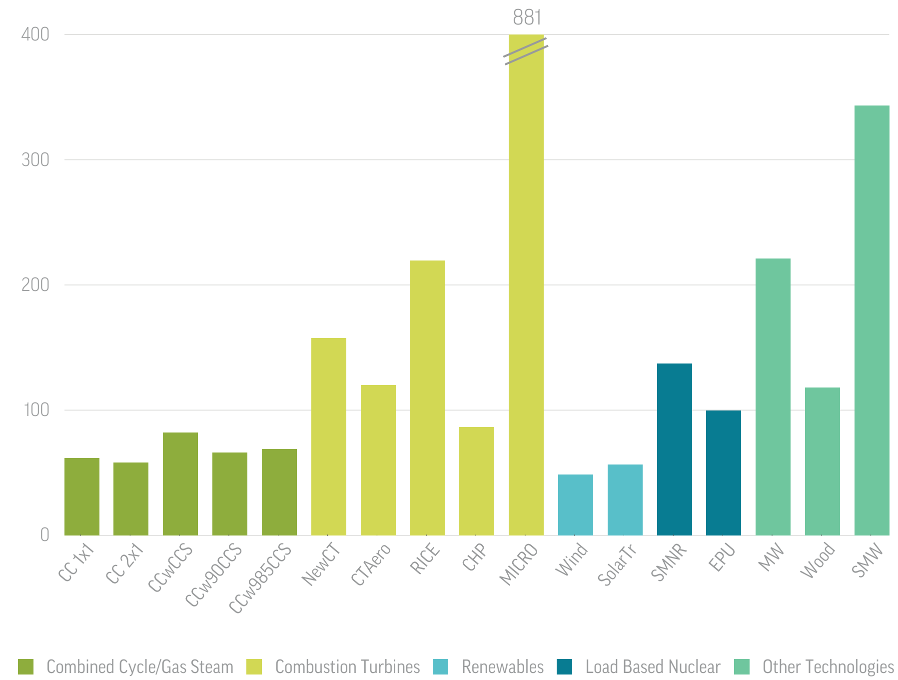
Figure 14.4.1: Overnight capital costs[1]

Resource	Abbreviation	Source	Data Year	Capital Cost ($/kW)
Combined Cycle/Gas Steam				
Combined Cycle - Single Shaft	CC 1x1	EIA	2021	1,082.27
Combined Cycle - Multi Shaft	CC 2x1	EIA	2021	957.05
Combined Cycle 90% Sequestration	CCwCCS	EIA	2021	2,570.14
Combined Cycle 90% CCS EPRI	CCw90CCS	EPRI	2021	1,673.60
Combined Cycle 98.5% CCS EPRI	CCw985CCS	EPRI	2021	1,843.40
Combustion Turbines				
Combustion Turbine - Industrial Frame	NewCT	EIA	2021	709.40
Combustion Turbine - Aeroderivative	CTAero	EIA	2021	1,169.24
Internal Combustion Engine	RICE	EIA	2021	1,813.16
Combined Heat and Power	CHP	DOE	2021	2,406.44
Renewables				
Land-Based Wind	Wind	NREL	2023	1,206.56
Solar - PV 1-Axis Tracking	SolarTr	NREL	2023	1,170.91
Base Load Nuclear				
Small Modular Reactor	SMNR	EIA	2021	6,801.74
Extended Power Uprate	EPU	DTE	2023	5,813.95
Other Technologies				
Municipal Waste	MW	EIA	2021	1,566.27
Wood and Other Biomass	Wood	EIA	2021	4,078.42

1 Overnight cost is the cost of a construction project if no interest accrued during construction, as if the project was completed "overnight." In table 14.4.1, overnight costs are used to compare the cost of each technology.

LCOE results from the reference scenario are shown in Figure 14.4.2. Each selected technology's resulting $/MWh value incorporates the respective capital, fuel, fixed O&M, variable O&M, insurance, emissions and tax costs.

Figure 14.4.2: Levelized cost of energy[1]

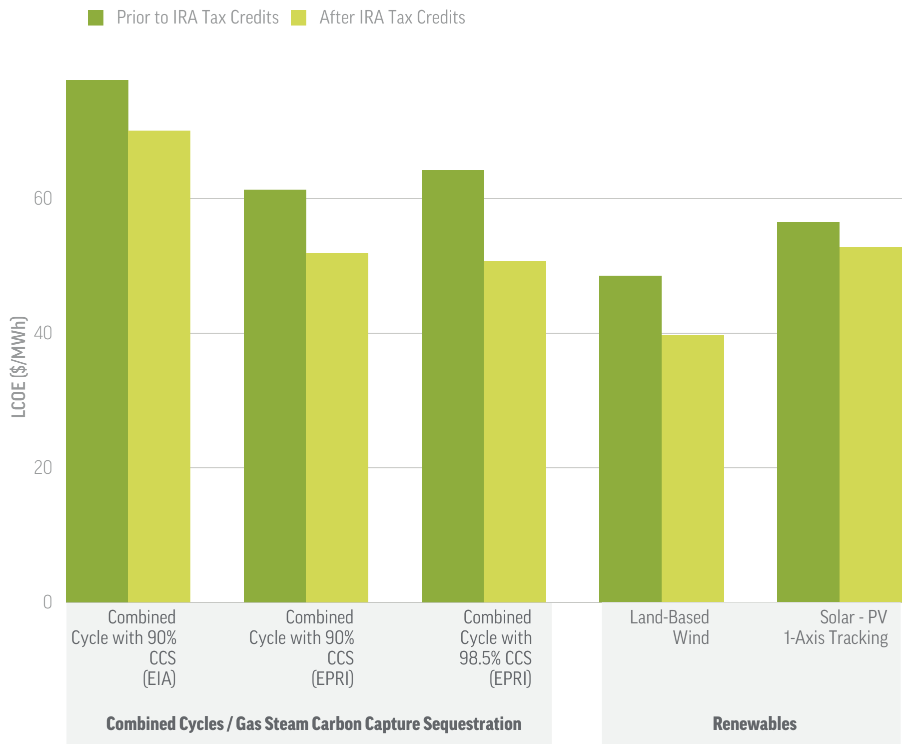


1 LCOE calculated for 2023 in-service resource as of year 2023

The objective of the LCOE technology identification process was to obtain a reference point of view leading to the EnCompass optimization process. Some technologies are screened out for further consideration in the modeling as their respective LCOE values represent high-cost outliers in the comparison analysis. Microturbines and solid municipal waste were not included in the EnCompass model as a result of the LCOE analysis.

In addition, the application of the tax credit provisions approved by the Inflation Reduction Act were considered to assess the impact in the affordability of the specific technology resources. This complementary assessment consisted of comparing the LCOE of selected technology resources before and after the inclusion of the tax credits changes approved in the IRA. Figure 14.4.3 shows the comparison LCOE data.

Figure 14.4.3: IRA LCOE comparison[1]



[1] LCOE with IRA tax credits calculated for 2023 in-service resources. Calculation performed as of 2023 for comparative basis

The LCOE is useful in comparing technologies, i.e., baseload, non-dispatchable, peaking, etc., to illustrate cost-based differences within a category. However, it has shortcomings as a comprehensive screening tool. While LCOE is a representation of costs, it is limited to one project per technology with only one defined start time and does not show how much market value the technology is creating in alternative scenarios (e.g., energy market, capacity market). Therefore, as a more comprehensive modeling approach, the IRP process evaluates a multitude of technologies, including natural gas units, coal units, nuclear units, renewable generation, demand-side management resources and emerging technologies, all offered in the EnCompass optimization model.

14.5 Modeling constraints

The starting year of the technologies that were evaluated was based upon how soon the resource could come online, either due to the assumed construction period or technology maturity. The starting years for the resources in the optimization are shown in Table 14.5.1.

Table 14.5.1: Starting year of resources in capacity expansion modeling

Technology	Starting Year	Technology	Starting Year
CT	2025	Wood and biomass	2027
CCGT	N/A	Utility-scaled lithium-ion battery	2024
CCGT w/CCS	2028	Lithium-ion battery DG	2023
Aeroderivative CT	2025	SMR	2035
RICE	2025	EPU	2035
Wind	2026 / 2028 in REFRESH	CHP	2025
Utility-scaled solar	2025	EWR	2023
Solar DG	2023	DR	2023
Solar-storage hybrid	2025	CVR	2026
Municipal waste	2026		

EnCompass does not have a theoretical limit on the number of resources that can be included in its optimization, but in practice it is limited by modeling time and computing capabilities. As the number of resources increases, the problem size and modeling time does as well. To reduce this issue, certain constraints or limits were introduced. Different constraints for the various resources included in the optimization, are shown in Table 14.5.2.

Table 14.5.2: Resource constraints

Resource Type	Constraints applied to all Scenarios except for REFRESH	Constraints applied to REFRESH
CCGT w/ CCS, CT, Aeroderivative CT, RICE, SMR	2 of each resource type available to be selected	2 of each resource type available to be selected
Municipal waste	1 resource available to be selected	1 resource available to be selected
CHP	Up to 27 MW to be selected	Up to 27 MW to be selected
Utility-scaled wind, utility-scaled solar	Up to 500 MW per year (combined) prior to 2026; after 2026 up to 1,000 MW per year (combined) to be selected	200 MW per year for wind 2028-2034. Solar 400 MW per year through 2028 and 800 MW between 2029 and 2034. After 2034 up to 1,000 MW per year (combined) to be selected
Utility-scaled lithium-ion battery	Up to 500 MW per year prior to 2027; 800 MW per year between 2027 and 2039; up to 1,200 MW per year between 2031 and 2035; and up to 2,000 MW per year after 2035 to be selected	Up to 500 MW per year prior to 2027; 800 MW per year between 2027 and 2039; up to 1,200 MW per year between 2031 and 2035; and up to 2,000 MW per year after 2035 to be selected

Experience has shown that delays in the MISO interconnection queue, recent RFP results, supply chain and labor market constraints and local opposition can limit the amount of renewable energy that can be built at any given time. By placing a reasonable limit on the amount of MW of renewable energy that can be built on an annual basis, the Company can help ensure that modeling results are reflective of what is feasible to implement. There are several factors that the Company considered when determining appropriate limits on new solar and wind projects in the IRP modeling. These factors included: 1) the status of and challenges with the generation interconnection queue process; 2) siting, permitting and environmental considerations; 3) recent RFP experience; 4) supply chain issues; and 5) limitations in the IRP modeling tool that, absent the use of MW limits in the modeling assumptions, would select excess renewable energy. An annual MW limit also allows the Company to take advantage of technological advancements and cost savings that may arise in the future. The Company is expecting to build on these advancements and efficiencies learned through the execution of the first several years of projects, thus, the annual MW limit increased over time.

14.6 Energy storage technologies

Grid-scale energy storage systems (ESS) are a collection of methods used to store electrical energy on a large scale within an electrical power grid. Grid-scale ESS help stabilize the grid by balancing electricity supply and demand over short- (sub-seconds to minutes) to longer-term (hours, days, weeks, etc.) durations. The four ESS services that can provide value to the grid in terms of generation application are:

- Ancillary services: ESS can help maintain the grid's performance by providing ancillary services, including spinning reserve and frequency regulation (e.g., balancing voltages on the grid). As the level of renewable deployment on the electric system increases, the need for these services may also increase. The extent to which the ESS are compensated for these services depends on the market in which they are operating.
- Capacity: ESS can be used as a peak shaving resource to reduce or defer investments in additional generation capacity. This includes the use of an ESS as a capacity resource.
- Price arbitrage: ESS can store energy produced during periods of low demand/prices and sell during periods of higher demand/prices. In the same context, ESS can also increase the value of renewable energy systems by storing and shifting renewable energy output to times of greater system need or to avoid curtailment (i.e., firming renewable energy capacity).
- Flexibility: ESS can ramp up very quickly to cover volatility in renewable generation. This occurs on a sub-hourly basis and can be challenging to quantify.

The following ESS technology categories comprise the ESS technologies considered by the Company in the IRP:

- New pumped hydroelectric storage.
- Compressed air energy storage (CAES).
- Battery storage (e.g., lithium-ion, sodium-sulfur, and lead acid).
- Thermal energy storage.
- Gravitational energy storage.

To determine which storage technologies to incorporate into its modeling, the Company performed an initial technical screening to assess each technology's feasibility for deployment. The results of this screening exercise are described below.

New pumped hydroelectric storage

Pumped hydroelectric storage uses electricity to pump water to a higher elevation. When required, water is released to drive a hydroelectric turbine. Beyond the existing Ludington facility, deployment of pumped hydro was screened out due to the geographical limitations of siting a new facility.

Compressed air energy storage (CAES)

CAES uses electricity to compress air into confined spaces. When required, air is released to drive the compressor of a natural gas turbine. CAES was screened out since its deployment is limited by the availability of suitable geologic formations and because there is limited commercial experience in the United States.

Battery storage

Batteries use electricity to store chemical energy, which can later be converted back into electrical energy when required. There is a range of different battery chemistries, which have the potential to operate in grid applications with varying operating characteristics and levels of technology maturity.

Thermal energy storage

Thermal energy storage uses a storage media such as water, molten salt or sand to store energy as heat. Thermal energy storage was screened out since it has seen limited electric grid deployment at grid-scale capacities in the United States.

Gravitational energy storage

Gravitational energy storage uses cranes or other mechanical systems to elevate weighted objects such as cement blocks to store potential energy. When energy generation is required, the blocks are lowered to generate electricity. Gravitational energy storage was screened out since the technology has limited demonstration in the United States.

Based on this technical assessment, lithium-ion batteries have the most desirable combination of operating parameters, system size and technology maturity.

The Company also looked at each of these battery technologies' historical costs and future-cost trajectories to further distinguish which technologies were most suitable for further inclusion in this IRP. Costs for lithium-ion batteries have declined significantly in recent years and the trend is expected to continue in the near term, driven in part by their applications in other sectors, such as electronics and transportation.

Given their superior combination of cost, cycle life, system size and technology maturity, lithium-ion batteries were selected for further evaluation in this IRP. See Exhibit A-3.2 Appendix C for the lithium-ion battery's assumed operating characteristics and costs considered for modeling. The battery storage units evaluated were assumed to have an installed capacity of 50-60 MW and storage capacity of 200-240 MWh, which equates to a four-hour duration. The objective for selecting this configuration was to create an asset that can provide both energy arbitrage and capacity value, with the full power rating qualifying for capacity credit in MISO. The assumed capacity credit for the battery alternatives was modeled as ELCC (effective load carrying capability) in the EnCompass model and determined using the resource adequacy study.

While lithium-ion is the most suitable technology in the near-term, the Company continues to monitor other battery storage technologies' development, as well as other non-battery storage options, and may update its assessment of these technologies as costs decline, performance improves and the market framework for storage evolves.

Battery benefits

Benefits attributed to battery energy storage systems in the modeling process are described below.

Ancillary service benefits – spinning reserve and frequency regulation

Spinning reserve is extra generating capacity available by increasing the output of generators already connected to the power system. Traditional generators must already be running and have room to ramp up quickly to cover spinning reserve. Batteries can also provide spinning reserve and can frequently do so more efficiently and effectively than traditional resources. Frequency regulation is providing balance to the grid during an imbalance of supply and demand of electricity. Changes in supply and demand for electricity can have a major effect on the frequency of the grid (60 Hz). For instance, if there is more demand for electricity than there is supply, then frequency will fall. Or, if there is too much supply, frequency will rise.. Another term that can be used to describe frequency regulation is "grid support." The market benefit from providing these two services is input as benefit to the battery system in the Encompass model. See Table 14.6.1 for the ancillary benefits modeled in EnCompass. The above-mentioned ancillary benefits are limited to the first 180 MW of energy storage.

Table 14.6.1: Ancillary benefits for energy storage systems

Battery Duration	Spinning Reserve	Frequency Regulation	Total Ancillary Services benefit
Values in levelized $/kW			
4	3.66	69.97	73.63
8	4.5	68.28	72.78
10	4.62	67.93	72.55

A hybrid (solar + storage) tied system benefit

The benefit of this alternative is that if the battery is charged exclusively by the tied solar units, then the battery is eligible for the solar investment tax credit, lowering the revenue requirement of this alternative. This assumption was used in all scenarios other than the REFRESH scenario, where the IRA tax credits were used for the storage resources. (The IRA provides tax credit for stand-alone storage.)

Flexibility benefit

The increase in non-dispatchable energy sources increases volatility of energy (grid imbalance), resulting in the flexibility violation. Flexibility violation is defined as the expected number of days per year where there is an imbalance in load and generation due to ramping constraints or required generator startup times (as opposed to loss of load due to a lack of system capacity). Since batteries are more flexible compared to fossil units, the incremental amount of ancillary services required to maintain baseline historical flexibility is less for a system with battery storage capacity. The flexibility benefit was determined by Astrapé Consulting, using the SERVM model. The flexibility benefit at full value shown in Table 14.6.2 will apply to the first 960 MW of battery and was included for battery alternatives in the emerging technologies scenario. The next 960 MW of batteries were assumed to have 50% of the flexibility value.

Table 14.6.2: Flexibility benefit for energy storage systems

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Flexibility benefit ($/kW)	3.38	6.92	12.88	19.12	29.46	40.27	51.56	58.46	63.07	67.85

14.7 Distributed generation resources

Through 2021, the Company had 6,337 distributed generation customers with approximately 47.1 MW of installed capacity. More than 99% of installed distributed generation capacity is solar. Table 14.7.1 summarizes the total distributed generation sites and capacity as of the end of 2021 by category. Most distributed generation sites fall under Category 1, with some under Category 2. There are currently no customers in Category 3. Category 1 is limited to sites with renewable generation less than 20 kW of installed capacity; Category 2 is limited to sites with renewable generation of more than 20 kW but less than 150 kW; Category 3 is limited to methane digesters between 150 kW and 550 kW. Table 14.7.1 also shows the percentage of the statutory cap each category has reached; Category 1 is capped at 0.5% of the Company's peak; Categories 2 and 3 are each capped at 0.25% of the Company's peak.

Table 14.7.1: Total distributed generation sites and capacity

	Customers	Capacity (MW)	Capacity Cap (MW)	Percent of Cap
Category 1	6,206	39.8	54.6	72.90%
Category 2	131	7.3	27.3	26.70%
Category 3	0	0	27.3	0.0%
Total	**6,337**	**47.1**	**109.2**	**43.10%**

As discussed in Section 10, the Company's load forecast projects a 9% compound annual growth rate for distributed generation through the study period. IRP modeling runs, including the Stakeholder scenario, included different levels of distributed generation.

