Initial Modelling Results Conversation

2023 Integrated Resource Plan (IRP)

Manitoba Hydro

Land acknowledgment

Manitoba Hydro has a presence across this province on Treaty 1, Treaty 2, Treaty 3, Treaty 4 and Treaty 5 lands and the original territories of the Anishinabe, Cree, Oji-Cree, Dakota, Dene peoples and homeland of the Métis nation.

We acknowledge these lands and pay our respects to the ancestors of these territories.

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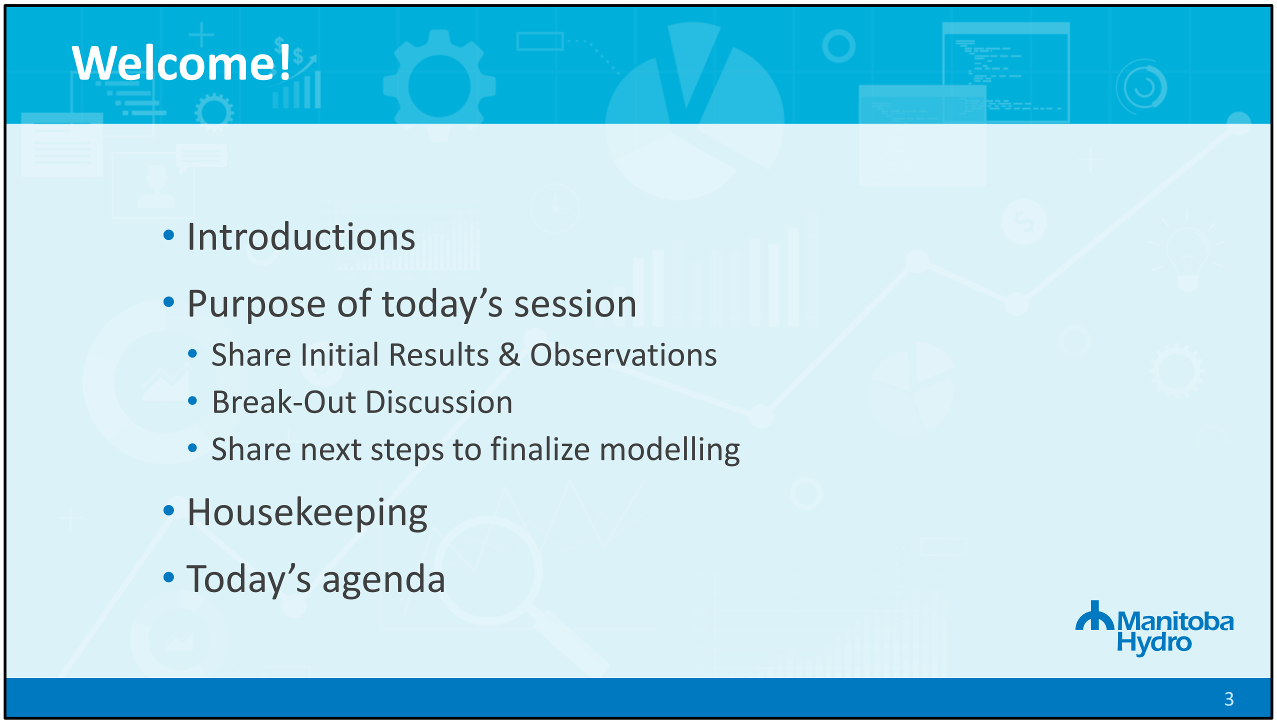


Good day! My name is Dave Bowen, I work for Manitoba Hydro and I am the Director of the Integrated Resource Planning Division (at the last session, you would have met Terry Miles, the former Director who has since retired). I would like to welcome everyone here today and thank you in advance for again taking time to be part of our Integrated Resource Planning process.

Over the past months, we have taken the 4 scenarios with the key inputs and started the modelling process. We have been learning how we could meet the potential needs of our customers over the next 20 years.

The purpose of today's session is to share with you the initial results from our IRP modelling.

This modelling builds on the previous round of engagement with customers and interested parties that occurred this spring. We have used that feedback to confirm the key inputs as well as the 4 scenarios that attempted to establish the book ends of the possible energy futures that Manitoba Hydro may need to respond to. That feedback has also been used to explore further, how different variations to the key inputs, resources, and other modelling aspects will impact the modelling outputs.

It's important we come to you now, to allow you to see and understand the initial results and provide feedback to us, so we can use this to finalize these initial results.

There are 2 items I'd like to point out before we get started.

The first is that our study period is 20 years, taking us from today to 2042. Based on your feedback, Scenario 4 represents a pathway towards net zero by 2050.

The second is that we've spent a lot of time to provide thoughtful cost information. These costs reflect future investments for Manitoba Hydro to continue to provide reliable electrical and gas service in the scenarios. They do not represent or attempt to represent, the whole life cost of climate change to our province.

Our team is represented by Lindsay Hunter, the Project Manager for the Integrated Resource Plan (IRP) project and Blair Mukanik, leading the technical collaboration who will be sharing with you today.

Thank you in advance for your questions and feedback.

