STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	
for authority to increase its rates, amend	)	Case No. U-20162
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MATTHEW T. PAUL

DTE ELECTRIC COMPANY
QUALIFICATIONS OF MATTHEW T. PAUL

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Q. What is your name, business address and by whom are you employed?

A. My name is Matthew T. Paul. My business address is One Energy Plaza Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a subsidiary of DTE Energy.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

Q. What is your educational background?

A. My formal education consists of a Bachelor of Science degree in Mechanical Engineering from Michigan State University and a Masters of Business Administration degree from the University of Chicago. I have also completed several Company sponsored courses and have attended various seminars to further my professional development with DTE Electric.

Q. Please summarize your professional experience.

A. From 1991 through mid-2000, I worked for Koch Industries in various engineering, trading, and leadership positions.

In June of 2000, I joined DTE's non-regulated coal company, DTE Coal Services, Inc. (DTECS) as Director, Trading. In this capacity, I was responsible for building and running DTECS' coal and emissions trading group. From 2000 through late 2012, I held various positions of increasing leadership at DTECS, eventually holding the position of President, DTECS from mid-2006 through late 2012. As President, DTECS, I was responsible for all aspects of the business.

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In November of 2012, I accepted the position of Director, Generation Optimization. In this position, I was responsible for all aspects of the Generation Optimization group including the Merchant Operations Center, Merchant Analytics Team, Wholesale Power, and Settlements.

In December 2014, I was appointed Executive Director - Generation Optimization and Corporate Fuel Supply. In this position, I was responsible for the dispatch of DTE Electric's generation assets into the MISO marketplace, the fossil fuel supply and transportation requirements for DTE Electric's fossil fuel electric generating assets, as well as the Company's coal transshipment facility, Midwest Energy Resources Company (MERC), located in Superior, Wisconsin. I also acted as DTE Electric's North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Senior Manager with responsibility for DTE Electric's NERC compliance organization and processes.

Q. What is your current position with the Company and what are your current responsibilities?

A. In October 2016, I was appointed Vice President Fossil Generation Plant Operations for DTE Electric. In this capacity, I am responsible for all phases of operations, maintenance, engineering, planning and expenditures associated with DTE's fossil fueled power plants, including our 84 peaking units, and our interest in the Ludington Pumped Storage facility with Consumers Energy.

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Q. Are you a member of any trade associations or participate on any Boards or Committees?

A. Yes, I am currently a member of the board of directors of the Reliability First Corporation. Reliability First is a regional entity reporting to NERC with a footprint spanning 13 states and the District of Columbia whose mission is to ensure the reliability and security of the Bulk Power System. I am also a member of the board of directors of the Michigan Manufacturing Association (MMA), a leading advocate for Michigan manufacturers.

Q. Have you previously provided testimony before the Michigan Public Service Commission (Commission)?

A. Yes. I provided testimony in the Company's 2016 Power Supply Cost Recovery Plan case, Case No. U-17920.

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Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the reasonableness and prudency of the operations and maintenance (O&M) and capital expenditures for steam power generation, hydraulic power generation (Ludington) and other power generation (peaking units) for the historical test year ending December 31, 2017, and the projected test period ending April 30, 2020. I will also address the following additional topics in my testimony:

1) I will explain forecasted changes in power plant capacity ratings on a yearly basis for 10 years looking forward (2018 through 2027). The capacity changes are associated with forecasted retirements of current generating assets, the addition of new generation assets, as well as changes in capacity ratings.

2) I will provide a review of Fossil Generation coal unit availability performance for five years prior and five years following the historic test year in this case. In addition to discussing availability, I will also discuss the planned and unplanned outage performance for these same timeframes. This data will show that the Fossil Generation coal unit Random Outage Factor (ROF), Planned Outage Factor (POF) and Equivalent Availability (EA) are forecasted to improve in the 2018-2022 timeframe compared to the 2012-2017 actual performance realized.

3) For capital expenditures, I will provide details of the historical 2017 level of expenditures on a plant level basis and provide forecasts of expenditures to be incurred from January 1, 2018 through April 30, 2020. This data will show the levels of expenditures related to routine maintenance, new environmental compliance requirements as well as expenditures related to safety and general reliability that have been, and will be made. I will also provide additional details on the portion of the Fossil Generation capital expenditures that are focused on

the Tier 1 coal-fired plants (Belle River and Monroe) and compare that with the far lower expenditures that are focused on the Tier 2 coal plants (St Clair, River Rouge and Trenton Channel).

4) I will provide a synopsis of the O&M and capital expenditures made to repair the damage caused by the 2016 St. Clair Power Plant fire and the actual and pending insurance recovery for this event.

5) I will discuss the Tier 2 coal units and specifically the logic of retiring the units over the 2020 to 2023 timeframe. The discussion focuses on the need to phase out the retirements between 2020 and 2023 due to environmental regulations, workforce planning concerns, the impact on the communities where the units are located and potential grid reliability concerns. I will show that the level of continuing capital expenditures forecasted in this case are reasonable and prudent in that they are limited to expenditures required to sustain safe and environmentally compliant operations of the Tier 2 plants.

6) I will support the multiple known and measurable changes in Fossil Generation O&M expenses that will span the timeframe from the 2017 historic test year in this case to the projected test year, ending April 30, 2020. These known and measurable changes include:

- St Clair Power Plant fire event recovery cost and insurance proceeds
- St Clair Power Plant normal operations adder
- St. Clair Power Plant Unit 4 retirement
- Fly ash settlement

7) I will describe the new combined heat and power (CHP) facility being built at the Ford Motor Company Research and Engineering Center in Dearborn, Michigan. Included will be a description of the major equipment being installed and planned

plant operations. Company Witness Mr. Feldmann will provide additional details for this project.

8) I support 2020-2022 Fossil Generation capital expense forecasts that are being introduced as part of a proposed infrastructure recovery mechanism (IRM). The Fossil Generation capital spend included in the proposed IRM are related to planned outage work of Tier 1 steam generating units including Monroe, Belle River, and Greenwood power plants, scheduled capital equipment replacements on these Tier 1 units, planned outage work on large natural gas fired peaking units, and the construction costs of the new combined cycle gas turbine (CCGT) generating plant expected to come online in 2022.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Schedule	Description
A-6	F1	Planned Long Range Fossil Generation Changes
A-6	F2	Fossil Generation Coal Unit Performance
A-12	B5.1	Projected Capital Expenditures – Steam, Hydraulic, and Other Power Generation
A-13	C5.1	O&M Expenses – Steam Power Generation
A-13	C5.4	O&M Expenses – Hydraulic Power Generation
A-13	C5.5	O&M Expenses – Other Power Generation
A-30	T3	Infrastructure Recovery Mechanism Capital – Fossil Generation Expenditures 2020-2022

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Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How is your testimony organized?

A. My testimony consists of the following four (4) parts:

Part I	Fossil Generation Plant Capacity and Availability
Part II	Fossil Generation Capital Expenditures
Part III	Fossil Generation Operating and Maintenance Expenses
Part IV	Infrastructure Recovery Mechanism (IRM)

Part I - Fossil Generation Plant Capacity and Availability

Fossil Generation Net Summer Installed Capacity

Q. Can you provide an overview of DTE Electric's Fossil Generation assets?

A. As of January 1, 2017, Fossil Generation's owned generation based on installed summer capacity ratings equaled 10,037 MW and was comprised of:

Rated Capacity (Summer) as of 1/1/2017	
Fossil Steam	7,019 MW
Peaking Plant	2,033 MW
Pumped Storage	985 MW
Total Fossil/Hydraulic System	10,037 MW

The Company's 7,019 MW's of fossil steam plant contains coal-fired units that provided 6,234 MW of capacity and a natural gas-fired unit that provided an additional 785 MW of capacity as shown below:

Rated Capacity as of 1/1/2017

Coal Steam Plants	Net Summer Capability	No. Units
Belle River (DTE ownership)	1,034 MW	2
Monroe	3,066 MW	4
River Rouge	272 MW	1
St. Clair	1,367 MW	6
Trenton Channel	495 MW	1
Total Coal Capacity (steam)	6,234 MW	14

Gas Steam Plants	Net Sumer Capability	No. Units
Greenwood	785 MW	1
Total Natural Gas (steam)	785 MW	1

The Michigan Public Power Agency (MPPA) is joint owner of Belle River Power Plant and its ownership entitlement is 18.61% (234 MW) of the plant. The MPPA ownership of Belle River is not included in the 1,034 MW Belle River Plant's capability shown above.

DTE Electric's peaking plants, along with DTE Electric's ownership share of the Ludington Pumped Storage facility, jointly owned with Consumers Energy, are shown below:

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Rated Capacity as of 1/1/2017

Pumped Storage and Peaking	Net Summer Capability	No. Units
Gas/Oil Combustion Turbines (10 locations)	1,905 MW	38
Diesel Generators (10 locations)	128 MW	46
Total Peaking Capacity	2,033 MW	84
Ludington Pumped Storage	985 MW	6
Total Pumped Storage/Peaking Capacity	3,018 MW	90

As evidenced by the data provided, DTE Electric's fossil generating system is diverse both with regards to size and fuel type. This diversity gives DTE Electric important flexibility in meeting the energy needs of its electric customers in a cost-effective and reliable manner.

Q. What standard or test is used to verify the capacity numbers stated above?

A. The Company's unit capacity testing protocols are defined in Power Plant Order (PPO) No. 302 titled "Generation Verification Test Capacity (GVTC)". This PPO requires that the capacities of all Fossil Generation units be verified in the manner specified by MISO. The PPO details requirements that must be followed across Fossil Generation, is approved by Fossil Generation management and is routinely updated to ensure it remains current.

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Q. Did Fossil Generation retire or rerate any generating units in 2017?

A. Yes. St Clair Unit 4, rated at 151 MW, was retired in November 2017. In addition, the capacity of Ludington Unit 5 was increased by 34 MW after completion of its upgrade overhaul in May 2017.

Q. Can you provide a summary of DTE Electric's Fossil Generation assets incorporating the 2017 Fossil Generation retirements and unit rerates as of December 31, 2017?

A. As of December 31, 2017, Fossil Generation's owned generation based on summer capacity ratings equaled 9,920 MW and was comprised of:

Rated Capacity (Summer) as of 12/31/2017

Type	Net Summer Capability	No. Units
Fossil Steam	6,868 MW	14
Peaking Plant	2,033 MW	84
Pumped Storage	1,019 MW	6
Total Fossil/Hydraulic System	9,920 MW	

Q. Can you provide a summary of Exhibit A-6, Schedule F1 titled "Planned Long Range Fossil Generation Changes Years 2017 through 2027"?

A. Exhibit A-6, Schedule F1 provides the 2017 actual generation rating changes and a 10-year projection of the forecasted changes in Fossil Generation unit capacity ratings for 2018 through 2027. Changes are based on the forecasted timing of upcoming unit retirements, development of new generation assets and minor changes to existing assets.

Q. Can you please explain the yearly changes in generation capacity shown on Exhibit A-6, Schedule F1 for 2017-2027?

A. As discussed previously, St. Clair Unit 4 was retired in November 2017 for a reduction of 151 MW of summer rated capacity and the capacity of Ludington Unit 5 was increased by 34 MW after completion of its upgrade overhaul.

In 2018, the Ludington Unit 6 upgrade will be completed for an additional 34 MW and DTE Electric's share of Belle River will increase by 8 MW due to replacement of the Unit 2 high-pressure turbine with a more efficient design.

In 2019, the Ludington Unit 3 upgrade will be completed for an additional 34 MW and DTE Electric's share of Belle River will increase by 8 MW due to replacement of the Unit 1 high-pressure turbine with a more efficient design.

In 2020, the Ludington Unit 1 upgrade will be completed for an additional 34 MW. Also in 2020, Fossil Generation is forecasting the retirement of River Rouge Unit 3, a 272 MW (summer rating) coal-fired unit. Finally, DTE Electric will be adding a 34 MW Combined Heat and Power facility to its generating fleet in 2020.

No changes are currently forecasted in the capacity ratings of the Fossil Generation fleet in 2021.

In 2022, Fossil Generation forecasts the retirement of St. Clair Units 1, 2, 3 and 6, representing a combined 776 MW of coal-fired summer rated capacity. Also in 2022, Fossil Generation will be adding a 1,100 MW CCGT plant to its portfolio.

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In 2023, the Company forecasts the retirement of Trenton Channel Unit 9, a coal-fired unit with a summer capacity rating of 495 MW, and St. Clair Unit 7, representing 440 MW of coal-fired summer rated capacity.

No changes are currently forecasted in the capacity ratings of the Fossil Generation fleet in 2024 through 2027.

Q. Why is DTE forecasting retirements of River Rouge, St. Clair, and Trenton Channel coal-fired generating units to occur between 2020 and 2023?