14.8 Market capacity purchases

As discussed in Section 4, a capacity need was not identified in the starting point capacity outlook until 2028 with the retirement of Belle River. It is uncertain how much, if any, capacity will be available in the market for the Company to purchase 10 years from now. Due to this uncertainty in the capacity market, zero capacity purchases were the general assumption for optimization modeling. However, as discussed in Section 15, the IRP modeling did consider a sensitivity in which the amount of capacity purchases available was raised to 650 MW starting in 2032. This sensitivity was performed on the reference and business as usual scenarios.

14.9 Long-term power purchase agreements

For the purposes of the resource screen within the IRP planning process, the Company's existing long-term power purchase agreements were assumed to be renewed.

14.10 Peaking generation

As discussed in Section 7, the Company has 1,998 MW of peaker generating capability in its fleet based on the summer capacity ratings of these units. There are 82 natural gas and oil-fueled peakers located at 19 different sites. As part of this IRP process, the Company conducted an assessment of peaking generation to determine whether to 1) continue or retain operations versus 2) retire the peaking units. Consistent with coal-fired power plants, when assessing and evaluating a generation resource such as a peaker, economics, resource adequacy, and grid reliability (transmission and distribution) are all factors that are considered in the decision-making process. The peaker analysis included forecasts of future O&M and capital costs for each peaker unit, an economic screening analysis, and a review of transmission and distribution impacts.

The analysis began by reviewing the type of peakers and determining which type should be further analyzed for this IRP. The Company's large gas turbine peakers are newer, have lower energy and fuel costs, and are expected to continue to run through the study period. For these reasons, they were not included in this analysis. The Company then focused its peaker analysis on the small gas-fired and oil-fired turbines and diesel engines. The Energy Supply and Distribution Operations (DO) teams reviewed the list of peakers to identify units to be evaluated and selected a subset of these peakers for analysis including peakers that are at retired power plant sites. This subset included peakers at Colfax, Oliver, Placid, Putnam, River Rouge, St. Clair, Wilmot, Northeast, Fermi, Superior, and Hancock. The Slocum peaker site has been identified for a proposed battery pilot as discussed in Section 9.6. Peakers not evaluated in the analysis include the units that currently support plant operations—the Belle River and Monroe diesel engines and Fermi 11-1 and 11-2 oil-fired turbines.

Peaker sites that were economic compared to retirement are recommended to remain operational. Peaker sites that were not economic and would not necessitate distribution system upgrades are being studied by MISO for potential retirement. Peaker sites that were not economic but would require distribution upgrades to enable their retirement require further evaluation as discussed in Section 12.4.

Endnotes

1. St. Clair and Trenton coal are suspended, but will be retired before the end of 2022.

2. Represents total capacity, DTE Electric's capacity is 1,034 MW

SECTION 15

15 Modeling results

15.1 Encompass optimization modeling results

Each scenario contained several sensitivities, the majority of which resulted in differing portfolios. The net present value revenue requirements (NPVRR) of the sensitivities under the same scenario were compared against that scenario's starting point portfolio or base. For example, the starting point portfolio in the emerging technologies (ET) scenario was compared against the ET scenario sensitivity portfolio with alternative retirement dates for the Monroe Power Plant.

15.2 Reference scenario results

Retirement analysis

The Company performed an extensive coal unit retirement analysis on its remaining coal resources in the Company's fleet, the Belle River and Monroe Power Plants, under the reference scenario. For Belle River, the team modeled both a staggered retirement (Unit 1 retired in a given year and Unit 2 retired in a separate year) and full retirement. This included modeling the staggered retirement of Belle River Units 1 and 2 in 2024/2025 and 2025/2026, respectively, and a full retirement in 2027. For Monroe, both a staggered retirement (Units 3 and 4 retired in a given year and Units 1 and 2 retired together in another year) and full retirement were modeled. This included the staggered retirement of the Monroe units in various years between 2028 and 2039, as well as full plant retirements in 2032 and 2035. Additionally, the Company evaluated converting the Belle River Power Plant from a baseload coal plant to a natural gas-fueled peaking resource. The Company modeled Belle River gas conversion with a staggered approach in the years 2025 and 2026.

The least-cost portfolio was the REF_CASE_8B sensitivity, which included the gas conversion of Belle River in 2025/2026, Monroe units 3 and 4 retirement in 2028 and Monroe Units 1 and 2 retirements in 2039. This least-cost plan had a NPVRR delta of $143 million lower cost than the REF_BASE. See Figure 15.2.1 below for retirement analysis results.

Figure 15.2.1: IRP retirement analysis results

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REF_CASE_8B_BRGAS_MN28_39	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) December 31, 2039	($143)
REF_CASE_3_BLR27_MNR39	Belle River retire May 31, 2027 Monroe retire December 31, 2039	($91)
REF_CASE_10_BLR28_MNR32_39	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2032/ (1-2) December 31, 2039	($86)
REF_CASE_ 2A_BLR25_26_MNR39	Belle River retire May 31, 2025/26 Monroe retire December 31, 2039	($7)
REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
REF_CASE_8A_BLR28_MNR28_39	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) December 31, 2039	$59
REF_CASE_7B_BLR25_26GAS_ MNR28_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$88
REF_CASE_1_BLR24_25_MNR39	Belle River retire May 31, 2024/25 Monroe retire December 31, 2039	$138
REF_CASE_9A_BLR28_MNR32_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2032/ (1-2) 2035	$176
REF_CASE_9B_BLR25_26GAS_ MNR32_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2032/ (1-2) 2035	$210
REF_CASE_2B_BLR25_26_GAS_ MNR39	Belle River convert to gas May 31, 2025/2026 Monroe retire December 31, 2039	$246
REF_CASE_6B_BLR25_26GAS_ MNR28_32	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2032	$285
REF_CASE_5A_BLR28_MNR35	Belle River retire May 31, 2028 Monroe retire May 31, 2035	$285
REF_CASE_12_BLR25_26GAS_ MNR30_35	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2030/ (1-2) 2035	$291
REF_CASE_7A_BLR28_MNR28_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$333
REF_CASE_11_BR28_MN30_35	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2030/ (1-2) 2035	$347
REF_CASE_5B_BLR25_26GAS_ MNR35	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2035	$351
REF_CASE_4_BLR28_MNR32	Belle River retire May 31, 2028 Monroe retire May 31, 2032	$510
REF_CASE_6A_BLR28_MNR28_32	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2032	$587

Other reference scenario sensitivities

In general, the model selected a high volume of renewables and storage ranging from 4,000 MW to 7,000 MW of solar, 5,000 MW to 9,000 MW of wind, and 500 MW to 2,000MW of storage over the study period. There were several key observations from the reference scenario sensitivities, such as:

- EWR: When there was incremental EWR to the Michigan Demand Response Statewide Potential Study, the additional EWR displaced the need for solar and storage in most cases. However, the higher the energy savings level target, the more expensive the portfolio was.
- Load & distributed generation (DG): The model did not select DG in the optimization, unlike utility scale solar and utility scale storage. However, when there was an assumed increase in the adoption of distributed generation in the load forecast, there was an apparent benefit. The higher levels of DG reduced the energy and capacity demands of customers, which in turn displaced the utility-scale solar build.

- Retirement: This sensitivity was conducted to determine the optimal replacement(s) for the peakers that were identified for potential retirement through the peaker analysis process.
- Renewables: Two sensitivities focused on the potential increase in voluntary green pricing (VGP) demand. The added capacity in turn reduced the amount of resources needed to meet the load demand, resulting in lower costs. The other two sensitivities offered in projects from the 2022 VGP RFP, between 2023 and 2025 into the optimization. However, the resources were not selected in the optimization.
- Transmission/capacity purchases: When capacity purchases were available to be selected, the purchases did offset some amounts of wind, solar and storage. The purchases mostly occurred in the last few years of the study period when it was most economic. When compared to modeling run REF_CASE_7B that had the same coal plant retirement schedule, the benefit was over $50 million. However, there is risk relying on the capacity market due to market uncertainty and potential increases in capacity costs.
- Demand response (DR): The aggressive and carbon price levels of DR from the Michigan Demand Response Statewide Potential Study, reduced the cost of the portfolios due to the lower cost of the programs.
- CO_2: Higher CO_2 allowance prices increased the overall portfolio costs of the EnCompass runs completed for this sensitivity. Modeling run REF_CASE_7B was the most economic when the analyzing higher CO_2 costs.

The least-cost portfolio was modeling run REF_2022VGP_CONTRCT, which was $632 million less than the base as fewer resources are selected in the optimization due to the increased VGP assumed in this sensitivity.

Figure 15.2.2: Reference scenario results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	REF_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	REF_ EWR 1.5% (2024)	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$335
	REF_ EWR 2.0%	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$947
	REF_ EWR 2.5% (2033)	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,061
	REF_ EWR 2.5%	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,623
Load & DG	REF_AGGRESSIVE_DG	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	($20)
	REF_DG_FIRM_CAPACITY	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$88
Retirement	REF_CASE_7B_Peaker_ Sensitivity	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$72
Renewables	REF_2022VGP_CONTRACT	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	($632)
	REF_CASE_AA_PROJECT	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	($429)
	REF_2022_RFP	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$84
	REF_2022_RFP_CASE_1	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$193

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Transmission/ Market Purchases	REF_650MW_Cap_Purchase	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$36
DR	REF_AGGRESSIVE_DR	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$69
	REF_CARBON_DR	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$77
CO_2	REF_HIGH_CO_2_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,670
	REF_HIGH_CO_2_CASE_6B	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2032	$1,709
	REF_HIGH_CO_2_CASE_7A	Belle River retire May 31, 2028 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$1,885
	REF_HIGH_CO_2_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$2,067
Ancillary Service	REF_BASE_FULL_ANC	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$94
	REF_FULL_ANC_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire (3-4) May 31, 2028/ (1-2) 2035	$103

15.3 Business as usual scenario results

The model selected a high volume of renewables and storage ranging from 5,000 MW to 14,500 MW of solar, 0 to 9,000 MW of wind, and 1000 MW to 6,000 MW of storage over the study period. Several observations from the MIRPP BAU scenario sensitivities were:

- EWR: The Statewide Potential Study was the most economic program as it was the sensitivity that allowed any EWR level (various levels were identified in section 6).
- Load: In the sensitivities where the load increased, more resources were selected to meet demand, which caused those sensitivities to be significantly more expensive. In the sensitivity that increased Choice capacity to 15%, the projected load forecast decreased, thus requiring fewer resources.
- Resources: The sensitivity that only allowed selection of combustion turbines (CTs) in the capacity expansion was not a viable portfolio. The model selected up to 4,400 MW of CTs, however, was unable to provide energy in all hours, as the EnCompass run resulted in unserved energy in the last years of the study period. This sensitivity also deployed existing demand response programs in all hours in several years of the study period.
- Retirement: When comparing the two retirement sensitivities, it was evident that the Belle River plant conversion from coal to natural gas provided a cost benefit. The conversion was more economic by approximately $360 million.
- Transmission/capacity purchases: Allowing market capacity purchases in the capacity expansion reduced the amount of resources selected in the optimization, thus reducing the cost of this portfolio when compared to its counterpart modeling run (MIRPP_BAU_CASE_7B).
- High gas costs: There were four sensitivities that tested the impact of a higher gas price forecast. Overall, the increase in the gas price forecast resulted in higher costs all the portfolios that were evaluated.

The least-cost portfolio when compared to the base resulted in over $1 billion of savings, however, it assumed that the Retail Choice cap increased from 10% to 15%. Although the lower demand results in fewer resources selected and reduces the overall revenue requirement for the Company, there would still be the need for additional resources given the declining reserve margins and need to maintain resource adequacy standards in Zone 7. Moreover, this portfolio assumes the Choice cap would increase in 2024 but such a policy change would require an amendment to Michigan law.

Figure 15.3.1: Business as usual scenario results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_BAU_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	MIRPP_BAU_EWR_OPT	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$269
EWR	MIRPP_BAU_EWR_2.5	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,982
Load	MIRPP_BAU_CHOICE_15_2024	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($1,067)
Load	MIRPP_BAU_CLIMATE_CHANGE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$524
Load	MIRPP_BAU_50_CHOICE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,924
Load	MIRPP_BAU_Port4_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$7,405
Resources	MIRPP_BAU_ONLY_CTS	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,206
Retirements	MIRPP_BAU_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$563
Retirements	MIRPP_BAU_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$922
Retirements	MIRPP_BAU_2019 _PCA	Belle River retire May 31, 2028/2029 Monroe retire December 31, 2039	$811
Transmission/ Market Purchases	MIRPP_BAU_CAPACITY_ PURCHASE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$188
High Gas	MIRPP_BAU_HIGH_GAS_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$2,082
High Gas	MIRPP_BAU_HIGH_GAS_ CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$3,602
High Gas	MIRPP_BAU_HIGH_GAS_ CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$3,695
High Gas	MIRPP_BAU_HIGH_GAS_ CASE_7B_W_SMNR	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$5,749

15.4 Emerging technology scenario results

In general, the model selected a high volume of renewables and storage ranging from 9,000 MW to 17,000 MW of solar, 0 MW to 7,000 MW of wind, and 2,000 MW to 6,500 MW of storage over the study period. Additionally, the team noted several observations from the MIRPP ET scenario sensitivities, explained below:

- EWR: The 2.5% EWR program resulted in a portfolio over $1.6 billion more expensive than the base.
- Load: The load demand significantly increased in the high load sensitivity. To meet the demand, the model selected a plethora of resources including solar, storage, natural gas, demand response, CVR, wood and biomass, and municipal waste. This portfolio also included the 2.5% to 2033 EWR level.
- Retirement: Based on the results of the retirement analysis performed on the reference scenario, six of those sensitivities were included in this ET scenario. The MIRPP_ET_BASE or starting point that included the Belle River retirement in 2028 and Monroe retirement in 2039

is the least-cost portfolio of the retirement sensitivities. The small modular nuclear reactor (SMR) resource was also evaluated to understand the impacts of a different clean dispatchable resource as a replacement once the Monroe Power Plant is fully retired. Including the SMR added over $1.3 billion to the portfolio.

- Renewables: This sensitivity is very similar to the MIRPP_ET_CASE_7B as it has the same retirement plan for Monroe (2028 and 2035) along with the Belle River conversion. Both plans get to the 25% renewables by 2030, but this sensitivity has a slightly different portfolio toward the end of the study period that switches the timing of the solar and storage builds, and because of that, makes it $7 million more expensive than MIRPP_ET_CASE_7B.
- High gas: There were three sensitivities that tested the impact of a higher gas price forecast. Overall, the increase in the gas price forecast resulted in higher costs in all the portfolios that were evaluated.

The least-cost portfolio was the base. All sensitivities that were completed on the ET scenario were more expensive on a NPVRR basis.

Figure 15.4.1: Emerging technology scenario results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_ET_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
EWR	MIRPP_ET_EWR_2.5	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,622
Load	MIRPP_ET_HIGH_LOAD	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$6,380
Retirement	MIRPP_ET_REF_CASE_8B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2039	$52
	MIRPP_ET_REF_CASE_9A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$214
	MIRPP_ET_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$341
Retirement (cont)	MIRPP_ET_CASE_11	Belle River retire May 31, 2028 Monroe retire May 31, 2030/2035	$397
	MIRPP_ET_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$399
	MIRPP_ET_CASE_6B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2032	$665
	MIRPP_ET_CASE_7B_SMNR	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$1,708
Renewables	MIRPP_ET_RENEW_25%_2030	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$406
High Gas	MIRPP_ET_HIGH_GAS_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$1,722
	MIRPP_ET_HIGH_GAS_CASE_7A	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	$2,632
	MIRPP_ET_HIGH_GAS_CASE_7B	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	$3,036

15.5 Environmental policy scenario results

The model selected a high volume of renewables and storage including 6,000 MW to 14,000 MW of solar, 3,000 MW to 9,000 MW of wind, and 2,000 MW to 7,000 MW of storage of storage over the study period from the MIRPP EP scenario sensitivities. Key observations included:

- EWR: The Statewide Potential Study was the most economic program, as it was selected in the sensitivity that allowed any EWR level to be selected.
- Load: The required sensitivity increased the load forecast substantially over the study period, driving the need for additional resources. This portfolio selected the highest amounts of solar, storage and DR amongst the other sensitivities of this scenario. In order to meet demand, the

model also selected additional natural gas resources including combined heat and power (CHP).

- Retirement: The two retirement sensitivities resulted in higher costs than the base, as it required more resources to compensate for the loss in capacity and generation due to the early retirement assumption of the Monroe Power Plant.
- High gas costs: There were three sensitivities that tested the impact of a higher gas price forecast. Overall, the increase in the gas price forecast resulted in higher costs in all the portfolios that were evaluated.

The least-cost portfolio was the base.

Carbon reduction scenario

The carbon reduction scenario was based on the environmental policy scenario high load sensitivity, which resulted in a 2025 carbon reduction greater than 32%. Therefore, when applying the two constraints 28% carbon reduction and 32% carbon reduction to the EnCompass runs, the constraint did not impact the run. Therefore, the two sensitivities resulted in the same portfolios and costs remained unchanged.

