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Clean Energy at the Crossroads of America: An Integrated Resource Plan for Northern Indiana Public Service Company, LLC (NIPSCO)

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This Capstone Project

Clean Energy at the Crossroads of America: An Integrated Resource Plan for Northern Indiana Public Service Company, LLC (NIPSCO)

by

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List of Abbreviations

Abbreviation	Definition
ATB	Annual Technology Baseline
BESS	Battery Energy Storage System
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CEPP	Clean Electricity Performance Program
CEM	Capacity Expansion Model
CF	Capacity Factor
CHOICE	Comprehensive Hoosier Option to Incentivize Clean Energy
CO_2	Carbon Dioxide
CPS	Clean Energy Portfolio Standard
CRF	Capital Recovery Factor
CT	Combustion Turbine
DER	Distributed Energy Resources
DCAP	Dependable Capacity
DSM	Demand Side Management
EIA	Energy Information Administration
eGRID	Emissions and Generation Resource Integrated Database
EPA	Environmental Protection Agency
EV	Electric Vehicles
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GW	Gigawatt (of power)
GWh	Gigawatt-hours (of energy)
H_2	Hydrogen
IAEA	International Atomic Energy Agency

ICAP	Installed Capacity
IRA	Inflation Reduction Act of 2022
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
FIT	Feed-in-Tariff
FOM	Fixed Operations and Maintenance Costs
KPI	Key Performance Indicators
kWh	Kilowatt-hours (of energy)
LSE	Load Serving Entity
L&R	Load and Resource
MHA	Month-Hour Average
MW	Megawatt (of power)
MWh	Megawatt-hours (of energy)
MISO	Midcontinent Independent System Operator
MMT	Million Metric Ton
NERC	North American Electric Reliability Corporation
NG	Natural Gas
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NIPSCO	Northern Indiana Public Service Company
O&M	Operations and Maintenance
OPEX	Operational Expenditure
OSW	Off-Shore Wind
PPA	Power Purchase Agreement
SAM	System Advisor Model
SB	State Bill

SMR	Small Modular Reactor
Solar PV	Solar Photovoltaic
T&D	Transmission and Distribution
US	United States
VOM	Variable Operations and Maintenance Costs
WACC	Weighted Average Cost of Capital

Executive Summary

An Integrated Resource Plan ('IRP') is an essential tool developed by utilities to plan for the future, identifying the most cost-effective and reliable mix of resources to meet the energy needs of their customers, including a planning reserve margin. The overall goal of an IRP is to help the Load Serving Entity ('LSE') operate in the framework of state mandated regulations to provide safe, reliable, and affordable electricity to its customers, while meeting any clean energy or environmental targets.

An IRP is developed by utilities to identify the optimal combination of demand- and supply-side resources needed to meet forecasted demand for energy and capacity, including a planning reserve margin, over a future period. The overarching goal of an IRP is to support the state utility regulatory body in fulfilling its constitutional and statutory obligations to provide safe, reliable, and affordable electricity, as well as in meeting its clean energy and environmental goals, where relevant.

The Northern Indiana Public Service Company, LLC ('NIPSCO'), along with other jurisdictional electric utilities, is required by the state utility regulator, Indiana Utility Regulatory Commission ('IURC') to present the IRP every three (03) years according to Indiana Code § 8-1-8.5-3(e)(2)[1].

This report outlines an IRP for NIPSCO, looking forward to the year 2050 and evaluating different pathways to net zero emissions. The steps we followed to develop this IRP took into account the planned retirement of existing fossil fuel generation, electrification load growth, and the adoption of distributed energy resources ('DER') and other technologies to meet NIPSCO's capacity and energy demands, as well as its clean energy goals.

The three scenarios that we assessed are summarized in Table 1. The reference case explores what it would look like if NIPSCO continues on its current path without adhering to any emissions reduction target. The alternative scenarios explore two pathways to reaching zero carbon emissions electricity by 2050, using only carbon-free and renewable resources.

	REFERENCE	100% RENEWABLE ENERGY	ZERO CARBON
All coal power plants retired by 2028	✓	✓	✓
Existing natural gas CT converted to H_2 CT in 2040	X	✓	✓
Offshore wind considered	X	✓	X
Nuclear considered	X	X	✓

Table 0-1: Scenario Summaries

[1] For more information: https://www.in.gov/iurc/energy-division/electricity-industry/integrated-resource-plans/

Key Metrics	2023 Reference	2050 Reference	2050 100% RE	2050 Zero Carbon
Installed Capacity (MW)	5,721	6,287	16,907	7,486
Energy Sales (GWh)	12,959	16,802	27,348	16,905
Fossil Fuel Share (%)	40%	54%	0%	0%
Renewable Energy Share (%)	60%	46%	95%	48%
Carbon Free Share (%)	0%	0%	0%	52%
Emissions (MMT-CO2)	4.3	3.2	0.0	0.0
Emissions Intensity (kg-CO2/MWh)	2,948	1,309	0	0
Total Costs (M$)	$ 904	$ 1,070	$ 3,691	$ 2,678
Average Retail Rate ($/kWh)	$ 7.0	$ 6.4	$ 13.5	$ 15.8

Table 0-2: Key Performance Indicators (KPI) of Scenarios

The results of our analysis show that both alternative scenarios demonstrated the feasibility of a zero-emissions electricity system with the Zero Carbon scenario providing the least cost pathway by 2050.

1. Introduction

1.a Company Background

NIPSCO was formed in 1912, and after a series of mergers and acquisitions over the century since then, came to be known as NiSource Inc. which is now its parent company. In 2015, NiSource became a stand-alone utility company and is now one of the largest fully regulated utility companies in the United States ('US'), serving approximately 3.5 million natural gas customers and 500,000 electric customers across six states through its local Columbia Gas and NIPSCO brands. The company, based in Merrillville, Indiana, has more than 8,000 employees. As of 2018, NiSource is the sole Indiana-based utility company, and is part of the Midcontinent Independent System Operator ('MISO') power market, specifically located within Local Resource Zone 6 ('LRZ6'), covering Indiana and parts of Kentucky.

NIPSCO specifically targets northern Indiana's 479,000 electric customers of twenty (20) counties in the state.

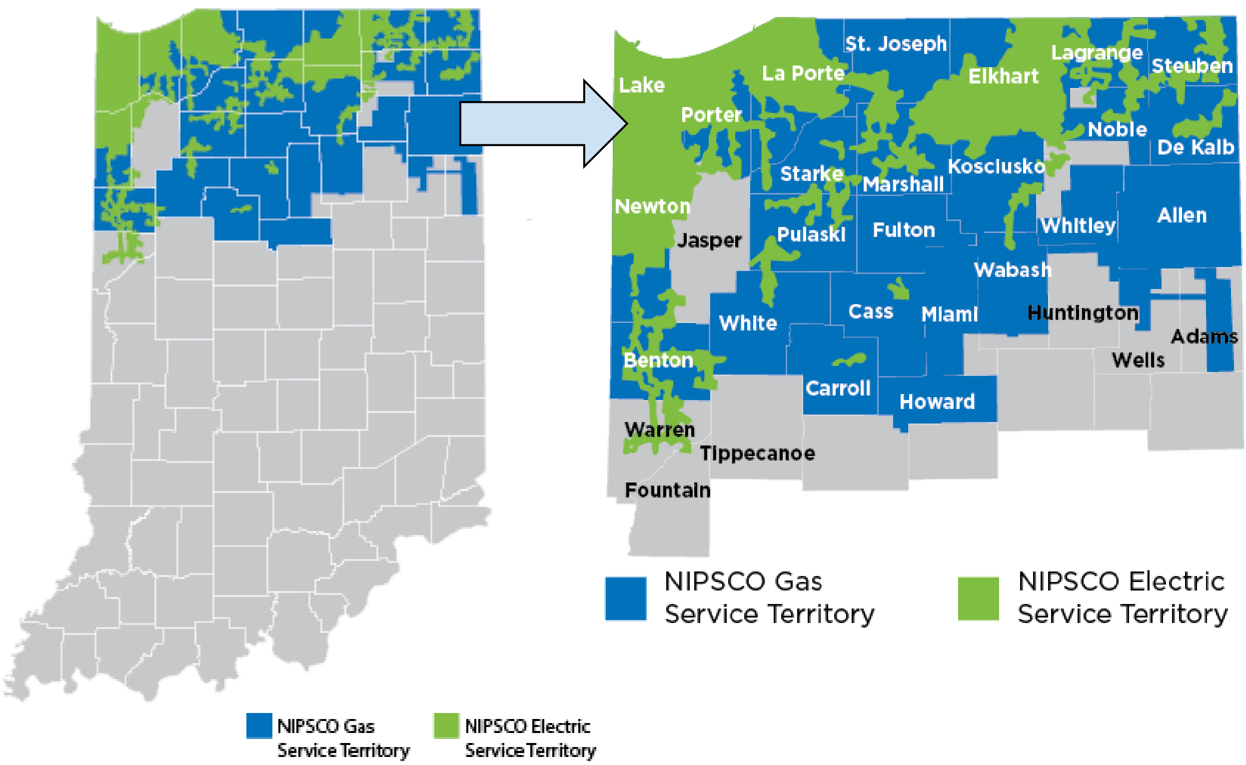

Figure 1-1: Map of NIPSCO Service Territory (2023)

Since NIPSCO introduced their plan in 2018, they have debuted renewable energy projects while retiring fossil fueled generation resources, with further reductions slated for the end of the decade and replaced with a diverse, flexible, and scalable mix of resources. In the near term, seven (7) more renewable projects are currently in development and projected to be operational by the end of 2023.

The utility is also interested in exploring potential hydrogen generation and other emerging energy storage technologies on the path to decarbonization, and forecasted the impact of customer owned distributed energy resources ('DER') and electric vehicles ('EV') in their purview.

1.b Policy and Regulatory Environment

In our work, we assume that the policy and regulatory environment remains unchanged through 2050.

1.b.i Local and State

NIPSCO is regulated by the IURC within the state of Indiana.

In May 2011, Indiana enacted State Bill 251 ('SB251')[2], creating the Clean Energy Portfolio Standard ('CPS'), also known as the Comprehensive Hoosier Option to Incentivize Cleaner Energy ('CHOICE') program. The program sets a voluntary goal of 10% clean energy by 2025, based on the amount of electricity supplied by the utility in 2010. Participating utilities receive incentives to increase their energy production from renewable energy.

Indiana's CPS includes twenty-one (21) eligible renewable energy technologies, but also conventional energy sources like nuclear, coal, and natural gas. The CPS allows up to 30% of the goal to be met with "clean coal" technology, combined heat and power, nuclear energy, natural gas that displaces electricity from coal, or net-metered distribution generation facilities. At least 50% of energy going towards the goal must be produced within Indiana.

As the CPS is voluntary, Indiana's LSEs have no statutory requirements to reduce their carbon emissions or invest in renewable energy. NIPSCO, however, has made a commitment to reduce its carbon emissions by 90% by 2030 across its generation portfolio.

1.b.ii Federal

NIPSCO's operations are subject to regulation by the Federal Energy Regulatory Commission ('FERC'), the North American Electric Reliability Corporation ('NERC'), the Nuclear Regulatory Commission ('NRC'), and the Environmental Protection Agency ('EPA'). These agencies regulate the activities of NIPSCO as they pertain to interstate and wholesale energy, electric reliability, nuclear power, and emissions and environmental impact.

NIPSCO does express policy uncertainty about federally sponsored financial incentives that could impact the outcomes of NIPSCO's preferred plan, such as the Investment Tax Credit ('ITC'), the Production Tax Credit ('PTC'), and the potential implementation of carbon tax, clean energy standard, or Clean Electricity Performance Program ('CEPP') that could impact the relative economics of different generating resource types.

For the purpose of this analysis, we will consider any applicable funding under the Inflation Reduction Act ('IRA') of 2022, a landmark U.S. federal law that encourages domestic energy production alongside promoting clean energy.