A. To comply with the 2023 implementation deadline for certain environmental regulations, significant capital investments would need to be made at the River Rouge, St. Clair, and Trenton Channel generating units, collectively referred to as the "Tier 2" units. As described in detail in Case U-18419, DTE concluded in the spring of 2016 that it would not be economically beneficial for DTE's customers to spend the money to comply with these regulations to keep the units running beyond 2023. Based on this conclusion and for other reasons explained further below, the Company made the decision to retire its Tier 2 plants prior to the implementation deadline and backfill that capacity with a combination of renewables, energy efficiency, demand response, and the recently approved Blue Water Energy Center, an 1,100 MW CCGT plant. However, given that these Tier 2 units comprise nearly 2,000 MW of net summer capability, it is reasonable and prudent to facilitate a phased transition between now and 2023 to maintain a safe and reliable supply of energy for our customers.

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Q. What factors other than environmental regulations are considered by the Company when making the determination to retire a generating unit and the associated timing of that retirement?

A. There are several factors to consider when determining whether a generating unit should be retired and the associated timing of that retirement. Among these factors include the age and condition of the generating unit, resource adequacy, grid reliability concerns, local community impacts, and workforce planning. Additionally, when considered along with the factors I mentioned above, an economic cost and benefit analysis can provide a general guideline for the reasonableness and prudency of continued operations of a particular generating unit.

Q. Why should resource adequacy be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. Because DTE Electric has the obligation to provide safe, reliable and affordable electricity to its customers, decisions around the addition of new capacity and/or the retirement of existing facilities must be carefully considered to ensure that the Company has sufficient resources to meet this obligation. DTE Electric cannot foresee or control other entities' various assumptions, projections and sometimes-changing decisions regarding plant retirements. There is also no guarantee that the Company's Tier 2 power plants will continue operations through their planned retirement dates. As a recent example, the Company had planned to retire St. Clair Unit 4 in 2022, but in 2017 decided to retire it due to the discovery of the degraded condition of an important piece of equipment. Because of these variables, it is important that the Company carefully consider its resource position relative to its MISO-imposed planning reserve margin requirement when considering the timing of its Tier 2 unit retirements. The retirement of a generating unit is likely a permanent decision with long-term consequences since the unit cannot simply be "un-retired" if underlying assumptions around resource needs were to unexpectedly change. Attempting to bring a unit back online once it has been retired would require the cleaning, inspecting and potential repairing of major equipment that has likely laid dormant since its retirement date, re-staffing of plant employees, undergoing a lengthy generator interconnection agreement process with MISO, and renewal of required permits.

Q. Why should grid reliability be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. Retirement of a generating unit has the potential to impact grid reliability. Section 38.2.7 of MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff[1] states that an owner of a generation resource that is planning to retire or suspend operations of all or any portion of that resource must notify MISO by submitting an Attachment Y Notification of Generator Change of Status form. The Attachment Y Notification must be submitted to MISO at least twenty-six (26) weeks prior to the requested status change unless the generation resource is inoperable due to a forced outage, in which case the Attachment Y Notification must be submitted at least thirty (30) days prior to the requested status change. In collaboration with the affected transmission owners, MISO will then perform a reliability study to determine whether the generation resource is necessary for the reliability of the transmission system based on the analyses described in Section 38.2.7 of MISO's tariff and the criteria set forth in the MISO Business Practices Manual. If, after completing a reliability study, MISO determines that a reliability concern exists, MISO may deem the generating unit to be a

[1] https://cdn.misoenergy.org/Tariff%20-%20As%20Filed%20Version72596.pdf

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System Support Resource (SSR), meaning that continued operation of that generating unit is required to maintain system reliability. MISO would require that a solution, such as transmission system upgrades or the installation of a new generating resource, be implemented before the generation resource is authorized to be retired or suspended. Even if a generating unit is not given an SSR designation, the MISO reliability study may identify unfavorable system conditions that could require mitigation solutions that have adverse impacts to our customers such as the need for firm load interruptions. Therefore, given that retirement of a generating unit has the potential to negatively affect the electrical grid and with it our customers, it is critically important to take grid reliability into consideration when making the determination to retire a generating unit and the associated timing of that retirement.

Q. Has DTE Electric filed any Attachment Y Notifications with MISO related to the Tier 2 units forecasted to retire between 2020 and 2023?

A. Yes. In January 2018, the Company filed confidential Attachment Y Suspension requests for its Tier 2 generating units to prompt MISO to study the impact of plant suspension on the transmission system. The decision to initiate the reliability study process with MISO was based on the Company's forecasted retirement of nearly 2,000 MW of generation between 2020 and 2023, coupled with the addition of the 1,100 MW combined cycle gas plant expected to come online in 2022.

Filing of the Attachment Y Suspension requests this year does not change the Company's need to file Attachment Y Retirement requests 26 weeks prior to the expected retirement dates for each unit. As mentioned earlier in my testimony and

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shown on Exhibit A-6 Schedule F1, the forecasted retirement dates for our Tier 2 generating units are:

- River Rouge Unit 3 2020
- St. Clair Units 1, 2, 3, 6 2022
- St. Clair Unit 7 2023
- Trenton Channel Unit 9 2023

Q. Has the Company received the final study reports from MISO for the Attachment Y Notifications it submitted for the Tier 2 Units?

A. Yes. The Company has received the final study reports for the River Rouge and St. Clair Attachment Y Suspension requests. These studies conclude that there are no reliability issues identified related to the suspension of the River Rouge and St. Clair units that would require the units to be designated as SSR units. However, the reports do indicate that retirement or suspension of these units may create thermal and voltage issues that could require the Company to shed firm load to ensure grid reliability. Although firm load shed is utilized as a countermeasure within MISO's planning criteria, the Company has significant concerns about implementing electrical service interruptions to our customers as a means of addressing known grid reliability issues. Maintaining and operating River Rouge and St. Clair power plants until their planned retirement dates will provide additional time to identify and implement alternative solutions that can ensure continued reliable electric service for its customers.

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Q. Has MISO indicated that any of the Tier 2 units could be deemed a System Support Resource (SSR)?

A. The confidential study that is currently in progress indicates that Trenton Channel Unit 9 provides critical reliability support to the grid. MISO could potentially deem Trenton Channel Unit 9 as a system support resource (SSR), meaning that MISO will not authorize DTE to retire the unit without proper measures and solutions in place to mitigate the identified grid reliability issues. DTE Electric will work closely with stakeholders in this process to evaluate solutions to mitigate the reliability concerns.

Q. How should local community impacts be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. The property tax assessments for DTE Electric's Tier 2 generating units make up a significant portion of the operating budgets for the city of River Rouge, the city of Trenton, and East China Township. Although the Tier 2 unit retirements planned over the next two to five years will lead to the loss of much of the tax revenue these communities depend on, announcing the retirements years in advance allows these communities time to complete needed planning activities and realize a smoother fiscal transition than would otherwise occur. Executing an immediate and unexpected unit shutdown of some or all the Tier 2 units would leave these communities with a large sudden shortfall in revenue. As a matter of fact, the Company received a letter, dated April 25, 2018, from the mayor of the City of River Rouge, expressing grave concerns over the potential early retirement of River Rouge Unit 3. In this letter, Mayor Bowdler stated, "The loss in this revenue would also make it difficult to continue to maintain the existing services provided by the City and would probably result in much of the City

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being shut down and only functioning on a part-time basis... the immediate closing of the plant would cripple the City of River Rouge and significantly impact the current residents and businesses way of life – from police and fire protection, library services, and rubbish collections everything will be affected." It is in the best interest of the communities in which our generating units operate, for the Company to thoughtfully develop and deliberately execute the retirement plan of our Tier 2 units and to communicate that plan well in advance to all affected parties. This allows the communities as much time as possible to prepare for the unavoidable loss of property tax revenue.

Q. Why should workforce planning be considered when making the determination to retire a generating unit and the associated timing of that retirement?

A. The employees stationed at our Tier 2 plants represent a significant percentage of the Fossil Generation workforce. The retirement of all these units at the same time would create a significant challenge in finding vacancies that match the specialized skill set that these transitioning employees have acquired at the Company over a period of years in operating and maintaining Company generation units. Phasing the Tier 2 retirements out over the next two to five years allows a systematic reduction in the number of employees at the Tier 2 plants by moving employees to the Tier 1 units where they can fill critical vacancies that require their unique skills. Therefore, it is in the Company's, our employees', and our customers' best interest to phase the retirement of the Tier 2 generating units between 2020 and 2023.

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Q. Has the Commission given guidance on how and when to properly analyze generating unit retirements?

A. Yes. On pages 48-49 of the MPSC Case No. U-18419 Order dated April 27, 2018, the Commission states, “The Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the company’s 2019 IRP analysis and the results of MISO’s Attachment Y reliability study. Other matters such as workforce and local government tax impacts may also be considered in a decision of this magnitude.” The Company plans on filing an IRP analysis with the Commission in March 2019.

Q. Can you summarize Fossil Generation’s plan for retirement of its Tier 2 coal-fired generating units?

A. Yes. Consistent with the aforementioned guidance given by the Commission in the MPSC Case No. U-18419 Order dated April 27, 2018, Fossil Generation considers factors such as resource adequacy, grid reliability, local community impacts, and workforce planning when making the determination to retire a generating unit and the associated timing of that retirement. The need to comply with the implementation deadline for applicable environmental regulations is driving a need to retire the Tier 2 units no later than the end of 2023. However, rather than planning to retire all the Tier 2 units in 2023, DTE Electric took into consideration the various factors mentioned above and believes staggering the unit retirements between 2020 and 2023 is the most reasonable overall approach. Despite the impending near-term retirements, Fossil Generation is committed to maintaining the units for continued safe and environmentally compliant operation.

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Fossil Generation Plant Performance

Q. How is Fossil Generation Plant performance monitored and calculated?

A. Fossil Generation utilizes equivalent availability factor (EAF), random outage factor (ROF) and planned outage factor (POF) to monitor overall unit performance. EAF is equal to 100 minus the ROF minus POF. Equivalent availability is equal to total possible megawatt-weeks minus planned outage megawatt-weeks minus random outage megawatt-weeks (full and partial derates) divided by total possible megawatt-weeks. Total possible megawatt-weeks are calculated by multiplying the net demonstrated capability of the unit by the weeks in the time-period (52 weeks per year). Planned outage megawatt-weeks refers to the equivalent number of weeks in the time-period that the unit is not available due to scheduled maintenance multiplied by the capacity that is out of service. Random outage megawatt-weeks is the number of weeks of unit unavailability caused by an outage or derate that is not planned or scheduled, multiplied by the capacity that is out of service.

Q. What are the major drivers of unit unavailability?

A. There are three major drivers of unit unavailability: (1) planned full unit or periodic maintenance outages, (2) unplanned or random unit outages, and (3) derates or partial unit outages which can be planned or unplanned.

Planned full outages and planned derates are those outages for which the Company has developed long range maintenance plans designed to sustain unit performance and proactively address emerging reliability issues. Unplanned unit outages and unplanned derates are those that occur due to either reliability issues common across the industry or unusual events which are unique to a specific DTE Electric Fossil Generation plant or unit.

Q. Can you explain Fossil Generation's 2017 total fossil fleet plant availability performance?

A. The EAF for Fossil Generation was 69.8% for the 2017 historic period. The 69.8% equivalent availability was the result of a 12.8% ROF and a 17.4 % POF. In 2017, total Fossil Generation assets included Greenwood, Belle River, St Clair, River Rouge, Trenton Channel, Monroe, peakers and Ludington power generation facilities. Fossil fleet availability for 2017 was reduced by multiple planned major overhaul maintenance outages completed on Belle River Unit 2, Greenwood Unit 1, St. Clair Units 4 and 7, Monroe Unit 2, Trenton Channel Unit 9, multiple large peaker units and Ludington Units. Less comprehensive planned outages were completed on many units to prepare for or recover from high peak load summer operations. The major items impacting the 2017 ROF were the fire damage to St Clair Unit 7 and the retirement of St Clair Unit 4.

Q. Why did the retirement of St Clair Unit 4 contribute to the ROF of the fossil generation fleet in 2017?

A. The North American Electric Reliability Corporation (NERC) Generating Availability Data System (GADS) reporting requirements dictated that the unit be placed into forced outage as soon as it is determined that repair of the unit was not going to be completed. The unit was placed into forced outage on June 21, 2017 and remained in this state until its official MISO retirement on November 13, 2017. This nearly 5-months of outage time on St Clair Unit 4 was coded as a forced outage, thus negatively impacting 2017 ROF.

Q. What was the equivalent availability of the coal units within the Fossil Generation fleet in 2017?

A. As shown on line 6 of Exhibit A-6 Schedule F2, coal plants had an equivalent availability of 69.2% in 2017. The 69.2% equivalent availability for coal plants in 2017 was the result of a 14.0% ROF and a 16.8% POF for those units. Coal plants include Belle River, St Clair, River Rouge Unit 3, Trenton Channel Unit 9, and Monroe power generation facilities.

Q. How did the performance of the Fossil Generation coal units in 2017 compare to the performance of the total Fossil Generation fleet?

A. The EAF of the Fossil Generation coal units performed on par with the total Fossil Generation fleet in 2017 and the year-over-year EAF of the coal generating units improved by 4.5% (64.7% in 2016 versus 69.2% in 2017).