Figure 15.5.1: Environmental policy scenario results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	MIRPP_EP_BASE	Belle River retire May 31, 2028	$0
		Monroe retire December 31, 2039	
EWR	MIRPP_EP_EWR_OPT	Belle River convert to gas May 31, 2025/2026	$80
		Monroe retire May 31, 2028/2035	
	MIRPP_EP__EWR_2.5	Belle River convert to gas May 31, 2025/2026	$2,091
		Monroe retire May 31, 2028/2035	
Load	MIRPP_EP_HIGH_ LOAD	Belle River convert to gas May 31, 2025/2026	$5,634
		Monroe retire May 31, 2028/2035	
Retirement	MIRPP_EP_CASE_7A	Belle River retire May 31, 2028	$351
		Monroe retire May 31, 2028/2035	
	MIRPP_EP_CASE_7B	Belle River convert to gas May 31, 2025/2026	$374
		Monroe retire May 31, 2028/2035	
High Gas	MIRPP_EP_HIGH_GAS	Belle River retire May 31, 2028	$408
		Monroe retire December 31, 2039	
	MIRPP_EP_HIGH_ GAS_CASE_7A	Belle River retire May 31, 2028	$1,344
		Monroe retire May 31, 2028/2035	
	MIRPP_EP_HIGH_ GAS_CASE_7B	Belle River convert to gas May 31, 2025/2026	$1,610
		Monroe retire May 31, 2028/2035	

15.6 High electrification scenario results

The HE scenario includes a higher level of customer demand driven by potential growth in electric vehicle sales. With the increased projected load growth, additional resources are required. In general, the model selected a high volume of renewables and storage, including 6,000 MW to 7,000 MW of solar, 7,000 MW to 8,000 MW of wind, and 2,000 MW to 3,000 MW of storage of storage over the study period. In addition to renewables, the model selected additional gas-fueled resources, such CCGTs with CCS and CTs. The least-cost portfolio when compared to the base was the HE_DR sensitivity at $4 million less than the base due to the lower demand response costs.

Figure 15.6.1: High electrification scenario results

Theme	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	HE_BASE	Belle River retire May 31, 2028	$0
		Monroe retire December 31, 2039	
Retirement	HE_DR	Belle River retire May 31, 2028	($4)
		Monroe retire December 31, 2039	
Resource	HE_CASE_7B	Belle River convert to gas May 31, 2025/2026	$192
		Monroe retire May 31, 2028/2035	
	HE_CASE_7A	Belle River convert to gas May 31, 2025/2026	$443
		Monroe retire May 31, 2028/2035	

15.7 Stakeholder scenario results

This model selected a high volume of renewables and storage, including 4,000 MW to 6,500 MW of solar, 8,000 MW to 9,500 MW of wind and 2,500 MW to 5,000 MW of storage over the study period. Several observations from the requested STAKE scenario sensitivities included:

- EWR: The 3% EWR level was very costly and resulted in the second most expensive sensitivity under the STAKE scenario.
- Load: This sensitivity was the most expensive compared to the base, which was attributed to the increase in load due to the fuel switching and incorporation of the costly 3% EWR level.
- DG: With the DG growth increased to 25% in the load forecast, the volume of resources selected was reduced, resulting in lower costs than the base.
- Resources: When natural gas resources were offered into the optimization, a combined cycle was economically selected and resulted in the second least-cost portfolio. Additionally, these sets of sensitivities showed that the reciprocating internal combustion engine resource was not economic. When the capital costs of this resource were lowered, it was not selected in the optimization.
- Retirements: Sensitivities 1 and 11 were very similar, however, due to reliability concerns, sensitivity 11 included four hydrogen fueled CTs as the dispatchable replacement when Monroe Power Plant is fully retired. Including the four CTs had over $160 million in value compared to sensitivity 1, which did not include the four CTs. Sensitivity 12 displayed both the value of the four CTs and the Belle River gas conversion; when compared to the base (which did not include the four CTs and conversion) it provided over $400 million in cost savings.
- CO_2: When the CO_2 emissions were constrained to an 80% reduction in 2030, the portfolio became more expensive due to the change in dispatch required to meet the reduction.
- Renewables and storage: The battery standard that was prescribed was costly and showed in the results of the delta revenue requirement. Additionally, Sensitivity 8 increased the amount of VGP projects that did not impact the revenue requirement (cost to customers), but covered the capacity need. It resulted in overall savings because it reduced the volume of new resources required.

The least-cost portfolio compared to the base stakeholder scenario was the doubled voluntary green power sensitivity at $787 million less.

Figure 15.7.1: Stakeholder scenario results

Theme	Request	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Starting Point	Starting Point	STAKE_BASE	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2035	$0
EWR	#5	STAKE_3.0_EWR	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$1,910
Load	#6	STAKE_FUEL_SWITCH	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$3,699
	#7	STAKE_25%_DG	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	($149)
Resources	#2	STAKE_INC_GAS_TECH	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	($517)
	#3	STAKE_LOW_RICE	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$224
Retirements	#12	STAKE_RET_BRGAS_ MR28_35_CT40	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($411)
	#11	STAKE_RET_BLR25_26_ MNR_ 28_30_H2CT	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$223
	#1	STAKE_RET_BLR25_26_ MNR_28_30	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$389
CO_2	#4	STAKE_CO_2_80_2030	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$223

Theme	Request	Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
Renewables & Storage	#8	STAKE_VGP_X2	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	($787)
	#10	STAKE_COMB	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$579
	#9	STAKE_BATT_STANDARD	Belle River retire May 31, 2025/2026 Monroe retire May 31, 2028/2030	$889

15.8 REFRESH scenario results

Eight scenarios were modeled for this IRP. The REFRESH scenario was the last developed. The IRP is an extensive process, spanning over several months. The assumptions utilized in the IRP were developed in December 2021. To account for the known changes impacting the natural gas prices and changes to the legislation, specifically, the Inflation Reduction Act (IRA), the REFRESH scenario was created in September 2022.

The natural gas price forecast used in the REFRESH scenario is based on forward pricing from August 2022 for years 2023 through 2027 then transitions to the 2022 EIA natural gas price forecast. Siemens incorporated this change into its Eastern Interconnect modeling to derive the relative impacts to the wholesale energy market price forecast. Additionally, aspects of the IRA relevant to the IRP were included to the extent they could appropriately account for the changes within the limited timeframe prior to filing the IRP. Tax credit provisions from the IRA impacting new solar, wind, storage, nuclear and carbon capture and sequestration technologies were incorporated into the EnCompass model.

Overall, with the tax provisions all the portfolios except for REFRESH_2019_PCA are more economic than the base. The various sensitivities included increased levels of renewables and storage, which benefits the portfolios due to the revenue requirement savings caused by the tax credits. In general, the model selected a higher volume of renewables and storage, including 6,000 to 7,000 MW of solar, 5,500 to 9,500 MW of wind and 1,000 to 2,000 MW of storage over the study period. The least-cost portfolio was the REFRESH_CASE_6B_BLR25_26GAS_MNR28_32.

Figure 15.8.1: REFRESH scenario results

Sensitivity Name	Retirement Assumption	NPV Rev Req Delta (M$)
REFRESH_2019_PCA	Belle River retire May 31, 2029/2030 Monroe retire December 31, 2039	$4,154
REFRESH_BASE	Belle River retire May 31, 2028 Monroe retire December 31, 2039	$0
REFRESH_2022_PRELIMINARY_PCA	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($110)
REFRESH_2022_PRELIMINARY_PCA_OPT	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($539)
REFRESH_CASE_7A_BLR28_MNR28_35	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2035	($620)
REFRESH_CASE_7B_BLR25_26GAS_MNR28_35	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2035	($705)
REFRESH_CASE_6B_PHASE	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2032	($849)
REFRESH_CASE_6A_BLR28_MNR28_32	Belle River retire May 31, 2028 Monroe retire May 31, 2028/2032	($941)
REFRESH_CASE_6B_BLR25_26GAS_MNR28_32	Belle River convert to gas May 31, 2025/2026 Monroe retire May 31, 2028/2032	($1,018)

15.9 Risk assessment

The PCA should be the most reasonable and prudent plan in the face of an uncertain future, especially given the dynamic nature of the energy industry and of emerging technologies. Risk analysis or risk assessment helps to hedge the uncertainties by evaluating how different portfolios would perform given a range of unexpected possible futures. All five DTE Electric planning objectives (safe, reliable and resilient, affordable, customer accessibility and community focus, and clean) were considered when designing the five risk-analysis approaches used in this IRP.

Affordability was partially addressed through the modeling optimization. Reliable and resilient was addressed in the resource adequacy analysis. Safe was fulfilled through setting the proper constraints in the modeling scenarios to comply with all regulations, and through ensuring the EnCompass optimization met these constraints. The other planning objectives of customer accessibility and community focus, and clean had to be handled qualitatively outside of the Encompass model or by using techniques that quantified these principles and compared alternative portfolios against each other based on how they ranked in each category. The Company used the latter approach.

As the PCA was being determined, multiple risk analyses were conducted to ensure the plan's prudency and robustness considering the planning objectives. The Company wants to minimize risk; therefore, the risk analyses were an essential part of the IRP process. Over time, commodity markets and environmental and regulatory conditions may be different than what was forecasted. Considering the market's uncertainty, the selected portfolio plan should be flexible enough to accommodate changes as they occur. The five methodologies of risk assessment used to review the feasibility of the PCA, described in Section 5.3, were 1) Stochastic risk assessment, 2) Stochastic reliability modeling (resource adequacy) modeling, 3) Evaluation of key IRP inputs, 4) Portfolio metric evaluation, and 5) Scenario and global sensitivity analysis. The results of the first four methodologies are included later in this section. Scenario and global sensitivity analysis is covered earlier in this section.

The Company chose stochastic analysis over generating near-term solutions, mean-variance portfolio analysis, or Monte Carlo simulation because stochastics are considered a best-in-class approach to risk assessment. This is based on a benchmark comparison performed of other utilities' IRPs, and due to the Company's experience with stochastics in its last two IRPs. The Company performed two types of stochastic risk assessment: an economic stochastic risk assessment where affordability is tested and a resource adequacy stochastic risk assessment that tests reliability and resiliency. Portfolio metric evaluation was chosen to assess key metrics quantitatively across the planning objectives. Evaluation of whether key inputs have changed and sensitivity and scenario analysis were used to demonstrate the PCA's reasonable risk under a variety of conditions.

15.10 Financial stochastic risk assessment

For the financial stochastic risk analysis, several steps were undertaken:

- Formulate assumptions. A probability distribution used in the stochastic analysis served to measure possible outcomes' likelihood given reasonable changes in assumptions. The mean of the probability distributions was generally represented by the underlying assumptions in the BAU and REF scenarios. Siemens constructed probability distributions for key drivers, including load growth, gas and coal prices, the price of carbon used for analytic purposes, and the cost of generating technologies. These distributions include the other scenarios and generally the sensitivities studied. The key drivers' probability distribution was developed from historical variance and a range of future forecasts. These assumptions are detailed in Exhibit A-3.2, Appendix L.
- Set up specific DTE Electric portfolio builds. Because this work was used to look at nine different Company resource plans in a probabilistic framework, the assumption was that each specific resource plan would be comprised of firm resources that remained online regardless of the probabilistic case (200 iterations). The nine plans evaluated through stochastic analysis represented a diverse mix of resources that met the reserve margin requirement through 2042. Each of the portfolios was set up, in turn, as a firm, specific resource plan that did not change with market and other uncertainties.
- Run Siemens' stochastic version of the AURORA model. Siemens ran its proprietary stochastic version of AURORA for the Company footprint, plus neighbors one transmission link away, with the resources shown in Table 15.10.1 treated as firm resources in each of nine build plans.

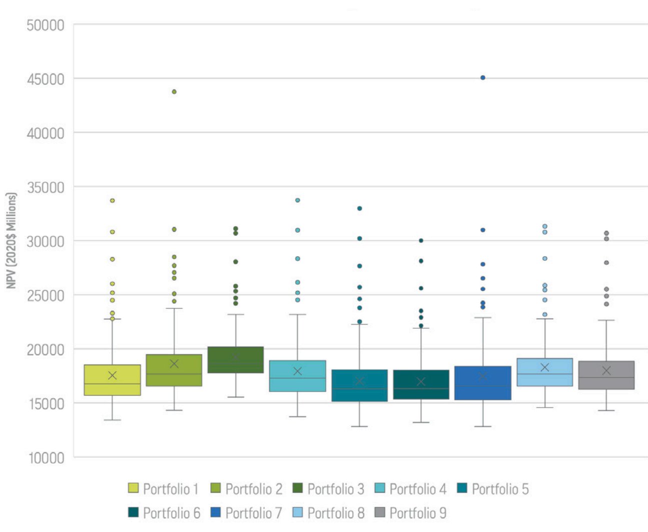
Table 15.10.1: Alternative resource plans for stochastic analysis

Portfolio #	Description
1	Preliminary PCA: BR Conv. Monroe ret 2028/2035
2	ET least cost plan (Base ret)
3	STAKE base plan: 2% EWR, BR ret in 25/26, Monroe ret in 2028 and 2034
4	REF 9A phase: BR not converted, ret in 2028, Monroe Retires in 2032 and 2035
5	REF least cost plan (BR Conv, Monroe ret 2028/2039)
6	EP least cost plan (Base ret)
7	BAU least cost plan (Base ret)
8	REFRESH 6B phase: BR converted, Monroe retires in 2028 and 2032
9	Final 2022 PCA: BR Conv. Monroe ret 2028/2035

The Base retirement is Belle River in 2028, Monroe in 2039

- Compare the nine build plans. The results of each draw for each portfolio can be seen on box and whisker plots, which show the 25th to 75th percentiles in the "box" and the local minimum below the 25th percentile in the lower whisker and the local maximum above the 75th percentiles in the upper whisker. The dots above the upper whisker are the outliers. See Figure 15.10.2

Figure 15.10.2: Stochastic risk results

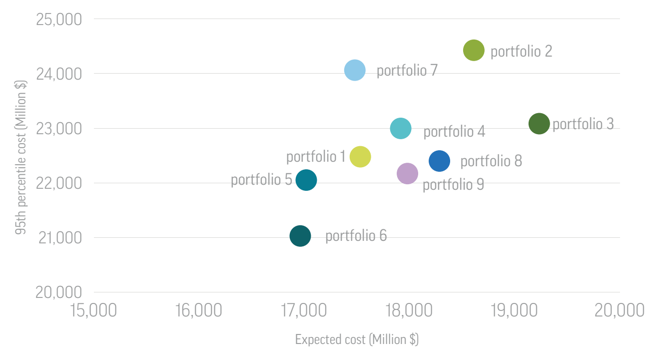


Because the analysis was probabilistic, each case could be stated in terms of an expected cost and the standard deviation of that cost or associated risk. This allowed a ranking of the cases in terms of expected cost and risk.

Interpretation of the results of the stochastic risk assessment

The goal of determining the expected (mean) portfolio cost and the 95th-percentile net present value (NPV) for the economic risk is to select a portfolio that is both lowest-cost and lowest-risk.(See Figure 15.10.3 for results.) The PCA is third best for economic risk and sixth of nine for the expected, or mean cost.

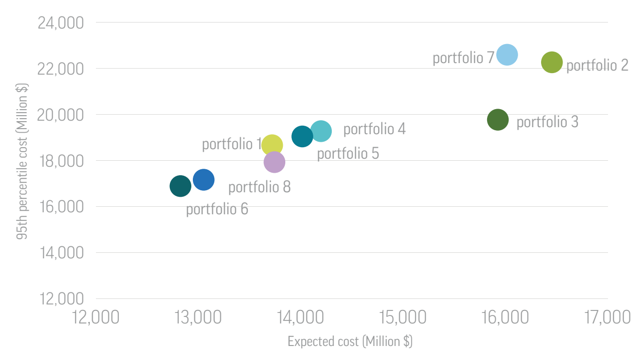
Figure 15.10.3: Stochastic results expected vs. 95th percentile cost



Stochastic risk assessment with IRA

The Stochastic risk assessment described above was performed without inclusion of the IRA tax credits. An adjustment was made to account for these tax credits as they would be applied to the nine portfolios. The results are shown in Figure 15.10.4. The PCA is now ranked third when the IRA tax credits are included.

Figure 15.10.4: Stochastic results expected vs. 95th percentile cost with IRA tax credits



15.11 Resource adequacy stochastic risk assessment

The resource adequacy analysis used 6,150 draws to thoroughly test the resource adequacy of the PCA under a variety of load and resource availability combinations in two key snapshot years. It is a form of stochastic risk focused on the reliability planning objective instead of the affordability planning objective, as in the other stochastic risk assessment described in Section 15.10. This analysis was performed by Astrapé Consulting using the SERVM model.

The key drivers that were varied included:

- Weather, which was taken from 41 weather years from 1980 to 2020 historical weather years.
- The load forecast uncertainty, which was varied between five different levels.
- The forced outages, which were varied across 30 different forced outage draws.

The Company's portfolio run through the SERVM model to test resource adequacy was the preliminary PCA in 2028 and 2035. The years 2028 and 2035 were selected because they coincide with the Monroe retirements and they have the largest changes in the fleet resources. The results of this modeling are shown in shown in Table 15.11.1.

Table 15.11.1: Results of resource adequacy analysis

Year	LOLE results	SERVM Surplus Capacity (UCAP)
2028	0.04	308 MW
2035	0.02	403 MW

The results showed that the preliminary PCA was resource adequate because it had a LOLE of 0.04 (one day in 25 years) in 2028 and a LOLE of 0.02 in 2035 (one day in 50 years). Both are lower than the MISO standard of 0.1, meaning that the system would be expected to have sufficient resources to meet the MISO resource adequacy standard.

In addition, the resource adequacy analysis was run on an extreme weather scenario. This scenario involved changing the weighting of the 41 weather years to achieve 34 "hot days" per year instead of the historical average of 28 used in the resource adequacy model. A hot day is defined as being at or above 86 degrees F in the DTE service area. The results of this extreme weather scenario were that the LOLE observed on the preliminary 2028 PCA was 0.05 instead of 0.04 (one day in 20 years instead of one day in 25 years). This showed that including the risk of extreme hot weather into the risk assessment increases the amount of UCAP resources needed by 40 MW in 2028 and 43 MW in 2035 to achieve the same reliability as historical weather.

After the preliminary resource adequacy modeling results were obtained, the results of the REFRESH scenario, which incorporated the IRA tax credits, were incorporated into the synthesis of results that inform the PCA. The PCA was changed as a result of this REFRESH scenario. Changes on the final PCA from the preliminary PCA included additional wind in 2028 and additional storage, wind and solar in 2035. These changes are shown in Table 15.11.2.

Table 15.11.2: DTE Electric portfolio changes

Years	Solar	Wind	Storage
Total change 2023-2028 (ICAP)		+100 MW	
Total change 2023-2028 (UCAP)		+12 MW	
Total change 2029-2035 (ICAP)	+1,153 MW	+1,172 MW	+1,200 MW
Total change 2029-2035 (UCAP)	+358 MW	+141 MW	+435 MW

A total of 358 MW solar, 153 MW wind and 435 MW of storage was added on a ELCC basis to the preliminary PCA to get to the final PCA. Since these are only additions of resources, the plan remains resource adequate and does not need to be reverified in the SERVM model.