[2] For more information: https://programs.dsireusa.org/system/program/detail/4832

1.c Existing System Demand and Supply

1.c.i Generation System

NIPSCO's resource portfolio is composed of its last remaining coal-fired plant (Michigan City Unit 12), two hydroelectric plants (Norway and Oakdale), a natural gas-fired combined cycle (Sugar Creek), two older vintage natural gas-fired peaking units at Schahfer (Units 16A and 16B), two older vintage wind contracts (Barton, Buffalo Ridge), and demand-side resources ('DSM').

The utility is pushing ahead with the build-out of multiple renewable energy resources in this decade, in an effort to realize a 90% carbon free generation portfolio by 2030, from a 2005 baseline.

Figure 1-2: Map of NIPSCO's Current Generation System (2023)

The current capacity mix is illustrated in the chart below, with fossil fuels representing 64% of the overall share.

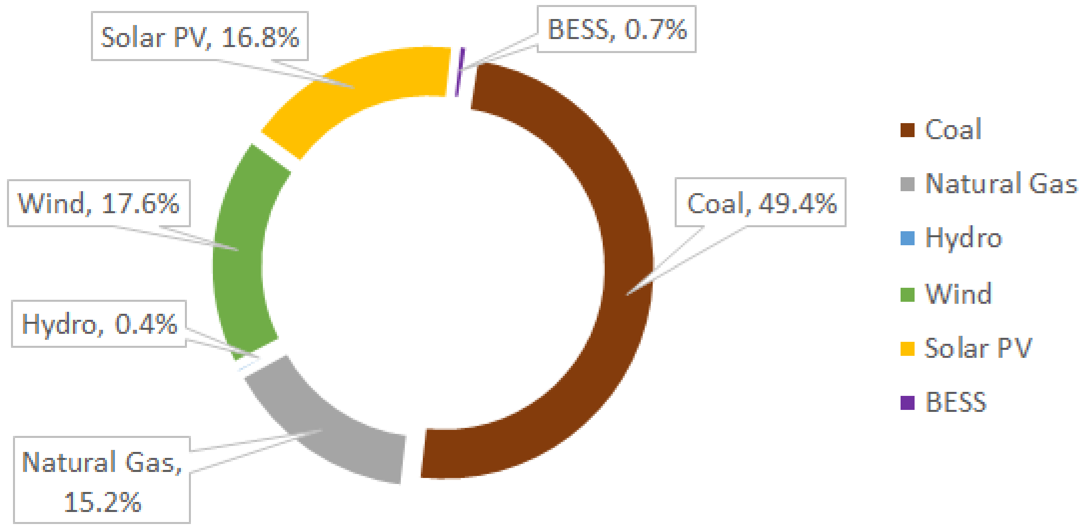

Figure 1-3: NIPSCO's Current Capacity Mix (2023)

1.c.ii System Capacity and Peak Load

NIPSCO's current ICAP is 3.6 GW, with summer peaks to be around 2.4 GW and winter peaks to be around 1.6 GW in 2023. Peak load expectations are over 600 MW lower than those from the 2018 IRP due to a new industrial service tariff, although interruptible demand response supply resources from industrial customers are also down.

The system currently has a surplus capacity until 2028 when some existing generation resources are scheduled to be retired.

NIPSCO's load forecast also includes electric vehicle penetration scenarios, representing between approximately 10 to 80 MW of peak load impact and up to 8% of total energy sales over the long term.

For the purpose of this IRP, a linearly increasing load profile through the decades is assumed, resulting in a 1.6 GW net capacity deficit in 2050.

1.c.iii System Age

NIPSCO's current system dates back to the early 19th century, with the Norway and Oakdale hydropower plants coming online in the 1920s, followed by coal and natural gas power plants in the 1970s and 80. The last fossil fuel generator, Sugar Creek, a Combined Cycle Gas Turbine ('CCGT') in Vigo county, commenced operations in 2002. The early 2020s have seen a slow influx of wind and solar photovoltaic ('PV') plants gain traction in NIPSCO's generation portfolio.

NIPSCO's resource portfolio is in the midst of a transition. Since the 2018 IRP, NIPSCO has proceeded with retirement activities at the R.M. Schahfer Generating Station. Schahfer Coal Units

14 and 15 were retired in 2021, while the remaining Schahfer Coal Units 17 and 18 are on track to retire by the end of 2023.

#	Generation Facilities	Installed Capacity (MW)	Fuel	County, State	Service Period
Current / Existing					
1	Michigan City	469	Coal	LaPorte, IN	2026 - 2028
2	R. M. Schaffer	1,780	Coal	Jasper, IN	2021 - 2023
3	R. M. Schaffer	155	Natural Gas	Jasper, IN	2025 - 2028
4	Sugar Creek	535	Natural Gas	Vigo, IN	2002 - Present
5	Norway Hydro	7.2	Hydro	White, IN	1923 - Present
6	Oakdale Hydro	9.2	Hydro	Carroll, IN	1925 - Present
7	Rosewater	102	Wind	White, IN	2021 - Present
8	Jordan Creek	400	Wind	Benton Warren, IN	2021 - Present
9	Indiana Crossroads I	300	Wind	White, IN	2021 - Present
10	Dunns Bridge I	265	Solar PV	Jasper, IN	2022 - Present
11	Brickyard	200	Solar PV	Boone, IN	2022 - Present
12	Greensboro	100	Solar PV	Henry, IN	2022 - Present
13	Greensboro	30	BESS	Henry, IN	2022 - Present
14	Indiana Crossroads	200	Solar PV	White, IN	2022 - Present

Table 1-1: NIPSCO's Current / Existing Generation Facilities

1.c.iv Additional System Assets

To replace the retired capacity at Schahfer, the company continues to make progress on its 14 approved renewable energy projects, including wind, solar, and solar plus battery storage resources, as part of our "Your Energy, Your Future" transition plan. These expected facilities are a combination of self-owned assets and Power Purchase Agreements ('PPA'). Two of these wind projects were placed in service in 2020 and the remaining 7 projects are expected to be completed in 2023. These planned renewable resources are expected to add 3.33 GW of installed capacity ('ICAP') with an additional $5bn in capital investments, much of which will stay in the Indiana economy.

#	Generation Facilities	Installed Capacity (MW)	Fuel	County, State	Service Period
New / Upcoming					
1	Green River	200	Solar PV	Breckinridge & Meade, KY	2023
2	Dunns Bridge II	435 + 75	Solar + BESS	Jasper, IN	2023
3	Cavalry	200 + 60	Solar + BESS	White, IN	2023
4	Gibson	280	Solar PV	Gibson, IN	2023
5	Fairbanks	250	Solar Pv	Sullivan, IN	2023
6	Indiana Crossroads II	204	Wind	White, IN	2023
7	Elliot	200	Solar PV	Gibson, IN	2023

Table 1-2: NIPSCO's New / Upcoming Generation Facilities

1.c.v Emissions

The current generation mix, with nearly 65% coming from carbon-emitting sources, was calculated to equal 4.9 MMT-CO_2 and have an emissions intensity of 2,500 kg-CO_2/MWh[3]. NIPSCO's electricity emissions intensity is vastly greater than both the average 449 kg-CO_2/MWh in the US[4] and 475 kg-CO_2/MWh globally[5].

1.d Resource Needs Assessment

NIPSCO's system peak demand is forecasted to grow from approximately 2.4 GW in 2023 to more than 3.1 GW by 2050. Based on the data from FERC Form No. 714 and our own calculations, we forecasted annual energy sales to increase from 20,741 GWh in 2023 to 25,001 GWh in 2050.

While NIPSCO has procured enough capacity to meet its Firm Load Obligations[6] through 2028, a gap begins to form as the forecasted load exceeds the existing capacity, starting 2029. As shown in *Figure 1-4*, the resource gap increases, driven by increasing average annual load growth of 0.75% between 2023 and 2050, as well as power plant retirements. In 2050, the forecasted shortfall is 1.6 GW.

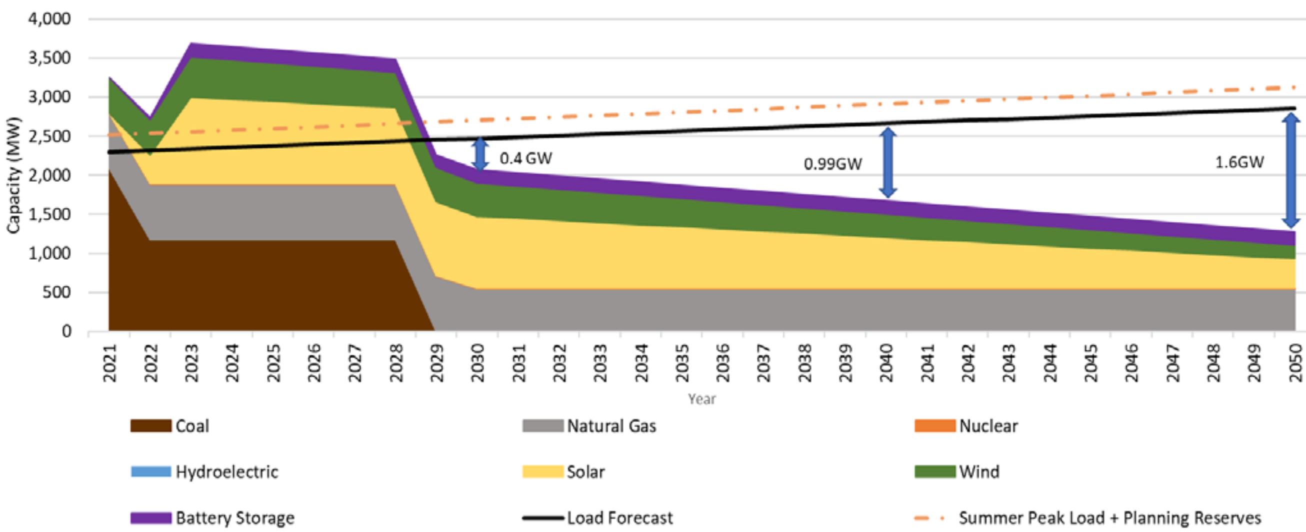

Figure 1-4: L&R Table

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3 United States Environmental Protection Agency's (US EPA) 2021 Emissions and Generation Resource Integrated Database (eGRID)

4 Energy Information Administration (EIA) - 2018

5 International Energy Agency (IEA) - 2018

6 NIPSCO's energy demand that has to be met following load reduction from DSM programs and customer-sited DER installations

2. Methodology

2.a Load Forecast

From NIPSCO's 2021 IRP, we obtained the base load projection through to 2050, which was relatively flat. It could be explained by NIPSCO's projection that winter peak load growth rate will be higher than the prevailing and traditionally higher summer peak load growth rate, which is easily served by existing resources. Hence, aggressive capacity expansion may not be required, but rather the focus is on transitioning the current fossil fuel generation resources to renewables and conversion of natural gas plants to hydrogen production facilities.

Secondly, NIPSCO is relying on demand side management (DSM) programs and energy efficiency measures to be a core part of the overall energy requirement, around 8% of overall capacity mix and 7% of the energy mix in 2050.

Lastly, NIPSCO projects that DER, Feed-in-Tariff ('FIT'), and thermal contracts will make up 8% of overall capacity mix and corresponding 1% of the energy mix in 2050.

To take a conservative approach, our modeling utilized historical hourly load data to capture NIPSCO''s annual load shape for the 8,760 hours of the year, which we got from FERC Form No. 714. From NIPSCO's IRP, we got the annual peak load profile, which includes EV propagation and other electrification such as heaters, electric stove, etc., ultimately resulting in a 3.85% average year-on-year load growth.

2.b Technical, Economic, & Environmental Data

2.b.i Technical Data

- The technical lifetimes of the resources were based on standard useful lifetime values from National Renewable Energy Laboratory ('NREL').
- NREL's SAM Model and Wind Prospector tools provided the renewable energy load profiles and capacity factors of the selected wind and solar resources.
- Heat rates for each existing thermal generator in NIPSCO's fleet came from FERC Form No. 1 for the years 2020 through 2022, with the exception of the Small Modular Reactors' ('SMR') heat rate which we obtained from the International Atomic Energy Agency ('IAEA').