Q. How has the year-over-year ROF performance of the Fossil Generation coal units changed?

A. Most coal units showed improved (lower) ROF in 2017 compare to 2016. Table 1 below summarizes those results. Large improvements can be seen on Monroe Unit 2, and St. Clair Units 1, 2, 3 and 6. Belle River Units 1 and 2, Monroe Units 1, 3 and 4, and Trenton Channel Unit 9 remained relatively flat, while St. Clair Units 4 and 7 and River Rouge Unit 3 showed a deterioration in ROF performance from 2016 to 2017.

Table 1
Coal Unit ROF Performance

	2016	2017	Delta
Belle River 1	4.84	4.47	-0.37
Belle River 2	4.19	6.13	1.94
Monroe 1	7.13	3.56	-3.57
Monroe 2	40.94	7.54	-33.40
Monroe 3	6.37	7.22	0.85
Monroe 4	8.15	7.60	-0.55
River Rouge 3	19.35	30.96	11.61
St. Clair 1	19.21	5.56	-13.65
St. Clair 2	31.02	16.57	-14.45
St. Clair 3	27.74	8.56	-19.18
St. Clair 4 (retired 11/2017)	24.93	42.4	14.47
St. Clair 6	53.52	28.89	-24.63
St. Clair 7	49.15	78.14	29.04
Trenton Channel 9	16.21	12.28	-3.93

Q. Can you provide additional details on the contributing factors on the units showing lower performance in 2017 compared to 2016?

A. During the planned St. Clair Unit 4 turbine inspection outage in late 2016 and early 2017, it was determined that the LP turbine discs and blades needed to be repaired or replaced. The cost of this repair proved to be financially unfavorable and the Company made the decision to retire the unit in June of 2017. The unit was placed into forced outage on June 21, 2017 per NERC GADS reporting requirements as soon as it was determined that repair of the unit was not going to be completed. It remained in this state until MISO granted its official retirement effective November 13, 2017. St. Clair Unit 7 was in forced outage from August 11, 2016 until August 31, 2017 to complete repairs required to return the unit to service following the August 2016 fire event and turbine failure. River Rouge Unit 3 experienced an extended unit derate followed by a maintenance outage to repair and replace degraded furnace rear wall refractory and insulation that was causing excessive furnace gas temperatures. These two events resulted in the ROF performance experienced at River Rouge Unit 3 in 2017.

Q. What are the projections for Fossil Generation coal unit availability for 2018 through 2022?

A. The coal unit equivalent availability is forecasted to be 73.4%, 74.4%, 77.0%, 78.1% and 79.0% for the years 2018-2022 respectively. Coal unit EAF, POF and ROF performance is shown in Exhibit A-6, Schedule F2 for the years 2012 through 2022. Actual data is provided for the years 2012-2017 while forecasted data is provided for 2018-2022.

Q. How does the forecasted coal unit availability compare to the actual historical coal unit availability?

A. As shown in Exhibit A-6 Schedule F-2, the average coal unit availability for 2012-2017 was 74.4% while the forecast of average coal unit availability for 2018-2022 is 76.4%.

Q. On what basis did you make your forecast of plant availability for 2018 and beyond?

A. The Fossil Generation forecasted plant availability projections are based on input from plant staff, plant reliability engineers, engineering subject matter experts (SMEs), historical unit performance, the known maintenance and operational status of each unit, and future planned outage schedules and work scope.

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Q. What is DTE Electric doing to maintain the overall availability of Fossil Generation coal units?

A. Company efforts to maintain overall Fossil Generation availability are based on placing priority on maintenance expenditures in the Tier 1 coal plants (Monroe and Belle River) to sustain high levels of performance, while minimizing long-term expenditures in the Tier 2 coal-fired units at Trenton Channel, River Rouge and St. Clair Power Plants. Although expenditures are being minimized at these three Tier 2 plant sites, all necessary work to safely operate the units and to comply with legal and regulatory requirements will be completed.

<u>Unplanned Outage Frequency Reduction</u> – Historically, boiler tube failures have been the largest factor contributing to unit random outages. These outages are typically relatively short in duration, normally lasting less than seven days each. However, each seven-day outage is the equivalent of approximately two percentage points of ROF. A formal Boiler Tube Failure Reduction (BTFR) team addresses all unplanned outages related to boiler tubes within the fossil fleet, utilizing industry data and experience as input to supplement their own expertise. This team utilizes all available outage opportunities to identify, prioritize, and recommend the most critical areas for boiler tube replacement based on equipment history, equipment inspection and data collection. They also consider recommendations of industry best practice groups such as the Electric Power Research Institute (EPRI) and OEMs. The conclusions drawn from these efforts drive project planning for O&M and capital expenditures as well as operational changes in order to improve reliability performance.

While turbine component failures on operating units are infrequent events, when they do occur, they can result in long duration outages that require months to complete the required repairs. Knowing that low-probability, high-impact events can have a significant effect on reliability, the Company established a rotor reliability team more than 10 years ago. The rotor reliability team is comprised of turbine, generator, vibration, fracture mechanics, nondestructive examination (NDE), metallurgy and chemistry experts. This team makes inspection and repair recommendations for Fossil Generation turbines, generators and boiler feed pump turbines that form the basis for planned outage work scope. These recommendations are based on EPRI and OEM recommendations, and experience gained from component failures in DTE equipment as well as failures in the utility industry.

<u>Planned Outage Improvement</u> – Fossil Generation continues its process of reviewing completed planned outages to ensure that future outages are completed with the goal of decreasing the overall cost without impacting the scope of work performed.

<u>Vendor Contracts and Workmanship</u> – Fossil Generation utilizes both Supplier Performance Management (SPM) and Quality Assurance (QA) initiatives to monitor and improve the performance of its major suppliers and contractors. SPM ensures that suppliers live up to their contract terms and are expeditious in resolution of disputes. The QA focus includes surveillances to ensure that suppliers have quality programs in place, that these programs are followed and that any non-conformances identified are both documented and corrected. The QA function ensures that corrective actions are put in place to proactively address issues before they occur and to ensure that items identified are addressed at the root cause level to prevent

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reoccurrence. Both SPM and QA provide positive impacts to the organization and its performance.

<u>Part II - Fossil Generation Capital Expenditures</u>

Q. Can you please provide an overview of your Part II discussion?

A. Yes. In this section of my testimony, I will discuss the following:

- Capital Planning Process
- 2017-2020 Capital Projects Summary
- Non-Routine Capital Expenditures
- Routine Capital Expenditures
- Summary of Tier 1 and Tier 2 Coal-Fired Generation Capital
- 2017-2020 AFUDC Estimate

<u>Capital Planning Process</u>

Q. Can you explain the Fossil Generation capital planning process?

A Yes. Capital projects are initiated to support safety, regulatory requirements, environmental compliance, plant-level reliability plans, OEM recommendations or the engineering recommendations of Fossil Generation's equipment and system experts. Capital expenditure requests require the initiation of an approved project form that includes a detailed explanation of the project and an initial estimate of the costs and benefits associated with the project. Projects are then further developed including work scope identification and ranking based on customer-centric economic metrics and other important drivers such as safety requirements, environmental regulations, and outage timing opportunities. The planned outage schedule heavily influences capital project timing since many capital projects are implemented during longer duration planned outages to minimize implementation impact on plant availability. During these planned outages, inspections are completed on critical systems to ensure that the outage being executed addresses the work needed to sustain future unit reliability. These inspections often reveal unanticipated damage because many of these systems cannot be thoroughly inspected or evaluated until they are disassembled during the outage.

Once capital project requests are fully developed, they are prioritized and presented for management review and approval. The review process focuses on ensuring that the projects represent the best solution to address the issue at hand and represent the least cost method for accomplishing the proposed work. Projects are approved if they are justified by an economic evaluation or required to meet safety and/or environmental regulations.

In summary, the capital spending and approval process is designed to identify the optimal allocation of capital resources to meet safety and environmental regulations while maintaining overall Fossil Generation reliability performance and minimizing costs.

Q. What do you mean by projects being justified by economic evaluation?

A. The prioritization of economic projects is based on an internal rate of return (IRR) analysis performed comparing the costs of implementing the new project to its customer benefits. Included in the analysis are projected capital expenditures, future avoided outages, as well as changes to unit capacity ratings, heat rate (efficiency) and fuel blending capabilities. Future avoided outage impacts include the value of avoiding events such as boiler tube failures, condenser or feedwater heater leaks and turbine blade failures. The IRR of the project is based on the O&M, capital expenditures and MISO market impacts of the unit's operations with and without the project being implemented over its useful life.

Q. What would be the consequences of not completing the capital projects approved by the process you just described?

A. Failure to complete the approved capital projects described in this case could negatively affect plant reliability, potentially leading to unit derates, unplanned outages, or even the premature forced retirement of a unit. This would result in increased Power Supply Cost Recovery (PSCR) costs, due to additional capacity and energy purchases, lost energy sales, and/or additional ancillary services costs.

Q. Can you explain the governance process for approval of Fossil Generation capital projects?

A. The capital governance process includes the documentation of project assumptions, calculation of costs and benefits, and a rigorous internal review. Projects costing less than $250,000 are approved by plant management, utilizing a project appropriation form, within a budget established based on historic plant spend. These projects generally do not require engineering and often reflect replacement-in-kind.

Projects that cost greater than $250,000 but less than $10 million and/or projects that require engineering are approved on an individual project basis by the Capital Governance Board (CGB) which consists of plant directors, the Director of Engineering and me.

Projects greater than $10 million require senior executive approval, while projects greater than $50 million require approval by the Finance Committee of DTE's Board of Directors.

2017-2020 Capital Projects Summary

Q. Can you provide a high-level discussion of the routine and non-routine capital expenditures being made by Fossil Generation during the historical year 2017 and the 28-month projected period ending April 30, 2020?

A. Yes. Fossil Generation completes routine ongoing expenditures across its existing generation fleet (steam power, hydraulic and peakers) to maintain safe, environmentally compliant, reliable, and efficient operations. The majority of these expenditures involve our Tier 1 plants.

Non-routine capital project expenditures are driven by steam power generation upgrades with a heavy focus on environmentally mandated work at our Tier 1 coal plants, restoration work required by the August 2016 St. Clair Power Plant fire event, decommissioning and environmental remediation projects at steam power generation plants, upgrades at the Ludington Pumped Storage Plant, and construction costs for the new CCGT and CHP plants.

Q. Can you explain Exhibit A-12, Schedule B5.1 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation" in more detail?

A. Exhibit A-12, Schedule B5.1 is a 9-page exhibit. Page 1 summarizes both "routine" and "non-routine" capital expenditures for 2017 (actual) through April 30, 2020 (forecasted) for Steam Power Generation, Hydraulic Power Generation (Ludington Pumped Storage) and Other Power Generation (Peaking Units, CCGT plant, and

CHP plant). Page 2 provides additional detail for major non-routine capital expenditures for Steam, Hydraulic, and Other Power Generation. Page 3 provides detail on line item 10 from page 2, the restoration projects associated with the August 11, 2016, St Clair Power Plant outage event. Page 4 summarizes routine Steam, Hydraulic and Other Power Generation capital expenditures by plant site and major category. Pages 5 through 8 provide additional detail for routine maintenance projects with a spend of greater than $1 million for 2017 through April 30, 2020. Finally, page 9 summarizes Allowance for Funds Used During Construction (AFUDC) included in the routine and non-routine capital expenditures.

Q. Can you provide additional details concerning Exhibit A-12, Schedule B5.1, page 1 of 9 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation"?

A. Yes. Line 2, Routine Steam Power Generation, includes capital expenditures necessary to operate and maintain DTE Electric's fossil steam power plant sites. Included are projects related to safety, boiler and turbine work, cables and controls, balance of plant projects and maintenance of environmental control systems. Safety expenditures includes the capital necessary to maintain a safe work environment and meet applicable safety regulations and standards. Boiler and turbine work includes the capital expenditures intended to maintain boiler or turbine operations, replace unreliable systems or equipment, maintain or improve heat rate (efficiency) and/or address operating and maintenance problems related to the boiler and turbine systems. Examples of these projects include replacement of worn or damaged turbine blades, air heater baskets, and boiler tube sections such as waterwalls, reheaters, superheaters and economizers. Cables and controls expenditures includes the capital

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intended to replace or improve distributed control systems, large power cables, main unit transformers, and electrical switchgear. The balance of plant area expenditures includes the capital associated with mobile equipment, station air compressors, general service water systems, fuel handling equipment and systems, and plant vehicles and computers. Routine environmental expenditures include the capital necessary to maintain operations of existing environmental control and monitoring equipment. An example of routine environmental expenditures is the ongoing replacement of the Selective Catalytic Reduction (SCR) catalyst beds previously installed at Monroe Power Plant to comply with nitrogen oxides (NO_x) emissions limits. These routine environmental capital expenditures to existing environmental systems differ from the non-routine environmental capital expenditures required to install any future new environmental systems.

Line 3, Non-Routine Steam Power, includes capital expenditures related to environmental compliance projects, site decommissioning, environmental remediation and required equipment modifications related to retired power generation assets, as well as other plant level projects such as physical and cyber security at generation sites.