15.12 Evaluation of key inputs

The IRP inputs were adopted in November 2021 through February 2022 before the optimization models were built. Before the filing, in August 2022, the inputs were considered again to determine if any of them had changed materially since the initial modeling. In addition, there were a few emerging industry issues that were considered, such as the IRA tax credits on renewables technologies, batteries and CCS. The decision on whether to update the input was based on how materially different it was, whether scenarios and sensitivities had been run that covered the uncertainty and therefore made updates unnecessary, and known challenges to updating (See Table 15.12.1). After considering 11 different inputs for potential revision, the Company decided that four had changed materially. They were: natural gas price, energy market associated with the updated natural gas prices, the recently implemented Inflation Reduction Act tax credits, and the cost estimate for the Belle River conversion.

Table 15.12.1 Evaluation of key inputs

Item	Input	Original input (starting point)	Most recent input (considered for Refresh case)	Decision
1	Near term gas prices	Forwards from Dec 2021	Forwards from July 2022	Material - updated in the Refresh run. The near term average gas forwards went up by 40-45% in the Refresh case
2	Long term gas prices	2022 Siemens Fundamental forecast	2022 EIA natural gas forecast	Updated in the Refresh run. The long term average gas price went up by about 4% in the Refresh case
3	Market prices	Forwards from Dec 2021	Forwards from July 2022	Material - updated to align with gas price in the Refresh run. Near term average went up by 37% for on Peak and 26% for off peak. The long term forecast went up by about 4%
4	Load forecast	Starting point loads	Starting point loads	There are other sensitivities that cover all variances of load
5	Tax Credits	HR 133 Consolidated Appropriations Act	New IRA rules-preimplementation	Material - updated in the Refresh run
6	Capital Cost alternatives	Publically available sources as of 2021 NREL ATB/2021 EIA	Publically available sources as of 2022 NREL ATB/2022 EIA	Capital costs were not changed to isolate the impacts of tax credit; complex to update in fundamental model
7	Coal prices	Forwards from Dec 2021	Forwards from July 2022	Immaterial - 2023-26 forwards for LSW changed an average of about 8%; complex to update in fundamental model
8	MISO seasonal construct	Annual capacity construct	MISO seasonal proposal approved by FERC	Unit accreditation not final; extremely complex for Encompass model

Item	Input	Original input (starting point)	Most recent input (considered for Refresh case)	Decision
9	MISO thermal unit accreditation methodology	Annual capacity construct	MISO seasonal proposal approved by FERC	Unit accreditation not final; extremely complex for Encompass model
10	MISO Demand Response accreditation methodology	Annual capacity construct	MISO seasonal proposal approved by FERC	Unit accreditation not final; extremely complex for Encompass model
11	Belle River gas Conversion	2021 internal DTE estimates	2022 B&W budget proposal	Belle River conversion capital was updated per latest cost estimates

In addition, the recently approved MISO seasonal thermal resource accreditation method is considered a material change, however, implementing new capacity accreditations on a seasonal basis is too complex to implement in the EnCompass model for this IRP. Instead, a capacity position comparison was performed under the portfolio metric evaluation risk assessment. A new REFRESH scenario was developed with the updated natural gas prices, market with the updated gas prices, and the changes in revenue requirement of alternative technologies impacted by the IRA. These technologies include: wind, solar, storage, SMR and CCGT with CCS. Refer to Figure 14.4.3 for LCOE comparison of wind, solar, and CCGT with CCS.

The IRA tax credits were very impactful to the EnCompass optimization performed on the REFRESH scenario. Additional amounts of solar, storage and wind technologies were found to be economic with the tax credits applied. The final PCA reflects these additional resources incorporated into the plan as early as feasible to capture the value of the IRA tax credits for DTE Electric customers.

15.13 Portfolio metric evaluation

The portfolio metric evaluation was a quantitative evaluation of several alternative portfolios that were evaluated for the PCA using four different quantitative measures. In our analysis, nine plans were analyzed in the areas of:

- Capacity position.
- Diversity.
- Economic stochastic with and without the IRA tax credits.
- Total CO_2 reduction.

The nine plans selected for analysis consisted of the same plans evaluated in the economic stochastic risk analysis.

The capacity position evaluation was performed by reviewing each portfolio capacity position in each year and determining how far at or above zero capacity each portfolio was in each year. In addition, there are multiple sources of uncertainty that exist which drive the PRMR, which is used to determine the capacity position. These include future thermal accreditation uncertainties, the recent MISO implemented seasonal capacity construct including a seasonal accreditation, and changes to the future DR accreditation. Due to this higher level of uncertainty, a higher level of long position will reduce the risk of not meeting the PRMR. The Company desires at least 500 MW surplus capacity due to the uncertainty from the new MISO construct and other factors listed above. 500 MW was selected because it is approximately 5% of the PRMR. See Table 15.13.1 for the results of this evaluation.

Table 15.13.1: Capacity position evaluation

Portfolio #	Portfolio name	2023-2042 average above PRMR (UCAP MW)	Number of years 2023-2042 with less than 500 MW UCAP Surplus (Years)	Rank
1	Preliminary PCA	392	13	7
2	ET least-cost plan	1015	7	1
3	STAKE Base plan	167	17	9
4	REF 9A phase	324	14	8
5	REF least-cost plan	465	9	5
6	EP least-cost plan	952	7	1
7	BAU least-cost plan	448	10	6
8	REFRESH 6B phase	751	7	1
9	Final PCA	835	7	1

Diversity

Diversity is important for an electric generating portfolio to ensure grid reliability, minimize impacts of commodity price spikes and minimize impacts of fuel supply interruptions. Components of an energy resource portfolio diversity that can be quantified include:

1. Variety, or the number of different categories.
2. Balance, or how evenly spread are the category populations.
3. Disparity, or how different are the different categories from each other.

The Company used the Stirling Diversity Index to calculate diversity of the nine portfolios across the study period of 2023 to 2042. The energy mix percentage was calculated for each category. The categories considered in the diversity analysis were: coal, gas, nuclear, pumped hydro, oil, solar, wind, battery storage, and other. Other includes DR, CVR/VVO, EWR and PURPA, contracts under Public Act 2 of 1989 (PA2). The product of the energy mix percent for each pair of categories and the disparity score was then determined. Finally, these products were summed and the higher value was considered more diverse.

The results of the diversity comparison are shown in Table 15.13.2. The top six portfolios are tightly grouped between 2.42 and 2.45 scores, with the higher score being more diverse. The PCA (portfolio 9) has the highest score indicating the highest diversity of the nine portfolios.

Table 15.13.2: Diversity comparison

Portfolio #	Portfolio name	Stirling diversity index average 2023-2042	Rank
1	Preliminary PCA	2.448	3
2	ET least-cost plan	2.427	7
3	STAKE Base plan	2.341	9
4	REF 9A phase	2.433	5
5	REF least-cost plan	2.429	6
6	EP least-cost plan	2.449	2
7	BAU least-cost plan	2.347	8
8	REFRESH 6B phase	2.44	4
9	Final PCA	2.451	1

Economic Stochastic analysis with and without the IRA tax credits

The economic stochastic risk assessment with the tax credits (see section 15.10) was also considered in the portfolio metric evaluation. See Figure 15.13.3 with the results expressed in box and whisker format. Table 15.13.4 shows the ranking of the portfolios in the economic stochastic risk assessment with tax credits included.

Figure 15.13.3: Stochastic risk with IRA tax credits included

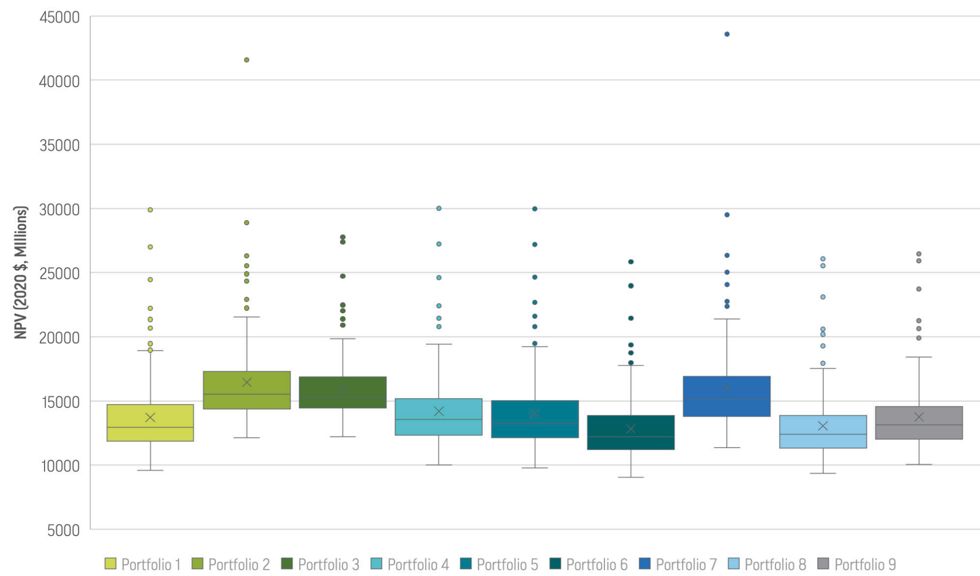


Table 15.13.4: Rank of the portfolios with IRA tax credits applied

Portfolio #	Portfolio name	Rank
1	Preliminary PCA	4
2	ET least-cost plan	9
3	STAKE Base plan	7
4	REF 9A phase	6
5	REF least-cost plan	5
6	EP least-cost plan	1
7	BAU least-cost plan	8
8	REFRESH 6B phase	2
9	Final PCA	3

The total forecasted amount of CO_2 in the study period of 2023-2042 is compiled in Table 15.13.5 for the nine portfolios. CO_2 tons is presented in both total fleet tons forecasted and total tons on a net short basis. The net short method is described in "Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases," a paper available on the EPRI website[1]. Traditional utility CO_2 accounting usually only counts CO_2 from the Company's fleet, and any CO_2 attributable to purchases or sales of power is ignored. In the net short method, the Company's generating units are divided into two groups: non-dispatchable and dispatchable. In the traditional sense (and in different contexts in other sections in this filing), dispatchable refers to sources of electricity that can be used on demand and dispatched, according to market needs. This is in contrast with non-dispatchable energy sources that cannot change their output, such as wind and solar, which are entirely dependent on the weather.

Table 15.13.5: Total CO_2 emissions comparison

Portfolio	CO_2 Tons fleet (Million tons)	CO_2 tons net short (Million tons)	Reduction from highest portfolio	Rank
Portfolio 1: Preliminary PCA	238	245	37%	4
Portfolio 2: ET least-cost plan	375	360	7%	8
Portfolio 3: STAKE Base plan	264	226	42%	2
Portfolio 4: REF 9A phase	268	271	30%	5
Portfolio 5: REF least-cost plan	254	270	30%	5
Portfolio 6: EP least-cost plan	362	321	17%	7
Portfolio 7: BAU least-cost plan	387	388	highest	9
Portfolio 8: REFRESH 6B phase	214	211	46%	1
Portfolio 9: Final PCA (REFRESH)	231	230	41%	3

For the purposes of the net short carbon accounting method, dispatchable refers to gas units, frequently on the margin serving the broader market ups and downs, while non-dispatchable refers to the traditional baseload resources, renewables and purchase contracts with specific assets. The non-dispatchable units' emissions are assumed to stay with the Company, as these resources are assumed to be serving customers at all times. Therefore, DTE Electric's coal, nuclear and renewable assets, and all PPAs are considered non-dispatchable for the purposes of carbon accounting. Dispatchable units are more likely to be on the margin and able to quickly ramp up and down to supply power to the MISO market and includes all gas units (CCGT and gas peakers).

The generation and the associated emissions from the non-dispatchable units are summed separately. Then the generation from the Company's non-dispatchable units are subtracted from DTE Electric customers' load. The difference is what is required to serve customers' load, beyond the output of the non-dispatchable units. This difference could be positive ("net short") when the Company needs to purchase additional electricity to serve its customers on an annual basis, or it could be negative if the Company is a net seller of electricity over the course of the year. A CO_2 intensity (pounds/MWh) corresponding to the U.S. natural gas fleet is applied to this difference. A gas fleet intensity was used as the basis for this carbon intensity calculation because gas units (CCGT and CT) are frequently marginal units supplying the market, meaning they are the next units to dispatch and thus set the market price. Renewables, base-load coal and nuclear are not typically considered marginal units in the market.

The comparison of forecasted CO_2 tons shows that the Monroe retirement date plays the biggest role in reducing the amount of CO_2 released. In the portfolios with the base retirements (ET, EP, and BAU) all have the highest CO_2 tons. The lowest CO_2 tons is in portfolio 8 with the 2028 and 2032 Monroe retirements. The STAKE base with 2028/2034 retirements is followed closely by the PCA with 2028/2035 Monroe retirements for the second and third least.

Conclusion of the portfolio metric evaluation

The PCA (portfolio 9) ranks high across all of the portfolio metrics as seen in Table 15.13.6.

Table 15.13.6: Portfolio risk summary

Portfolio	Capacity position	Diversity	Stochastic risk with tax credits	CO_2 tons reduced
Portfolio 1: prelim PCA	7	3	4	4
Portfolio 2: ET least-cost plan	1	7	9	8
Portfolio 3: STAKE Base	9	9	7	2
Portfolio 4: REF 9A phase	8	5	6	5
Portfolio 5: REF least cost plan	5	6	5	5
Portfolio 6: EP least cost plan	1	2	1	7
Portfolio 7: BAU least cost plan	6	8	8	9
Portfolio 8: REFRESH 6B phase	1	4	2	1
Portfolio 9: Final PCA	1	1	3	3

This means that the PCA is a robust portfolio: reliable in terms of capacity position, diverse, low cost in an uncertain future with low economic risk, and in the top third in terms of CO_2 tons reduction. The other strong portfolio is portfolio 8, a portfolio based on the least cost plan optimized on the REFRESH scenario. Portfolio 8 has Monroe retirements of 2028 and 2032. While a 2032 Monroe retirement is desirable in terms of reducing CO_2 the fastest, this portfolio has greater execution risk in terms of the timelines to build the large amount of replacement resources and required grid upgrades than the PCA. The PCA takes a more measured approach in terms of required grid upgrades and build of replacement resources to maintain reliability. The PCA balances decarbonization with affordability and maintains higher reliability by keeping ~1,500 MW of firm dispatchable resources on the system for three extra years, allowing time to fully work through the complex interconnection processes and new resource bid, design, build, and start up processes and additional time for emerging technology advancement.

15.14 Conclusion of the risk assessment

The five types of risk assessment that were performed support that the PCA is economic under a variety of situations, is robust and prudent, and is extremely flexible to incorporate emerging technologies. The PCA was fourth in the economic stochastic analysis and third in the economic stochastic analysis with the IRA tax credits included. The PCA meets the desired resource adequacy target. The portfolio metric evaluation showed excellent to moderate performance of the PCA across all four metrics (diversity, capacity position, economic stochastic risk, and CO_2 emissions). Given the pace of change in the energy industry and market conditions, the Company completed an assessment of the data assumptions used in the IRP starting point against current information. This resulted in the development of the REFRESH scenario, which incorporated the results of the IRA tax credits passed in August into the IRP capacity expansion optimization. The Company updated the PCA as a result of this scenario. The final PCA is more affordable, more reliable and decarbonizes faster than the preliminary PCA. Finally, the PCA was considered across multiple diverse futures with the scenario analysis discussed earlier in Section 15.

Endnotes

1. DTE Electric's CO_2 reduction goals are based on the net short method of carbon accounting, which utilizes Scope 1 CO_2 emissions from DTE Electric's electric generating units and adjusts for purchases and sales of power. More information about the net short method can be found at https://www.epri.com/research/products/000000003002015044

SECTION 16

16 Proposed course of action

16.1 Overview

DTE Electric continues to make progress on its decarbonization journey and transformation of the electric generation fleet that serves its 2.3 million customers in Southeast Michigan. While developing the 2022 IRP, the Company sought customer and stakeholder feedback and centered the plan on what was important based on that feedback: a PCA that provides reliable and affordable power from a diverse mix of clean energy resources.

The Company's IRP builds on the foundation of the 2019 PCA and continues the growth and acceleration of cleaner generation resources and commitment to reducing energy waste. The 2022 IRP studied a 20-year period (2023-2042) and resulted in a PCA that includes the adoption of 15,400 MW of renewable energy and 1,810 MW of storage, the retirement of over 4,100 MW of coal-fired generation, the incorporation of demand-side management programs and the integration of reliable dispatchable generation from the conversion of the Belle River Power Plant from coal-fired to a natural gas peaking resource. The result is a reliable, affordable, diversified energy mix that our customers can rely on, and a cleaner environment for our families, homes, communities, businesses and the state of Michigan.

The Company is committed to, and has a long history of, environmental conservation and stewardship, and protecting its communities, employees and customers. In May 2017, DTE Electric announced a long-term carbon reduction goal to reduce CO_2 emissions by more than 80% by 2050 (from a baseline of 2005). In May 2018, the Company made a commitment to achieve 50% clean energy by 2030. Half of this, or 25%, will come from renewable energy, with the other half coming from energy waste reduction. In early 2019, the Company accelerated the 80% carbon reduction goal by a decade to 2040, with an interim goal of a 50% carbon reduction by 2030. Later that year, the Company announced its net zero goal by 2050. In 2021, the Company accelerated its carbon reduction goal to 50% by 2028. The 2022 PCA advances the Company's current interim CO_2 emissions reduction goals by planning to achieve a 65% reduction in 2028, 85% reduction in 2035, and a 90% reduction by 2040. DTE Electric remains committed to going as fast as it can to reach net zero emissions while maintaining reliability and affordability. Because it is approximately 5% of the PRMR, 500 MW was selected. The Company will continue to assess its decarbonization goals, just as it has done multiple times since we set our first goal in 2017.

The Company's PCA plans additional environmental benefits, as it significantly reduces nitrogen oxide (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), volatile organic carbon (VOC) and mercury (Hg) from operations.