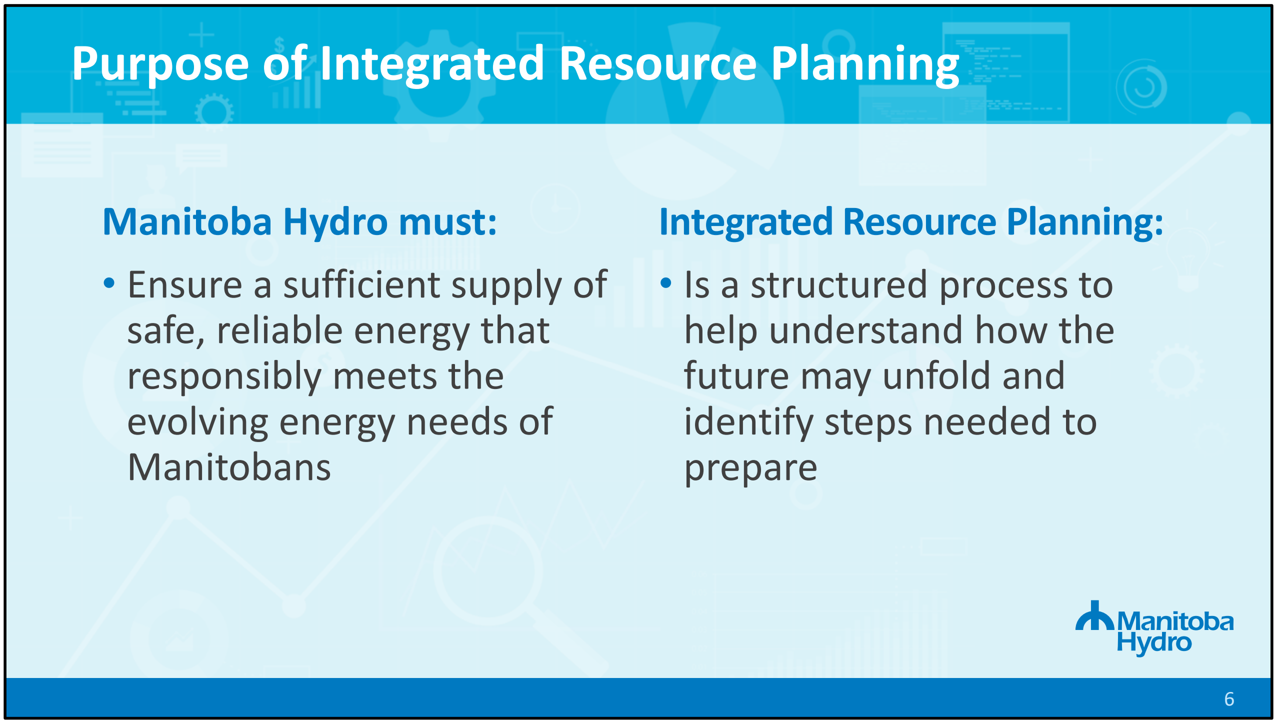
Agenda

- Background
- Initial Modelling Results – Scenarios
- Initial Modelling Results – Prioritized Sensitivities
- Initial Modelling Results – Summary of Observations
- Breakout Discussion
- Next Steps

Hi, I'm Lindsay Hunter. Before we get into the details of our initial results from our modelling, we wanted to first take a few minutes to review some of what we presented in our last round of engagement, what we heard from customers and interested parties, and how we used that feedback in our IRP analysis.

Some of you may also have attended our IRP Modelling Information Session – if so, thank you! For those who were unable to attend, we did provide links to that same information in the invitation sent for today's session.

It is important background and helpful in understanding our discussions today -- so, before we get into the initial results, we will quickly review some of that content.



Why are we doing our Integrated Resource Plan, or IRP?

At Manitoba Hydro, we supply electricity and natural gas to customers across the province of Manitoba.

This means we have to plan to make sure there is enough supply of these energy sources to meet demand. In fact, we have been doing this planning for over 60 years.

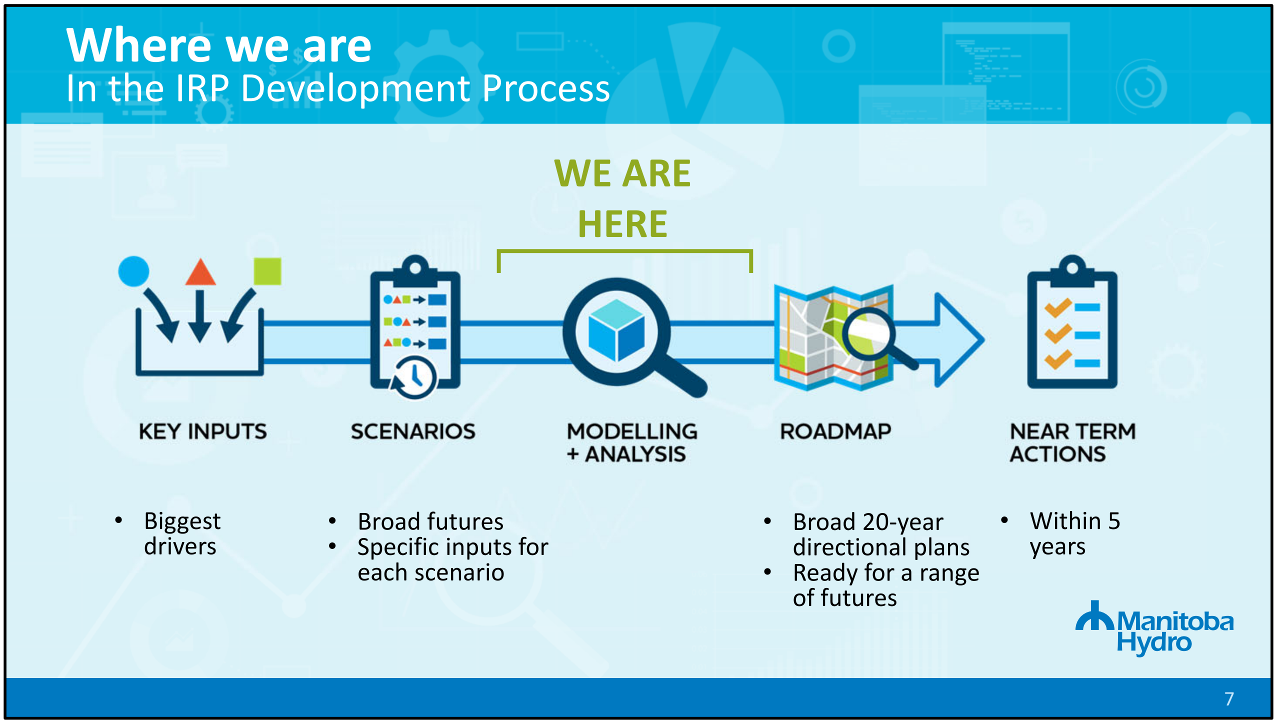
But now, the evolving energy landscape is changing how our customers will use their energy at home, for their vehicles and at work. Developing an Integrated Resource Plan is one change we've made to evolve our planning process to help us prepare.

Developing our Integrated Resource Plan is not a process to decide how the future **should** unfold, but to ensure that the path forward can respond to how it **might** unfold.

Our IRP:

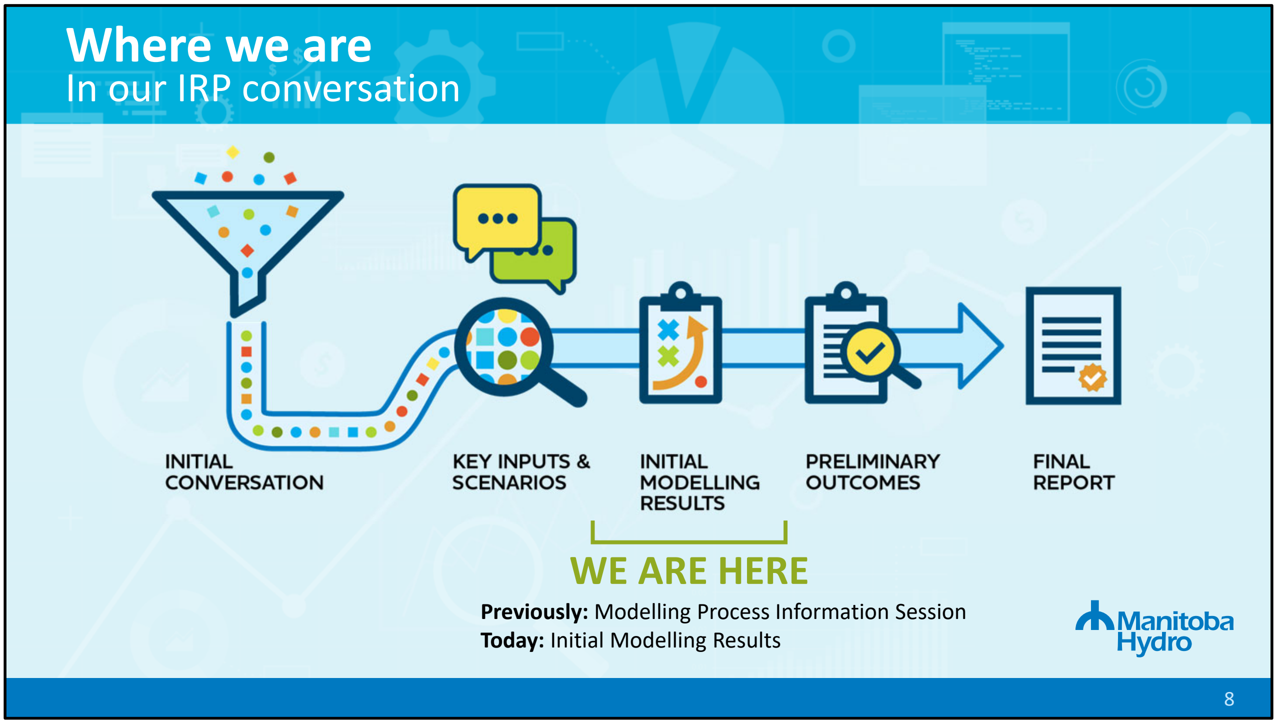
- Is a planning process that is forward looking over 20-years,
- It is informed by our engagement with customers and interested parties,
- It identifies a broad range of futures,
- And, it will identify a broad range of options to respond to whatever future might unfold.