2.b.ii Technology Costs

- For each type of generator, NREL ATB provided capital expenditures ('CAPEX'), fixed and variable operations and maintenance ('FOM' & 'VOM') costs.
- To determine the annualized fixed costs, we calculated a Capital Recovery Factor ('CRF') based on NIPSCO's discount rate / weighted average cost of capital ('WACC') of 7.26% per its 2021 IRP and the expected economic lifetimes of the resource which we equated to the technical lifetimes.
- The variable and marginal costs were calculated by multiplying the fuel costs, provided by NREL ATB, by the generator heat rate and adding the resulting value to the variable O&M.
- To determine the current transmission and distribution ('T&D') cost, we analyzed 2020, 2021 and 2022 data from FERC Form no. 1, the annual regulatory requirement for Major

electric utilities, licensees and others (18 C.F.R. § 141.1). From this report we determined the T&D share electricity rate and assumed the costs from 2020 to 2050 in proportion to the peak load.

- Lastly, in scenarios where offshore-wind is present, an additional $100/kW-yr was added for transmission cost.

2.b.iii Fuel Costs

We used the 2022 EIA Annual Energy Outlook to obtain projected fuel prices of natural gas, coal, and uranium.

2.b.iv Emissions Profiles

We determined the emissions and emissions intensity of fossil fuel generators from EPA Emission Factors for Greenhouse Gas Inventories.[7]

2.b.v Solar Photovoltaic

We modeled the hourly output of wind and solar generators using the NREL System Advisor Model ('SAM'). Solar output was modeled in the vicinity of NIPSCO's highest loads in Noble County, Indiana.

2.b.vi Onshore Wind

Wind output was modeled at locations in central and northern Indiana, preferentially close to existing wind power projects in the state. The location we chose has the highest potential for onshore wind in the area where NIPSCO operates. From our calculations and the NREL SAM, capacity factor for this location is 32.5%, and it is located in Honeyville, LaGrange County, Indiana.

2.b.vii Offshore Wind

Offshore wind is built in northwest Indiana, in the waterbody of Lake Michigan. Lake Michigan has a surface area of 22,404 mi^2 or 58,030 km^2. Only 234 mi^2 or 610 km^2 is in Indiana. From the NREL report for the Department of Energy 'Computing Americas Offshore-Wind Energy Potential,' we determined an average wind speed of 8.25-8.5 m/s and a capacity factor of 34.5%. In terms of area, even though it is challenging to develop such technology in Lake Michigan, we determined that building 1.2GW offshore wind may take up a quarter of the lake covered by the state of Indiana.

2.b.viii Nuclear

We considered one type of nuclear technology in our model - the modern SMRs with a typical capacity of 350 MW per unit, which can also be clustered together.

2.b.ix Batteries (NaA, Li-ion, Pb-acid)

In all scenarios, our model only considers short-duration diurnal chemical battery storage with battery efficiency of 90% i.e. 10% one-way losses.

[7] For more information: https://www.epa.gov/sites/default/files/2021-04/documents/emission-factors_apr2021.pdf

2.b.x Hydrogen Electrolysis

We assumed a hydrogen electrolyzer efficiency of 75% i.e. 25% losses, which is a conservative estimate for current electrolyzer technologies. Hydrogen electrolyzers are included only in the Zero Carbon and 100% Renewable scenarios.

2.c Metrics

The following metrics were analyzed in assessing the outputs of our modeling results:

2.c.i Installed Capacity

Installed capacity is the total generating capacity that an electric utility has installed and is available for operation at any given time. The installed capacity is typically measured in megawatts (‘MW’). It includes all power generation sources owned and operated by the electric utility, such as fossil fuel, nuclear power plants, hydroelectric power plants, wind turbines, and solar panels.

2.c.ii Dependable Capacity

Dependable capacity is the maximum amount of electricity that a utility can reliably produce at any given time, taking into account the performance of power generation equipment, transmission and distribution infrastructure, and other factors that may impact the reliability of the system and is measured in MW. Electric utilities must maintain a sufficient amount of dependable capacity to meet the electricity demand of their customers, even during periods of peak demand or unexpected disruptions to the system.

2.c.iii Energy Generation

Energy generation refers to producing electricity from various sources, including fossil fuels, nuclear energy, and renewable sources, such as wind, solar, hydro, and geothermal. It is typically measured in gigawatt hours (‘GWh’). The process of energy generation involves converting the potential energy of these sources into electrical energy that can be used by customers. The generation of electricity is typically carried out by large power plants, which can vary in size and capacity, and some are designed to operate continuously, while others are designed to operate only during periods of peak demand.

2.c.iv Curtailment

Curtailment for an electric utility refers to the reduction or limitation of power output from a generating unit or renewable energy source due to a variety of factors, including transmission constraints, generation oversupply, or system instability. Curtailment typically occurs when the supply of electricity exceeds the demand for it and the available transmission capacity to deliver the electricity to customers. As an addition, curtailment can have significant economic and environmental impacts. For example, curtailed renewable energy production can result in lost revenue for renewable energy producers and increased costs for electric utilities.

2.c.v Planning Reserve Margin (PRM)

Planning Reserve Margin (‘PRM’) is the percentage difference between the total capacity of a utility's power generation resources and the forecasted peak demand for electricity. The PRM is calculated as a percentage of the forecasted peak demand, and it represents the excess generating capacity that the utility has available to meet unexpected increases in demand or to cover outages of power-generating resources. NIPSCO’s PRM is about 9.4%, which we made it possible to achieve for all of our scenarios.

2.c.vi Capacity Factor (CF)

Capacity factor (‘CF’) of a generator is the unitless ratio of actual electrical energy output over a given period of time to the theoretical maximum electrical energy output over that period. The CF allows us to examine a generator’s reliability as it measures how often its running at maximum power. This can help in making economic decisions about inclusion of certain generators in the utility’s portfolio.

2.c.vii Revenue Requirement

Revenue requirement is a component of the regulatory framework for electric utilities. It ensures that utilities can provide reliable and affordable service to their customers while also earning a reasonable rate of return on their investment. The revenue requirement is determined through a rigorous regulatory process that considers various factors, including the utility's operating costs, capital expenditures, and the cost of capital. Ultimately, the goal of the revenue requirement is to balance the interests of the utility, its customers, and the regulatory body that oversees its operations. In our analysis, we did not consider NIPSCO’s profit margins nor taxes as an adder to the revenue requirement.

2.c.viii System Costs

System costs are associated with generating, transmitting, and distributing electricity to customers. These costs comprise generation, transmission, distribution, and other administrative and overhead costs which we did not account in our models.

- Generation costs include fuel expenses, power plant operation and maintenance, and related expenses.
- Transmission costs encompass building and maintaining transmission lines and ancillary services such as voltage control and frequency regulation.
- Distribution costs include constructing and maintaining distribution lines, transformers, meters, and other necessary equipment for electricity distribution.

We determined that it is essential for electric utilities to analyze both fixed and variable costs of the system costs, where fixed costs are expenses that remain constant, and variable costs vary with the electricity demand.

2.c.ix Retail Rates

Retail rates are the prices that electric utilities charge their customers for the electricity they consume. These rates are typically set by regulatory bodies, such as state public utility commissions, and are designed to cover the costs of generating, transmitting, and distributing electricity to customers.

Retail rates typically comprise the cost of energy generation, transmission, distribution, and customer service. The cost of customer service includes the costs associated with billing and customer support; this is not in our analysis and is at the discretion of NIPSCO to bill this cost.

2.c.x Emissions

Emissions are the total amount of greenhouse gases ('GHG') and other air pollutants released into the atmosphere due to the utility's operations. Electric utilities must monitor and report their total emissions of GHG and other air pollutants to regulatory bodies, such as the EPA in the US. Total emissions are typically reported through annual emissions inventories that detail the types and amounts of pollutants emitted by the utility's power plants and other operations.

2.c.xi Emissions Intensity

Emission intensity in the electric utility industry refers to the amount of GHG and other air pollutants emitted per unit of electricity the utility generates. By reducing their emission intensity, electric utilities can lower their overall environmental impact and contribute to mitigating climate change. The emission intensity is typically measured in grams of CO_2-equivalent (CO_{2e}) per kilowatt-hour ('kWh') of electricity generated.

2.d Capacity Expansion Model

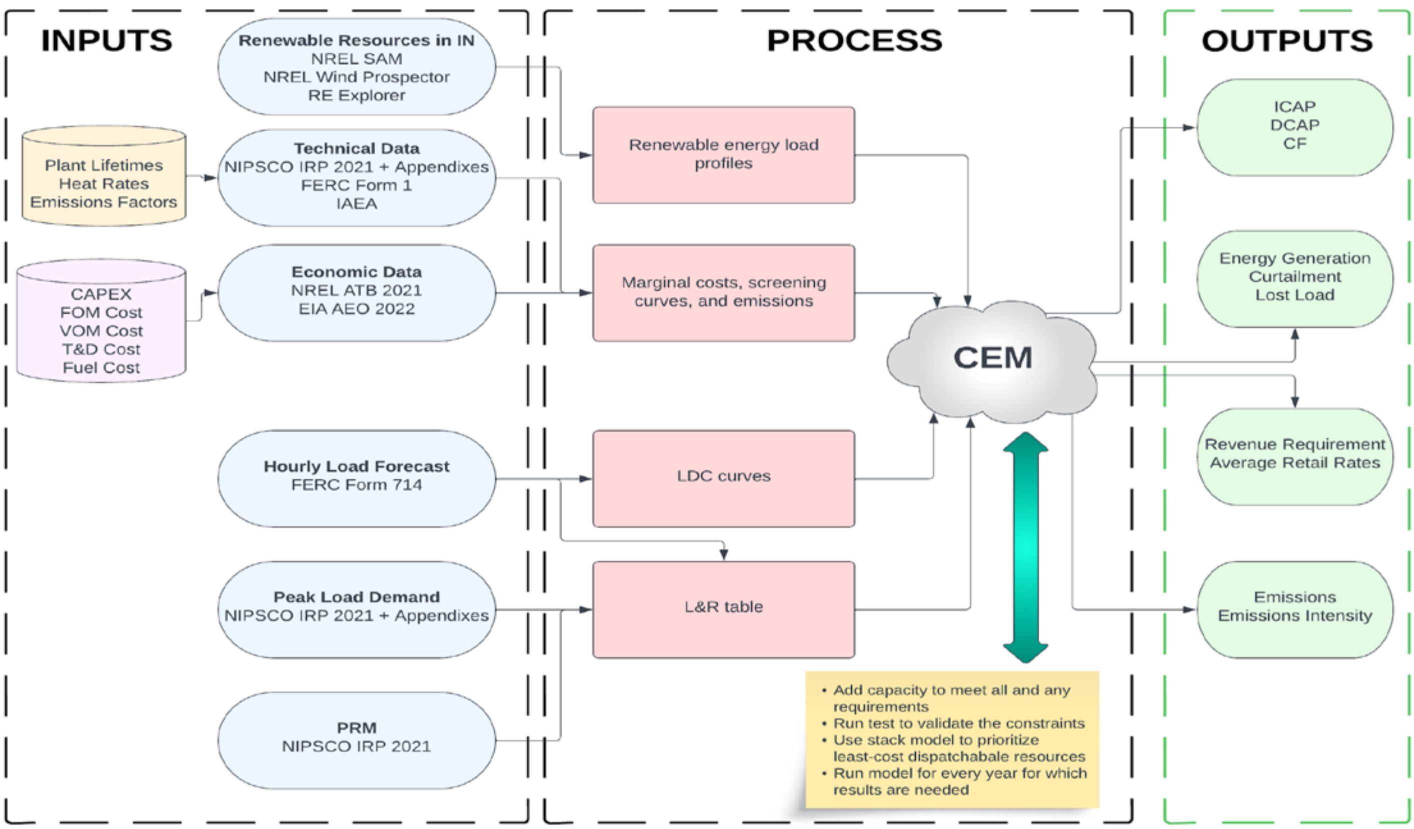

Figure 2-1: Methodology for the CEM

The Capacity Expansion Model ('CEM') is a tool used for long-term planning of electricity systems. It aims to determine the least-cost combination of electricity generators, T&D infrastructure, and energy storage necessary to reliably meet the projected load over several years or decades. In developing the reference and alternative scenarios as described in §3 of this report. We adjusted the resource mix to ensure that we meet the objectives of reliability requirements, renewable energy targets, and internal goals while minimizing costs.