Line 6, Routine Hydraulic Power Generation, includes the routine capital expenditures necessary to operate and maintain the Ludington Pumped Storage facility of which DTE Electric has a 49 percent ownership interest.

Line 7, Non-Routine Hydraulic Production Plant, includes the capital expenditures related to the efficiency upgrade project currently underway at the Ludington Pumped Storage facility of which DTE Electric has a 49 percent ownership interest. This multi-year project includes installation of new higher efficiency hydraulic turbines, main unit transformers and upgraded generators.

Line 10, Routine Other Power Generation, includes capital expenditures related to maintaining peaker site operations and peaker control system upgrades to meet the requirements of the MISO ancillary services market.

Line 11, Non-Routine Other Power Generation, includes those capital expenditures related to augmenting certain peaker units to provide black start capability to restart the electric power grid in the event of a major blackout like the one that occurred in 2003. This augmentation is needed because some of the coal units that are currently providing black start capability are slated for retirement by 2023. This line also includes capital expenditures related to the development and construction of a 1,100 MW CCGT plant and a 34 MW CHP plant.

<u>Non-Routine Capital Expenditures</u>

Q. Can you summarize Exhibit A-12, Schedule B5.1, page 2 of 9 entitled, "Projected Capital Expenditures Steam, Hydraulic and Other Power Generation – Non-Routine"?

A. Page 2 of Exhibit A-12, Schedule B5.1 provides project level detail for non-routine capital expenditures completed and planned for Steam Production, Hydraulic, and Other Power Generation from 2017 through April 30, 2020.

Line No.

Q. Can you explain line 2 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 2 (Monroe Dry Fly Ash Basin) represents a project required to maintain the exterior slope of the onsite fly ash landfill berm. This work is necessary to restore embankment degradation resulting from the natural freeze thaw cycles that occur in Michigan.

Q. Can you explain line 3 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 3 (Monroe Fly Ash Basin Vertical Extension) represents a project to expand the storage capabilities at the existing fly ash basin to begin storing dry fly ash while meeting the coal combustion residuals (CCR) requirements.

Q. Can you explain line 4 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 4 (Monroe Coal Combustible Residuals Transfer Pad) represents a project needed to build a new concrete storage containment pad that allows for storage of fly ash until it can be transported to a landfill. This pad accommodates fly ash removed during normal plant cleaning activities and meets the EPA CCR rule requiring that temporary storage of fly ash be executed in a manner that does not allow it to contact the ground or ground water.

Q. Can you explain line 5 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 5 (Monroe ELG Fly Ash Dry Conversion) represents a project required to convert the existing wet fly ash transport system at Monroe Power Plant to a dry fly ash transport system in accordance with EPA's fly ash Effluent Limitation Guidelines (ELG) rule promulgated in 2015 requiring all fly ash transport systems be dry by 2023. Conversion to a dry fly ash transport system will require installation of new

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piping to pneumatically transport ash from each generating unit's precipitator to new storage silos.

Q. Can you explain line 6 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 6 (Monroe Dry Fly Ash Processing) represents a project intended to reduce the amount of fly ash that will need to be transported from Monroe Power Plant to the onsite landfill. Ash processing will allow for fly ash with high carbon content to be treated and turned into an acceptable product for use in concrete manufacturing. Reducing the amount of fly ash placed in the landfill will minimize cost increases related to the new environmental requirements.

Q. Can you explain line 7 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 7 (Monroe Site Security) represents a project intended to improve Monroe Power Plant Site Security. General site access security improvements as well as specific security enhancements for critical equipment are being implemented to mitigate design basis security threats. In addition to physical security, NERC CIP compliance requires the Company to protect its cyber assets to minimize the risk to the electrical grid. These details on these cyber related security initiatives are confidential and are therefore not being provided in order to maintain the integrity of these measures.

Q. Can you explain line 8 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 8 (DSI/ACI Control Projects) represents a project required to finalize improvements to the DSI/ACI control system for St Clair Unit 7.

Line No.

Q. Can you explain line 9 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 9 (316b) includes costs to complete studies for meeting EPA 316(b) rules on cooling water intake structures at existing power plants. Under their authority to administer the National Pollutant Discharge Elimination system (NPDES), the Michigan Department of Environmental Quality (MDEQ) has asked that additional biological baseline sampling be completed at Monroe and Belle River Power Plants. It is expected that the reports for each power plant will be filed as part of the NPDES reapplication process with MDEQ in 2020.

Q. Can you explain line 10 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 10 (St. Clair Fire Restoration) details the actual expenses required to finish restoring the St. Clair Power Plant and its generating units to full service following the August 2016 outage event.

Q. Can you explain in more detail the work and expenses required to restore plant infrastructure and unit operations following the August 2016 outage event at St. Clair Power Plant shown in line 10?

A. As previously discussed in Case No. U-18255, St. Clair Unit 7 experienced a turbine blade failure on August 11, 2016. As a result of the Unit 7 blade failure and ensuing fire, the turbine house roof as well as several plant common and other unit specific equipment areas were also damaged. Please see Exhibit A-12, Schedule B5.1, page 3 of 9 for a detailed listing of the equipment replaced in 2017.

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Q. Can you explain line 11 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 11 (St. Clair Fire Insurance Recovery) details insurance recovery proceeds, all of which received will be credited to capital accounts for fire restoration work performed at St. Clair Power Plant.

Q. Can you explain line 12 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 12 (Trenton Channel Aux Boiler & Main Steam Reducing Station) details the actual spend that occurred in 2017 to finalize the installation of auxiliary steam boilers and supporting equipment that became necessary after the retirement of Trenton Channel Units 7A and 8 in 2016.

Q. Can you explain line 13 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 13 (Trenton Channel Ash Handling & Sibley Quarry Landfill) summarizes the expenditures planned to meet the CCR regulations for Trenton Channel Power Plant and the Sibley Quarry Landfill. At Trenton Channel Power Plant, a new concrete storage containment pad was required to permit storage of fly ash removed during normal cleaning activities until it can be transported to a landfill. This project meets the EPA CCR rule requiring that temporary storage of fly ash be completed in a manner that prevents it from coming into contact with the ground or ground water. Sibley Quarry work activities include the installation of groundwater monitoring equipment and a workplan study in preparation for eventual termination of landfill activities.

Line
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Q. Can you explain lines 16-18 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Lines 16-18 details non-routine capital projects associated with environmental remediation projects at River Rouge, St. Clair and Monroe power plant sites.

Q. Can you explain line 16 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 16 (River Rouge Bottom Ash Remediation) represents a project that is required to comply with the EPA CCR rule and ensure groundwater adjacent to the River Rouge bottom ash basin is collected and monitored per the plant's NPDES permit. The groundwater is collected through a series of wells and monitored prior to discharge.

Q. Can you explain line 17 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 17 (St. Clair Scrubber Basin Remediation) represents a project that is required to permanently close the St. Clair scrubber basin by removing the existing scrubber sludge and transporting it to a landfill. The scrubber sludge was a by-product of a pilot plant scrubber that was installed and operated on St. Clair Unit 6 in the late 1970s.

Q. Can you explain line 18 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 18 (Monroe Inactive Impoundment Remediation) represents a project that is required to segregate coal pile run off and other non-bottom ash discharges from the existing inactive bottom ash basin in association with EPA 40 CFR Part 257. Additionally, monitoring equipment will be installed to ensure that the outfall from the coal pile runoff basin meets all MDEQ and EPA requirements.

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Q. Can you explain lines 19-22 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Lines 19-22 detail steam plant removal costs associated with the retirement and decommissioning of power generation assets at Harbor Beach and Conners Creek power plants, and selected equipment removal work associated with River Rouge Unit 2, and Trenton Channel Units 7A and 8. Removing retired steam generating units involves three primary activities: decommissioning, decontamination, and demolition. Decommissioning activities include the cost to isolate all unit systems and equipment to prepare them for removal from the site. This includes electrical, mechanical, plant controls, water and gas service shutdown and disconnection from the transmission system. Decontamination includes disposing of hazardous materials (including draining oils, chemicals and other fluids), cleaning tanks and pipelines, and removing batteries. Demolition includes tearing down buildings, removing and remediating the coal pile, asbestos abatement, and remediating (fill and cap) ash basins and ponds.

Q. Can you explain line 26 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 26 (Ludington Upgrades) provides yearly detailed costs for the efficiency upgrade project being completed at the Ludington Pumped Storage Facility that is being managed by CMS Energy, Ludington's majority owner. The projected spend represents DTE Electric's 49% share of project costs during the projected period. The unit upgrades are scheduled to be completed between 2015 and 2020.

Q. Can you explain line 27 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 27 (Ludington Transformers) represents a project that is needed to replace the existing main unit transformers at the Ludington Pumped Storage facility. The new larger transformers are required to support the additional capabilities gained from the generator upgrades being executed as part of the efficiency upgrade projects. The forecasted spend represents DTE Electric's 49% ownership interest in the facility.

Q. Can you explain lines 30-32 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 30-32 details non-routine capital projects associated with construction of new CCGT and CHP plants as well as improvements to the security and blackstart capabilities of peaker sites.

Q. Can you explain line 30 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 30 (Combined Cycle – 2022) represents a project to build a nominal 1,100 MW combined cycle gas turbine (CCGT) generating plant on 40 acres adjacent to the existing Belle River Power Plant. This location was strategically selected due to its proximity to transmission lines and high-pressure gas pipeline infrastructure. Engineering and development of this project is currently underway, groundbreaking is scheduled for late 2018, and the plant is expected to be commercially operational by May of 2022.

On April 27, 2018, the MPSC issued an Order in Case No. U-18419 approving DTE's application for three certificates of necessity (CON) for this plant. In approving the CONs, the commission determined through an open hearing process that the energy to be supplied by the project is needed, a natural gas fired CCGT plant was the most reasonable and prudent means of meeting DTE Electric's future energy needs, and that the Company can recover up to $951.8 million in costs for the plant through future rates. Per the requirements of MCL 460.6s (7), DTE Electric will provide an annual update to the Commission on the status of project costs and schedule.

Q. Can you explain line 31 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 31 (Peaker Site Security & Black start) represents a project to augment certain peaker units to provide black start capability to restart the electric power grid in the event of a major blackout like the one that occurred in 2003. This augmentation is needed because some of the coal units that are currently providing black start capability are slated for retirement by 2023. Because black start capabilities are critical to grid reliability, the specific capabilities and units designed as black start assets are kept confidential.

Q. Can you explain line 32 of Exhibit A-12, Schedule B5.1, page 2 of 9?

A. Line 32 (Ford CHP Unit) is a project to build a 34 MW combined heat and power (CHP) pilot facility. As indicated by Witness Feldmann, Ford Motor Company has determined that the infrastructure supporting their Dearborn Research and Engineering campus in Dearborn Michigan required significant upgrades and replacements to meet the needs of its employees with highly efficient and environmentally compliant systems. The upgrade planned by Ford included replacement of the complex's Central Energy Plant which includes chilled and hot water systems, on site energy storage, steam generation and distribution, geothermal energy and electrical energy. As part of that larger project, DTE Electric will develop a new 34 MW CHP plant to be located on Ford property. The CHP plant will provide electrical energy to serve Ford and other DTE Electric customers along with process steam to support the needs of the Ford Motor Company Research and Engineering

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Center complex. The project is expected to be completed by December 31, 2019 for $62.3 million.

Q. What major equipment is included in the CHP project?

A. The CHP project consists of two 14.5 MW gas turbine generators and two heat recovery steam generators (HRSG). The steam produced by the HRSG's feed a common 5 MW condensing steam turbine generator and provides the process steam demands of the Ford Research and Engineering Center complex in Dearborn Michigan. Also included in the plant design are gas compressors, boiler feed pumps, deaerators, reverse osmosis water treatment systems, cooling towers, plant control systems and a myriad of other smaller components and system needs to operate a fully functional and independent electrical generating plant.

Q. Can you provide more details on the anticipated plant operations, efficiency and environmental controls associated with this CHP project?

A. The two gas turbine generators will operate on natural gas and utilize dry low-NOx combustors for NOx emissions reduction. The HRSGs will be provided with economizers to maximize unit efficiency. The plant will be highly flexible and capable of functioning at various output levels to meet varying demands for steam and electricity production.

Q. What impact will the Ford CHP have on Fossil Generation O&M requirements for the tenure of this case?

A. The new CHP plant will be operational by the end of 2019. Per the O&M agreement between DTE Electric (Owner) and DTE Energy Services (Operator), all major and day-to-day operations and maintenance expenses will be borne by the Operator. Accordingly, there are no O&M expenses related to the Ford CHP project in this case.

Q. Are there circumstances where DTE Electric would bear some O&M expenses associated with the long-term operations of the new CHP plant?

A. Yes, it is possible that that the Company could incur some O&M costs during the life of this asset. The Owner and Operator have agreed to operations and maintenance activities that will be provided by the Operator to the Owner at no cost. However, there are certain items that fall outside of this scope of Operator-provided work. Examples of these items include control systems upgrades or variable frequency drive replacements more than two times during the life of the asset, changes in applicable law leading to increased Operator's costs, and modifications to the facility specifically required by the Owner.