These options will be detailed in a roadmap, not a specific development plan, with near-term actions to help define the steps for informing potential major decisions on infrastructure development or investments.



Our IRP Development process breaks down into five stages as shown on this slide. We are now in the modelling and analysis stage. That means we are reviewing the scenarios we discussed with you last round and their impacts on resources, cost, and other factors through a technical lens.

As we finish our modelling and analysis, we will use the information gained to develop the Integrated Resource Plan, including the roadmap and near-term actions.



An important part of our IRP Development is our conversations with customers and interested parties. The feedback received is informing the development of our IRP. These conversations complement our IRP Development Process, as each engagement phase is aligned with IRP development milestones.

In our previous round of engagement, we discussed the preliminary work to develop our key inputs and scenarios. We hosted a number of workshops to seek feedback. We also presented the same information to the general public and to our list of 5,000 subscribers who have identified they wanted to participate in the IRP development. We also conducted research with some of our larger customers to understand how their energy use may transition in the future.

The initial modelling results we are going to share today use the key inputs and scenarios developed with the feedback from these earlier conversations.

Round 2 Engagement Scenarios
Key Input comparisons

	Scenario 1: Slow decarbonization & slow decentralization	Scenario 2: Modest decarbonization & modest decentralization	Scenario 3: Steady decarbonization & modest decentralization	Scenario 4: Accelerated decarbonization & steady decentralization
Economic growth	●	●●	●●	●●●
Decarbonization policy	●	●●	●●●	●●●●
Electric vehicles	●	●●	●●●	●●●●
Natural gas changes	●	●●	●●●	●●●●
Customer self-generation	●	●●	●●	●●●

● represents amount of change

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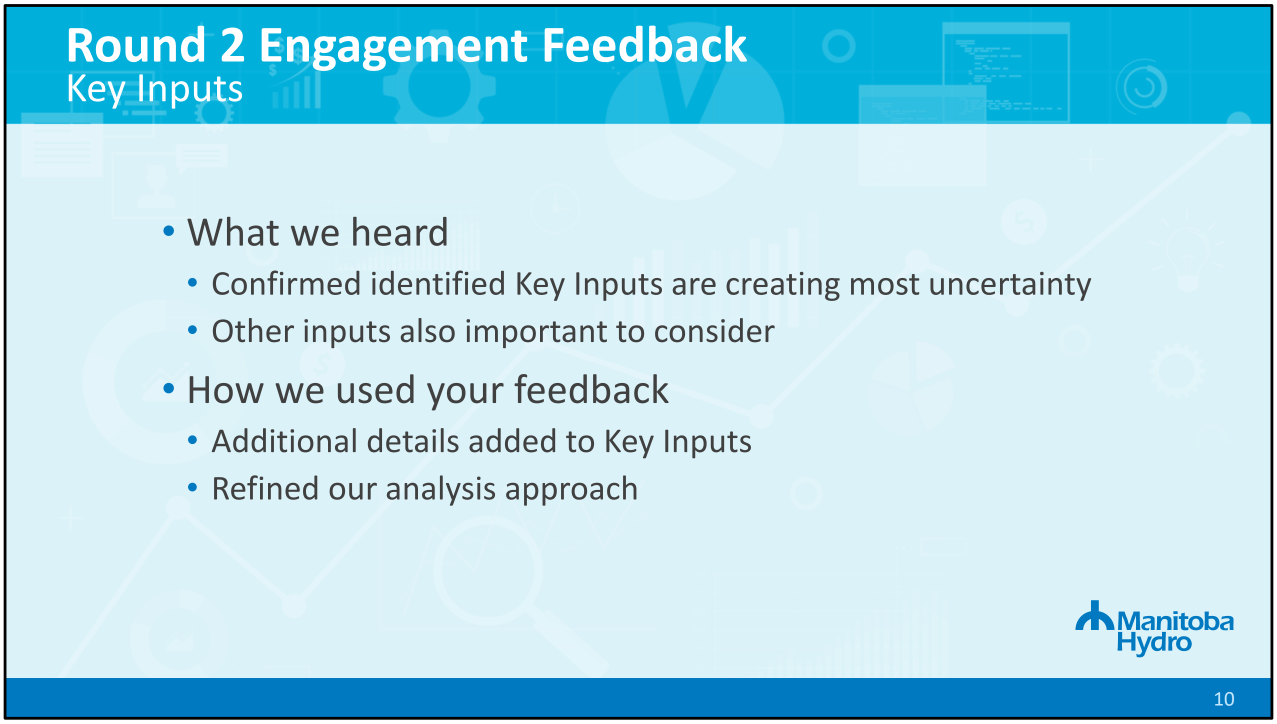
Let's review these five key inputs and four scenarios that are the backbone of our modelling. The key inputs you see here on the left were developed to represent the changes that will have a significant impact on future energy needs.

They are economic growth, decarbonization policy, electric vehicles, natural gas changes and customer self-generation.

The four scenarios use a combination of these key inputs – specifically, the amount of change in these key inputs – to represent a specific energy future. The scenarios were set to represent broad possibilities of what the future may be.

We have previously shared how the feedback gathered in the last round of engagement was used, but let’s review it here quickly.



First, the key inputs... During our discussions last spring, we received a lot of feedback on the key inputs -- feedback that helped us feel confident we had correctly identified those creating the most uncertainty in the evolving energy landscape. We also heard that factors driving net-zero Greenhouse Gas or GHG emissions are top of mind.

In addition, we had feedback telling us other inputs are important to consider, such as:

- Sustainable development
- Energy efficiency, and
- Factors influencing economic growth.

We've used this feedback in multiple ways. One way was to clarify additional factors that were driving the key inputs – factors such as technology availability and viability, particularly with electric vehicles.

We also used this feedback to help refine and finalize our analysis approach, particularly with our sensitivity analysis, which we will discuss later in this session.