The generation costs are calculated by considering both fixed costs and variable costs. The fixed costs include annualized expenses for FOM and CAPEX, multiplied by the CRF. The variable costs are the addition of fuel costs and VOM expenses, then multiplied by the appropriate heat rates for each generator technology.

The model also incorporates T&D costs, which are determined based on historical data and the relationship between these costs and annual peak load. These costs are added to the generation costs to obtain the total revenue requirement. Our analysis does not include variations of the load forecast, however, the inclusion of offshore wind in the 100% RE scenario incurs additional T&D costs.

The CEM employs a stack model based on production cost modeling principles. It dispatches resources based on their marginal costs, considering the least-cost combination of wind, solar, hydro, and nuclear. The model dispatches renewables by using the hourly generation shapes from NREL SAM.

Storage is included to capture any excess generation and lower power curtailment, with a target capacity factor of 17% for diurnal lithium-ion storage technology. This is followed by hydrogen production, and the remaining curtailed.

Market prices are determined based on the dispatched resource mix after storage, and storage is charged only when renewable generation exceeds the load. Therefore, in low-renewable scenarios, storage is not cost-effective, and only a small amount is added in high-renewable scenarios.

After determining the wind, solar, and storage capacity, the model compares the resulting net load duration curve with screening curves of dispatchable resources to optimize the remaining capacity mix. Electrolyzers for hydrogen production are included until their capacity factor drops to 30% to ensure competitive hydrogen prices. The model calculates various metrics that help with the analysis, discussed in §2.c prior.

For the NIPSCO"s electricity generation system, a similar capacity expansion model methodology is used to identify capacity gaps in future years. The first year where the projected load exceeds the available capacity defines the test year, requiring additional generating capacity to be built to meet the forecasted peak load plus the Planning Reserve Margin (PRM). Figure 1-4 in §1.d shows this projection in a L&R graph.

In summary, capacity expansion models like the CEM described simulate and optimize electricity generation and transmission capacity investments by considering various inputs, including technology costs and performance, fuel prices, load forecasts, and policy requirements, if applicable. These models help system operators and utilities identify the most cost-effective resource mix that meets reliability, environmental, and policy constraints.

3. Scenario Descriptions

3.a Overview & Key Considerations

Our research question for this exercise is: what are the most promising and feasible technological solutions for achieving net-zero emissions by 2050, and how can they be implemented at scale for northern Indiana consumers?

To answer this question and develop the IRP for NIPSCO, we began by creating a load forecast that considered the expected growth in electricity demand due to the electrification of transportation, heating, and other sectors over the decades leading up to 2050.

Our analysis considered various factors such as the availability and cost of renewable resources, the need for backup generation and energy storage, including hydrogen electrolysis and dispatch. To maintain system reliability and affordability, all scenarios have several constraints e.g. there is no load loss in year-around operations, a PRM of 9.4% is considered, which is the same as mandated by NIPSCO, and curtailment levels are capped at 30%.

We explored several scenarios to develop our IRP, distinguished by the differences in technologies used for power generation on the supply side. The first scenario was the Reference scenario, which assumes business as usual practices that continues fossil fuel usage as the primary energy source. The 100% Renewable Energy scenario, where we considered augmenting our renewable energy portfolio with onshore wind, offshore wind, solar PV and short-duration storage primarily. In the Zero Carbon scenario, we explore the possibility of using clean energy sources of power such as nuclear in conjunction with renewable energy technologies. Long duration storage in the form of hydrogen electrolyzer was considered in both the 100% RE and Zero Carbon scenarios.

By considering and comparing these scenarios, we developed a comprehensive IRP that accounts for the complex and evolving energy landscape through the decades. The IRP positions us to meet the energy needs of our customers in a cost-effective and sustainable manner.

3.b The Role of Hydrogen

Hydrogen fuel, H_2, is a promising alternative to fossil fuels that has the potential to power a variety of devices, including vehicles, power plants, and industrial processes in the state of Indiana. Electrolysis and steam methane reforming are the most common methods to produce hydrogen fuel. Hydrogen fuel cells, which combine hydrogen gas with oxygen in a fuel cell to produce electricity, can be used to generate electricity in a variety of ways, including powering buildings, generating electricity for the grid, and powering vehicles.

However, there are several considerations when incorporating hydrogen fuel into utility generation in Indiana. Infrastructure for producing, storing, and transporting hydrogen gas would need to be built and maintained. The cost of producing and maintaining hydrogen fuel cells can be expensive, but as the technology becomes more widespread, the cost is expected to decrease. While hydrogen fuel cells are more efficient than traditional combustion engines, there is room for improvement in efficiency through research and development. Safety is also an important consideration since hydrogen gas is highly flammable and requires special handling and storage procedures to ensure safety.

Incorporating hydrogen fuel into utility generation in Indiana could help reduce the state's carbon emissions and address climate change. It is important to consider using renewable sources of hydrogen, such as from water electrolysis using renewable electricity sources like wind or solar power, to further reduce carbon emissions and promote sustainable energy production. Government support, financial incentives for research and development, and investment in infrastructure can also benefit the development and deployment of hydrogen fuel technology in Indiana. Collaboration among industry, academia, and government can help to accelerate the development and deployment of hydrogen fuel technology in Indiana.

Hydrogen fuel has several advantages, including its scalability, potential for energy storage, and ability to be used for co-generation. Its integration into utility generation in Indiana will require investment in infrastructure, research and development, and public education and awareness. With the right support, hydrogen fuel could become an important part of Indiana's energy mix, providing a clean and sustainable source of power for the state's residents and businesses. Hydrogen production and electrolysis is considered in both our alternate scenarios.

3.c Reference

The reference case scenario is a baseline projection of what NIPSCO's generation resources could look like if it continues on its current path. Alternative scenarios are compared against this. This scenario assumes that no new environmental or GHG emissions standards will be imposed on NIPSCO and ignores NIPSCO's target for 90% carbon free electricity by 2030, but does take into account any fossil fuel power plants' planned retirements.

In this scenario, resource procurements were done in proportion to NIPSCO's 2021's generation mix of technologies outlined in its 2021 IRP. , which includes natural gas, solar PV, and onshore wind. New transmission infrastructure cost was only evaluated for the annual load growth, and power imports from outside NIPSCO territory were not considered.

3.d 100% Renewable Energy

The 100% RE scenario was designed to imagine a carbon-free energy future for NIPSCO, with only renewable resources including offshore wind after 2030, and the production of hydrogen fuel as a long-duration storage in 2040. It adheres to capacity retirements of fossil fuel resources as outlined in the NIPSCO's 2021 IRP, and considers retrofit of existing CT plants for hydrogen electrolysis.

3.e Zero Carbon

The Zero Carbon scenario was designed to incorporate all renewable and clean energy resources, except offshore wind, with a goal of at least 48% clean energy and 52% renewable energy mix by 2050. We believe that such a scenario can reveal important information about inherent technological advantages and limitations, and the costs associated with them. This scenario assumes that SMRs will be operational starting in the 2020s[8], and a small amount of hydrogen fuel production for energy storage is also considered.

4. Results

In this section, we present the recommended capacity mix, generation, system economics, and emissions data, and an overview of how the system performs in 2050.

4.a Summary

The scenarios analyzed in the document involve different capacity additions to meet energy targets.

In the Reference scenario, natural gas-powered CCGT and CT capacity is primarily added to fulfill the resource deficit. As for the wind and solar PV there is no additional added capacity besides the existing ones built by NIPSCO. The total installed capacity increases by 9% to 6,287 MW in 2050, with 165 MW of battery storage needed.

In the Zero Carbon scenario, the goal is to reduce emissions to zero while adding SMRs as generators. This resulted in a larger increase in installed capacity to about 7,486 MW in total or about 24% more than in the year 2023 that includes hydrogen, wind and solar PV. The percentage of capacity generation of clean energy compared to renewables is 52% to 48% respectively. Additionally, 565 MW of short duration storage and 606 MW of hydrogen electrolyzer capacity are added to manage the curtailment.

The 100% RE scenario aims for 100% renewable energy penetration, requiring the highest installed capacity of over 14,470 MW in total or about 66% more than in 2023. The additions mainly consist of renewables such as on-shore wind, off-shore wind, storage and solar PV accounting for the largest portion. To handle the curtailment and shift energy generation 3,602 MW of storage capacity including hydrogen electrolyzer. H_2 CTs and electrolyzer storage play a crucial role in providing dependable capacity in this scenario.

The 100% RE and Zero Carbon scenarios have significantly higher installed capacity compared to the Reference scenario. In the alternative scenarios, the only source of new flexible thermal capacity allowed, i.e. generators that can ramp up and down as needed, are H_2 CTs and nuclear SMRs. These are essential in providing the dependable capacity required in a high intermittent renewable energy system.

4.b System Capacity

In all our scenarios, system capacity had to be expanded to meet the load growth and compensate for retirements through the decades.

[8] For more information: https://www.ans.org/news/article-3780/indiana-smr-bill-signed-into-law/