In its 2019 PCA, the Company announced the retirement of Belle River by 2030. In October 2021, DTE Electric accelerated the date to cease the use of coal as a fuel source in 2028 to align compliance plans with the United States Environmental Protection Agency's (EPA) Effluent Limitation Guideline (ELG) rules. This PCA proposes converting Belle River to a natural gas peaking resource in 2025 and 2026 (Unit 1 and Unit 2, respectively). The converted plant will provide reliable generation for customers, especially when customer demand is higher (such as in high or peak summer heat) or when other supplies are unavailable to keep power supply reliable. Belle River, expected to be retired by 2040, ensures electric reliability (resource adequacy and grid reliability) at a low cost as the Company integrates thousands of megawatts of renewable energy generation and battery storage.

Central to the Company's PCA is the full retirement of coal-fired generation. DTE Electric has two coal-fired steam power plants remaining in its fleet: the Belle River and Monroe Power Plants.

Monroe Power Plant is a 3,066 MW coal-fired power plant located in Monroe County. Monroe, which has four units, is the fourth largest power plant in the U.S. and represents approximately 30% of the Company's current generation capacity. The 2019 PCA planned Monroe's retirement date as Dec. 31, 2039. Monroe plays a critical role in providing reliable power to support Michigan's residents and the overall economy. This 2022 PCA commences Monroe's closing in 2028 – nearly 12 years ahead of our previous plan – with the retirement of Units 3 and 4. This phased approach, which will include collaboration with stakeholders and the community, will conclude in 2035 with the retirement of Units 1 and 2.

The conversion of the Belle River Power Plant to a natural gas peaking resource retains 1,270 MW of Midcontinent Independent System Operator (MISO) Zone 7 (nearly all of the lower state of Michigan) capacity and facilitates the early retirement of 1,535 MW, or about half of Monroe, in 2028. The full retirement of coal in DTE Electric's portfolio by 2035 – retiring the last major coal plant in Michigan[1] represents a truly transformational shift in the way we plan for, produce, and deliver electricity. The Company's coordination with the local transmission company, ITC, also indicated the Belle River conversion maintains electric grid reliability without having to invest near-term in expensive transmission facility upgrades.

The Company believes its PCA is transformational and stems from a comprehensive planning process that brings new resources online in the state of Michigan in advance of planned retirements. As it will be described throughout the filing, the PCA ensures electric reliability, resource diversity, and flexibility to mitigate risks facing the energy industry. It allows DTE Electric to time affordable, cost-competitive solar and energy storage projects early in the planning period in advance of initiating Monroe's phased retirement. The PCA also lays out a path to meaningfully accelerate interim carbon emissions goals as the Company continues to make progress toward its net zero goal. The PCA also includes a placeholder for a low or zero carbon, dispatchable resource slated in the mid-2030s supporting the retirement of the last two units at Monroe. The Company will monitor developments of emerging technologies in this fast-changing environment and continue to evaluate options to fill this critical need for dispatchable generation in future IRPs.

16.2 Proposed course of action details

Over the 20-year study period, DTE Electric's PCA:

- Develops 6,500 MW of solar.
- Develops 8,900 MW of wind.
- Develops 1,810 MW of battery storage.
- Ceases coal-fired generation operations and converts Belle River from a 1,270 coal-fired baseload power plant to a 1,270 MW natural gas peaking resource in 2025 (Unit 1) and 2026 (Unit 2). As a peaker, the Belle River Power Plant would operate at peak demand times. In addition, it will support a significant transition period in the energy industry in Southeast Michigan and across the broader region with the integration of high levels of renewables and battery storage and retirement of the first two units of Monroe Power Plant in 2028. This gas peaker would be retired by 2040.
- Retires Units 3 and 4 at Monroe Power Plant, a total of 1,545 MW of coal-fired generation in 2028 – 12 years earlier than previously announced - and retires Units 1 and 2, 1,541 MW of coal-fired generation, in 2035.
- Incorporates the maximum amount of achievable EWR potential identified in the 2021 Michigan EWR Statewide Potential Study, an average of 1.5% per year over the PCA study period.
- Deploys 38 MW of conservation voltage reduction/volt var optimization (CVR/VVO).
- Incorporates a 946 MW clean, dispatchable resource in 2035 when the final two units of the Monroe Power Plant retire. While clean, dispatchable technologies to support net zero are still emerging and require further development, the technology currently selected in the IRP is a natural gas combined cycle turbine with carbon capture and sequestration (CCGT with CCS).

The Company is well positioned to implement the PCA having carefully considered the approach and sequencing of new investments and retirements. There are essential regulatory and financial proposals to support the successful implementation of the PCA, including the pre-approval of certain costs, regulatory asset treatment for the Monroe Power Plant and the coal handling assets at Belle River, and a financial incentive mechanism applicable to purchased power agreements (PPAs).

The result of DTE Electric's PCA is a fully integrated proposal that ties the Company's decarbonization journey to the proposals described above, and in the testimonies, and exhibits filed in this proceeding. Therefore, any modification to, or rejection of, a proposal made in the PCA impacts the PCA's viability and the Company's willingness to execute on the remaining portions of the PCA. As such, the Company reserves the right to abandon or amend its PCA if the Commission rejects or modifies any of the Company's proposals presented in this IRP.

PCA 2023-2027

The first five years of the Company's PCA accelerate the initial 1,270 MW of coal retirement at Belle River and repurposes the asset to support reliability, integrate a mix of renewables and storage, incorporate demand-side resources, and set a strong foundation from which the PCA continues to build:

- Renewables – 800 MW solar.
- Battery storage – 240 MW.
- EWR – 2% annual savings in 2023, then an average of 1.6% annual savings, consistent with the maximum amount of

achievable potential as identified in the Statewide Potential Study.

- CVR/VVO – 15 MW.

Implementation of the solar and storage resources, in addition to the Belle River peaking resource identified in the first five years of the PCA, is necessary for the Company to proceed with the retirement of the first two units of Monroe Power Plant in 2028.

Belle River conversion

The Belle River conversion sets the stage for the retirement of the first two units of Monroe in 2028 – 12 years earlier than planned in the 2019 PCA. The conversion provides DTE Electric's customer base a reliable, dispatchable resource as large amounts of intermittent resources replace dispatchable coal resources. As a peaking resource, Belle River will operate during times when customer demand is higher (peak) or when other supply resources may be unavailable.

Including a Belle River conversion in the PCA is a more affordable path to accelerated decarbonization. When pairing a two-unit retirement of Monroe with a conversion of Belle River, the plan saves customers over $200 million in net present value revenue requirement (NPVRR) over alternatives that do not include a conversion while retiring two units of Monroe early. In terms of overall capital costs, a Belle River conversion is around $130 per kilowatt (kW), a fraction of the cost of a new natural gas combustion turbine ($800/kW) or a new CCGT ($1,110/kW). Additionally, the Belle River conversion is an efficient use of existing infrastructure. The transmission system reliability studies conducted by ITC indicate that converting the Belle River Power Plant provides near-term savings of $350 million in transmission system impacts.

It also significantly reduces carbon emissions from current operations, achieving an approximate 90%-95% carbon reduction from current annual levels. In addition, by enabling two units at Monroe to retire 12 years earlier than originally planned, the Belle River conversion will further facilitate additional fleet-wide carbon emissions reductions, allowing DTE to achieve a 65% carbon reduction goal in 2028

The Belle River peaking resource will be a transition asset, helping to bridge the period of time from when natural gas must play a role in supporting a reliable retirement of coal to low or zero carbon, dispatchable emerging technologies are both commercially available on a utility scale and more affordable. As a transition asset, the Belle River peaking would retire by 2040.

Conversion of the Belle River Power Plant won't just impact the Company's customers, MPPA's customer base will be impacted as well. They will continue to receive benefits of a cost-effective resource that provides reliability and capacity– as well as the reduced emissions – once converted.

PCA 2028-2032

With the PCA's identified resources and financial mechanisms in place by 2027, DTE Electric will be positioned to advance to the next phase of the PCA, from 2028-2032, which includes the following:

- Renewables.
  - Solar – 3,600 MW.
  - Wind – 1,000 MW.
- Battery storage – 520 MW.
- Monroe Units 3 and 4 retire in 2028 – 1,545 MW.
- EWR – an average 1.2% annual savings, consistent with the the maximum amount of achievable potential as identified in the Statewide Potential Study.
- CVR/VVO – 23 MW.

The first 10 years (2023-2032) of the Company's PCA relies on known, commercially available technologies to ensure a reliable, flexible and affordable transition, laying the foundation for continued progress toward DTE Electric's and the State's net zero commitments.

PCA 2033-2042

The second half of the Company's PCA, from 2033-2042, includes the following:

- Renewables.
  - Solar - 2,100 MW.
  - Wind - 7,900 MW.
- Battery storage – 1,050 MW.
- Retirement of Monroe Units 1 and 2 in 2035 – 1,531 MW.
- Retires the Belle River natural gas peaking resource by 2040 – 1,270 MW.
- EWR – an average 1.6% annual savings, consistent with the the maximum amount of achievable potential as identified in the Statewide Potential Study.
- Low or zero carbon, dispatchable 946 MW placeholder resource in 2035; currently identified in this IRP as a CCGT with CCS.

While the first half of the 20-year proposal relies on known, readily available technologies, we expect costs and commercially available technologies will change before implementing the second half of the plan. While renewables, battery storage, and demand-side management programs will play a key role in the Company's transition toward cleaner energy through 2042, the resource and grid reliability impact of the final exit of coal will require the build-out of both a dispatchable resource to support resource adequacy and grid infrastructure development to ensure a reliable transition.

Both the advancement of emerging technology options and the development of grid infrastructure require time and further planning and development to fully retire Monroe (Units 1 and 2) and Belle River reliably and affordably. The Company expects its overall supply mix will become increasingly reliant on intermittent resources during this timeframe (e.g., approximately 60% by 2042). This increased reliance on intermittent resources, when combined with the scale of the Belle River and Monroe power plants and their role in providing critical grid reliability functions, adds complexities to the development of solutions. The deployment of renewable energy at this scale in the 2030s will also require collaboration with communities to facilitate siting and permitting, improvements to the generation interconnection processes, and upgraded and/or new transmission facilities. The implementation of the PCA will also depend on the results of competitive procurement processes for new resources, as market conditions may vary from the assumptions used in the modeling and thereby affect timing and resource selection.

While the need for a dispatchable resource is identified in this PCA, low or zero carbon dispatchable technologies are not commercially viable today but will continue to evolve over time. The Company considers this a generic dispatchable resource pending further advancements in technology and commercial availability. DTE Electric anticipates the cost and commercial availability of emerging technologies to change, so the Company will remain flexible and continue to evaluate technologies, such as CCGTs with CCS, small modular nuclear reactors (SMR or SMNR), and mid- to long-duration storage, in future IRPs.

Additional reliability challenges when the Belle River natural gas peaking resource is retired, further highlights the need to continue to evaluate the resource and reliability needs of the changing grid as technology, the industry, and plans evolve.

PCA benefits

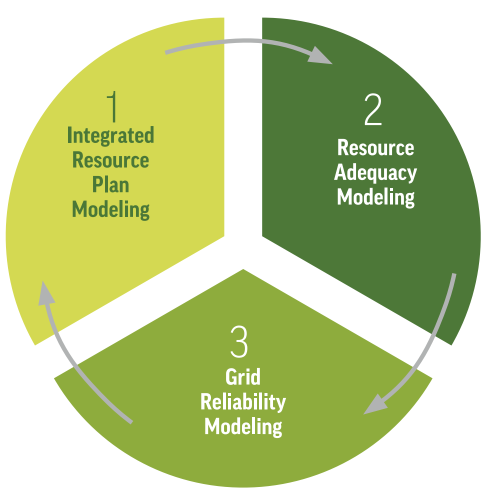
The PCA provides a reliable, affordable path to decarbonization while creating long-term value for our customers and ensuring the Company's financial health through the transition

- Transforms DTE Electric's generation mix to cleaner, more diverse sources.
  - Includes 15,400 MW of renewables and 2,350 MW of storage deployed in Michigan by 2042.
  - Redirects $2.4 billion from coal to cleaner sources of energy over the 2019 plan.
  - Ends the use of coal by 2035 with a responsible, phased retirement schedule protecting reliability and affordability.
  - Accelerates our previously announced carbon reduction goals, achieving a 65% reduction in 2028, 85% in 2035, 90% by 2040, and net zero by 2050.
    - The plan's timelines are ahead of the timelines in the MI Healthy Climate Plan[2] and will help support Michigan's economy-wide greenhouse gas (GHG) emissions reductions interim goals of 28% by 2025 and 52% by 2030 from 2005 levels.
    - Exceeds the Federal goals for the United States under the Paris Agreement to reduce US greenhouse gas emissions 2% below 2005 levels in 2030 and achieve a net zero emissions economy by 2050.
  - Provides the highest generation diversity among alternative portfolios analyzed for risk, as described in Section 15, and aligns with customer feedback provided through the Voice of the Customer research, where respondents shared a broad acceptance and desire for a diverse and balanced mix of sources.
  - Prioritizes reliability while preparing for our customers' needs.
  - Incorporates results from resource adequacy and grid modeling into the IRP process, reducing risks to customers by having sufficient, local, and diverse energy and capacity resources.
  - Leverages the converted Belle River Power Plant to support customers through periods of high customer demand and while DTE Electric integrates thousands of megawatts of renewables.
  - Reduces near-term reliability risk associated with the need for substantial reactive power support (650 megavars) when both Belle River and Monroe retire.
  - Mitigates risks of relying on capacity markets that are subject to price volatility and tightening electricity supplies.
- Creates long-term value for our customers and communities.
  - Realizes $1.4 billion in reduced costs compared to our 2019 plan.
  - Reduces the PCA-related revenue requirement impacts by 2.18% CAGR[3], as well as the rate impacts compared to the base plan in place over the 20-year period.
  - Positions the Company to take advantage of tax incentives and other benefits of the Inflation Reduction Act (IRA) of 2022, thereby supporting the affordability of the plan.
  - Preserves valuable interconnection rights and efficiently uses existing infrastructure in the proposed Belle River conversion from coal to natural gas.
  - Defers $350 million in transmission upgrades providing near-term savings to customers.
  - Drives about $9 billion of investment in clean energy over the next 10 years, creating or retaining over 25,300 Michigan jobs, supporting the State's economy while addressing climate change and maintaining reliable power.
  - Incorporates stakeholder feedback.
  - Maintains the Company's commitment to engaging coal plant communities to ensure a close partnership in advance of and during the transition period.
  - Maintains the Company's no layoff commitment to employees.
  - Adopts the maximum amount of EWR levels achievable based on the findings of the MPSC Statewide Potential Study released in 2021, helping to defer the need for new generation while also helping eligible customers manage their energy bills.

Electric reliability is the highest priority in the Company's planning process and the foundation of the PCA. DTE Electric is responsible for providing a reliable supply of power to its customers in all hours of the year. DTE Electric's system is connected to the broader grid and to ensure reliability the Company must plan for its future considering the broader energy market conditions across Michigan and the MISO region. Because the PCA sets the retirement schedule for the Company's remaining two coal-fired power plants totaling approximately 4,100 MW of generation and recognizing that the region is shifting from traditional dispatchable generation to significantly more intermittent resources, the Company expanded the scope of evaluating potential electric reliability impacts to ensure the PCA is reliable, resource adequate and diverse.

DTE Electric's system is connected to the broader grid and to ensure reliability the Company must plan for its future considering the broader energy market conditions across the region. Because the PCA sets the retirement schedule for the Company's remaining two coal-fired power plants totaling approximately 4,100 MW of generation and recognizing that the region is shifting from traditional dispatchable generation to more intermittent resources, the Company expanded the scope of evaluating potential electric reliability impacts to ensure the PCA is reliable, resource adequate and diverse. The Company engaged with Astrapé and ITC to leverage a three-phased, iterative approach as shown in Figure 16.2.1 that prioritized electric reliability while also seeking an affordable path to decarbonization.

Figure 16.2.1: Reliability approach



By leveraging this comprehensive approach, DTE Electric is able to de-risk the PCA by ensuring customers have sufficient, local, and diverse energy and capacity resources. Specifically, grid reliability and resource adequacy are supported by two essential components of the PCA: 1) the Belle River conversion provides a critical reliability backstop as DTE Electric accelerates the retirement of the first 1,535 MW of coal at Monroe in 2028, and 2) the development of sufficient resources including renewables and storage in advance of the 2028 retirements ensures supply reliability for customers.

The plan also considers resource availability and weather variability and expects resources to be located in the state of Michigan rather than relying on new or existing resources outside of the state, which may or may not exist or be available to Michigan customers. The MISO Planning Resource Auction for Planning Year (PY) 2022/23 showed that even when the Effective Capacity Import Limit (ECIL) was sufficient to import capacity, there were not enough resources external to Zone 7 available.

16.3 Evaluation of the PCA

The PCA is robust and prudent, meeting the Company's planning objectives of safe, reliable and resilient, affordable, customer accessibility and community focus, and clean.

The IRP process requires electric utilities to seek the most reasonable and prudent means of meeting customers' short and long-term energy and capacity needs. To do this, the Company defined a plan that best meets the planning objectives and statutory requirements, while also considering areas of importance expressed by stakeholders. The Company developed a robust plan that performed well under a variety of scenarios and sensitivities using the planning objectives and statutory criteria as an evaluation framework.

DTE Electric analyzes the modeling results and then conducts the initial synthesis of results, which supports the determination of a preliminary PCA. The preliminary PCA is then further analyzed through additional analyses. These analyses included: 1) capacity expansion and production costs modeling (typically known as "IRP modeling"); 2) transmission grid reliability and power flow studies, including coordination with ITC on impacts of new generation and retirements on the transmission system; 3) resource adequacy studies including loss of load expectation (studying reliability of supply at all hours of the year under different conditions) and effective load carrying capacity (studying the contribution of particular resources, such as solar and battery storage to help meet peak demand); 4) special studies on power plant retirements (decommissioning); 5) environmental assessment; 6) risk assessment; and 7) financial modeling and rate impact analysis.

While the capacity expansion modeling helps identify least-cost plans to meet future energy and capacity needs based on the various assumptions, additional data and analyses are needed to formulate a PCA given transmission and resource adequacy impacts and the sequencing of new renewable generation construction in advance of coal retirements. The Company looks across multiple modeling outputs to identify a portfolio that best aligns with the planning objectives and that performs well when considering a variety of risk assessments.