Round 2 Engagement Feedback
Scenarios

- What we heard
  - Appropriate bookends for the evolving energy landscape
  - Allow for a pathway to net zero GHG emissions
  - Potential for futures with different combinations of inputs between the bookends
- How we used your feedback
  - Scenario 4 represents net-zero GHG emissions trajectory
  - Refined our analysis approach

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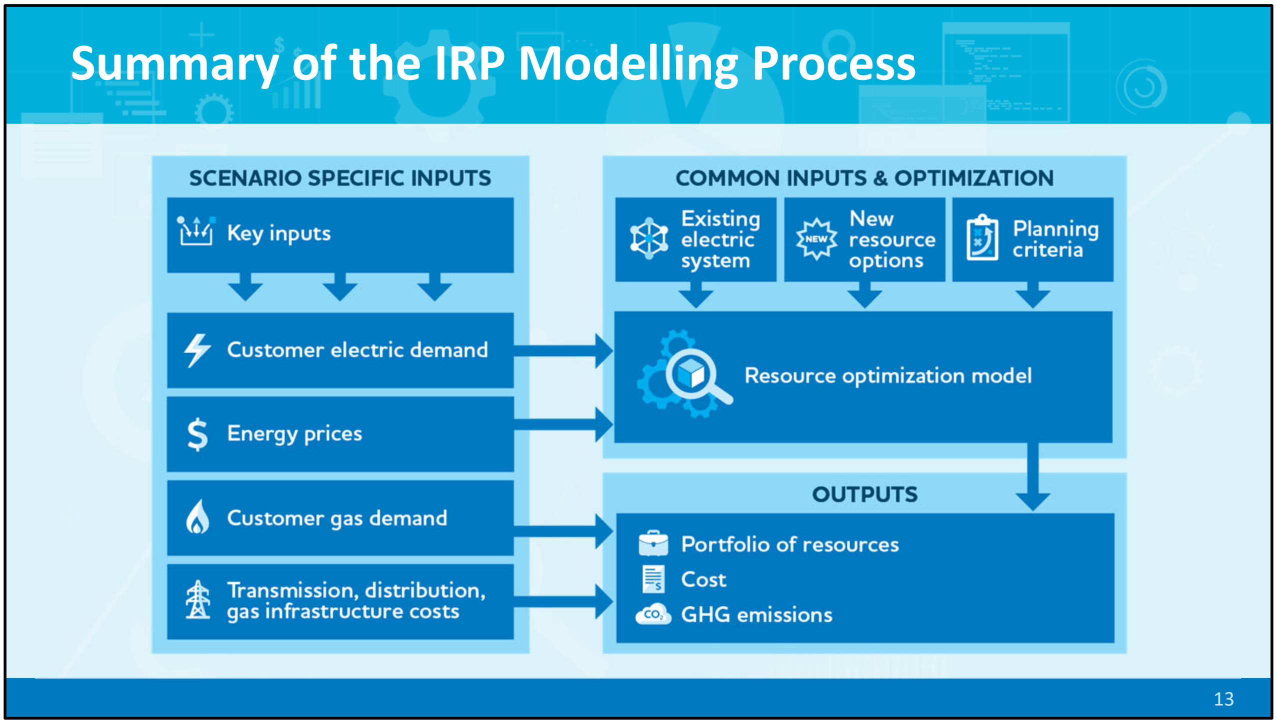
Now let's talk about the scenarios... When we asked about the scenarios we presented, the feedback was that they were appropriate bookends for the evolving energy landscape, so long as Scenario 4 reflected a path towards net zero GHG emissions. We used this feedback to ensure that Scenario 4 did in fact represent such a path.

We also heard that there is potential for futures that are different combinations of inputs between the bookends than what we presented. We used this feedback to help refine our sensitivity analysis, which we will discuss later.

The following few slides are a high-level overview of our IRP Modelling Information session held a few weeks ago. Again, a link to a summary of those materials was included in the invitation to this meeting, but we will quickly review some of the most important information now.



In that previous session, we shared the IRP Modelling Process as shown here.

The purpose of this modelling process is to simulate the electrical system, so that we can explore how best to meet our customers' future energy needs. While the modelling process is mainly focused on the electrical system, assumptions for natural gas have been factored in.

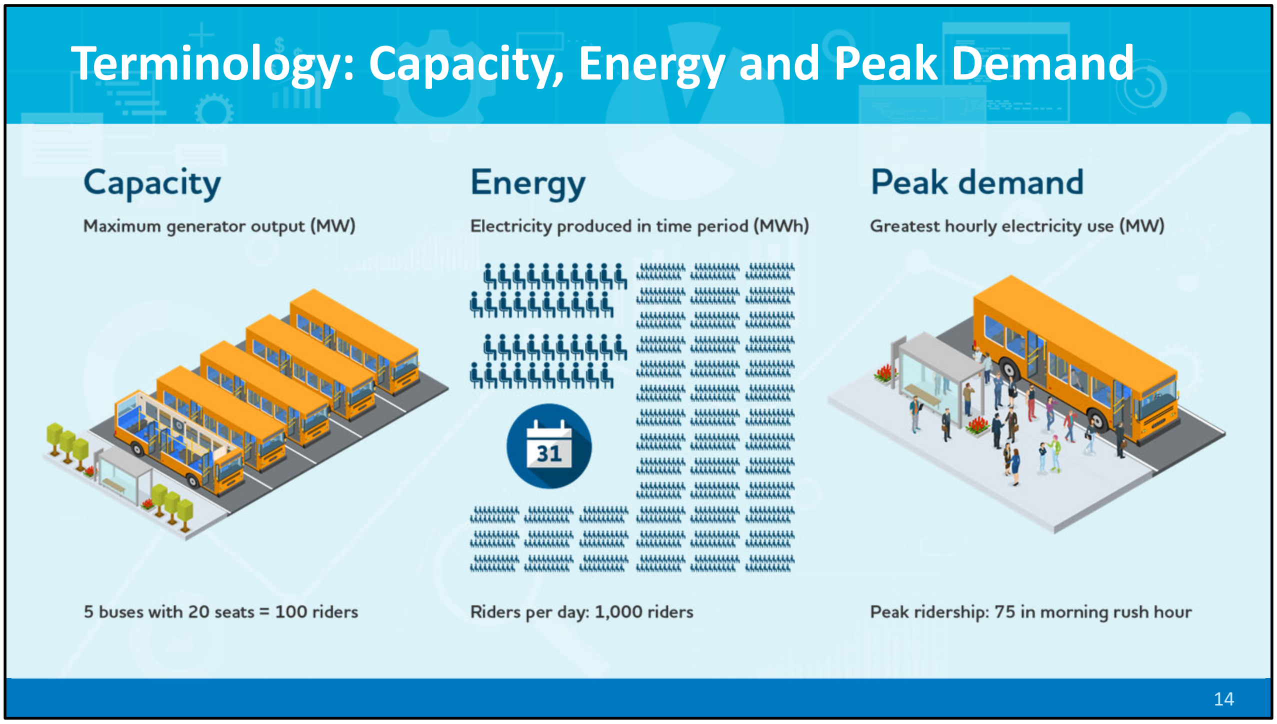
Generally, the process can be explained as follows:

- The model uses some information that is the same for each of the scenarios – the top three right-hand boxed – and represent: the existing electrical system; all the new resource options the model can select; and the planning criteria.