4.b.i Nameplate Capacity

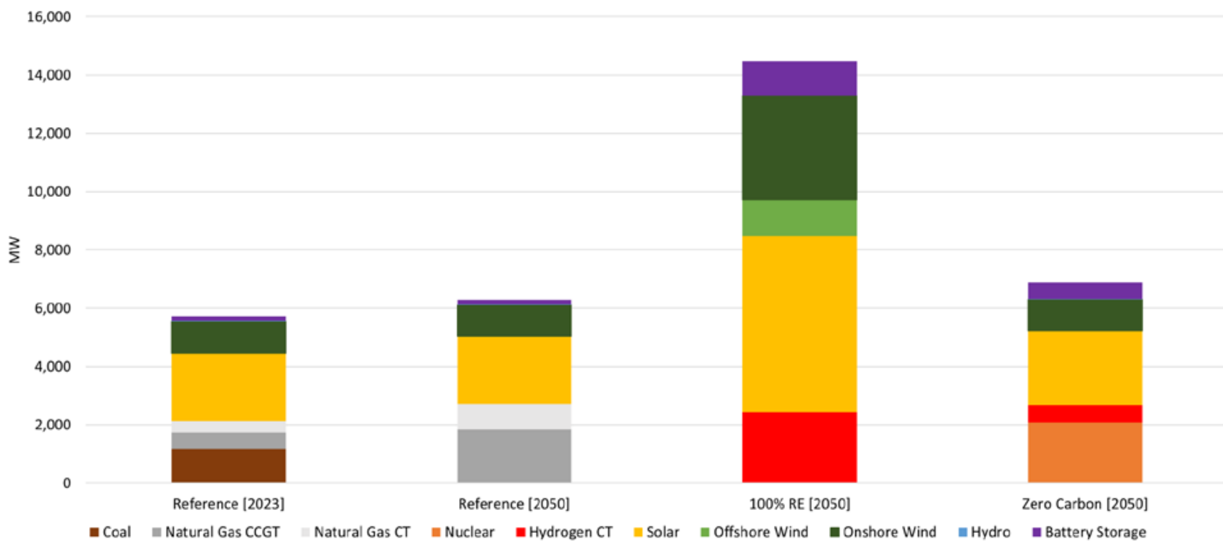

Figure 4-1: System Nameplate Capacity Mix by Scenario

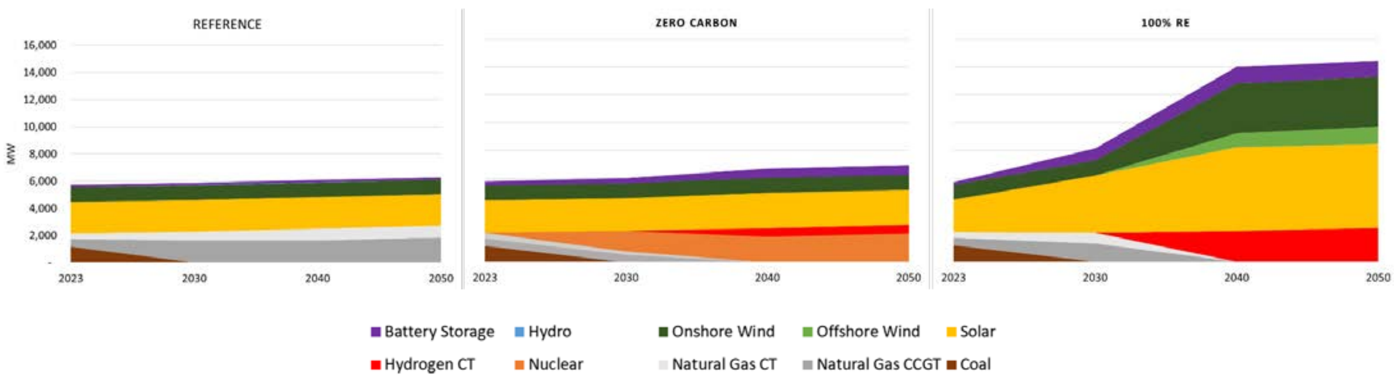

Figure 4-2: System Nameplate Capacity Mix by Decade

In the Reference scenario, the capacity increases to 0.56 GW by 2050. Since we do not assume emissions constraints in this case, the need for new capacity builds was purely based on least-cost considerations hence CCGTs and CTs comprised nearly 54% of the new capacity. However, we did consider the retirement of the coal power plants in 2028 as per NIPSCO's original plan. 165 MW battery storage is built to capture some of the overgeneration by renewables. Additional CCGT and CT units were built in the 2020s, 30s and 40s to cater to the load demand.

In the Zero Carbon scenario, the capacity increases to about 1.2 GW by 2050, with wind and solar comprising the lion's share of the overall generation capacity at 48%, and the remaining 52% covered by nuclear SMRs. The SMRs can serve much of the base load that is unable to be met by a purely renewables scenario without building substantial dependable capacity. 565 MW of short-duration Li-ion storage and 606 MW of H_2 CTs are used as dispatchable and flexible thermal resources, with 252 MW of existing natural gas CTs converted to H_2 CTs in the year 2040.

In the 100% RE scenario, the capacity increases to nearly 9 GW by 2050, the highest of all scenarios. All coal and natural gas plants are retired in 2028 and 2040 respectively. Off-shore wind energy plays a significant role in filling in the capacity deficit starting in the year 2039 with 1.25 GW built through 2050. This is followed by onshore wind with about 3.6 GW and lastly solar PV with the highest capacity of about 6 GW of the overall share. A substantial amount of dispatchable capacity is still necessary to ensure the system is reliable during times with low solar and/or wind output, and this need is met by about 2.5 GW of H_2 CTs and 1.2 GW of short-duration Li-ion battery storage. The H_2 CTs also include converted natural gas CCGTs/CTs with about 2.1 GW and an additional of about 400 MW newly built H_2 CTs.

A solar PV or wind resource generally has a lower capacity factor than a thermal power plant, therefore it takes more installed capacity for renewables and storage to replace the energy provided by thermal generation. This is why there is more H_2 CT capacity accounted for in 100% RE compared to Zero Carbon.

Figures 4-1 and 4-2 compare the capacity mix of today's NIPSCO system and the results of the three scenarios.

4.b.ii Dependable Capacity

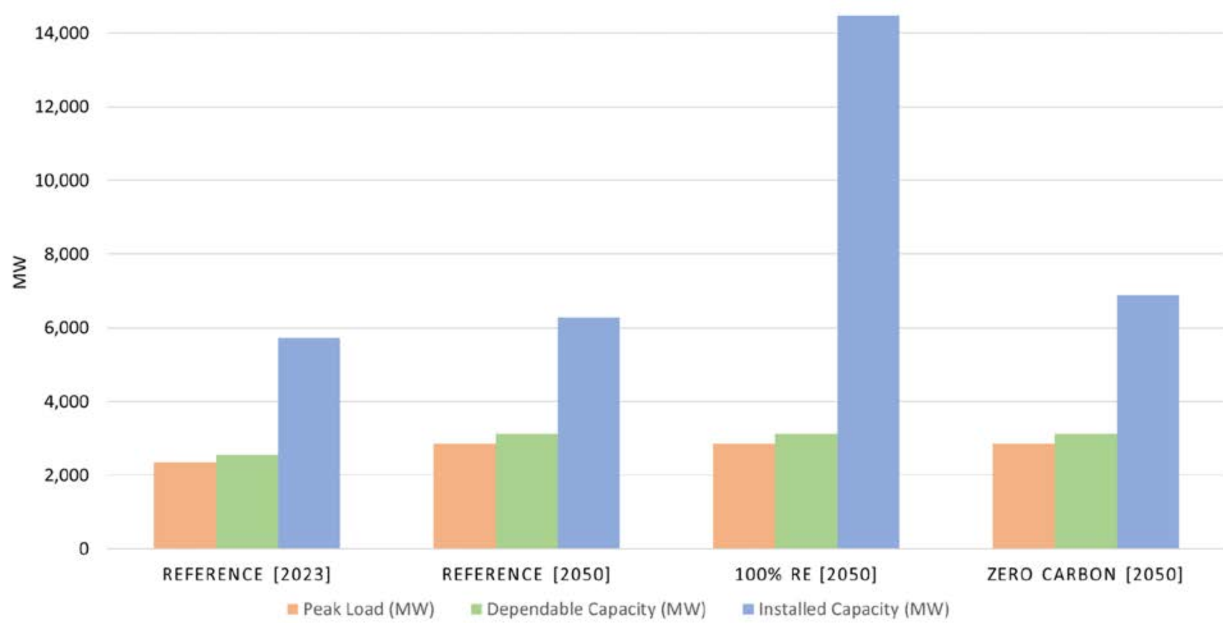

Figure 4-3: System Dependable Capacity Mix by Scenario

NIPSCO required a 9.4% reserve margin of dependable capacity above the peak load forecast for each year. In all our scenarios, the dependable capacity meets NIPSCO's PRM. It is worth noting that the 100% RE scenario requires a much greater amount of wind and solar PV nameplate capacity, along with battery storage and hydrogen production, to meet the PRM goal. Hence, the amount of dependable capacity provided by renewables and storage are deployed in foremost priority to reduce the system peak load.

4.c Energy Generation

In the Reference scenario, the energy need is largely met with natural gas-powered CCGTs and CTs, comprising 54% of total energy generation. The amount of renewables to meet the target load and PRM requirement add 7,774 GWh of energy.

The Zero Carbon scenario generation mix is balanced between renewables and clean energy resources. Solar, wind, and a small amount of hydro combined provide 8,162 GWh, followed by the nuclear SMRs which generate 8,741 GWh, with H_2 CTs coming in last at 3 GWh.

In the 100% RE, solar generates the most energy at 11,988 GWh or 44% of the total energy needs, followed by on-shore wind at 37%, off-shore wind 14%, H_2 CT at 5% and hydro with a negligible share. Short-duration battery storage and hydrogen electrolyzers enable the system to capture the overgeneration from renewables for use later. The H_2 CTs generate 1,362 GWh, significantly more than the Zero Carbon case as there is no other available thermal resource on the system in this scenario.

In all our scenarios, we kept curtailment very low. In Reference and Zero Carbon is negligible with 1.3% and 1.8% respectively. While as for the 100% RE scenario we reached a curtailment below 18%.

Figures 4-4 and 4-5 represent the energy generation mix by scenario and decade for all resources and any curtailment.

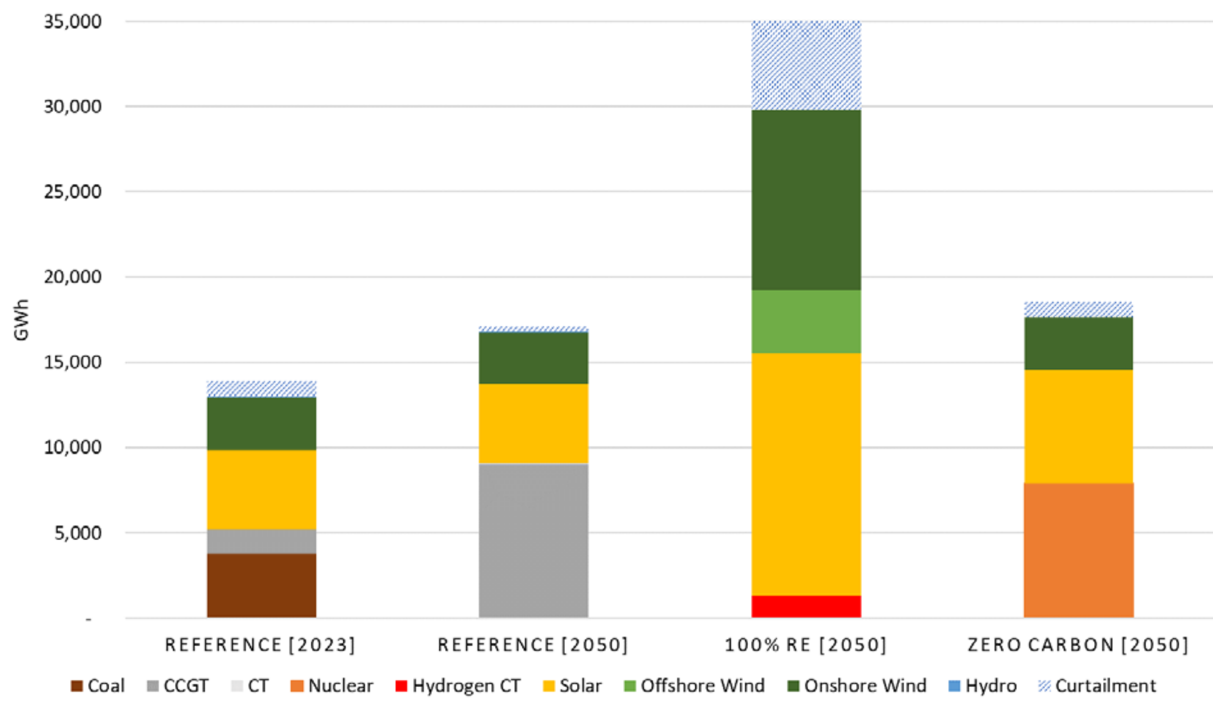

Figure 4-4: System Energy Generation Mix by Scenario

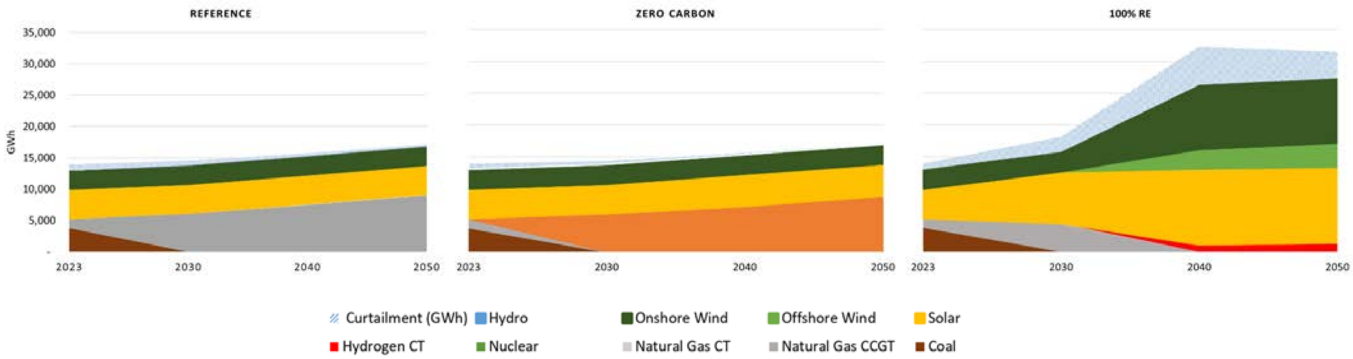

Figure 4-5: System Energy Generation Mix by Decade

Figure 4-6 represents the shares of fossil fuel, renewable energy, and clean energy in the overall energy generation of each scenario.