16.4 Implementation plan

The Company has developed an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the PCA focusing on the first three years following approval of this IRP. The implementation plan will vary depending on the specific resource. Overall, the Company is effectively positioned to implement the near-term investments, and will secure the necessary workforce, resources, materials, and contracts.

The Company also has considerable experience designing and implementing EWR and DR programs and delivering results. It has an established network for contractors and channels for outreach and delivery.

Consistent with our past practices and our commitment to support Michigan-based suppliers, the Company will strive to utilize Michigan workers as we implement the PCA. In our request for proposals and during contracting, we have traditionally indicated a preference for suppliers and projects that have Michigan headquarters and that utilize Michigan workers and will continue to do so. DTE has invested nearly $16 billion with Michigan-based vendors since 2010, creating and sustaining 54,000 Michigan jobs.

16.5 Regulatory requests to support transition

The transition of generation has far-reaching impacts and requires a level of certainty to ensure we are able to plan for customer needs well in advance of implementation and that we serve our customers in an affordable and reliable manner. Due to the large-scale transformation proposed by DTE Electric in this IRP, we put forward three requests that are integral to the progression of the proposal:

1. Pre-approval of the costs associated with the conversion of the Belle River Power Plant, and costs associated with certain demand response programs.

2. An update to the current financial compensation mechanism for purchased power agreements to support the generation transition as authorized by Michigan Law under MCL 460.6t(15).

3. Accounting treatment for the net book value and decommissioning costs associated with Monroe Power Plant and the retiring coal handling assets at Belle River, as well as ongoing investments needed at Monroe to operate safely and reliably through retirement.

Approval of these requests as proposed would provide DTE Electric the assurances necessary to proceed with the implementation of the proposed generation transformation and progress our decarbonization plans affordably and reliably.

Endnotes

1. The Company has been unable to confirm the expected retirement status of the remaining two known utility or municipally operated primary coal with gas facilities, Munising Power Plant and MSC Sebewaing. It is possible that non-utility (i.e., private industrial users) may continue to operate coal facilities behind-the-meter in Michigan.

2. "https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.d?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588"

3. Compound annual growth rate

SECTION 17

17 Rate impact and financial information

17.1 Customer rate impacts

The year-over-year revenue requirement associated with the Company's PCA was compared to the year-over-year revenue requirement of the reference scenario. The year-over-year revenue requirement is inclusive of rate base, fixed and variable O&M, fuel costs and emission costs.

The PCA includes 15,400 MW of renewable energy and 1,810 MW of battery storage, as well as the retirement of over 4,100 MW of coal-fired generation. Comparing the PCA to the reference scenario shows a residential rate impact that ranges from a high of a 2.76% increase to a low of a (6.00%) reduction over the 20-year study period. Over the first five years of the study period, the average incremental change for residential customers is 0.66%, or an average of 0.12 cents per kilowatt-hour increase per year. While the annual change in revenue requirement varies year to year, the net impact to customers over the entire study period is forecasted to be beneficial to customers and produce a net decrease in rates over time. The compounded annual growth rate (CAGR) of the change in revenue requirement across the study period is (2.18%) and is negative for all customer classes, including (1.74%) for residential.

17.2 Financial assumptions

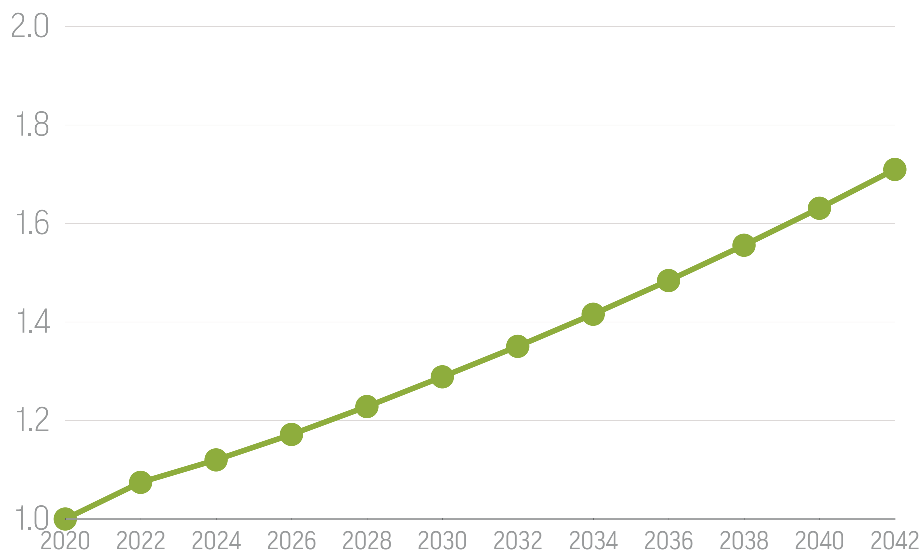
The EnCompass optimization model utilized the financial ratios provided in Case No. U-20561. The levelized cost of energy analysis also used the same financial information as appropriate. The pre-tax marginal cost of capital was used to calculate the return on rate base. Capital's after-tax weighted cost was used to calculate the allowance for funds used during construction (AFUDC). Capital's pre-tax weighted cost was used as the discount rate in calculating the annual revenue requirement streams' net present value. A list of the financial assumptions is shown in Table 17.2.1.

Table 17.2.1: DTE Electric financial assumptions

	Percentage
Long-Term Debt	50.0%
Common Equity	50.0%
Cost of Debt (Pre-Tax)	4.22%
Cost of Equity (After-Tax)	9.90%
Marginal Cost of Capital (After-Tax)	7.06%
Marginal Cost of Capital (Pre-Tax)	8.79%
Cost of Capital for AFUDC	5.46%
Discount Rate	6.79%
Tax Rate	25.91%

The modeling used the deflator series representing an inflation rate, shown in Figure 17.2.2, based on the unadjusted Consumer Price Index. This deflator series was used throughout the scenario development and in the alternatives development, and was tied to the sales forecast developed by the load forecasting group.

Figure 17.2.2: DTE Electric deflator series



SECTION 18

18 Environmental

18.1 Overview

DTE Electric has a long history of environmental conservation and stewardship, and is committed to protecting its communities, employees, customers and the planet. In May 2017, it was one of the first energy companies to announce a long-term carbon-reduction target to reduce CO_2 emissions by more than 80% by 2050 from a baseline of 2005, positioning the Company as an industry leader in reducing greenhouse gases. In 2018, the Company announced a goal of achieving 50% clean energy by 2030, which it will achieve by using more natural gas, wind and solar, and by improving customers' energy-saving options. The Company is also planning to account for the carbon it produces for customers, including that produced by the power it purchases.

The plan for reducing the Company's CO_2 emissions makes business sense and ensures safe, reliable, affordable cleaner energy for its customers. It also allows the Company to implement a long-term generation-transformation strategy in which more than half of the energy produced is generated from zero-emitting resources. In the 2019 IRP, the Company accelerated its carbon reduction goal by a full decade by pledging to reduce carbon emissions by 80% by 2040. In 2020, the Company announced a goal of net zero by 2050. With the plans laid out in this IRP, the Company is able to take the next step on its clean-energy journey, and is announcing that it is accelerating its interim carbon reduction goals to 65% in 2028, 85% in 2035, 90% by 2040. See Table 18.1.1 for DTE Electric's carbon reduction goals.[1]

Table 18.1.1 DTE Electric carbon reduction goals

Announcement Year	2017 Goal	2019 Goal	2021 Goal	2022 Goal
Carbon Reduction Goals[1]				
	30% by early 2020's	32% by 2023	32% by 2023	32% by 2023
	45% by 2030	50% by 2030	50% by 2028	65% by 2028
	75% by 2040	80% by 2040	80% by 2040	85% by 2035
	80% by 2050	Net zero by 2050	Net zero by 2050	90% by 2040
				Net zero by 2050

1 Compared to a 2005 baseline

The Company is committed to operating in a manner that complies with or exceeds federal, state and local environmental regulations, rules, standards and guidelines, which are described in this section.

18.2 Environmental stewardship

DTE Electric's environmental compliance includes completed environmental-controls retrofits for existing coal-fired plants to operate in compliance with all applicable regulations while the plants continue to operate. This includes installation of emission controls on all four units at the Monroe Power Plant in 2014 and at all remaining coal-fired power plant units in 2016 to comply with Mercury and Air Toxics Standards and other regulations.

Several regulations under the Clean Air Act, Clean Water Act and the Resource Conservation and Recovery Act will likely affect coal-fired power plants in the coming years. The regulations have different implementation timelines and will have various outcomes for the Company. Regulatory compliance and some of these regulations' effects are discussed further in this section.

18.3 Environmental compliance

Steam Electric Effluent Limitation Guidelines

Effluent Limit Guidelines (ELGs) are national wastewater discharge standards that are developed by the EPA on an industry-by-industry basis. The EPA's ELGs regulate how electric utilities must manage certain wastewaters. These are technology-based regulations and are intended to represent the greatest pollutant reductions that are economically achievable for an industry. EPA promulgated the Steam Electric Power Generating (SEPG) ELGs in 1974, and amended the regulations in 1977, 1978, 1980, 1982, 2015 and 2020. The regulations cover wastewater discharges from power plants operated by utilities. The ELGs are incorporated into National Pollutant Discharge Elimination System (NPDES) permits.

In late 2015, the EPA issued its final rule related to wastewater discharge or ELG for steam electric power generators. The new requirements covered some specific wastewater discharges from coal plants. On Oct. 13, 2020, the EPA finalized the ELG Reconsideration Rule, which revised some requirements from the 2015 version of the ELG rule. The Reconsideration Rule revised requirements for two specific waste streams produced by steam electric power plants: flue gas desulfurization (FGD) wastewater and bottom ash transport water (BATW). The Reconsideration Rule provides additional compliance opportunities by finalizing subcategories, such as for the cessation of coal burning activities.

The Reconsideration Rule provides opportunities for the Company to evaluate existing ELG compliance strategies and make any necessary adjustments to ensure full compliance with the ELGs in a cost-effective manner. The EPA set the applicability dates for BATW and FGD wastewater retrofits to be "as soon as possible," beginning Oct.13, 2021 and no later than Dec. 31, 2025. For facilities pursuing the FGD wastewater Voluntary Incentives Program (VIP), compliance shall be achieved no later than Dec. 31, 2028. Compliance schedules for individual facilities and individual waste streams are determined through issuance of new NPDES permits by the state of Michigan.

The Company had two options to achieve compliance under the Reconsideration Rule for BATW and FGD wastewater. The first option was to design and engineer new technologies that are compliant with the ELG requirements for BATW and FGD wastewater. The second option was to pursue a compliance subcategory for BATW and FGD wastewater that the EPA established within the Reconsideration Rule. One compliance subcategory allowed for companies to attain compliance with the ELGs for both BATW and FGD wastewater by ceasing coal burning activities, which includes retiring coal-fired unit(s) or converting unit(s) to other fuels. If companies certified that unit(s) will retire the use of coal or refuel, they can continue to operate those units until their specified coal retirement date, which is required to be before Dec. 31, 2028. For the electrical generating unit(s) that certified under this subcategory, companies need to maintain the existing standard limits already in effect for BATW and FGD wastewater discharges.

In addition to the cessation of the coal burning activities subcategory, the Reconsideration Rule also provided a compliance subcategory specific to FGD wastewater. The Reconsideration Rule established Best Available Technology (BAT) standard discharge limits for FGD wastewater discharges and finalized the VIP subcategory. Under the VIP, companies may choose to meet more stringent effluent limits established by the EPA based on the model technology of membrane filtration or zero-liquid discharge. If a company chose the VIP option, the applicability date for FGD wastewater compliance would be extended to Dec. 31, 2028.

To establish compliance for either of the subcategories detailed previously, companies were required to submit a Notice of Planned Participation (NOPP) to the state permitting agency by Oct. 13, 2021. DTE Electric submitted the NOPP(s) to the Department of Environment, Great Lakes, and Energy (EGLE) in Michigan on that date. Once submitted, companies are required to submit annual progress reports to EGLE to ensure the commitment of compliance under the subcategories. A cessation of coal NOPP was submitted for Belle River Power Plant on Oct. 13, 2021. A VIP NOPP was submitted for the Monroe Power Plant on Oct. 13, 2021.

At Belle River, fly ash is currently dry managed and therefore there are no implications with the requirements of the ELGs for fly ash treatment water (FATW). Additionally, the power plant was constructed and operates without FGDs, therefore, there is no FGD wastewater. However, the bottom ash is currently collected using transport water and the ELG Reconsideration Rule requires the Company to achieve compliance with BATW discharge requirements. As mentioned, the Company submitted an NOPP for cessation of coal at Belle River and the evaluation of an alternative fuel source. As outlined in this IRP, the Company intends to convert Belle River to natural gas between 2025 and 2026. As a result of this conversion, and the previously submitted NOPP, the plant is utilizing a subcategory in the rule for ELG compliance by ceasing coal operation. The Company will avoid approximately $55 million in capital spend to build a new, ELG-compliant, bottom ash handing system.

At Monroe, the Company is currently implementing projects for FATW ELG compliance according to the 2015 ELG Rule that will allow the plant to continue operating beyond 2023. FATW is regulated by the 2015 version of the ELG rule which requires system upgrades to be completed no later than Dec. 31, 2023. Monroe did not have the infrastructure required to reliably comply with the 2015 ELG mandate related to fly ash in order to maintain environmental compliance. Therefore, in 2016 DTE Electric moved forward with a FATW compliance project that entailed design and engineering, procurement, demolition of existing system, and construction of a new, fully automatic, vacuum-to-pressure fly ash handling system. Upon completion, Monroe's fly ash transport and storage system will be in compliance with the ELG requirements for zero liquid discharge and able to reliably remove 100% of the fly ash it produces in a dry capacity. The new system will have adequate storage and loadout capabilities to continue to operate for the remaining life expectancy of the plant. Following installation, there will be a start-up and optimization period to get the equipment operating reliably and consistently to meet ELG standards by Dec. 31, 2023.

For BATW wastewater ELG compliance, the Company will achieve compliance at Monroe by the end of 2025. The Company plans to terminate the use of water for bottom ash at Monroe. In place of water conveyance, a dry drag chain conveyor system will be installed. The project is currently approved for engineering, design, and initial work.

Plans for compliance with the FGD wastewater ELG have changed with this IRP. As mentioned above, the Company submitted an NOPP for the VIP at Monroe. The PCA in this IRP includes the retirement of Units 3 and 4 at Monroe by 2028. This will significantly reduce the amount of FGD wastewater generated at the plant and will decrease compliance costs. Although the specific technology for compliance has not been finalized, it is expected that through the early retirements of Units 3 and 4, the Company will avoid approximately $32 million in capital spend for FGD wastewater compliance. The capital spend for FGD wastewater compliance for four units at the plant was projected to be $127 million, while the capital spend for the remaining two units outlined in the PCA is projected to be $106 million.

Coal Combustion Residual Rule

The EPA's Coal Combustion Residual (CCR) Rule regulates how electric utilities must manage and dispose of CCR in landfills and impoundments. On Aug. 28, 2020, the EPA published an amendment to the CCR rule (the Part A Rule) that requires all unlined surface impoundments to cease receipt of waste and initiate closure as soon as technically feasible, but no later than April 11, 2021. The Part A Rule also provided utilities the ability to request site-specific alternative closure deadlines through a demonstration process to obtain EPA approval. On Nov. 12, 2020, EPA published an additional amendment to the CCR rule (the Part B Rule) that allows utilities the opportunity to demonstrate that their unlined surface impoundments have an alternate liner system that is as protective as a CCR rule compliant liner system. The demonstration processes included in the Part A Rule and Part B Rule require EPA approval to continue operating the Company's unlined CCR surface impoundments.

The Company submitted Part B Rule applications to perform Alternate Liner Demonstrations for the Monroe Fly Ash Basin (FAB), the BRPP Bottom Ash Basins (BAB) and the BRPP Diversion Basin. The EPA is currently reviewing the submittals and the outcome of their review will determine the timeline for closure of these unlined surface impoundments. The Company is currently closing the Monroe BAB by removal of all ash. Closure of the Monroe BAB was initiated and is anticipated to be completed in accordance with the timeline required by the CCR rule. Closure is required to be complete within five years (with the opportunity for five two-year extensions, if necessary). Compliance costs for closure of the of the ash basins mentioned above are not impacted by the early retirements proposed in the PCA in this case. The Company's coal ash landfills – Range Road Landfill, Monroe CCR Landfill, and Sibley Quarry Landfill – will continue to receive CCR through the active life of the respective power plants that deposit ash at these locations. These landfills will be closed in place by installing cover material over the ash deposits at the end of their active life. The Company is currently making infrastructure improvements at Sibley Quarry Landfill to enhance storage capability, including the ability to accept the CCR material coming from the Monroe Bottom Ash Basin. There is not expected to be a significant reduction in compliance costs for closure of the Company's coal ash landfills due to the early retirements proposed by the PCA in this case, however savings of approximately $6 million are projected for the closures of Sibley Quarry and the Monroe CCR landfill as a result.

In addition to capital expenditures required to comply with the CCR regulations, there is ongoing operations & maintenance (O&M) required for compliance through inspections, monitoring, reporting, and requirements of the regulations. O&M expenditures for the Company's seven CCR units will be incurred once the units have been closed. Those seven sites include the Belle River and Monroe BABs, the Belle River Diversion Basin, the Monroe FAB, and the Range Road, Monroe CCR, and Sibley Quarry Landfills. Beyond the date of each site closure, O&M costs include ongoing monitoring and site preservation, in addition to O&M costs for remediation that are accounted for in environmental reserve accounts. The Company has one environmental reserve associated with CCR expenses at Belle River. The environmental reserve for Range Road Landfill is for groundwater remediation required by Part 115 of the Natural Resources and Environmental Protection Act of 1994, as amended. The groundwater is managed through an EGLE approved Remedial Action Plan that includes operation and maintenance of two French drain systems to capture off-site shallow groundwater to the northwest, northeast, and east of the landfill.

National ambient air quality standards

The Clean Air Act (CAA) requires that the EPA set national ambient air quality standards (NAAQS) for six pollutants: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O3), particulate matter (PM), and sulfur dioxide (SO_2). NAAQS are set by the EPA at levels deemed to be protective of public health and the environment. The standards are reviewed periodically and may be revised based on that review. Areas in which pollutant levels in ambient air are below the NAAQS are designated as attainment, while areas with levels above the standards are designated as nonattainment. As the standards are specific to a geographic area, not a point source, the plans to meet the standards require collaboration between the state regulatory agency, in this case EGLE, and the specific emitting sources within the defined nonattainment area.