- Shown at the left are the other inputs that are specific to each scenario. In part, these use the key inputs to establish projections for customer electric and gas demand, which we will share today.

- The resource optimization model at centre right uses these two groups of inputs to determine when new supply is needed to meet demand. The model optimized to find the lowest cost way to meet customers’ future capacity and energy needs.

- The output of the model is a portfolio of resources that meets the defined scenario load projection at the lowest net system costs. The outputs also include total Greenhouse Gas Emissions for Manitoba Hydro’s electrical and natural gas systems, which we use to explore the total provincial emissions.



Now, before moving forward, there are a few key terms that we want to clearly define – these are terms we will use a lot throughout the rest of the session.

Simply put, Manitoba Hydro's electrical generation system provides both energy and capacity, which are different ways to think about electricity. To explain the difference, we've included an analogy, using transit buses. In this analogy buses represent the electrical system and passengers represent electricity.

When we say Capacity: we are referring to the maximum amount of electricity that can be made by generators at any particular time. This is typically measured in megawatts.

- For the bus analogy, it is the maximum number of people that can get on the bus at any one time, limited by the number of seats on each bus. In this example, 5 buses with 20 seats means you have a capacity of 100 riders.

When we say Energy: we are referring to both what is made and what is used over a period of time. So, for example, the amount of electricity produced throughout a 24-hour period. This is typically measured in megawatt-hours.

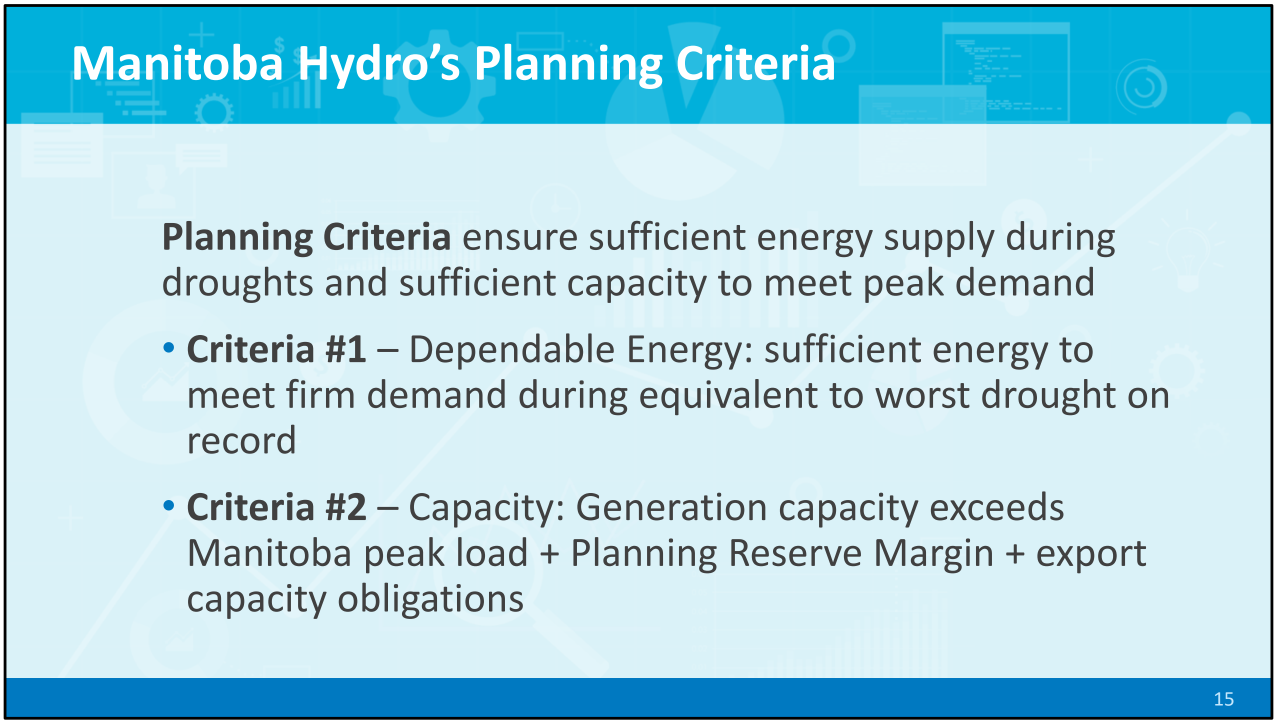
- For the bus analogy, it is how many people are transported in a day using the 5 buses. During the course of one full day you might move 1,000 riders.

When we say Peak demand: this refers to the specific time of the day that has the single greatest need for energy. For Manitoba, this happens in the winter when we have customers heating with electricity.

- For the bus analogy, peak demand is the highest number of passengers at a given point in the day. In this case, you see peak ridership at 75 people during the morning rush hour.

All three of these concepts have to work together when planning the electrical system. The system has to have capacity to meet the peak demand that customers place on it (so, number of rush hour passengers), and it must be able to provide the energy required throughout the whole day.

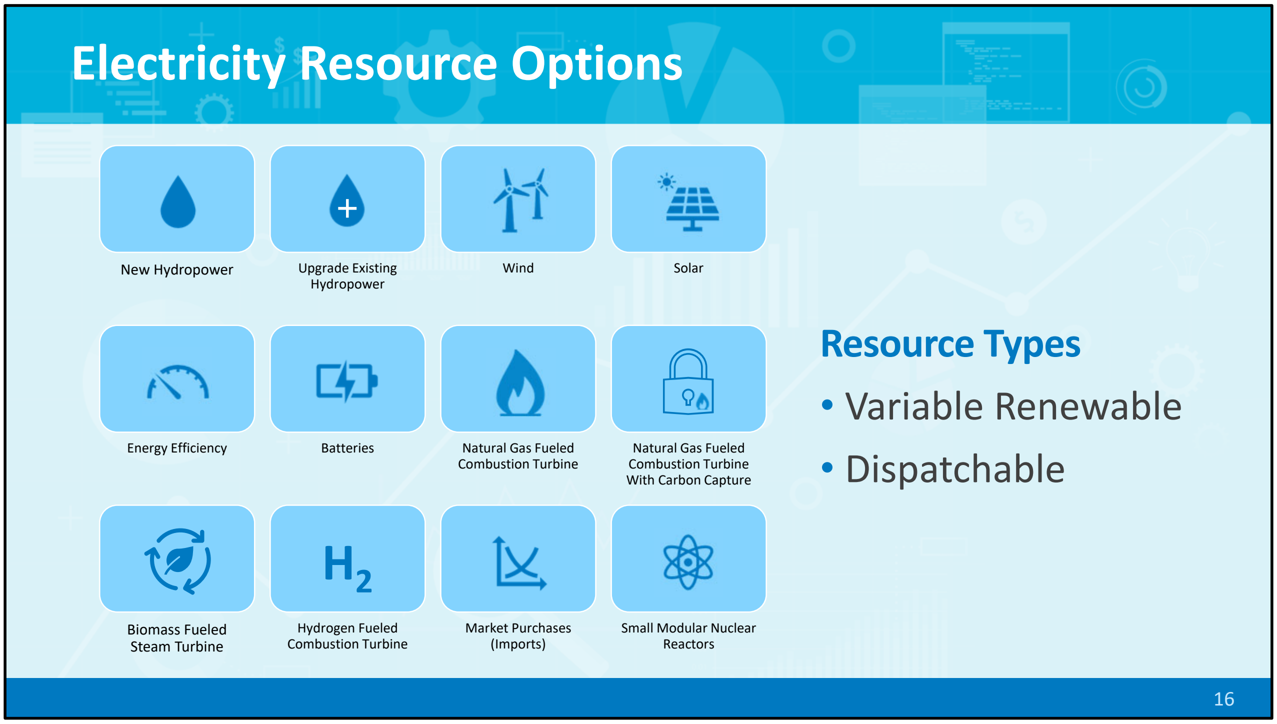
When the peak demand is greater than the system capacity, or energy supply over time is short, we either need to add more generation capacity to the system (so, add more buses during the peak times) or reduce demand (have less people on the bus during peak times). But, we still need to make sure that all passengers can be moved throughout the whole day.