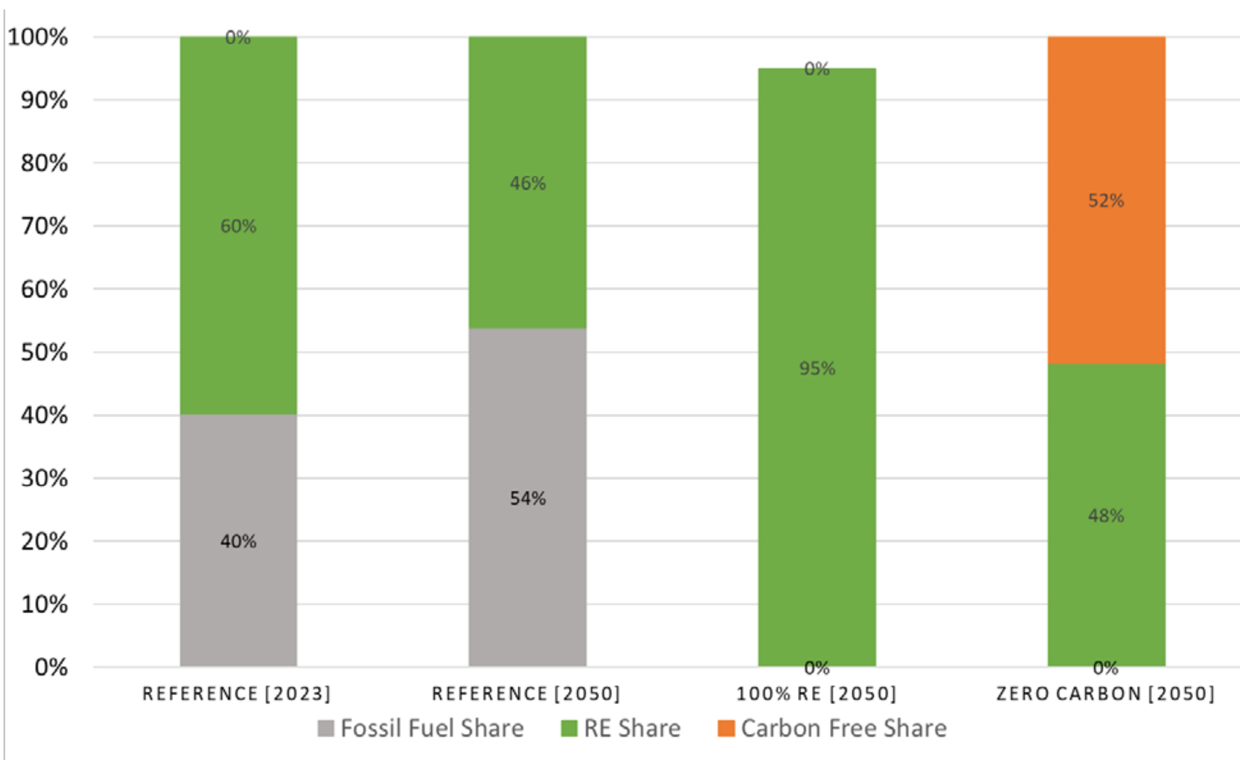

Figure 4-6: System Energy Generation Share by Scenario

Figure 4-7 demonstrates what the annual energy profile of each scenario would look like in 2050, via a month-hour average dispatch ('MHA') chart. The MHA chart for the Zero Carbon scenario shows how nuclear serves the largest share of baseload and accounts for more than 50% of the total generation. The rest of the load is served by sufficient wind and solar generation. Short-duration battery storage provides additional energy primarily in the summer season as it is the season with the highest peak load. Mostly during the months of April and May, energy generation from solar and wind is curtailed.

From the MHA chart for the RE100 scenario, it can be inferred that solar PV and wind provide

95% of the generation. With the summer peak driving the amount of solar PV and storage installed capacity, we see substantial curtailment in the months leading up to summer. H_2 CTs fill the gap that renewables and storage cannot, providing generation primarily in the Fall and Winter months. We selected CTs and CCGTs appropriate to our Screening Curve as the dispatchable thermal resources to ensure that we have sufficient peaking thermal plants on the system if needed.

The trends in energy generation align closely with the capacity outcomes in various scenarios. Wind and solar energy sources, which incur minimal operating costs, are utilized to their maximum potential. However, due to their limited capacity factors 23% for solar and an average of 33% for both off-shore and on-shore wind and intermittent nature, these resources are supplemented by dispatchable generators to meet the remaining energy requirements. The prices of their respective fuels primarily influence the dispatch decisions of these generators. Nuclear fuel is the most cost-effective option, followed by natural gas and hydrogen.

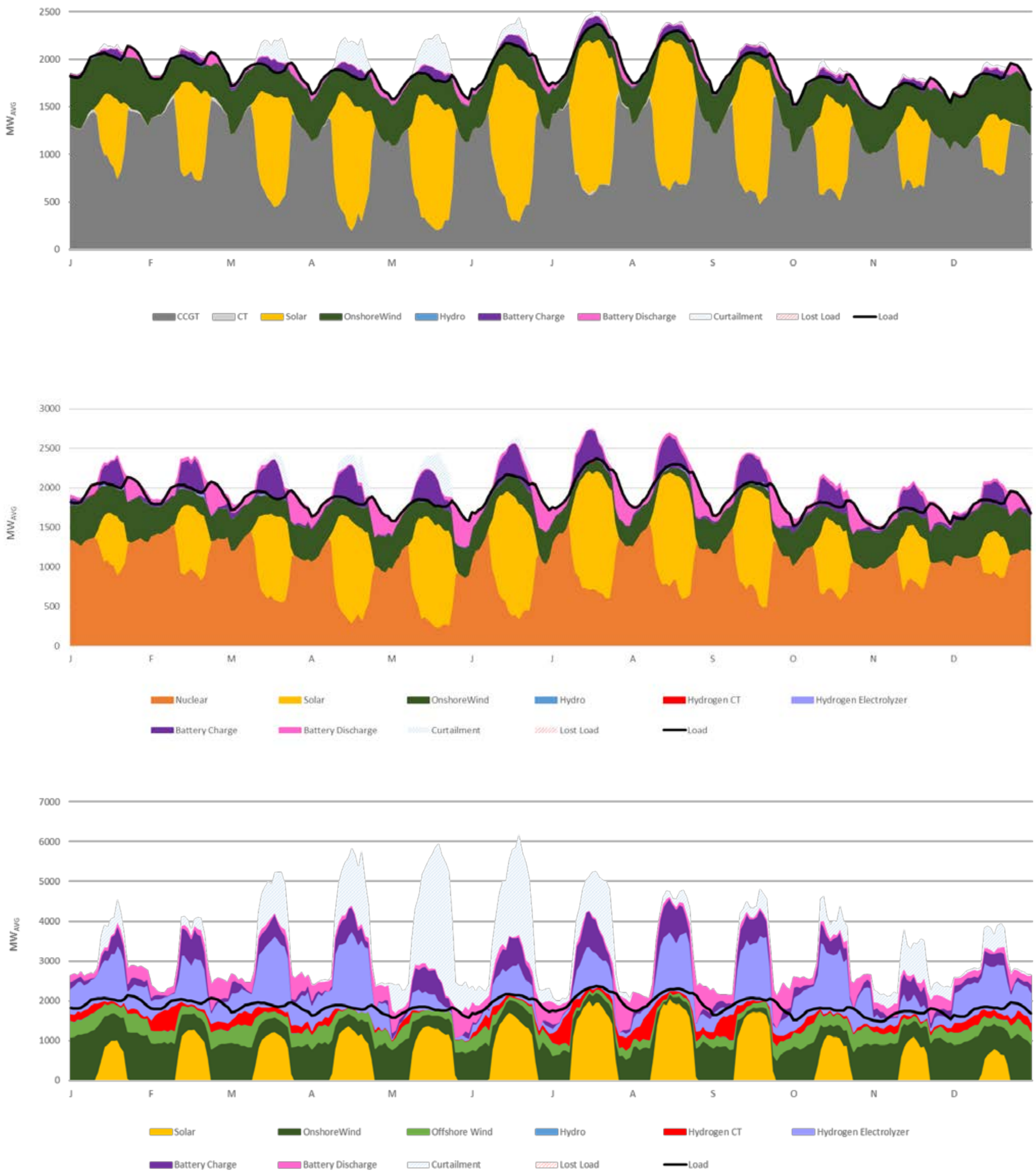

Figure 4-7: Month-Hour Average Dispatch by Scenario in 2050

4.d System Costs, Revenue Requirement & Average Rates

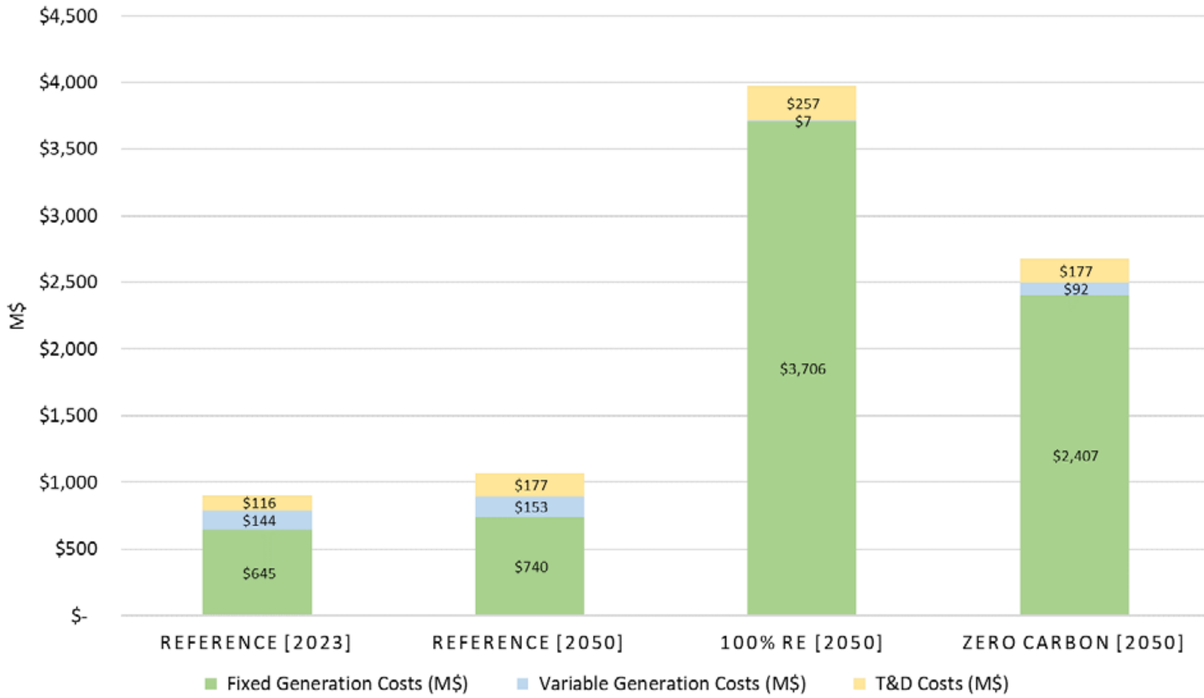

Figure 4-8: System Costs by Scenario

Our analysis revealed that the amount of nameplate and dependable capacities required in the resource mix drove the cost differences in the three scenarios analyzed.