<u>Routine Capital Expenditures</u>

Q. What information is provided on page 4 of Exhibit A-12, Schedule B5.1?

A. Page 4 provides a summary of the routine capital expenditures for steam power, hydraulic power (Ludington) and other power generation (peakers) facilities from 2017 through April 30, 2020 broken down by site and by major spending category.

Q. What were Fossil Generation's routine capital expenditures in 2017 for Steam Power Generation?

A. During 2017, Fossil Generation routine capital expenditures related to steam power generation were $216.2 million as shown on Exhibit A-12, Schedule B5.1, page 4 of

9, line 8. These expenditures included the following projects that individually exceeded $1 million as detailed on page 5 of Exhibit A-12, Schedule B5.1:

- Expenditures on Belle River Unit 2 included $1.3 million for replacing four economizer outlet, primary air fan outlet and precipitator inlet expansion joints to reduce failures that cause unit derates or outages. In addition, $1.4 million was spent on the installation of a wet dust collector. The new wet dust collector replaced two dry dust collectors and improved combustible dust control following National Fire Protection Association (NFPA) guidelines. Four Intermediate Pressure (IP) turbine stop valves and IP turbine control valves were rebuilt at a cost of $2.3 million to ensure the continued reliable operation of these critical safety systems. The High Pressure (HP) turbine replacement project was completed at a cost of $4.4 million to resolve reliability issues. These reliability issues were related to loose stationary and rotating blades and continued cracking of the outer casing of the HP turbine. Boiler waterwall panels and front lower slope tubes were also replaced on Unit 2 to mitigate quench cracking damage and deformation from fallen slag. These tube replacements totaled $7.4 million.
- Common projects at Belle River included $1.4 million to cap and close a section of the Range Road Landfill as required by the landfill operating license. To satisfy the landfill license requirements, it is necessary to cover the closed sections with two feet of clay cover and six inches of top soil and to ensure soil stabilization by planting native grasses on the site. $2.1 million was spent to replace the existing Bradford breaker style coal crusher with a new hammer mill style coal crusher. As part of this same project, a tramp iron detection system and coal sizing grid bypass chute was installed around the crusher. Coal crushers are

an integral part of the coal processing system to ensure coal mill reliability required for maximizing boiler combustion performance.

- $2.3 million was spent on Greenwood Unit 1 to rebuild the internal steam path components of 11 different turbine valves including the turbine stop valves, control valves, equalizing valve, and ventilator valve. The frequent start/stop cycles and large load swings experienced by this turbine make these valves prone to high levels of wear.
- For Monroe Unit 1, $1.0 million was spent to engineer and procure 4,300 square feet of waterwall tubes due to deterioration from corrosion fatigue combined with fireside corrosion, creep damage, and tube thinning. $1.4 million was spent on replacing two SCR Catalyst layers to comply with air permit emissions limits for NO_x and ammonia slip guidelines. $2.0 million was spent to engineer and procure materials for the Secondary Superheater (SSH) inlet pendant replacement project. This project replaced the 53 SSH inlet pendant assemblies that were 46 years old. These original equipment SSH inlet pendants are at end of useful metallurgical life and experiencing failures due to graphitization, thermal fatigue and wall loss in multiple areas impacting boiler reliability. $2.5 million was spent to rebuild coal mill silos 1-2, 1-4, and 1-5 due to the corrosive and abrasive properties of coal. $2.7 million was spent on the North and South Boiler Feed Pump Turbine Blade projects. Blade rows 4, 5, 6A and 6B were replaced due to damage found during internal inspections and similar damage found on other Monroe boiler feed pump turbines.
- Monroe Unit 2 had several projects executed during the periodic outage in 2017. Two hundred fourteen (214) economizer tube assemblies were replaced for $1.8 million due to washout and thinning of the tube walls caused by soot blower

erosion. Sections of the reheat outlet pendants were replaced for $2.1 million due to failures related to localized stress induced precipitation hardening (SIPH). $2.6 million was spent on installing SCR catalyst on layer 2 which was vacant and replacing layer 4 to comply with air permit emissions limits for NO_x and ammonia slip guidelines. The horizontal reheater tubes were replaced for $2.7 million due to ID oxygen pitting, fly ash erosion, and abrasive wear between the horizontal reheater and primary superheater tubes. The Unit 2 generator had developed multiple shorted turns and needed to be rewound to ensure unit reliability at a cost of $4.0 million. Like other Monroe units, Unit 2 had dynamic rotating classifiers installed on the coal mills. Replacing the static classifiers to improve combustion and reduce the slagging and fouling inherent with varying fuel blends for $6.8 million will help reduce PSCR costs. For similar reasons as Unit 1, the Secondary Superheat Inlet Pendants on Unit 2 were replaced for $11.2 million. Lastly, $15.5 million was spent on Unit 2 to replace waterwall tubes that exhibited fireside corrosion due in part to the low NO_x reducing atmosphere found in the combustion zone of the Monroe boilers.

- On Monroe Unit 3, $1.2 million was spent to rebuild coal mill 3-4 due to service hours and lube oil analysis indications of deteriorating internal components. $1.8 million was spent to engineer and procure tubes for the west half of the main unit condenser which are 44 years old and had deteriorated due to ammonia grooving, general erosion, and stress corrosion cracking.
- $1.2 million was spent on Monroe Unit 4 to procure a replacement SCR catalyst to comply with air permit emissions limits for NO_x and ammonia slip guidelines. In addition, $1.2 million was spent to engineer, procure and install blade rows 4, 5, 6A and 6B for the North Boiler Feed Pump Turbine.

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- Common projects at Monroe include $1.2 million to replace all five canal gates that were original plant equipment and had deteriorated due to corrosion. The canal gates need to be operable in the winter to allow condenser cooling water temperature to be controlled which prevents freezing of the intake screens avoiding plant outages. 100 pole mounted lights were replaced for $1.2 million to improve visibility of pedestrian traffic, road hazards, and general driving conditions during non-daylight hours. The old Bradford breaker style coal crusher was replaced with a new hammer mill style coal crusher. As part of this project a metal detection system and coal sizing grid bypass chute was installed for $1.5 million. This new coal crusher improves coal quality being processed by the coal mills improving combustion and reducing boiler and coal mill maintenance. $1.6 million was spent to rebuild the Unit 1 and 2 cascade counterweight room walls to contain coal fines and prevent leakage of these highly combustible fines into other areas of the plant. $1.8 million was used to engineer, procure, and install an upgrade to the makeup water system used to make ultrahigh purity boiler feedwater. The upgrade allowed use of less expensive general service water (river water) as its supply source rather than city (potable) water that has traditionally been used at Monroe. Two Caterpillar D10 dozers were purchased for $2.8 million to replace mobile equipment that had exceeded their economically maintainable service lives. $3.3 million was spent to replace a dust collector with a wet scrubber, including additions of explosion ventilation doors and ductwork meeting NFPA guidelines. $3.6 million was spent for engineering the fuel supply control system replacement like one recently completed at Belle River Power Plant. Lastly, $4.2 million was spent to engineer, procure, and install a new soot blowing air compressor to ensure sufficient high

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pressure air is available to meet plant demands and eliminate the need for rental compressors.

- St. Clair Unit 6 spent $2.3 million to engineer and procure two rows of L-0 blades for both low-pressure turbines, due to erosion damage on the blade tips.
- St. Clair Unit 7 had several projects completed during the 2017 periodic outage. $1.0 million was spent to rebuild Coal Mill D due to service hours and lube oil analysis indications of deteriorating internal components. Corroded coal bunker walls were replaced to eliminate coal spillage into the boiler house at a cost of $1.1 million. The cold end baskets of the north and south air preheater were replaced for $1.1 million based on inspections which revealed corrosion and erosion impacting 50-80% of the heating element material. $1.1 million was spent on replacing the Unit 7 stack liner insulation due to degradation and safety concerns with falling insulation. The reheat pendants were replaced for $2.9 million to maintain unit reliability. These pendants were 47 years old and had experienced increasing frequency of leaks due to thinning from scale exfoliation, oxygen pitting, soot blower erosion and thermal fatigue. $3.4 million was spent on replacing waterwall tubes experiencing fireside corrosion and quench cracking thermal fatigue damage. Quench cracking results when waterwall surfaces are cleaned to remove ash accumulations that form during combustion of low sulfur western coal. Lastly, $5.3 million was spent on replacing both rows of the L-1 blades in Low Pressure Turbine 1 and both rows of the L-0 blades in Low Pressure Turbine 2.
- A common project at St. Clair included a Caterpillar D10 dozer purchased for $1.5 million to replace equipment that was beyond its economically maintainable service life.

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Q. What are the routine projects with projected capital expenditures greater than $1 million in 2018 for Steam Power Generation?

A. Planned 2018 maintenance projects greater than $1 million are detailed on page 6 of Exhibit A-12, Schedule B5.1 and discussed below.

- $3.7 million will be spent to engineer and procure the Belle River Uni1 1 HP Turbine replacement. The HP turbine is being replaced because of the risk of blade failures from loose stationary and rotating blades. The blades have been retightened twice and based on OEM recommendations the blades cannot be tightened again and must be replaced.
- Expenditures on Monroe Unit 1 during the periodic outage will include $1.0 million to re-tube the north boiler feed pump turbine condenser which is original plant equipment and shows deterioration due to ammonia grooving, general erosion and stress corrosion cracking. $1.2 million will be spent to overhaul the steam path components of the turbine valves to ensure the continued reliable operation of this critical safety system. Feedwater Heater No. 3 will be replaced for $2.1 million due to an internal malfunction leading to damage to upstream heaters. Installation of the Flue Gas Desulfurization (FGD) booster fans made the ID fan discharge dampers redundant and they will be removed for $2.6 million. Removal of ID fan dampers will eliminate the risk of flue gas leaking from duct work. Two hundred fourteen (214) economizer tube assemblies will be replaced for $2.9 million due to sootblower erosion which causes washout and thinning of the tube walls. ID oxygen pitting, fly ash erosion, and abrasion between the horizontal reheater and primary superheater, requires the horizontal reheater tubes to be replaced for $2.9 million. Boiler combustion control and unit reliability require that various expansion joints be replaced for $3.3 million. The

boiler flue gas system has over 100 expansion joints on each unit and these expansion joints have a finite life requiring Monroe to engage in a continuing replacement program. These replacements are part of that continuing program. Coal mill silos will be rebuilt due to deterioration caused by the corrosive and abrasive properties of coal. Three silos are scheduled for replacement to restore their structural integrity for $3.3 million. To ensure continuing compliance with air permit emissions limits for NO_x and ammonia slip guidelines two SCR catalyst layers will be replaced for $3.8 million. The Secondary Superheat Inlet Pendants will have the 48-year old inlet pendant assemblies replaced. These original equipment SSH Inlet Pendants are at end of useful metallurgical life and experiencing failures due to graphitization and significant wall loss in multiple areas impacting boiler reliability and will be replaced for $11.9 million. Approximately 5,000 sq. ft. of boiler waterwall tubes will be replaced for $11.9 million. These tubes are exhibiting corrosion fatigue failures that are occurring due in part to the low NO_x reducing atmosphere found in the Monroe boilers combustion zone. Boiler tubes sections will be replaced with material that includes an Inconel weld overlay protective coating that is resistant to the harsh boiler combustion zone conditions. Inconel protective coatings have been utilized for over 10 years and have proven well suited for this application.

- In 2018, Monroe Unit 3 will replace blade rows 4, 5, 6A and 6B on the south boiler feed pump turbine as has been done on other Monroe units in 2016 and 2017 for a cost of $1.3 million. Secondary superheater inlet pendants will be procured to allow their replacement because the pendants have reached the end of their useful metallurgical life due to graphitization and significant wall loss for $1.8 million. Replacement of the SSH inlet pendants which are 44 years old will restore reliability of this component. Two coal silos are scheduled for replacement to restore structural integrity for $2.2 million. The coal mill silos will be rebuilt to restore deterioration caused by the corrosive and abrasive properties of coal. Two SCR catalyst layers will be procured for $2.2 million to ensure continued compliance with air permit emissions limits for NO_x and ammonia slip guidelines. One layer will be installed in 2018 and the other in 2019 during the periodic outage. SCR catalysts lose activity with use as they are exposed to boiler flue gas and ash. Periodic replacement with new or regenerated catalyst is required approximately every two years to maintain NO_x removal performance.

- Monroe Unit 4 secondary superheater inlet pendants will be procured to allow their replacement due to graphitization and significant wall loss in various areas for $1.1 million. Replacement of the SSH inlet pendants which are 44 years old will restore the reliability of this component. $1.8 million will be spent to rebuild coal mill 4-5 silo to restore structural integrity. Engineering and procurement of materials to replace one depleted SCR layer to comply with the air permit NO_x limits and ammonia slip guidelines will be completed for $2.3 million.
- A major fuel supply project is being undertaken at Monroe to replace the 40-year old fuel supply control system for $8.3 million. The availability of replacement equipment and vendor support is inadequate which puts the ability to fuel the plant at risk while also creating safety concerns. The system is very complex with 10 transfer houses, 26 conveyors, 9 miles of belts, 51 diverting gates, 12 feeders, 6 rotary plow feeders, 2 tripper cars, 2 crushers and 28 coal storage silos located throughout the coal yard and inside the plant requiring a very extensive control system to manage and deliver coal to the plant. The fuel supply system

can deliver various blends of Low Sulfur Western coal (LSW), High Sulfur Eastern coal (HSE) and Pet Coke to the plant. The work scope of this project includes updating all as-built drawings showing I/O terminations, installing a new DCS control/annunciation system, replacing all relay logic panels, augmenting the existing fiber optic network, updating the Fuel Supply control room to include new operator interface equipment and upgrading the 4160V breaker and starter controls to Intelligent Electronic Devices (IED). A similar fuel supply controls project upgrade was completed at Belle River Power Plant in 2016.