When solving for potential resource options to meet a specific load, the model must meet Manitoba Hydro’s planning criteria – criteria that are specific to our predominately hydropower system and that underpin all our planning decisions. These two specific criteria are included in the model to determine when and how much of each new supply resources is needed to meet the demand in each scenario.

The first criteria requires that there is sufficient energy supply to meet demand during a repeat of the worst drought on record. This is called **Dependable Energy**. Dependable Energy includes hydropower generation as well as generation from wind turbines, natural gas generators and imported electricity.

The second criteria is for **capacity**, and requires that there is sufficient capacity to meet Manitoba’s peak load (on the coldest day in the winter), plus any committed export contracts, plus a planning reserve margin. Because equipment does breakdown from time to time, and we do experience extreme weather events, this planning reserve margin increases the required capacity to make sure we are prepared for such events.

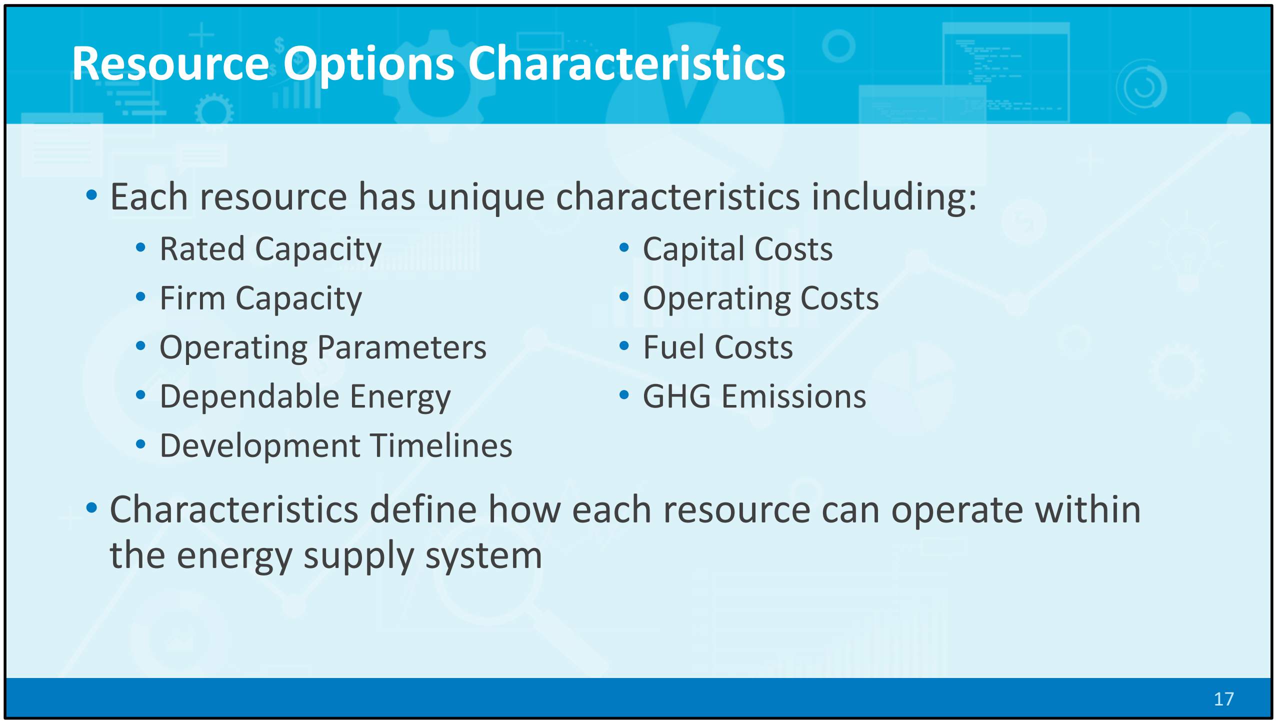


The model also includes a broad range of supply resources as summarized on this slide.

Some of these are intermittent, or variable renewable, which means that they can only produce energy when the right conditions exist, such as the sun is shining. Variable renewable resources are good for energy needs but cannot always be counted on for capacity because they cannot be reliably operated during peak demand.

Other resources are dispatchable, which means they can be turned on and off as needed to produce energy. Not only do dispatchable resources provide both energy and capacity, they also are usually very good options to provide capacity to support variable renewable resources.

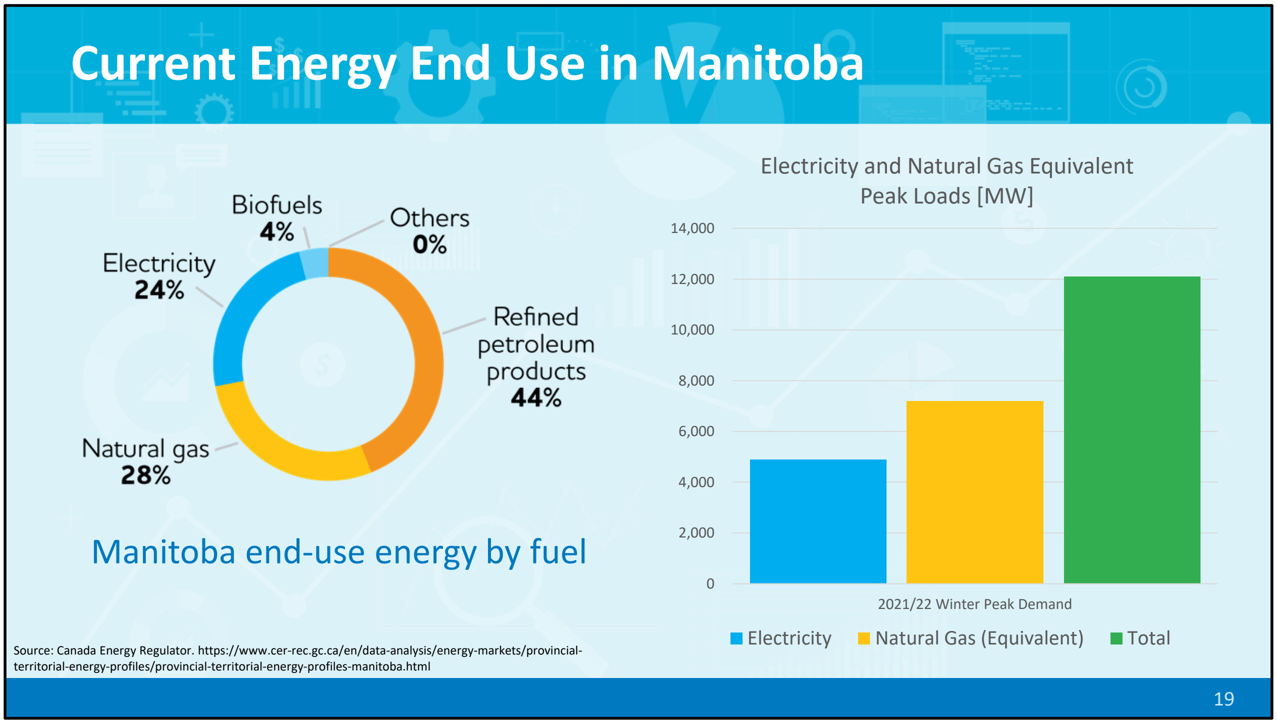
The model also includes energy efficiency measures that can be implemented by customers to reduce their total demand. Including these allows the model to explore how energy efficiency can reduce load and contribute to reducing the amount of overall generation required.