The Reference case has the lowest total cost by virtue of no emissions reduction goals, hence NIPSCO can continue to operate fossil fuel plants and not have to invest in renewable or clean energy infrastructure. The total system costs came to $1.1B here.

The Zero Carbon scenario, although cheaper than 100% RE, stood at a cost of $2.7B mostly due to the high CAPEX of building the nuclear SMRs. Renewable energy and H_2 production, even though a small percentage, are also a component of the overall fixed cost.

The 100% RE case only used renewable resources of power and thus required building a substantial amount of nameplate capacity to meet the generation and reserve requirements, as well as storage and H_2 production facilities to cover the variable output of renewable energy generation. As a result, this was the most expensive scenario requiring an investment of $3B.

Variable generation costs also contributed to the difference in system costs. The 100% RE scenario had a very low cost of $7M as there is no additional cost for fuel besides the hydrogen costs which is produced from NIPSCOs retired natural gas plants. Compared to 100% RE, the Zero Carbon scenario is 92% more expensive due to the high cost of uranium fuel, whereas the Reference scenario is 96% greater due to the cost of natural gas.

The T&D costs remained constant through the three scenarios, scaled to the forecasted load increase in 2050. However, there is an additional $100/kW-yr of T&D cost in the 100% RE scenario, attributed to the inclusion of off-shore wind.

The fixed and variable generation costs greatly influence the differences in NIPSCO's revenue requirements and average retail rates. Figure 4-11 shows these differences across all scenarios.

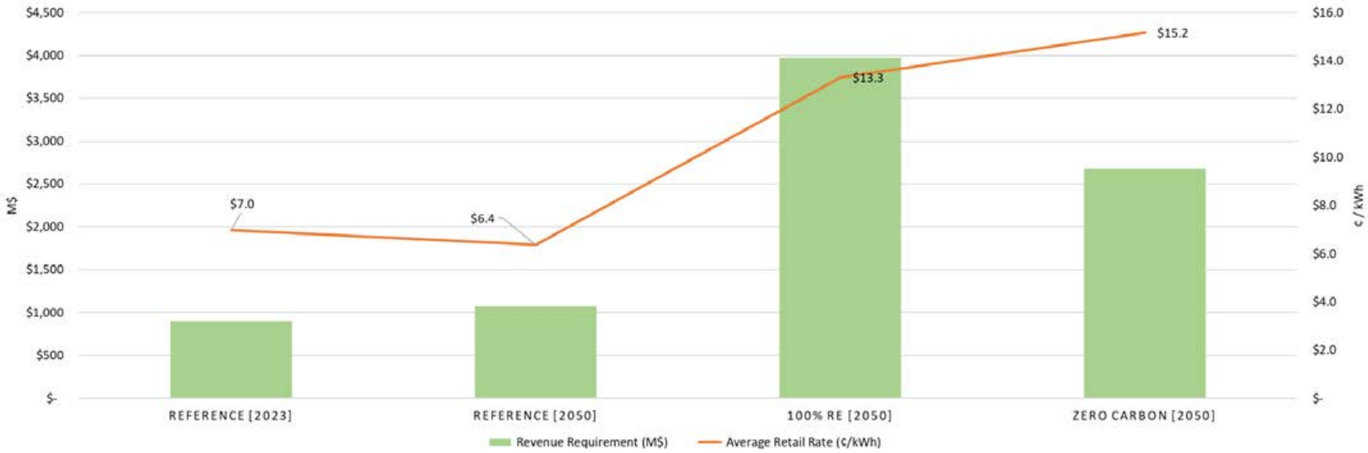

Figure 4-9: Revenue Requirement & Average Rate by Scenario

4.e Emissions & Intensity

Our analysis considered total emissions and emissions intensity of CO2 across all scenarios, as it is one of the foremost goals of this IRP. The baseline total emissions in 2023 are 4.3 MMT of CO_2 with a corresponding intensity of about 2,950 kg/MWh.

In the Reference scenario, emissions decline to almost half by 2030 because of coal plants being retired, but steadily rise again to 3.2 MMT by 2050, as more natural gas CCGTs/CTs are added to the capacity mix to meet the load demand.

The emissions in the 100% RE scenario reduce to about 1.6 MMT by 2030 for the same reason. The reason that this amount of emissions still exists is because of the natural gas CCGTs/CTs still in operation during this decade, prior to being phased out or converted to H2. The Zero Carbon scenario follows the same logic, except that only a single newly built CT in 2023 is still in operation by 2030 therefore resulting in a lower emissions intensity. In both of our alternate scenarios, zero emissions are achieved by 2040.

Figures 4-12 and 4-13 depict the emissions and emissions intensity across all the scenarios.

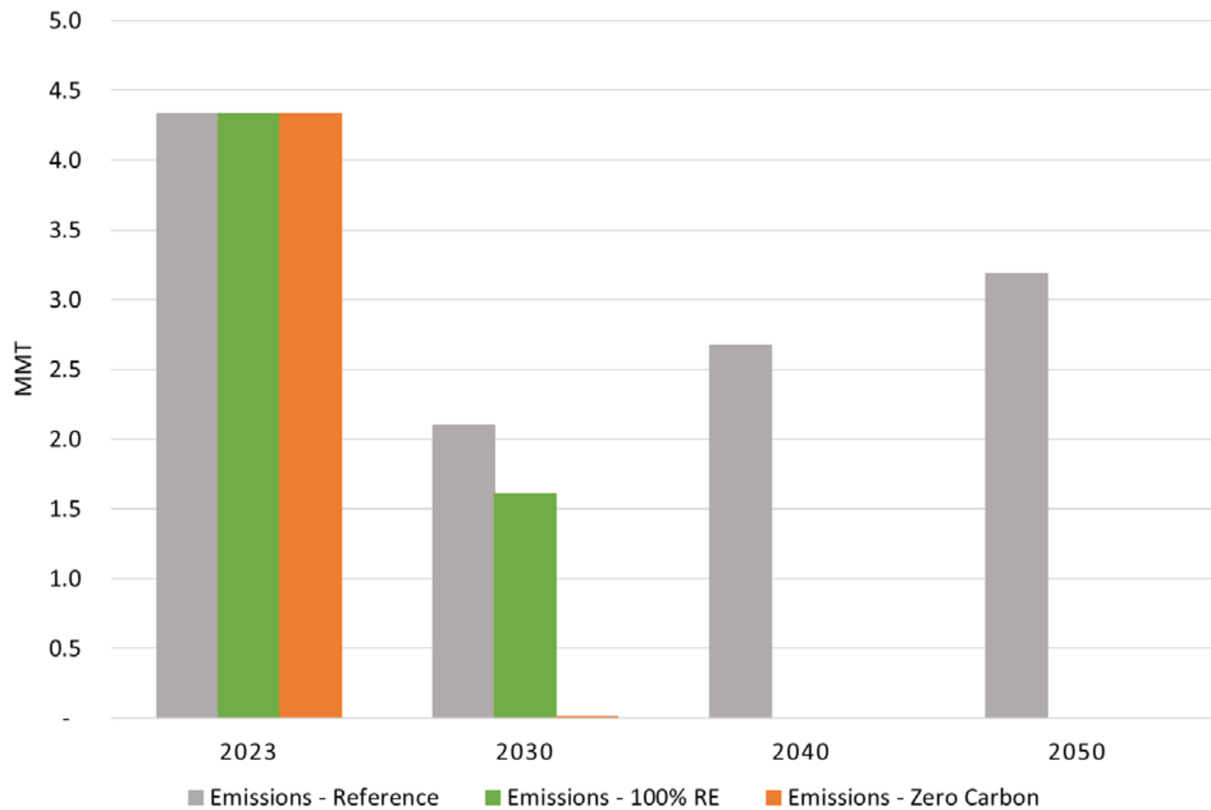

Figure 4-10: Emissions by Scenario

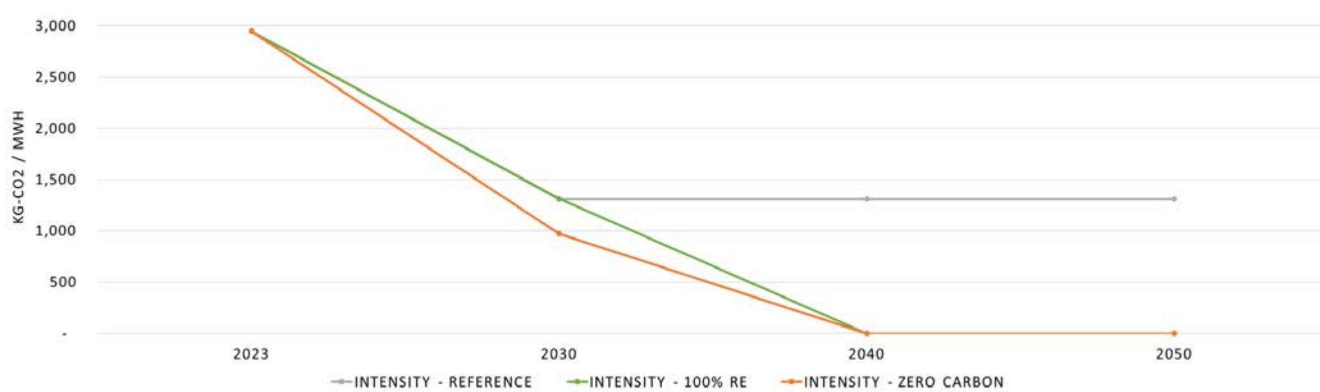

Figure 4-11: Emissions Intensity by Scenario

5. Conclusions

This report presents three different scenarios for NIPSCO's future generation resources, with two scenarios achieving zero emissions by the year 2050. The findings demonstrate that investment in renewable and clean energy resources is necessary to reach zero emissions and ensure long-term sustainability for northern Indiana consumers.

Although the Reference case is the cheapest way to meet the energy demand in 2050, it does not consider a carbon-free future for the residents of Indiana and thus not a feasible path for NIPSCO to continue on, especially with climate change and rising temperatures being a formidable threat to the well-being of humans and ecosystems worldwide.

It should be noted that Indiana is not a very resource-rich state when it comes to renewable energy systems. Low capacity factors for solar and wind mean that more capacity has to be installed to cover the shortfall from traditional fossil fuel plant retirements which currently account for over 60% of the generation. This ultimately comes at a substantial cost.

The Zero Carbon scenario consists of at least 48% renewable energy and 52% of clean energy mix by 2050 and SMRs as the only source of dispatched capacity allowed. The Zero Carbon scenario will also have less overall land use, since it has less wind and solar capacity than 100% RE, which invariably also reduces the need for building more T&D. Moreover, Zero Carbon is an inherently more flexible and resilient system due to inclusion of SMRs and H_2 CTs. Lastly, although it is the cheaper of the two alternative options for NIPSCO to pursue, it delivers 127% higher average retail rates to the end customers.

100% RE is important in that it is not subject to federal and state level regulations over permitting required to build nuclear plants. By that token, there would be less resistance by the public, especially residents of communities nearby to the proposed nuclear sites. Additionally, this scenario provides a good opportunity to produce and sell hydrogen from the excess generation of renewables. Hydrogen is 5% of the overall generation mix in this modeled scenario. However, the system cost is substantially more expensive than both the Reference and Zero Carbon scenarios and comes at 93% average retail rate increase to consumers.

Based on these findings, it is recommended that NIPSCO pursue the Zero Carbon scenario as it achieves the emissions targets and is a more cost effective and resilient system.

We are of the opinion that an optimized storage model could have allowed us to incorporate and dispatch more types of long-duration storage, as well as enhance the operation of the H_2 CTs for lowering system peak loads and harnessing curtailment more effectively. On the demand side, NIPSCO's forecast for decreased loads due to DSM programs, energy efficiency and conservation measures, FIT and the adaptation of DER will have a significant impact on the overall peak load demand and aid in increasing CF of renewable resources, thus lessening the need for building more generation capacity and ultimately reducing system costs. Additionally, thermal contracts and PPAs for imported energy could also be considered.