- Other Monroe fuel supply common equipment projects include $1.7 million to be spent for the coal crusher CR-01 sizing grid and bypass chute to assist with crushing low-sulfur western coal and coal fines separation. $2.1 million will go towards upgrading the 45-year old medium voltage switchgear that needs to be replaced to ensure the continued reliable operation of these safety systems. Dust collectors will be replaced on conveyors for Units 1 and 2 to mitigate combustible dust for $5.3 million and an additional $2.2 million will be spent on upgrading the train unloading conveyor chute to comply with the NFPA combustible dust guidelines.
- Monroe plant common equipment projects include precipitator SIR lifting rails and trollies for $1.0 million to assist with replacing failed parts and reducing safety risk. $1.4 million will also be spent to install an upgrade to the makeup water system which previously used city water to supplement the boiler rather than general service water. Monroe will also have its plant air and soot blowing air supply augmented by installing new compressors at a cost of $4.1 million. Additional soot blowing high pressure air supply is required to adequately clean boiler waterwalls, superheaters, reheaters, economizers and air heaters of ash

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accumulations. If the ash removal is inadequate, tube passages plug and air flow is restricted though the boiler. Pluggage can cause overheating and hard ash accumulations which require extended duration forced outages to remove.

- River Rouge Unit 3 will rebuild the steam path components of the Reheat and Intercept Stop Valves for $1.6 million. This is mandatory work required to ensure the continued reliable operation of these critical safety systems. Failure of these valves to perform a safe shutdown of the turbine upon a generator trip can cause a turbine over speed event leading to catastrophic failure, potentially resulting in large components becoming ejected from the turbine casing creating an unacceptable personnel safety risk.
- St. Clair Unit 6 will rebuild the steam path components of the turbine valves for $1.5 million to ensure continued reliable operation of these critical safety systems. Also, $4.1 million will be spent to install the L-0 blade rows on low pressure turbines, LP1 and LP2 due to erosion damage on the blade tips.
- Trenton Unit 9 will replace the main steam piping tee due to an internal inspection that revealed evidence of two separate cracks in the shoulder areas on the north and south sides of the tee. The tee is seam welded and predisposed to creep fatigue cracking. This safety driven project will be completed for $1.6 million. In addition, $1.7 million will be spent to engineer and procure blade rows 4, 5 and 6 on the south boiler feed pump turbine due to industry wide known blade failures.

Q. What are the routine projects with projected capital expenditures greater than $1 million in 2019 for Steam Power Generation?

A. Planned 2019 maintenance projects greater than $1 million are detailed on page 7 of Exhibit A-12, Schedule B5.1 and discussed below.

- Expenditures on Belle River Unit 1 will include $2.2 million to replace four economizer outlet, primary air fan outlet and precipitator inlet expansion joints to reduce failures that cause unit derates or outages. Four Intermediate Pressure (IP) turbine stop valves and four IP turbine control valves will be rebuilt at a cost of $3.0 million to ensure the continued reliable operation of these critical safety systems. Approximately 2,500 square feet of boiler waterwall panels will be replaced on Unit 1 to mitigate quench cracking damage on the tubes. The tube replacements total $5.7 million. The HP turbine will be replaced at a cost of $8.8 million to resolve reliability issues related to blade failures caused by loose stationary and rotating blades. The blades have been tightened twice and based on OEM recommendations the blades cannot be retightened again and must be replaced. For Belle River Unit 2 $1.0 million will be spent to engineer and procure blades for the LP turbine due to blade erosion on the L-0, L-1, L-2, and L-3 blade rows. $1.1 million will also be spent to engineer and procure approximately 2,500 square feet of waterwall tubes for the 2020 periodic outage. Failure mechanisms being mitigated include fireside corrosion and quench cracking.
- Common projects at Belle River include $1.5 million to replace dust collector 109/110 with a wet type dust collector including explosion ventilation doors and ductwork that meet the NFPA guidelines.

- For Monroe Unit 2, the 2-6 coal mill silo will be rebuilt to restore structural integrity for $1.4 million. A replacement SCR catalyst layer will be installed to ensure compliance with the air permit NOx limits and ammonia slip guidelines for $2.0 million.
- During the Monroe Unit 3 periodic outage many projects will be executed. One coal silo is scheduled for replacement to restore structural integrity for $1.0 million. $1.2 million will be spent to overhaul the steam path components of the turbine valves to ensure the continued reliable operation of this critical safety system. For $1.3 million, the reheat stop valves will be upgraded to achieve 4-5 years of service life. The north and south FGD booster fan hub and blades are part of the original 2009 installation. The fans require new internal components to restore design capabilities and will be replaced for a cost of $1.4 million. $1.5 million will be spent to improve the overall integrity of the ID Fan discharge ductwork and eliminate the safety hazard associated with leaking flue gas. $2.0 million will be spent to replace the expansion joints on Low Pressure Turbines A and B. $2.0 million will be spent to install tubes in the west half of the main unit condenser which are 44 years old and deteriorated due to ammonia grooving, general erosion, and stress corrosion cracking. ID oxygen pitting, fly ash erosion, and abrasion between the horizontal reheater and primary superheater, require the horizontal reheater tubes be replaced for $2.9 million. Boiler combustion control and unit reliability require that various expansion joints be replaced for $3.5 million. The boiler flue gas system has over 100 expansion joints on each unit and these expansion joints have a finite life requiring Monroe to engage in a continuing replacement program. These replacements are part of that continuing program. $5.5 million will be spent on replacing SCR Catalyst layers 2, 3 and 4

to comply with air permit emissions limits for NOx and ammonia slip guidelines. $10.9 million will be spent to replace the 53 Secondary Superheater (SSH) inlet pendants. These original equipment SSH Inlet Pendants are at end of useful metallurgical life and experiencing failures due to graphitization, thermal fatigue and significant wall loss in multiple areas impacting boiler reliability. Lastly, $14.0 million will be spent to install approximately 4,000 square feet of waterwall tubes due to deterioration from corrosion fatigue combined, fireside corrosion, creep damage, and tube thinning.

- For Monroe Unit 4, $1.0 million will be spent to engineer hot end air heater baskets that have degraded due to corrosion of the basket elements. The replacements will restore physical integrity and heat transfer to improve boiler efficiency. $1.0 million will be spent to install tubes in the east half of the main unit condenser which are 45 years old and deteriorated due to ammonia grooving, general erosion, and stress corrosion cracking. $1.1 million is planned for the secondary superheat inlet pendants which replaces the 53 SSH inlet pendant assemblies that are 46 years old. $1.5 million will also be spent to engineer and procure approximately 4,000 square feet of waterwall tubes that will be replaced due to deterioration from corrosion fatigue combined with fireside corrosion, creep damage, and tube thinning. The generator stator which is approaching 45 years of age will need a rewind for $2.9 million due to deterioration of the brazed joints which causes stator coil leaks and deterioration of the stator slots allowing stator coil movement.
- Fuel supply common projects at Monroe include $1.5 million to install a new main transfer tower coal chute from CVC-6 to CVC-7 and CVC-8 to reduce combustible dust and $1.8 million to rebuild the Unit 3 and 4 cascade

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counterweight room to mitigate coal fine that contaminate other areas of the plant. Dust collectors will be replaced on conveyors for Units 3 and 4 to mitigate combustible dust for $7.0 million. Combustible dust control is required to mitigate the risk of explosions and fires that can otherwise occur. Lastly, $7.9 million will be spent on the fuel supply controls replacement project.

- Monroe plant common projects include $1.0 million to support NERC CIP medium to low impact migration throughout the fleet.
- For St. Clair Unit 7, plans are to rebuild the steam path components of the turbine valves for $1.5 million to ensure continued reliable operation of these critical safety systems.
- St. Clair common projects include replacement of a coal conveyor belt for $1.0 million, installation of a 3TH3 dust collector with a wet dust collector meeting NFPA safety guidelines for $2.0 million.
- For Trenton Unit 9, $1.5 million will be spent to install blade rows 4, 5 and 6 on the north boiler feed pump turbine due to industry wide known blade failures. The steam path components of the turbine valves will be rebuilt for $1.5 million to ensure continued reliable operation of the critical safety systems.

Q. What are the routine projects with projected capital expenditures greater than $1 million to be executed in the first four months of 2020 for Steam Power Generation?

A. Planned 2020 maintenance projects greater than $1 million are detailed on page 8 of Exhibit A-12, Schedule B5.1 and discussed below.

- Expenditures on Belle River Unit 2 will include approximately 2,500 square feet of boiler waterwall panels to be replaced to mitigate quench cracking and fireside corrosion damage on the tubes. The tube replacements total $2.0 million. The LP turbine blades will be replaced due to blade erosion on the L-0, L-1, L-2, and L-3 blades for $3.0 million.

- Monroe Unit 4 periodic outage expenditures include $1.0 million for the air heater hot-end basket replacements to restore physical integrity and heat transfer to improve boiler efficiency. In addition, $1.2 million will be spent for expansion joints replacements for boiler combustion control and unit reliability. The coal mill 4-1 silo will be rebuilt to restore structural integrity for $1.4 million. The generator stator is approaching 45 years of age and needs to be rewound for $3.7 million. The generator's brazed joints have deteriorated resulting in stator cooling water leaks, stator slot damage and stator coil movement. $4.0 million will be spent to replace approximately 4,000 square feet of waterwall tubes damaged from fireside corrosion. Lastly $4.7 million is planned for the secondary superheat inlet pendant project which replaces the 53 SSH inlet pendant assemblies that are 45 years old.
- Monroe common projects include $1.4 million to replace three coal mill silos to restore structural integrity.

Q. What were Fossil Generation's routine capital expenditures in 2017 for Hydraulic Power generation (Ludington)?

A. During 2017, Fossil Generation routine capital expenditures for the Ludington Pumped Storage facility were $2.5 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 9. Expenditures were related to unit maintenance and auxiliary equipment upgrades and switchgear replacements.

Q. What will be Fossil Generation's routine capital expenditures for Hydraulic Power Generation (Ludington) in the 16 months ending April 30, 2019?

A. During the 16 months ending April 30, 2019, Fossil Generation routine capital expenditures for the Ludington Pumped Storage facility are projected to be $5.5 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 9. Investments will be related to unit maintenance and auxiliary equipment upgrades.

Q. What will be Fossil Generation's routine capital expenditures for Hydraulic Power Generation (Ludington) in the projected test year, the 12 months ending April 30, 2020?

A. During the 12 months ending April 30, 2020, Fossil Generation routine capital expenditures for the Ludington Pumped Storage facility are projected to be $5.4 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 9. Investments will be related to unit maintenance and auxiliary equipment upgrades.

Q. What were Fossil Generation's routine capital expenditures in 2017 for Other Power Generation (Peakers)?

A. During 2017, Fossil Generation routine capital expenditures for peaking units were $26.5 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 10. This included $1.8 million for a control system upgrade due to obsolescence on the Belle River diesel peakers, and $2.4 million for combustion cans overhaul at Renaissance. $4.0 million was spent for a hot gas path overhaul on Delray 11-1, and $5.8 million for a generator field rewind and hot gas path overhaul on Delray 12-1. Northeast 12-1 and Superior 11-4 had combustion can and hot gas path overhauls completed for $6.5 million

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Q. What will be Fossil Generation's routine capital expenditures for Other Power Generation (Peakers) in the 16 months ending April 30, 2019?

A. During the 16 months ending April 30, 2019, Fossil Generation routine capital expenditures for peaking units is expected to be approximately $32.4 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 10. This includes $1.0 million for a generator field replacement on Hancock 11-3. $2.0 million will be spent to engineer a new Continuous Emissions Monitoring Systems (CEMS) for the Belle River Peakers and to replace the CEMS controls at the Renaissance peakers. $2.4 million will be spent for a hot gas path component overhaul on Delray 12-1, $3.1 million for insulator replacements at the Renaissance Peakers, $4.4 million for combustion can overhauls on Greenwood 11-1 and Renaissance Unit 4, and $9.4 million for control system upgrades due to obsolescence at sites placed into service between 1966 and 1999.

Q. What will be Fossil Generation's routine capital expenditures for Other Power Generation (Peakers) be in the projected test year, the 12 months ending April 30, 2020?