Within the model, each of the resource options have different characteristics that define how they are simulated. This allows the model to evaluate the potential role of each resource option in the system. These characteristics include things such as:

- Rated capacity, which is the maximum possible output of the resource.
- Firm capacity, which is the capacity that can be relied upon during peak demand. In many cases, this is linked to the variability of a resource, such as wind.
- Development timelines, which is how long it will take to put a new resource into service.
- Capital costs to build the resource, as well as costs for ongoing operation of the resource.
- Fuel costs, if applicable.
- And, any associated GHG emissions emitted, if applicable.

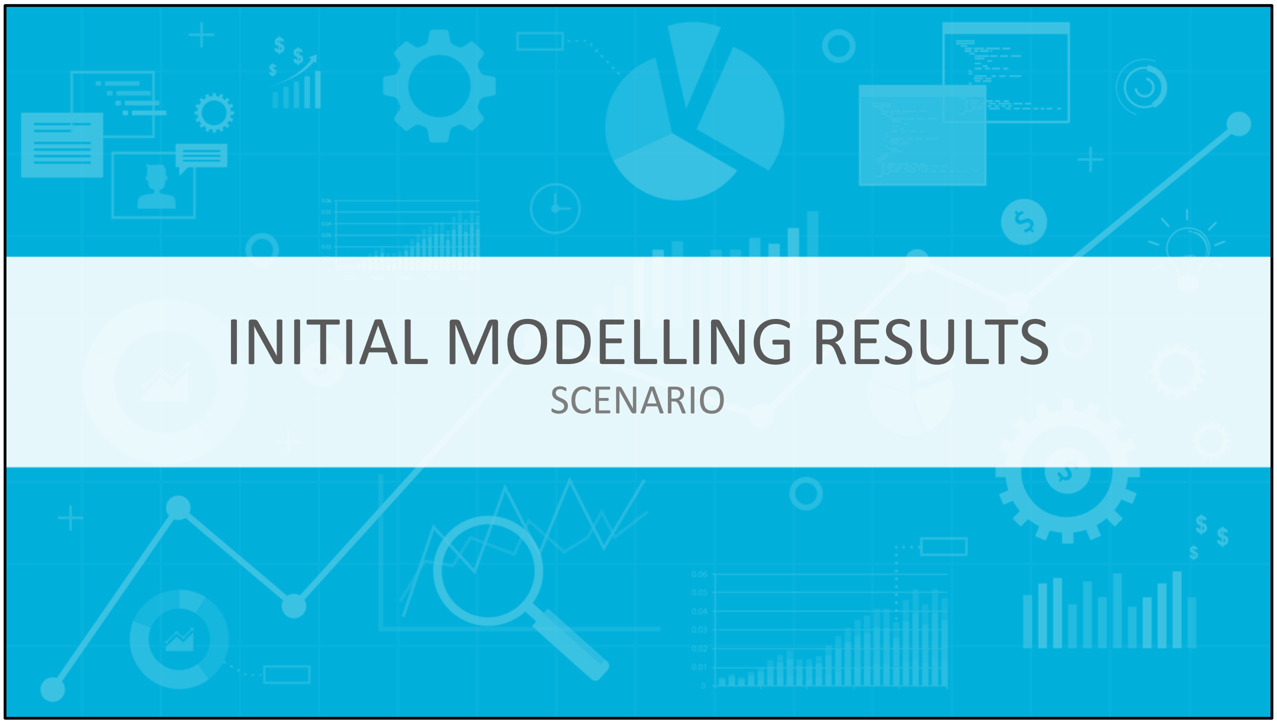
The last piece of background that we want to review here quickly is the information on current energy use in Manitoba.



In Manitoba, electricity and natural gas contribute almost 50% of total energy used. The remaining energy is mainly refined petroleum products, which are generally used to fuel vehicles.

Decarbonization is a main driver of the evolving energy landscape. The scale of achieving decarbonization through electrification can be seen by the graph on the left-hand side. Overall, our existing electricity supply and delivery system accounts for only 24% of the energy used in the province. If other fuels for transportation (at 44%) and the uses of natural gas (at 28%) are decarbonized through electrification, this would result in a significant increase in electricity use as compared to what we see today.