It is difficult to predict how NIPSCO's system will transform over the decades, given the changing landscape of energy supply and demand as it pertains to public opinion, regulatory policy, global supply chain constraints, the pace of technological innovation, and the continuing effects of climate change. However, this IRP attempts to provide a foothold upon which further conversation can be had about NIPSCO's future resource planning.

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Northern Indiana Public Service Company LLC - 2021 Integrated Resource Plan Appendix B
Northern Indiana Public Service Company LLC - 2021 Integrated Resource Plan Appendix D
Northern Indiana Public Service Company LLC - 2021 Integrated Resource Plan Appendix E

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Appendices

Appendix I: Key Metrics Summary for All Scenarios

Key Metrics	2023 Reference	2050 Reference	2050 100% RE	2050 Zero Carbon
System Overview				
Peak Load (MW)	2,337	2,854	2,854	2,854
Installed Capacity (MW)	5,721	6,287	14,470	6,880
Reserve Capacity (MW)	220	269	269	273
Dependable Capacity (MW)	2,557	3,123	3,123	3,127
Energy Generation (GWh)	12,959	16,802	27,348	16,905
Fossil Fuel Share (GWh)	5,215	9,058	0	0
Fossil Fuel Share (%)	40%	54%	0%	0%
Renewable Energy Share (GWh)	7,744	7,744	27,348	8,165
Renewable Energy Share (%)	60%	46%	95%	48%
Clean Energy Share (GWh)	0	0	0	8,741
Clean Energy Share (%)	0%	0%	0%	52%
Curtailment (GWh)	948	291	4,167	222
Curtailment Share (%)	7.89%	1.76%	17.98%	1.33%
System Costs				
Fixed Generation Costs (M$)	$ 645	$ 740	$ 3,428	$ 2,399
Variable Generation Costs (M$)	$ 144	$ 153	$ 7	$ 102
T&D Costs (M$)	$ 116	$ 177	$ 257	$ 177
Revenue Requirement (M$)	$ 904	$ 1,070	$ 3,691	$ 2,678
Average Retail Rate ($/kWh)	$ 0.07	$ 0.06	$ 0.13	$ 0.16
Change from 2023 Reference Rate (%)	0.0%	-8.7%	93.4%	126.9%
Emissions Data				
Emissions (CO2-MMT)	4.3	3.2	0.0	0.0
Emissions Intensity (kg-CO2/MWh)	2,948	1,309	0	0
Installed Capacity (MW)				
Coal	1,177	0	0	0
Natural Gas CCGT	549	1,836	0	0
Natural Gas CT	407	863	0	0
Hydrogen CT	0	0	2,437	606
Hydrogen Electrolyzer	0	0	2,437	606
Nuclear	0	0	0	2,076
Battery Storage	165	165	1,165	565
Solar	2,330	2,330	6,025	2,540
Onshore Wind	1,083	1,083	3,583	1,083
Offshore Wind	0	0	1,250	0
Hydro	10	10	10	10
Net Generation (GWh)				
Coal	3,758	0	0	0
Natural Gas CCGT	1,457	9,007	0	0
Natural Gas CT	0	51	0	0
Hydrogen CT	0	0	1,362	3
Nuclear	0	0	0	8,741
Solar	4,636	4,636	11,988	5,054
Onshore Wind	3,080	3,080	10,192	3,080
Offshore Wind	0	0	3,778	0
Hydro	28	28	28	28

Appendix II: Key Metrics Summary for Reference Scenario by Decade

Key Metrics	2023	2030	2040	2050
System Overview				
Peak Load (MW)	2,337	2,854	2,854	2,854
Installed Capacity (MW)	5,721	5,865	6,076	6,287
Reserve Capacity (MW)	220	233	251	269
Dependable Capacity (MW)	2,557	3,087	3,105	3,123
Energy Generation (GWh)	12,959	13,780	15,256	16,802
Fossil Fuel Share (GWh)	5,215	6,037	7,512	9,058
Fossil Fuel Share (%)	40%	44%	49%	54%
Renewable Energy Share (GWh)	7,744	7,744	7,744	7,744
Renewable Energy Share (%)	60%	56%	51%	46%
Clean Energy Share (GWh)	0	0	0	0
Clean Energy Share (%)	0%	0	0	0
Curtailment (GWh)	948	751	486	291
Curtailment Share (%)	7.89%	5.77%	3.29%	1.76%
System Costs				
Fixed Generation Costs (M$)	$ 645	$ 758	$ 719	$ 740
Variable Generation Costs (M$)	$ 144	$ 136	$ 128	$ 153
T&D Costs (M$)	$ 116	$ 133	$ 155	$ 177
Revenue Requirement (M$)	$ 904	$ 1,027	$ 1,003	$ 1,070
Average Retail Rate ($/kWh)	$ 0.07	$ 0.07	$ 0.07	$ 0.06
Change from 2023 Reference Rate (%)	0.0%	6.8%	-5.8%	-8.7%
Emissions Data				
Emissions (CO2-MMT)	4.3	2.1	2.7	3.2
Emissions Intensity (kg-CO2/MWh)	2,948	1,309	1,309	1,309
Installed Capacity (MW)				
Coal	1,177	0	0	0
Natural Gas CCGT	549	1,625	1,625	1,836
Natural Gas CT	407	652	863	863
Hydrogen CT	0	0	0	0
Hydrogen Electrolyzer	0	0	0	0
Nuclear	0	0	0	0
Battery Storage	165	165	165	165
Solar	2,330	2,330	2,330	2,330
Onshore Wind	1,083	1,083	1,083	1,083
Offshore Wind	0	0	0	0
Hydro	10	10	10	10
Net Generation (GWh)				
Coal	3,758	0	0	0
Natural Gas CCGT	1,457	6,029	7,454	9,007
Natural Gas CT	0	8	58	51
Hydrogen CT	0	0	0	0
Nuclear	0	0	0	0
Solar	4,636	4,636	4,636	4,636
Onshore Wind	3,080	3,080	3,080	3,080
Offshore Wind	0	0	0	0
Hydro	28	28	28	28

Appendix III: Key Metrics Summary for 100% RE Scenario by Decade

Key Metrics	2023	2030	2040	2050
System Overview				
Peak Load (MW)	2,337	2,854	2,854	2,854
Installed Capacity (MW)	5,721	8,156	14,005	14,470
Reserve Capacity (MW)	220	232	251	269
Dependable Capacity (MW)	2,557	3,086	3,105	3,123
Energy Generation (GWh)	12,959	15,735	26,306	27,348
Fossil Fuel Share (GWh)	5,215	4,430	0	0
Fossil Fuel Share (%)	40%	28%	0%	0%
Renewable Energy Share (GWh)	7,744	11,306	26,306	27,348
Renewable Energy Share (%)	60%	72%	96%	95%
Clean Energy Share (GWh)	0	0	0	0
Clean Energy Share (%)	0%	0	0	0
Curtailment (GWh)	948	2,378	6,082	4,167
Curtailment Share (%)	7.89%	17.80%	30.08%	17.98%
System Costs				
Fixed Generation Costs (M$)	$ 645	$ 1,076	$ 3,071	$ 3,428
Variable Generation Costs (M$)	$ 144	$ 104	$ 5	$ 7
T&D Costs (M$)	$ 116	$ 173	$ 195	$ 257
Revenue Requirement (M$)	$ 904	$ 1,353	$ 3,271	$ 3,691
Average Retail Rate ($/kWh)	$ 0.07	$ 0.09	$ 0.12	$ 0.13
Change from 2023 Reference Rate (%)				
Emissions Data				
Emissions (CO2-MMT)	4.3	1.6	0.0	0.0
Emissions Intensity (kg-CO2/MWh)	2,948	1,311	0	0
Installed Capacity (MW)				
Coal	1,177	0	0	0
Natural Gas CCGT	549	1,326	0	0
Natural Gas CT	407	752	0	0
Hydrogen CT	0	0	2,222	2,437
Hydrogen Electrolyzer	0	0	2,222	2,437
Nuclear	0	0	0	0
Battery Storage	165	865	1,165	1,165
Solar	2,330	4,120	6,025	6,025
Onshore Wind	1,083	1,083	3,583	3,583
Offshore Wind	0	0	1,000	1,250
Hydro	10	10	10	10
Net Generation (GWh)				
Coal	3,758	0	0	0
Natural Gas CCGT	1,457	4,362	0	0
Natural Gas CT	0	68	0	0
Hydrogen CT	0	0	1,076	1,362
Nuclear	0	0	0	0
Solar	4,636	8,198	11,988	11,988
Onshore Wind	3,080	3,080	10,192	10,192
Offshore Wind	0	0	3,022	3,778
Hydro	28	28	28	28

Appendix IV: Key Metrics Summary for Zero Carbon Scenario by Decade

Key Metrics	2023	2030	2040	2050
System Overview				
Peak Load (MW)	2,337	2,854	2,854	2,854
Installed Capacity (MW)	5,721	5,974	6,665	6,880
Reserve Capacity (MW)	220	233	251	273
Dependable Capacity (MW)	2,557	3,087	3,105	3,127
Energy Generation (GWh)	12,981	13,736	15,326	16,905
Fossil Fuel Share (GWh)	5,237	29	0	0
Fossil Fuel Share (%)	40%	0%	0%	0%
Renewable Energy Share (GWh)	7,744	7,764	8,165	8,165
Renewable Energy Share (%)	60%	57%	53%	48%
Clean Energy Share (GWh)	0	5,943	7,161	8,741
Clean Energy Share (%)	0%	0.432642218	0.467226276	0.517037974
Curtailment (GWh)	978	675	382	222
Curtailment Share (%)	8.15%	5.17%	2.55%	1.33%
System Costs				
Fixed Generation Costs (M$)	$ 645	$ 1,757	$ 2,206	$ 2,399
Variable Generation Costs (M$)	$ 144	$ 70	$ 83	$ 102
T&D Costs (M$)	$ 116	$ 133	$ 155	$ 177
Revenue Requirement (M$)	$ 905	$ 1,960	$ 2,444	$ 2,678
Average Retail Rate ($/kWh)	$ 0.07	$ 0.14	$ 0.16	$ 0.16
Change from 2023 Reference Rate (%)				
Emissions Data				
Emissions (CO2-MMT)	4.3	0.0	0.0	0.0
Emissions Intensity (kg-CO2/MWh)	2,948	972	0	0
Installed Capacity (MW)				
Coal	1,177	0	0	0
Natural Gas CCGT	549	549	0	0
Natural Gas CT	407	252	0	0
Hydrogen CT	0	0	606	606
Hydrogen Electrolyzer	0	0	606	606
Nuclear	0	1,475	1,861	2,076
Battery Storage	165	265	565	565
Solar	2,330	2,340	2,540	2,540
Onshore Wind	1,083	1,083	1,083	1,083
Offshore Wind	0	0	0	0
Hydro	10	10	10	10
Net Generation (GWh)				
Coal	3,779	0	0	0
Natural Gas CCGT	1,458	29	0	0
Natural Gas CT	0	0	0	0
Hydrogen CT	0	0	3	3
Nuclear	0	5,943	7,161	8,741
Solar	4,636	4,656	5,054	5,054
Onshore Wind	3,080	3,080	3,080	3,080
Offshore Wind	0	0	0	0
Hydro	28	28	28	28

Appendix V: Emissions Factors, Operating Lifetimes, and Heat Rates of Resources

Resource Type	Emissions Factor (kg-CO2/MMBtu)	Operating Life (yrs)	Average Heat Rate (MMBtu/MWh)
Coal	95.68	40	10.16
Natural Gas CCGT	53.06	40	6.36
Natural Gas CT	53.06	40	9.72
Hydrogen CT	0	40	10.1
Hydrogen Electrolyzer	0	40	0
Nuclear	0	60	10.44
Battery Storage	0	15	0
Solar	0	30	0
Onshore Wind	0	25	0
Offshore Wind	0	25	0
Hydro	0	100	0