In 2010, the EPA established a new one-hour SO_2 NAAQS, which resulted in an area in southern Wayne County being designated as nonattainment in 2013. This area included the Company's River Rouge and Trenton Channel power plants. The Company implemented significant SO_2 emissions reductions at both power plants to help achieve attainment in the area. Parts of a State Implementation Plan (SIP) submitted by the state of Michigan were disapproved by EPA, which recently proposed a Federal Implementation Plan for the area. The retirements of River Rouge and Trenton Channel power plants mean no further action in this area for the Company.

The same 2010 SO_2 NAAQS that affected the Wayne County plants also impacted a small portion of St. Clair County. An area of St. Clair County that includes Belle River and St. Clair Power Plant was designated as nonattainment in late 2016. The Company installed SO_2 monitors near the power plants to monitor actual SO_2 emissions. Using this data, and the retirement of St. Clair in 2022, EGLE submitted a Clean Data Determination (CDD) to EPA, which was subsequently approved. The CDD demonstrates that ambient air quality in the area shows attainment with the SO_2 NAAQS standard. While the CDD approval doesn't automatically redesignate the area to attainment, no further action was required regarding emissions reductions at the Company's plants. In addition, the Company has accepted lower permitted SO_2 emission limits at Belle River. These emission limits allow for the area to show attainment via air dispersion modeling. EGLE is currently developing a redesignation request for the area based on this modeling which will then be submitted to EPA for approval.

In 2015, the NAAQS for ozone was lowered from 75 parts per billion (ppb) to 70 ppb. As a result, a seven-county area of Southeast Michigan was designated as nonattainment for ozone. This area includes many of the Company's fossil fuel-fired electric generating facilities. The nonattainment area is impacted by many other industries and factors. The Company, among other industrial sources in the area, are collaborating with EGLE to develop a SIP, as required, for ozone. The emission reductions associated with the Company's PCA include further reductions in ozone in the future through decreases in NOx and VOC emissions. At this time, it is not believed that additional emissions reductions from the Company's facilities would be required in the SIP.

Thermal discharge regulations

The thermal discharge regulations under Section 316(a) of the Clean Water Act (CWA) regulate heated discharges from processes, including power plants, into Waters of the United States (WOTUS) through the National Pollutant Discharge Elimination System (NPDES). Company facilities with thermal discharges are regulated by EGLE through the NPDES permitting process. There are various impacts to the Company's facilities depending on the current and future operation.

The Fermi 2 plant and Blue Water Energy Center have installed cooling towers and are compliant with the 316(a) regulations. Greenwood Energy Center uses cooling sprays in the water discharge loop to cool water to levels that are compliant with 316(a) regulations with no further controls. At Belle River, a rapid mixer diffuser is installed in the mixing zone of the plant discharge outfall to the St Clair River. The diffuser is considered BAT and there are no additional controls required. The BWEC discharge also uses this outfall. The conversion of Belle River to natural gas proposed by this IRP will reduce the water use by the plant as well as the associated thermal impact on the plant's water discharge on WOTUS. Current plans for Monroe are to perform biological studies on the plant's water discharge outfall in 2024. These studies will be conducted to determine whether there is an impact on the aquatic ecosystem in the area. Once the studies are performed, any requirements related to 316(a) will be included in the plant's NPDES permit. The proposed retirement of Units 3 and 4 by 2028 included in this IRP will reduce the thermal impact on the plant's water discharge on the associated WOTUS. Beyond the cost of the biological studies at Monroe, additional costs associated with 316(a) regulations, if any, are unknown at this time.

Cooling water intake structure regulations

The EPA finalized regulations on cooling water intake structure (CWIS) under Section 316(b) of the Clean Water Act (CWA) in August 2014 for power plants and other facilities. The regulations affect cooling water intake at existing facilities in two main ways: first, existing facilities are required to reduce fish impingement on the screens; second, existing facilities are required to conduct studies to determine whether and what controls would be required to reduce the number of aquatic organisms entrained by the cooling water system. CWIS at Company facilities are regulated by EGLE through the NPDES permitting process.

There are not expected to be any impacts at Fermi 2 due to the use of a closed-cycle cooling system at the plant. Current plans are that Greenwood will limit cooling water intake to less than two million gallons per day (MGD) and will not be impacted by the 316(b) regulations. Belle River and Monroe use once-through cooling systems, which entails taking in non-contact cooling water, then discharging it back to the body of water with no recirculation. The CWISs are equipped with screens that prevent debris from being taken into the plant systems. The impact of 316(b) at Belle River is expected to be minimal based on the cooling water intake design. Additionally, the natural gas conversion of Belle River proposed by the PCA in this case would reduce the water intake need at the plant and the associated impact. The Company's expectation is that Monroe will be required to install new cooling water intake screens and install a fish return system to comply with 316(b) regulations.

Through the early retirements of Units 3 and 4 proposed by the PCA in this case, the Company will avoid approximately $24 million in capital spend for 316(b) compliance. The capital spend for 316(b) compliance for all four units at the plant was projected to be $81 million, while the capital spend for the two remaining units outlined in the PCA is $57 million. It is unknown at this time what costs for entrainment may be incurred by the Company for Monroe. These costs will also be reduced by the proposed retirements of Units 3 and 4. These costs and compliance requirements associated with 316(b) will be incorporated through the NPDES permitting process.

Greenhouse Gas Regulations

In August 2015, the EPA finalized new source performance standards (NSPS) for existing power plants under Section 111(d) of the CAA and for new sources under Section 111(b) of the CAA as part of the Clean Power Plan (CPP). The rules underwent significant legal challenges, and the existing source rule was stayed by a 2016 U.S. Supreme Court decision, pending judicial review. In 2017, an Executive Order was issued, which instructed the EPA to review the final rules. On Oct. 16, 2017, the EPA published a proposal to repeal the CPP in the Federal Register. The standards for new sources under Section 111(b) were not part of the stay and remained in effect.

In August 2018, the EPA proposed the Affordable Clean Energy (ACE) Rule as a replacement for the previously proposed CPP rule for existing sources, which never went into effect. The final ACE rule was published on June 19, 2019. On Jan. 19, 2021, the D.C. Circuit Court vacated the ACE rule and remanded to the EPA for further proceedings. EPA issued a memorandum on Feb. 12, 2021 regarding the status of ACE and CPP indicating that they did not expect states to take any further action to develop and submit plans under 111(d) with respect to GHG emissions. On Oct. 29, 2021, the U.S. Supreme Court (SCOTUS) agreed to hear an appeal of the D.C. Circuit Court decision vacating the ACE rule.

SCOTUS issued an opinion on June 30, 2022, holding that EPA lacked authority under Section 111 of the Clean Air Act to set an emission cap for GHGs based on generation shifting. The SCOTUS decision also remanded the case for further proceedings. While this case continues and the ultimate outcome is uncertain, the Company has no plans to amend its current goal to achieve net zero emissions by 2050. The Company is also announcing new CO_2 reduction targets through the PCA in this case. While the Company is reviewing the impacts of this ruling and subsequent responses from federal and state regulators, the Company continues on its path to achieve net zero emissions by 2050 with acceleration of its interim emissions reduction targets supported by this IRP.

Although there are currently no regulations for reducing CO_2 emissions from electric generating units, nor any federal taxes or fees associated with CO_2 emissions, CO_2 emission adders were included in some modeling sensitivities and CO_2 emissions were considered as part of the Company's IRP risk assessment as discussed in Section 15.

Cross-State Air Pollution Rule

The Cross-State Air Pollution Rule (CSAPR) is the most recent EPA regulation targeting interstate and regional transport of air pollution and replaces the Clean Air Interstate Rule (CAIR). Like CAIR, CSAPR establishes a cap-and-trade program to limit SO_2 and NO_2 emissions from electric utilities. It establishes emissions allocations for each generating unit in a group of Midwestern states, including Michigan. These allocations are reduced over time, through a phased approach. Although the allocations are made at the unit level, CSAPR allows for emissions-allowance trading among utilities covered by the rule, compliant with CAIR/CSAPR.

In February 2022, the EPA proposed an update to the CSAPR as part of the "Good Neighbor" plan for the 2015 ozone NAAQS. The provisions of the plan and the CSAPR update would reduce the emissions allowances to Group 3 states, Michigan included, that are contributing to downwind states' ozone levels. Allocations of emission allowances would be reduced under the plan and CSAPR update. While the plan and CSAPR update have not yet been finalized, it is not expected that the changes will impact the operation of the Company's facilities outlined in this IRP.

18.4 Capital cost to comply with environmental regulations

Table 18.4.1 summarizes the costs associated with the PCA for ELG, 316(b), and CCR for the Belle River and Monroe Power Plants and the Company's landfills.

Table 18.4.1: Capital cost estimate for environmental compliance

Project	Estimated Compliance Cost
ELG – Monroe Fly Ash	$37M
ELG – Monroe Bottom Ash	$78M
ELG – Monroe FGD	$106M
ELG – Belle River Bottom Ash	--
CCR – Monroe BAB	$49M
CCR – Monroe FAB	$201M
CCR – Monroe CCR Landfill	$27M
CCR – Belle River Ash Basins	$20M
CCR – Range Road Landfill	$14M
CCR – Sibley Quarry Landfill	$33M
316(b) – Monroe CWIS	$57M
Total	**$622M**

18.5 Emission projections

The Company modeled five portfolios in this IRP as follows:

- Portfolio 1: previously approved portfolio run in the Michigan Integrated Resource Planning Parameters (MIRPP) business as usual (BAU) scenario (optimized through the current study period).

- Portfolio 2: the Company's PCA portfolio run in the MIRPP BAU scenario.
- Portfolio 3: optimized portfolio in the MIRPP BAU scenario.
- Portfolio 4: optimized portfolio in the MIRPP BAU scenario with high load sensitivity.
- Portfolio 5: reasonable alternatives to the PCA presented by the Company in the BAU scenario.

Annual emissions projections from the IRP modeling for carbon dioxide (CO_2), carbon monoxide (CO), lead (Pb), mercury (Hg), nitrogen oxides (NOx), particulate matter (PM), sulfur dioxide (SO_2), and volatile organic carbon (VOC) were made for each of the portfolios. While the results of the portfolios differ, the modeling performed shows that portfolios 2 through 5 allow the Company to accelerate its CO_2 reduction goals. A summary of emissions projections for portfolio 2 (the Company's PCA) is shown in Figures 18.5.1 and 18.5.2. The figures represent annual mass emissions from Company-owned sources.

Figure 18.5.1: CO_2, NOx, SO_2, and CO emissions summary

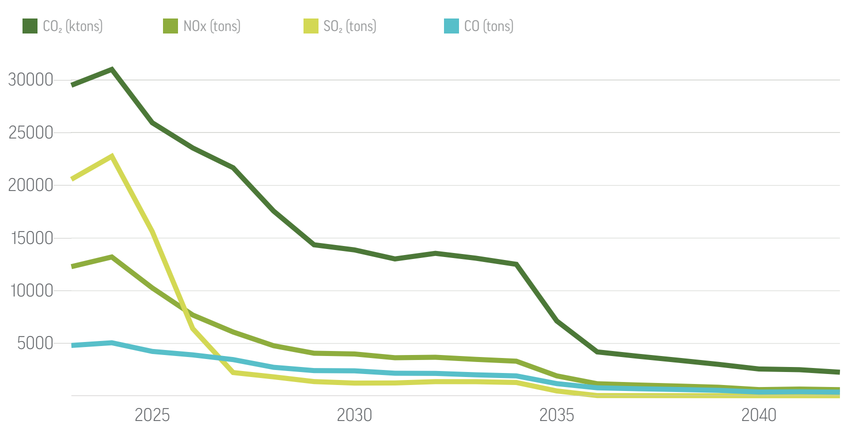
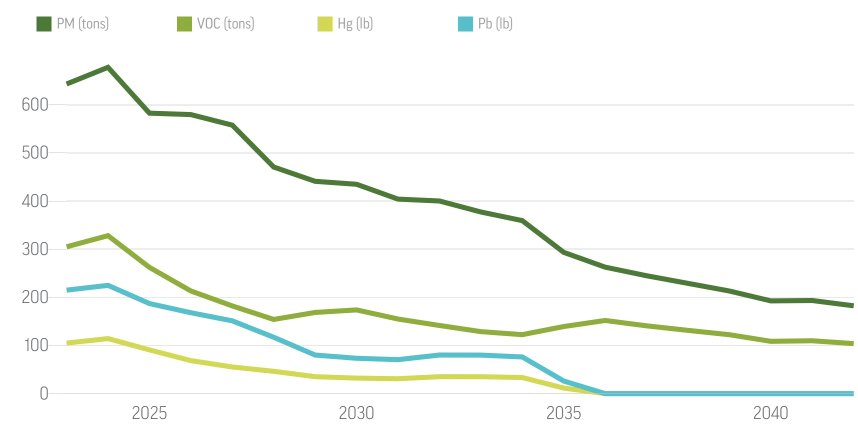


Figure 18.5.2: PM, VOC, Hg, and Pb emissions summary



The proposed changes in operation and retirement dates for Belle River and Monroe in this IRP are meaningful changes from the previous IRP which have a major impact on emissions. The PCA in this case projects emissions for Belle River from 2023 through the proposed retirement in 2039 (emissions from coal through natural gas conversion and emissions from natural gas after) versus the 2019 IRP which had Belle River operating on coal through 2030 with retirement after. See Table 18.5.3 for a comparison of the 2022 and Portfolio 1 emissions reductions.

Table 18.5.3: Emissions reduction summary

Pollutant	2023-2039 Emissions (tons, CO_2 million tons)					
	Belle River		Monroe		Total	
	PCA	Portfolio 1	PCA	Portfolio 1	PCA	Portfolio 1
CO_2	29	48.3	142	273	171	321
SO_2	56,543	135,909	20,802	37,563	77,344	173,472
NOx	26,663	46,080	40,070	76,658	66,732	122,738

18.6 Environmental justice

As part of the IRP process, the Company performed an environmental justice (EJ) analysis that aligns with the state of Michigan's definition of EJ. The state describes environmental justice as "the equitable treatment and meaningful involvement of all people, regardless of race, color, national origin, ability, or income and is critical to the development and application of laws, regulations, and policies that affect the environment, as well as the places people live, work, play, worship, and learn."

The purpose of the EJ analysis is two-fold. First, the IRP EJ analysis helps inform DTE Electric's modeling and planning process by identifying, qualitatively and quantitatively assessing the potential environmental and public health impacts of various alternative portfolios, including impacts on vulnerable communities. Second, the EJ screening and analysis ensure the advisory opinion of EGLE in the utility IRP cases is supported by an environmental and health impact analysis. For each identified portfolio, the Company:

1. Calculated the emissions from each owned generation facility and MISO electricity purchases for nitrogen oxide (NOx), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), volatile organic carbon (VOC), mercury (Hg), lead (Pb), and carbon dioxide (CO_2).

2. Performed an EJ screening and assessment of the potential impacts to vulnerable communities of air emissions, early retirement of fossil-fueled facilities, as well as the impact on water quality, waste disposal, and expected changes in land use for new or retiring resources.

3. Determined health impact estimates for air emissions.

EJ Screening

The Company used the EPA Environmental Justice Screening and Mapping Tool (EJSCREEN) Version 2.0 to perform an EJ screening. All fossil fuel-fired generating facilities were included in the screening. The goal of the screening was to identify vulnerable communities located within a three mile radius of each facility, which was determined in consultation with EGLE and MPSC Staff. Vulnerable communities were identified as having an EJ index at or above the 80th percentile. Each facility was mapped using EJSCREEN. Using EJSCREEN, four of the Company's facilities were identified as having at least one environmental index at or above the 80th percentile within a three mile radius of the facility. The facilities with at least one EJSCREEN environmental index at or above the 80th percentile are Delray Peakers (DEL), Northeast Peakers (NE), River Rouge Power Plant (RRPP; now retired), and Superior Peakers (SUP). The EPA EJSCREEN tool does not have a composite environmental index that combines other indexes to determine a more holistic percentile for a given site. With this in mind, other sites were assessed as to whether there was a reasonable potential that the surrounding area could be above the 80th percentile under a composite index, depending on the methodology used to develop a composite index. Taking this into consideration and based on EJSCREEN data, Dearborn Energy Center and Monroe were included in the EJ analysis. A summary of environmental indexes for those facilities with at least one environmental index at or above the 80th percentile in EJSCREEN is included in Table 18.6.1.

Table 18.6.1: Environmental index summary for facilities with at least one environmental index at or above the 80th percentile

Index	Delray	Northeast	River Rouge	Superior
PM 2.5	95	89	94	81
Ozone	94	89	93	81
2017 Diesel PM	96	91	95	82
2017 Air Toxics Cancer Risk	95	90	95	81
2017 Air Toxics Respiratory	95	89	94	81
Traffic Proximity	96	91	94	82
Lead Paint	96	92	95	78
Superfund Proximity	91	89	92	78
RMP Facility Proximity	98	97	99	77
Hazardous Waste Proximity	98	93	97	89
Underground Storage Tanks	97	94	96	85
Wastewater Discharge	96	71	96	94

While EPA EJSCREEN is a screening tool to identify environmental index values for a given area, it is not a method to compare the various portfolios for environmental justice impact within the screening. However, the various portfolios can be qualitatively assessed to compare the impacts of the portfolios. For example, continuing to operate Belle River on coal versus converting to natural gas would increase emissions, water use, water discharge, and ash generation. Similarly, operating Monroe longer than the dates proposed in the PCA in this case would have similar increases. Although Belle River and Monroe are not located in areas identified as vulnerable by the EPA EJSCREEN tool, the associated emissions, water impacts, and waste generation reduction do reduce the overall impact in the area.