A. During the 12 months ending April 30, 2020, Fossil Generation routine capital expenditures for peaking units is expected to be approximately $20.0 million as shown on Exhibit A-12, Schedule B5.1, page 4 of 9, line 10. This includes $1.3 million to install CEMS on the Belle River Peakers, $3.8 million for hot gas path component overhauls on two Fermi Peaking units, $2.5 million for a spare Renaissance transformer, $4.1 million for combustion can overhauls on Renaissance Units 2 and 3, and $1.2 million for a new control system and motor control center on Fermi 11-1.

<u>Summary of Tier 1 and Tier 2 Coal-Fired Generation Capital</u>

Q. Please explain the tiered maintenance strategy Fossil Generation employs for its generating units.

A. In anticipation that certain coal-fired generating units would be retired many years before others, a tiered maintenance and capital expenditure strategy was developed. The Tier 1 long-term coal-fired units are identified as Belle River and Monroe while the remainder of the coal-fired units are classified as Tier 2 units. Fossil Generation operates its coal fleet with two distinct strategies that drive both the O&M and capital expenditure plans for the different tiers. Investments in Tier 1 coal units are designed to achieve 1st quartile reliability performance as measured by ROF, while investments in Tier 2 units are being limited to those required to maintain safe and environmentally compliant operations until the units are retired over the next five years.

Q. Can you explain how the tiered maintenance expenditure strategy is translating into different capital expenditure levels at the Tier 1 coal units compared to the Tier 2 coal units?

A. Yes. I have prepared two tables with data extracted from the Exhibit A-12 Schedule B5.1 pages 2 and 4 in this proceeding that clearly shows that expenditures are being minimized at the Tier 2 coal units as they are moving towards retirement. The expenditure levels are shown in Table 2 while Table 3 shows that data as percentages. During the 2017-April 30, 2020 timeframe of this proceeding, Fossil Generation is expending a combined $660 million in routine capitalized maintenance and non-routine capital additions for its Tier 1 and Tier 2 coal-fired units. The six Tier 1 coal units (Belle River 1-2 and Monroe 1-4) are receiving 69% of this total capital for routine capitalized maintenance while 16% is going towards the Tier 1 non-routine capital additions, primarily for environmental related projects. The seven Tier 2 coal units (St Clair 1-3, 6-7, River Rouge 3 and Trenton Channel 9) are receiving just 14% of the total expenditures for their capitalized maintenance and just 1% for their non-routine capital additions. It should be noted that maintenance must continue to be performed on the Tier 2 plants to ensure that they operate safely and are environmentally compliant until their retirements. Some of that maintenance is categorized as capitalized maintenance as opposed to O&M expense per the accounting rules with which the Company must comply.

Table 2 – Capital Expenditures 2017-April 30, 2020

Tier 1 vs Tier 2 Coal Plants
Dollars (000's)

		2017-April 30, 2020	Exh. A-12, Sch. B5.1
Tier 1	Routine (Capitalized Maintenance)	455,184	Page 4, lines 3 & 7 (b,e,f)
	Non-Routine Additions	107,394	Page 2, lines 2-7 & 9 (b,e,f)
	Total Tier 1	**562,578**	
Tier 2	Routine (Capitalized Maintenance)	93,862	Page 4, lines 4-6 (b,e,f)
	Non-Routine Additions	4,011	Page 2, lines 8, 12 & 13 (b,e,f)
	Total Tier 2	**97,873**	

Table 3 – Capital Expenditure 2017-April 30, 2020

Tier 1 vs Tier 2 Coal Plants

Percentage Expenditure by Category

	Routine Maintenance	Non-Routine Additions	Total
Tier 1 Coal Units	69%	16%	85%
Tier 2 Coal Units	14%	1%	15%

Q. Can you explain in more detail the continuing routine capital expenditures at River Rouge Power Plant?

A. River Rouge Unit 3 is scheduled to operate until its currently planned retirement in May of 2020. From now until the plant's retirement, it is necessary to operate the plant in a safe and environmentally compliant manner. River Rouge Power Plant spent $5.4 million in 2017 and plans to expend $4.9 million in the 28-month period including 2018, 2019 and the first 4 months of 2020 for routine capitalized maintenance. These expenditures are mainly related to the replacement of pumps, motors, valves, instruments and control system components to maintain continued operations in a safe and environmentally compliant manner.

Q. Does the Company provide additional support for the ongoing capital expenditures to allow the safe and environmental compliant operations of River Rouge Unit 3?

A. Yes. Witness Dimitry presents the results of an economic analysis that compares operating and maintaining River Rouge Unit 3 until its planned retirement date in 2020 to retiring that unit at the end of 2018. Three sensitivities were conducted using different capacity price assumptions, and resulted in economic outcomes that showed

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the 2020 retirement scenario as economically favorable, essentially neutral, or unfavorable depending on which capacity price assumption is used.

Q. Can you provide justification for performing the analysis with various capacity pricing assumptions?

A. Yes. As described by Witness Dimitry, the Company considered multiple capacity pricing alternatives for this analysis, ranging from a low forecast based on modeling conducted by PACE Global, an energy industry consulting firm, to the MISO Zone 7 Cost of New Entry (CONE) at $90.70 / kW-year. The Company feels that it is important to consider a wide range of capacity pricing scenarios when performing an economic analysis, given the nature of capacity pricing. While the most recent auction clearing price for MISO Zone 7 capacity was $10.00 / MW-day, prices would go to CONE if unforeseen circumstances led to a situation where total MISO planning resources did not meet the system-wide planning reserve margin requirement or if resources identified in the MISO Planning Resource Auction didn't meet Zone 7's local clearing requirement. While there is no way of knowing if such unforeseen circumstances would arise, it is prudent to include these sensitivities in an economic analysis given the reliability impact such an event would have on the electrical grid, thus negatively impacting our customers.

Q. What is your conclusion regarding the planned retirement of River Rouge Unit 3?

A. Given the range of economic outcomes showing the 2020 retirement scenario as economically favorable, essentially neutral, or unfavorable as compared to the 2018 retirement scenario, coupled with the other factors explained in my testimony on pages 13-20, continued operations of River Rouge Unit 3 until the planned retirement date of May 2020 is in the best interest of our customers and needed to support grid reliability, resource adequacy and workforce planning while minimizing the negative impacts to our local communities. Further justification for continued operations of River Rouge Unit 3 until its planned retirement date of May 2020 is provided by the MISO Attachment Y reliability study report for River Rouge Unit 3. The report specifically indicates that retirement or suspension of River Rouge Unit 3 may create thermal and voltage issues that could require the Company to shed firm load to ensure grid reliability. Although firm load shed is utilized as a countermeasure within MISO's planning criteria, the Company has significant concerns about implementing electrical service interruptions to our customers as a means of addressing known grid reliability issues. Maintaining and operating River Rouge Unit 3 until its planned retirement date of May 2020 will provide additional time to identify and implement alternative solutions that can ensure continued reliable electric service for its customers.

<u>2017-2020 AFUDC Estimate</u>

Q. Do the capital expenditures you are supporting include an allowance for funds used during construction (AFUDC)?

A. Yes, capital expenditures include an allowance for funds used during construction (AFUDC) for eligible projects that are in Construction Work in Progress (CWIP). At the direction of Company Witness Ms. Uzenski, AFUDC is applied to projects greater than $50,000 and lasting more than six months, except for large environmental projects which are exempt from AFUDC treatment.

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Q. How much AFUDC is assumed in the projected test period for Fossil Generation?

A. AFUDC for Fossil Generation is included on Exhibit A-12, Schedule B5.1, page 9 of 9. As shown, the Fossil Generation AFUDC is projected to be $4.1 million for the 12-month period ending April 30, 2020. This amount includes $1.9 million for routine expenditures and $2.2 million for project specific expenditures. A historical trend is used to estimate AFUDC on routine capital since the mix of eligible projects is consistent year to year, while the AFUDC is calculated specifically on a project by project basis for eligible non-routine projects. The authorized cost of capital rate used is 5.34% per the U-18255 rate order. For additional details on AFUDC refer to Witness Uzenski.

Part III - Fossil Generation Operating and Maintenance Expenses

Q. What is the process used to prepare the Fossil Generation Operating and Maintenance (O&M) projected level of expense?

A. Projected O&M expense is developed by taking historical O&M expenditure data and adjusting for any known projected period changes. Plant level changes include labor and material cost increases, year-over-year variations in periodic outage work, cost variations related to environmental equipment operation, non-periodic maintenance cost variations driven by predictive maintenance programs and other known changes.

The overall Fossil Generation O&M projection is developed by adjusting the actual historic test year (2017) results for rate case adjustments between witnesses, normalization adjustments to the 2017 data and known and measurable adjustments to handle O&M changes (up or down) due to changes that are anticipated to occur by the end of the forecasted test year.

Fossil Generation operations expenses are those associated with day-to-day operation of the Company's generating units, including certain Account 501 fuel handling expenses. Fossil Generation maintenance expenses are associated with periodic outage, non-periodic outage, and other maintenance activities. Other maintenance activities include standard day-to-day work to maintain plant equipment, such as inspections, servicing, and minor maintenance that does not require the unit to be taken offline to complete.

Fossil Generation O&M is presented in three major cost categories as shown below:

- Steam Power Generation
- Hydraulic Power Generation
- Other Power Generation

Q. What were Fossil Generation's historical O&M Expenditures for 2017 for Steam Power Generation?

A. During 2017, Steam Power Generation adjusted O&M expenses totaled $274.1 million as shown on Exhibit A-13 Schedule C5.1, line 19, column (g). This was comprised of $134.4 million in operations costs and $139.7 million in maintenance costs. The $8.1 million of Steam Power Generation O&M that relates to Fuel Supply and MERC Fuel Handling is sponsored by Company Witness Mr. Milo on Exhibit A-13, Schedule C5.2 and is subtracted on line 20 (Note 1), resulting in remaining Steam Power Generation adjusted O&M in the amount of $266.0 million.

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Q. Can you provide an overview of Exhibit A-13, Schedule C5.1?

A. Exhibit A-13, Schedule C5.1 is a two-page exhibit. Page 1 of Schedule C5.1 shows total test period O&M for Steam Power Generation by starting with the 2017 actual O&M expenses and adjusting for rate case eliminations, normalization adjustments, and inflation adjustments. The normalization adjustments are required to determine the portion of the 2017 O&M expenses that will reoccur in the 12-month period ending April 30, 2020. Those normalization adjustments are shown in note 4 on page 1. There are no additional known and measurable adjustments required in column k to determine the O&M required in the 12-month forecasted test period ending April 30, 2020. Page 2 provides additional detail of the $23.1 million of 2017 costs experienced due to the St. Clair August 2016 Outage Event equipment repair/restoration shown in Note 4 on Page 1. The two pages of Exhibit A-13, Schedule C5.1 are discussed in more detail in testimony that follows.

Q. What are the major O&M expense categories found in Exhibit A-13, Schedule C5.1?

A. The expenses shown in Exhibit A-13, Schedule C5.1 are categorized into the major categories of operations and maintenance consistent with FERC accounting guidelines.

Operations account 500 includes the cost of plant management for the individual plant sites, their supporting staffs and the Fossil Generation Engineering Support Organization. Plant management includes plant site director, area managers and administrative support. The major supporting staffs in this area are the technical and engineering personnel associated with problem solving daily plant operating issues, obtaining and interpreting test data and developing long term operating and maintenance plans to maintain plant availability and efficiency.

Operations account 501 "Fuel Handling" includes expenses incurred for coal train and vessel unloading, ash disposal, coal pile management and mobile equipment operations. Depending on plant site and delivery options, plants maintain and manage a coal pile inventory that can vary over many months. Larger coal pile inventories are required at Belle River and St. Clair power plants at the end of December to ensure adequate coal supplies when vessel deliveries cannot be obtained due to winter ice on the Great Lakes.

Accounts 502 and 505 represent operations personnel and materials expenses associated with direct operating supervision and control of boiler, turbine, generator, water and environmental control systems. Shift supervisor and control room supervising operators are key to the successful steam power generation unit operations that are required to ensure adequate and cost efficient production of electrical energy for our customers. Their labor expenses are captured in these accounts.

Account 506 "Misc. Steam Power Expenses" includes Instrument and Controls personnel to troubleshoot and calibrate the vast array of complex instruments and controls found on steam generating units. Also included in this account are operations of all common equipment such as water, air and cooling equipment systems. Plant buildings and grounds cleaning, landscaping, snow removal and maintenance are also captured in this account.

Maintenance accounts 510 through 514 capture expenses associated with planned and unplanned maintenance activities. These expenses mostly consist of the planned maintenance activities that generally occur on a two to five-year interval on all boiler systems and on a six to ten-year interval on turbine systems. Account 510 captures management of the plant maintenance area including area managers and general foremen. Account 511 covers maintenance of common infrastructure areas such as roofs, windows and roads. The major area of expense captured in account 512 "Maintenance of Boilers" includes maintenance expenses for internal and external labor and all materials associated with planned and unplanned outage work on the boilers. The boiler maintenance scope of work includes the boilers, air and flue gas systems, ash handling and fuel burning equipment. The major area of expense captured in account 513 "Maintenance of Electric Plant" includes internal and external labor and materials expenses associated with work on turbines. The major area of expense captured in account 514 "Maintenance of Misc Steam Plant" includes internal and external labor and materials expenses for maintenance of all common equipment such as water, air and cooling equipment systems.

Q. Can you provide additional detail on the O&M expenses incurred by the Company's Steam Power Generation during 2017?

A. In the historic period of 2017, the Company spent $266.0 million in Steam Power Generation O&M expenses after adjustments and reclassifications. Planned major periodic maintenance outages were executed in 2017 on Belle River Unit 2, Greenwood Unit 1, St Clair Unit 4, St Clair Unit 7, Monroe Unit 2 and Trenton Channel Unit 9. Also completed during 2017 were multiple short duration unit tune-up outages on the Belle River, St Clair, River Rouge, Trenton Channel and Monroe units to allow their continued efficient operation burning high percentages of lower sulfur content western coals. Costs for the portions of outages that occur in 2017 and 2018 will be captured in those respective years.

The other category of maintenance expenses incurred during the historic period were associated with regular plant maintenance while units were in operation or expenses to repair or replace equipment during a forced or unplanned unit outage. These short duration unplanned maintenance outages can generally be completed in three to seven days and will be experienced at varying intervals on all steam power generating units depending on the severity of their service cycles and the time elapsed since their last planned maintenance outage.

During the projected 12-month period ending April 30, 2020, the Company will execute four periodic maintenance outages on Belle River Unit 2 and Monroe Units 1, 2 and 3. As in the historic period, short duration unit tune-up outages will also be completed on the St Clair, Belle River, River Rouge, Greenwood, Trenton Channel and Monroe Units to optimize continuing performance.

Q. What adjustments were made to the historical test period amounts?

A. First, Fuel Handling O&M expenses recorded in Fuel Account 501 are added to Steam Power O&M in column (d). This amount includes Fuel Supply and MERC Fuel Handling for which an adjustment is made in column (e) to reclassify non-O&M fuel handling sponsored by Witness Milo (Note 3). In column (f), five (5) normalizing adjustments, netting to $1.9 million, were made to eliminate non-recurring expenses. These five items are identified in Note 4. The forecasts for these

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expenses through the projected test period are based on the historic labor and materials expenses as adjusted for escalation. The labor and material inflation adjustment factor of 3.0% for 2018, 2.9% for 2019 and 1.0% for the first four months of 2020 is supported by Witness Uzenski.

Q. Can you provide a further explanation of the net $1.9 million normalizing adjustment shown on note 4 of Exhibit A-13, Schedule C 5.1, page 1 of 2?

A. Yes. The $1.9 million of normalizing adjustments shown in this exhibit is made up of 5 line-item adjustments.

Line 1 shows $23.1 million of O&M expense associated with the August 2016 St. Clair outage event caused by a turbine blade failure on Unit 7 that was incurred in 2017. This amount is being eliminated because it is considered a one-time occurrence and not representative of future plant operations.

Line 2 shows $3.6 million added in as a normalization change to reflect normal 2017 plant operations that were interrupted by continuing work to restore plant equipment and systems after the August 2016 St. Clair Power Plant outage event. Had the Company not been expensing $23.1 million to restore the plant and plant equipment damaged in the August 2016 outage event, normal plant operations would have required funding of $3.6 million.

Line 3 shows a reduction of $1.4 million for operations and maintenance expenses associated with St. Clair Unit 4 that will no longer be incurred because of the unit's retirement.

Line 4 shows the $21.2 million of insurance proceeds (credit) received in 2017 associated with the St. Clair fire event O&M expenses. Since this credit does not repeat in the projected test year ending April 30, 2020, this amount is added back as an increase to future O&M.

Line 5 shows an increase of $1.6 million needed to offset a credit booked in 2017 for ash sales that occurred in 2016. The credit was not booked in 2016 due to a pending legal settlement. After finalization of the legal settlement, the 2016 ash sale credit was booked in 2017 along with the normal 2017 ash sale credit creating a higher than normal credit in the historic test period of this case. The $1.6 million adjusts the 2017 expenses to normalize for this timing issue of accounting entries.

Q. Can you explain Exhibit A-13, Schedule C 5.1, page 2 of 2?

A. Yes. Page 2 of Exhibit A-13 Schedule C 5.1 provides further details of the $23.1 million credit being applied to the 2017 actual O&M expenses by showing the specific units or common systems that these charges are attributable to.

Q. Can you summarize Exhibit A-13, Schedule C5.4, entitled "Operations and Maintenance Expenses - Hydraulic Power Generation"?

A. Exhibit A-13, Schedule C5.4 represents DTE Electric's share of the continuing operation and maintenance expense of the Ludington Pumped Storage facility. As a 49 percent owner of this facility, the Company incurs expenses for operating and maintaining the facility. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses as adjusted for escalation. The labor and material inflation adjustment factor of 3.0% for 2018, 2.9%

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for 2019 and 1.0% for the first four months of 2020 is supported by Witness Uzenski. No other historical or projected adjustments were made to Hydraulic Power Generation Projected Operation and Maintenance expenses.

Q. Can you summarize Exhibit A-13, Schedule C5.5, entitled "Operations and Maintenance Expenses - Other Power Generation?

A. Exhibit A-13, Schedule C5.5 represents DTE Electric's peaker fleet O&M costs. DTE Electric owns and operates a quantity of peaking units ranging from 2.5 MW diesel fueled engines to newer 165 MW natural gas fired combustion turbines. The main driver of projections for these expenses through the projected test period is the labor and material required to support these peaker assets. Included in this category will also be the labor expenses for the Generation Optimization and Integrated Resource Planning teams. The forecasts for these expenses through the projected test period are based on the historic labor and materials expenses as adjusted for escalation. The labor and material inflation adjustment factor of 3.0% for 2018, 2.9% for 2019 and 1.0% for the first four months of 2020 is supported by Witness Uzenski.

Q. Did you make any adjustments to the historical test period operations and maintenance expenses for other power generation?

A. Yes, I eliminated $17.7 million of expenses related to the renewable energy program in column (d) because they are handled by a separate surcharge not associated with this proceeding.

Q. What are your thoughts concerning the level of DTE Electric's historical and projected capital and O&M expenses contained in your testimony?

A. DTE Electric has been reasonable and prudent in past capital and O&M expenditures and I anticipate this to continue through the projected test period and beyond. During this same time frame, generation unit availability is managed through a rigorous process that continues to be focused on prudent capital and O&M expenditures. I believe that DTE Electric has fully justified its request for recovery of the Fossil Generation plant expenses that are set forth in my testimony and associated exhibits.

Part IV - Fossil Generation Infrastructure Recovery Mechanism (IRM)

Q. What is Fossil Generation proposing in support of an Infrastructure Recovery Mechanism (IRM) for capital expenditures?

A. As part of the IRM process being introduced by Company Witness Stanczak, a portion of Fossil Generation's future capital expenditures will be included in an IRM. The Fossil Generation capital expenditures proposed to be included in this IRM are related to planned and scheduled work needed to ensure continued safe and reliable operations of our Tier 1 steam generating units (Monroe, Belle River and Greenwood) and peaker generating units, along with capital expenditures related to the construction of an 1,100 MW CCGT plant.

Q. What categories of projects are being proposed as part of the IRM in Exhibit A-30 Schedule T3 for 2020-2022?

A. Fossil Generation is proposing that a portion of expenditures related to the following categories be included in the recovery mechanism:

- Planned outage work on Tier 1 steam generating units

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- Scheduled capital equipment replacements on Tier 1 steam generating units
- Planned outage work on large gas fired peakers
- Costs to build a new gas fired combined cycle generating unit

Q. Can you provide examples and justification for completing the Monroe/Belle River/Greenwood Planned Outages work shown on line 1 of Exhibit A-30 Schedule T3?

A. The planned outage work for Monroe, Belle River, and Greenwood as part of the IRM timeframe of 2020-2022 is similar to the work included in my earlier testimony for the same units in the years 2017 through the first four months of 2020. Monroe, Belle River, and Greenwood steam generating units receive periodic outage maintenance on a two to four-year cycle. During these periodic outages, boilers, turbines, generators, electrical systems, environmental equipment and safety systems are inspected, repaired and have components replaced to allow the units to sustain safe, reliable and environmentally compliant operations. For example, the selective catalytic reduction (SCR) system installed at Monroe Power Plant to control boiler NOx emissions requires that its catalyst beds be replaced on a routine basis to sustain required performance levels. Additionally, critical safety systems such as turbine stop valves are overhauled during these major periodic outages to ensure their proper operation if events require their activation.

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Q. Can you provide examples and justification for completing the Monroe/Belle River/Greenwood Scheduled Work shown on line 2 of Exhibit A-30 Schedule T3?

A. The scheduled work for Monroe, Belle River, and Greenwood steam generating units includes work on the plant common systems, environmental projects and site security work that can typically be completed without the units in planned outage. Plant common systems work includes projects on fuel supply control systems, plant switch gear, combustible dust management, coal silo restorations, water treatment equipment, air compressors and auxiliary boiler tube replacement projects. Environmental work includes ground water monitoring, NPDES environmental monitoring and reporting systems, and maintenance of environmental basins, liners and other waste segregation systems. Site security work includes projects that control access to facilities and critical equipment with the intent of protecting the integrity of the bulk electrical system. Performing these projects is required to sustain continued safe, reliable and environmentally compliant operations of the Tier 1 steam generating units.

Q. Can you provide examples and justification for completing the Peaker Planned Outage work shown on line 3 of Exhibit A-30 Schedule T3, for large gas fired peakers?

A. The planned outage work for the large gas fired peakers (Belle River, Dean, Delray, Greenwood and Renaissance) as part of the IRM timeframe of 2020-2022 is similar to the work included in my earlier testimony for the same units in the years 2017 through the first four months of 2020. Planned outage scope for large gas fired peakers includes combustion zone overhauls and replacements of control and electrical systems. The need for combustion zone overhauls on large gas fired peakers is based on well-defined requirements that are triggered by a combination of run hours and the number of startup events. Control system replacement projects are based on parts and technology obsolescence and compatibility with other new systems. Electrical system projects include main unit transformers and generator rewinds. The work performed during these periodic outages allows the unit to continue to provide safe and reliable service.

Q. Can you describe line 4 of Exhibit A-30 Schedule T3, labelled New 1,100 MW Combined Cycle Generation?

A. The expenditures shown on line 4 are the remaining costs to complete the construction of an 1,100 MW combined cycle gas turbine plant. On April 27, 2018, the MPSC issued an Order in Case No. U-18419 approving DTE's application for three certificates of necessity (CON) for this plant. In approving the CONs, the commission determined through an open hearing process that the energy to be supplied by the project is needed, a natural gas fired CCGT plant was the most reasonable and prudent means of meeting DTE Electric's future energy needs, and that the Company can recover up to $951.8 million in costs for the plant through future rates. Per the requirements of MCL 460.6s (7), DTE Electric will provide an annual update to the Commission on the status of project costs and schedule.

Q. Will the Company provide additional information around the scope of the projects supporting the categories shown on Exhibit A-30 Schedule T3?

A. Yes. As described by Company Witness Stanczak, in the fall of the year preceding the upcoming IRM year, the Commission will be provided a report detailing the

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Company's IRM plan for the next year. In that report, Fossil Generation will list specific projects and the associated capital expenditures related to the four line items shown on Exhibit A-30 Schedule T3 for the upcoming IRM year.

Q. What information will the Company provide to reconcile the projected capital expenditures shown in Exhibit A-30 Schedule T3 to the actual capital expenditures for each IRM year?

A. After completion of the most recent IRM year, the Company will provide to the Commission Staff a report on the actual work completed in the same form as that provided in the previous fall for work related to the four line items shown on Exhibit A-30 Schedule T3. Company Witness Stanczak discusses the reconciliation process in additional detail in his testimony.

Q. Is the Company proposing any program metrics related to the Fossil Generation capital expenditures proposed within the IRM?

A. Yes. The Company is proposing metrics for each category of Fossil Generation capital expenditures proposed within the IRM on Exhibit A-30 Schedule T3. Company Witness Stanczak describes the proposed reporting process for the program metrics in his testimony.

For line 1, Monroe/Belle River/Greenwood Planned Outages, the program metrics may include number of boiler overhauls, number of turbine overhauls, number of SCR layers replaced and number of electrical system replacements versus targets provided in the prior year.

For line 2, Monroe/Belle River/Greenwood Scheduled Work, the program metrics may include the number of fuel supply overhauls, number of infrastructure overhauls and number of site security initiatives completed versus targets provided in the prior year.

For line 3, Peaker Planned Outages, the program metrics may include the number of combustion path overhauls completed versus targets provided in the prior year.

For line 4, New 1,100 MW Combined Cycle Generation, we will provide an annual update to the Commission on the status of project costs and schedule, per the requirements of MCL 460.6s (7).

Q. Are there any additional performance indicators the Company will report to allow the MPSC Staff to assess the benefits of the projects contained in the IRM?

A. Yes. Fossil Generation will provide a report to the Commission Staff on unplanned unit outages that have occurred due to failures on components replaced within IRM projects completed in the preceding year.

Q. Does this complete your direct testimony?

A. Yes, it does.