As stated, the PCA in this case provides for significant emissions reductions. The PCA will also result in reductions in water intake and discharge as well as waste generation and disposal, including ash. Water use will be reduced significantly by the conversion to natural gas at Belle River and the early retirements at Monroe. The natural gas conversion and future operation proposed by the PCA, in this case at Belle River, will reduce water used for electric generation at the plant by 60% which will reduce the Company's water use by 15% overall. Water use at Monroe will decrease by 50% with the retirement of the first two units and will be eliminated with the retirements of the remaining two units. These reductions in water use will also decrease the water discharge from the facilities, including thermal discharge reductions. Blue Water Energy Center uses some water for cooling, but more than 90% less than Belle River currently uses operating on coal. The Company's peakers and other remaining units do not use water for operation.

Waste generated at Belle River and Monroe will also decrease significantly with the conversion of Belle River to natural gas and early retirements of the Monroe units. This includes bottom ash, fly ash, and other wastes. The generation of bottom ash and fly ash will be eliminated at Belle River once the conversion to natural gas is complete. Bottom ash and fly ash generation will decrease by 50% with the retirement of the first two units and will be eliminated with the retirements of the remaining two units. The Company has no other units that generate ash. The reductions in ash generation will have a corresponding reduction in the amount of ash sent to landfill.

The four sites identified as having an environmental index at or above the 80th percentile are all either peaker sites or have peakers. The Company performed a peaker analysis which was considered in the IRP modeling. The peakers located at the RRPP site are being evaluated for retirement with transmission studies underway by MISO. Retirement of the peakers at the RRPP site would have further positive impact on the area. The retirement of Northeast peaker 11-1 will also have a positive impact on the areas identified.

Impact assessment

In addition to the EJ screening, the Company used the EPA Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) Web Edition (https://cobra.epa.gov) to determine the health impact estimates for the air emissions reductions proposed by the PCA in this case. COBRA can be used to explore how changes in air pollution can affect human health and estimate the economic impact that impact on human health may have. COBRA was used to assess the overall fleet-wide health impacts and associated costs for portfolios 1, 2 and 5. Impacts and associated costs were analyzed to the county-level, the most refined level that can be assessed using COBRA. The impacts were also assessed at the state-level. Emissions projections of 2023 and 2042 were used to evaluate the impacts for the assessment. County-level impacts were assessed for Wayne, St. Clair, Monroe, Macomb, Oakland and Washtenaw Counties.

The COBRA model summarizes impacts for change in incidence (cases, annual) and monetary value (dollars, annual) for 12 health endpoints. A low and high value are provided for mortality and nonfatal heart attacks endpoints. The assessment of health impacts using the COBRA tool showed an overall benefit for all portfolios that were assessed (1, 2 and 5). A summary of the results of the health impact assessment using the COBRA model based on the PCA is provided in Table 18.6.2. The low value is used in the table for those endpoints for which low and high values are provided by the COBRA model.

Table 18.6.2: COBRA health impact assessment summary (state-level)

Health Endpoint	Change in Incidence (Reduction)	Monetary Value
Mortality	9.8	$95,700,000
Nonfatal Heart Attacks	0.98	$145,842
Infant Mortality	0.05	$586,448
Hospital Admits, All Respiratory	1.9	$103,304
Hospital Admits, Cardiovascular (except heart attacks)	2	$71,843
Acute Bronchitisw	10.8	$6,639
Upper Respiratory Symptoms	195	$8,317
Lower Respiratory Symptoms	137	$3,695
E.R. Visits, Asthma	4.4	$2,484
Asthma Exacerbation	204	$15,124
Minor Restricted Activity Days	5841	$512,073
Work Loss Days	983	$196,744

Endnotes

1. DTE Electric's CO_2 reduction goals are based on the net short method of carbon accounting, which utilizes Scope 1 CO_2 emissions from DTE Electric's electric generating units and adjusts for purchases and sales of power. More information about the net short method can be found at https://www.epri.com/research/products/000000003002015044

SECTION 19

19 DTE Electric IRP Report summary

Summary

The goal of the Company's IRP process is to find the most reasonable and prudent path to accelerate decarbonization, while keeping the energy DTE Electric provides reliable and affordable.

DTE Electric's proposed plan will dramatically reduce carbon emissions through the addition of renewable energy sources and the phased retirement of the Company's last two coal-fired power plants. It will strengthen the reliability of the electric generation system by diversifying the Company's energy mix, converting the Belle River Power Plant to natural gas, and reducing exposure to volatile market prices. In addition, it will protect affordability by reducing the projected cost of the plan by $1.4 billion over our 2019 plan, redirecting $2.4 billion from coal to cleaner energy sources, and continuing to help customers lower their energy costs through energy waste reduction and demand response programs. The plan also positions the Company to leverage the Inflation Reduction Act for the benefit of our customers.

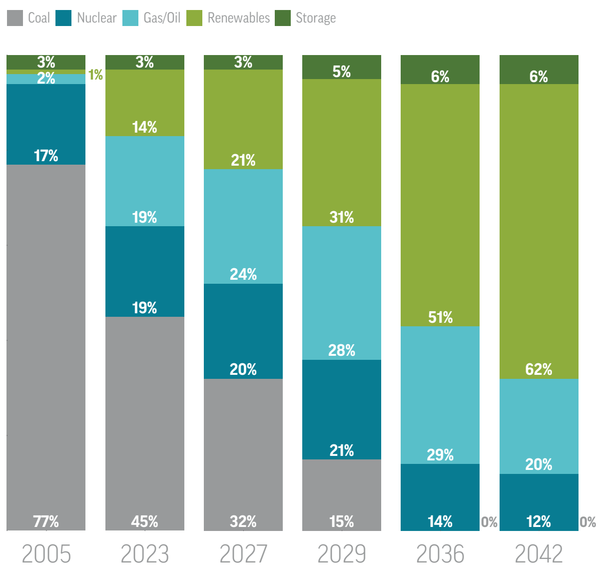
After many months of extensive research and analysis, DTE Electric is confident that this proposed plan is the right path forward. The 2022 IRP will lead to a reliable, affordable, and diverse energy mix that customers can depend on and a cleaner energy future for Michigan. Highlights of the plan are shown in Figures 19.1.1-19.1.3.

The Company is seeking the approval of the IRP and a determination that the PCA is the most reasonable and prudent means of meeting the Company's energy and capacity needs. Due to the large-scale transformation proposed by DTE Electric in this IRP, the Company is also requesting: 1) pre-approval of capital costs associated with specific investments ($135 million Belle River conversion and $8.7 million in demand response) that are commenced within three years of the Commission's approval of the Company's IRP and PCA; 2) approval the Company's proposed financial compensation mechanism under MCL 460.6t(15) for all new and modified PPAs; and 3) approval of regulatory asset treatment for Monroe Power Plant and the retiring coal handling assets at the Belle River Power Plant.

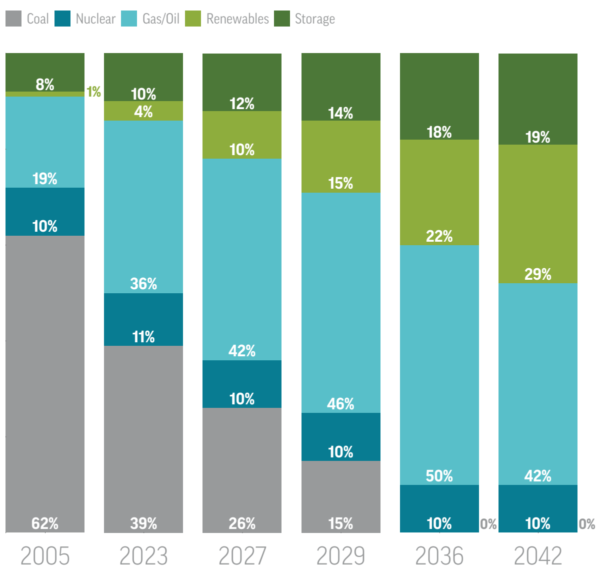
This IRP marks the start of a formal process before the MPSC. The Company filed the IRP in November 2022 and it will be evaluated by the Commission according to Michigan laws and rules. The review process will include formal hearings and opportunities for interested parties to intervene. The Commission approves a plan if it determines the plan represents the most reasonable and prudent means of meeting the utility's energy and capacity needs. The MPSC issues its initial decision within 300 days, and its final decision within 360 days of the date of filing.

Figure 19.1.1: Proposed generation mix change (MWh and MW)

Proposed generation mix changes
(2005-2042, MWh%)



Proposed capacity mix changes
(2005-2042, MW%, UCAP or Firm capacity)



Does not include Demand Response

Figure 19.1.2: Plan summary (MW capacity)

15,400 MW
of renewables and

1,810 MW
of storage by 2042

Transforms DTE Electric's generation fleet, resulting in a total of 18,400 MW of renewables and a total of 2,900 MW of storage by 2042

1,300 MW
coal to natural gas

Repurposes existing infrastructure at the Belle River Power Plant by converting its fuel source from coal to natural gas

4,100 MW
coal plant retirements

Ends the use of coal in 2035 with a responsible, phased retirement schedule that protects customer affordability and reliability

1.5%
energy waste reduction

Continues to focus on customer programs by targeting an average of 1.5% energy waste reduction savings over the study period (maximum amount of achievable potential)

Figure 19.1.3: Implementation timeline for first 10 years (capacity MW)

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
COAL RETIREMENTS (MW)			Belle River unit 1 -635	Belle River unit 2 -635		Monroe units 3 and 4 -1500				
SOLAR (MW)[1]				400	400	400	800	800	800	800
WIND (MW)						200	200	200	200	200
NATURAL GAS (MW)			Belle River unit 1 conversion 635	Belle River unit 2 conversion 635						
STORAGE (MW)			60[2]	60	120	120				400
ENERGY WASTE REDUCTION	2%	1.7%	1.6%	1.5%	1.3%	1.2%	1.1%	1.0%	1.4%	1.5%
CVR/VVO (MW)				7.5	7.5	7.5	7.5	7.5		

1 Does not include ~950 MW of currently approved projects at the time of IRP filing which is already included in planned renewable build.
2 Includes 14 MW Slocum battery project with an expected in service date in 2024.

Glossary

The following definitions are not intended to set forth official Company policy or interpretation, but are provided solely to assist the reader in understanding this report.

Allowance for funds used during construction (AFUDC): The net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when used.

Ancillary services: Services that ensure reliability and support the transmission of electricity from generation sites to customer loads. Such services may include load regulation, spinning reserve, non-spinning reserve, replacement reserve, and voltage support.

Availability: The percentage of time that a unit is available to generate electricity. It is determined by dividing the total hours the unit is available to generate by the total hours in the period.

Baseload (24/7) generation: Baseload generation is traditionally comprised of generators that run almost continuously to serve a base level of demand that is typically present on the system due to everyday needs.

Capacity factor: A measure of how much a generating facility's capacity is used during a period. Expressed as a percentage, it is calculated by dividing the actual energy produced during a specific period by the unit's rated generating capacity over the same period.

% Capacity factor = (energy produced) / (plant capacity x time)

Combined cycle: A generating unit that utilizes a combination of one or more combustion turbines in conjunction with heat recovery steam generator(s) (HRSG) and steam turbine(s), which typically burn natural gas as fuel.

Combined heat and power: The concurrent production of electricity or mechanical power and useful thermal energy (heating and/or cooling) from a single source of energy.

Demand: The energy required at the customer's meter.

Demand-side management (DSM): Programs designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape. The proposed programs support the objectives of conservation, load shifting and peak shaving.

Dispatch: The assignment of load to specific generating units and other sources to affect the most reliable and economical supply as system load rises or falls.

Dispatchable resource: A non-intermittent resource (e.g., coal, natural gas) that can be committed in the market and scheduled by the system operator (e.g., RTO) to meet constantly changing demands.

Distributed generation: Customer-sited Resources that are: 1) interconnected to the distribution system on the customer's side of the utility's service meter and 2) installed to offset site load with incidental export.

Effective load carrying capability (ELCC): Methodology to determine the capacity credit of a resource by means of estimating the contribution that an individual generator makes to overall system resource adequacy while also considering the probabilistic nature of generation shortfalls and time-varying electric demand as driving factors. Specifically, ELCC is a measure of the additional load that the system can supply with the particular generator of interest, without a change in reliability.

Heat rate: A measure of generating plant efficiency in converting the heat content of its fuel to electrical energy, expressed in BTU/kWh. It is computed by dividing the total BTU content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

Intermittent resource: A generator that that provides electrical energy output that varies over time with the natural fluctuations of the resources.

Least-cost portfolio/plan: A set of resources within the 2023 to 2042 study period that are selected as the optimal resource plan under a specific scenario.

Levelizing: A mathematical operation whereby a nonuniform series of annual payments is converted into an equivalent uniform series considering the time value of money.

Load factor: The ratio of the average load supplied during a designated period to the peak or maximum load occurring in that period. It is expressed as a percentage.

Local clearing requirement: A MISO requirement for how much generation must come from local sources.

Loss of load expectation (LOLE): The frequency that there will be insufficient resources (native generation and purchases) to serve firm load. DTE Electric's reliability criterion is one day in 10 years' loss of load expectation.

Planning period: The time during which resource options are added to meet the expected future electrical loads. For this IRP, the planning period is 2023-2042.

Pumped storage: The process of producing electricity during peak periods with water-driven turbines. The water storage reservoir is filled by motor-driven pumps during off-peak hours when inexpensive power is available.

Renewables: An energy source that occurs naturally in the environment, such as solar energy, wind currents and water flow.

Reserve margin: The difference between net system capability and system maximum load requirement (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements and unforeseen loads. This is often expressed as a percentage of peak load.

Reserve margin = 100 x (Total System Capacity – Peak Load)/Peak Load

Resource plan: A strategy for meeting the expected future electrical demand through the addition of supply-side and/or demand-side options. For this IRP, resource plans were developed for several different scenarios and sensitivities.

Revenue requirement: The revenue that must be obtained to cover all expenses (operating and financing), all taxes, and the opportunity to earn a fair return to equity investors.

Scenario: A unique set of assumptions grouped to best represent the effect of some potential future occurrence.

Sensitivity: A subset of a scenario in which the same basic assumptions are used as in the controlling scenario, but certain other parameters are modified to determine specific effects that might occur.

Shortfall: When the local resources can't meet the reserve margin requirement.

Starting point: When the IRP modeling began, in January 2022, an assessment of the current state of the inputs at that time was completed. This set of resources throughout the 2023 to 2042 study period stayed consistent through the optimization modeling.

Index of abbreviations

ACI – Activated Carbon Injection

AFUDC – Allowance for Funds Used During Construction

BAU – Business as Usual (scenario)

BESS - Battery Energy Storage Systems

BWEC – Blue Water Energy Center

BYOD – Bring Your Own Device

CAA – Clean Air Act

CAES – Compressed Air Energy Storage

CAGR – Compound Annual Growth Rate

CAIR – Clean Air Interstate Rule

CC, CCGT – Combined Cycle Gas Turbine

CF – Capacity Factor

CHP – Combined Heat and Power

CPP – Clean Power Plan

CO_2 – Carbon Dioxide

COG – Coke Oven Gas

CCR– Coal Combustion Residual

CCS - Carbon Capture and Sequestration

CR - Carbon Reduction (scenario)

CSAPR – Cross-State Air Pollution Rule

CT – Combustion Turbine

CWA – Clean Water Act

CVR – Conservation Voltage Reduction

DER - Distributed Energy Resource

DG – Distributed Generation

DR – Demand Response

DSI – Dry Sorbent Injection

DSM– Demand-Side Management

DTE – DTE Energy Company

ECIL – Effective Capacity Import Limit

EE – Energy Efficiency

EIA – Energy Information Administration

ELCC – Effective Load Carrying Capability

ELG – Effluent Limitation Guidelines

EO – Energy Optimization

EP – Environmental Policy (scenario)

EPA – Environmental Protection Agency

EPRI – Electric Power Research Institute

ESS – Energy Storage Systems

ESP – Electrostatic Precipitator

ET– Emerging Technologies (scenario)

EV - Electric Vehicle

EWR – Energy Waste Reduction, also referred to as Energy Efficiency

FERC – Federal Energy Regulatory Commission

FGD – Flue Gas Desulfurization

FOM – Fixed Operating and Maintenance

FRAP – Fixed Resource Adequacy Plan

GW – Gigawatt, One Billion Watts

GWh – Gigawatt Hours

HAP – Hazardous Air Pollutant

HE - High Electrification (scenario)

HELM – Hourly Electric Load Model

HRSG – Heat Recovery Steam Generator

HSE – High-Sulfur Eastern Coal

HVAC – Heating, Ventilation and Air Conditioning

ICAP – Installed Capacity

IGCC – Integrated Gasification Combined Cycle

IPP – Independent Power Producer

IRP – Integrated Resource Plan

ITC – International Transmission Company

ITC – Investment Tax Credit

kW – Kilowatt, One Thousand Watts

kWh – Kilowatt Hours

LCOE – Levelized Cost of Energy

LF – Load Factor

LOLE – Loss of Load Expectation

LOLEWG – Loss of Load Expectation Working Group

LRTP- Long Range Transmission Plan

LSW – Low-Sulfur Western Coal

LTC – Load Tap Changers

MERC – Midwest Energy Resources Co

MISO – Mid-Continental Independent Transmission System Operator, Inc.

MN– Monroe Power Plant

MPPA – Michigan Public Power Agency

MPSC – Michigan Public Service Commission

MTEP – MISO Transmission Expansion Plan

MW – Megawatt, One Million Watts

MWh – Megawatt Hours

NAAQS – National Ambient Air Quality Standards

NO_2 – Nitrogen Oxide

NPV – Net Present Value

NPVRR – Net Present Value Revenue Requirement

O&M – Operating and Maintenance

OFA – Over-Fire Air

PA – Public Act

PCA – Proposed Course of Action

PPA – power purchase agreement

PRMR – Planning Reserve Margin Requirement

PTC – Production Tax Credit

PURPA – Public Utility Regulatory Policies Act

QF – Qualifying Facility

RAN – Resource Availability and Need

RIIA – Renewable Integration Impact Assessment

REC – Renewable Energy Credit

REF – Reference Scenario

REP – Renewable Energy Plan

RFP – Request for Proposal

RICE – Reciprocating Internal Combustion Engine

RPS – Renewable Portfolio Standard

SCR – Selective Catalytic Reduction

SIP – State Implementation Plan

SO_2 – Sulfur Dioxide

STAKE - Stakeholder (scenario)

UCAP – Unforced Capacity

USRCT – Utility System Resource Cost Test

VVO – Volt Var Optimization

ZRC – Zonal Resource Credits