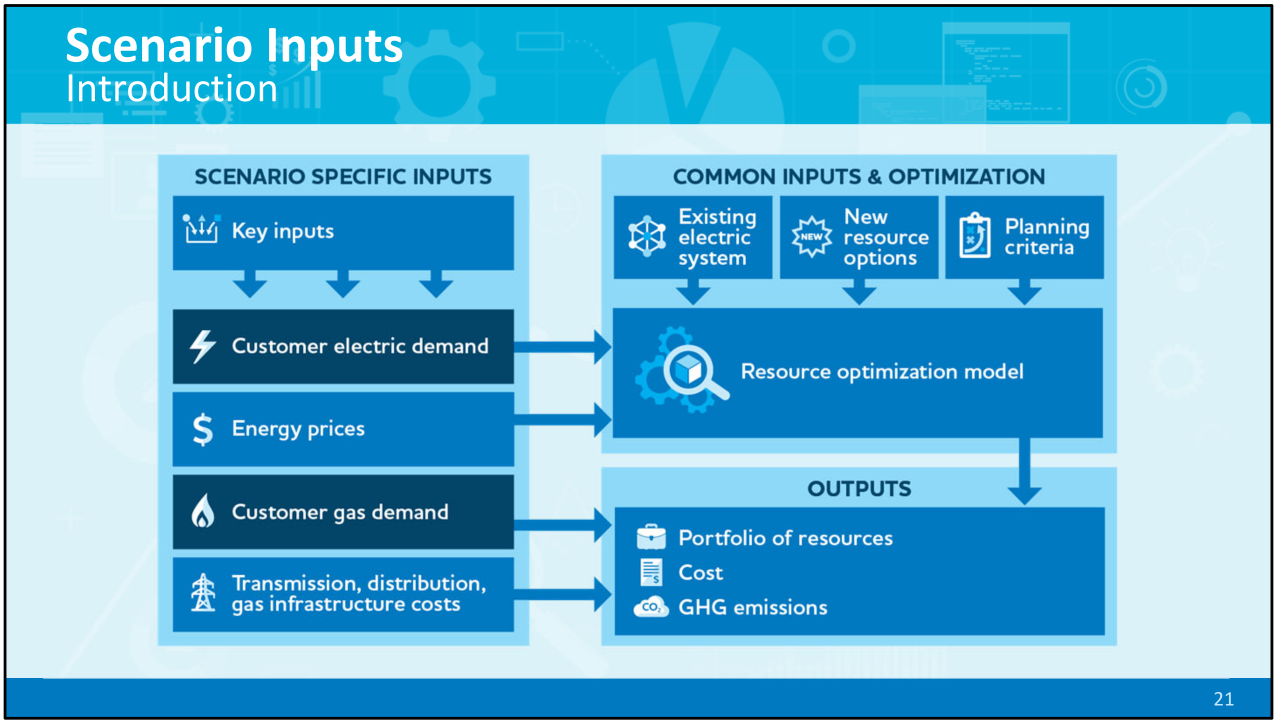
To illustrate this, is a specific example of our natural gas usage in the graph on the right. This data is from last winter, when peak electrical demand in Manitoba (the blue column) was approximately 4,900 MW. During that same winter, the natural gas hourly peak demand in Manitoba (the yellow column) was the electrical equivalent of more than 7,000 MW. If we were to serve this gas demand exclusively with electricity, Manitoba Hydro would have to more than double the size of our current electricity system (this is the difference between the green total column and the blue electricity column).



As mentioned earlier, we are using the IRP to help shift how we engage with our customers and interested parties, and ensure your feedback and perspectives inform our analysis and IRP Report. We also want to improve the visibility of how we approach our analysis and how we interpret what the modelling is communicating.

Talking to you now, before we finalize our modelling and analysis, allows an opportunity to get feedback to inform the remainder of our modelling.

Because we are still in the middle of our modelling phase, the results that we are sharing are very much preliminary at this point. They may be revised once the modelling is finalized. Like many things, our modelling process is iterative. As we continue the modelling process with different model runs, the outputs allow us an opportunity to learn new things in the results that were not evident before.



The first step in generating the outputs and our initial modelling results is developing the two scenario specific inputs within our IRP Modelling process – the customer electric and gas demand projections.

Scenarios
Input comparisons

	Scenario 1: Slow decarbonization & slow decentralization	Scenario 2: Modest decarbonization & modest decentralization	Scenario 3: Steady decarbonization & modest decentralization	Scenario 4: Accelerated decarbonization & steady decentralization
Economic growth	●	●●	●●	●●●
Decarbonization policy	●	●●	●●●	●●●●
Electric vehicles	●	●●	●●●	●●●●
Natural gas changes	●	●●	●●●	●●●●
Customer self-generation	●	●●	●●	●●●

● represents amount of change

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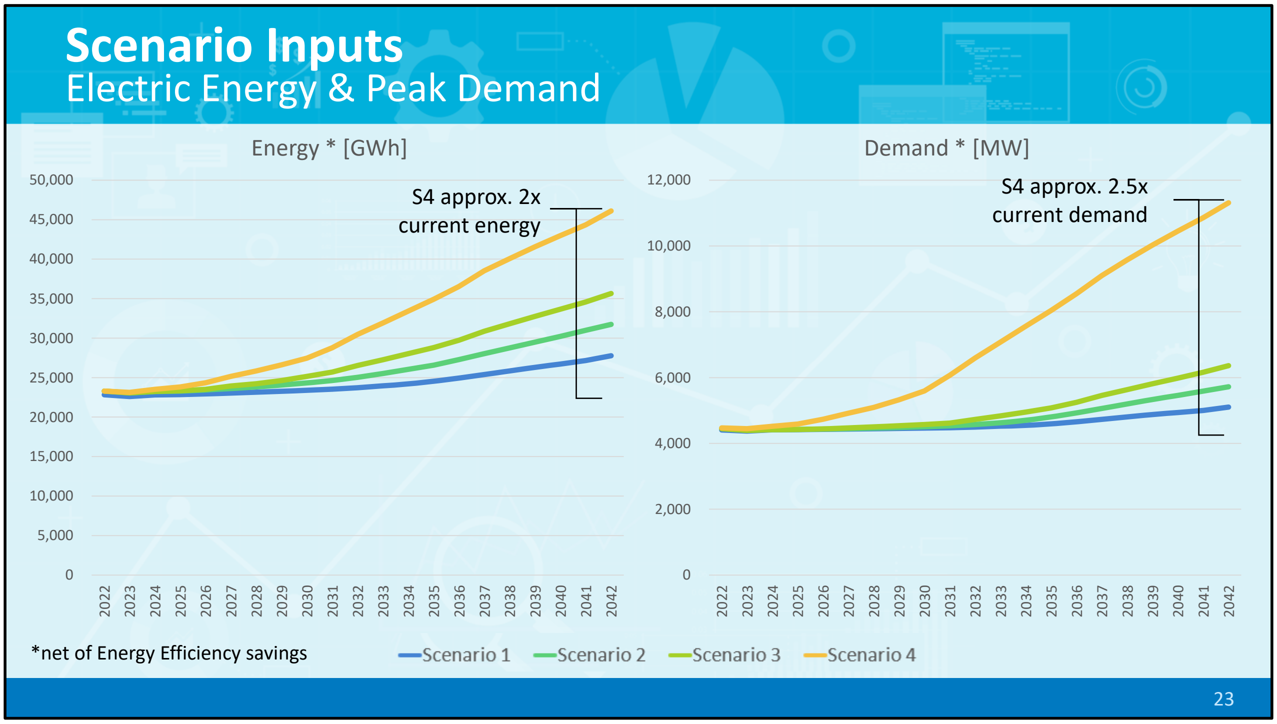
Returning again to this chart presented earlier, we can see the different pace of change for each Key input and for each scenario assumed for the IRP analysis. Scenario 4 is of particular importance in our initial results, given the assumptions around our customers' electricity and natural gas needs that accelerate decarbonization as compared to the other scenarios.

The scenarios were developed to be bookends for potential energy futures. Based on the research and feedback gathered in our last round of engagement, we associate specific values to each of the key inputs for each scenario. We use these to generate electric and natural gas demand projections that are the basis of our IRP modelling.

The scenarios assume that the type of energy customers use may change, but that they will continue using energy like they do today. For example, customers will continue charging EVs like they do today, as there is nothing in place to influence when they charge.

Sensitivities are where we start to introduce interventions and other constraints for each scenario to explore their effects on our outputs and initial modelling results. We will discuss these in more detail later in the presentation.



We use the key inputs, as well as other data, to develop the demand projection for each scenario.

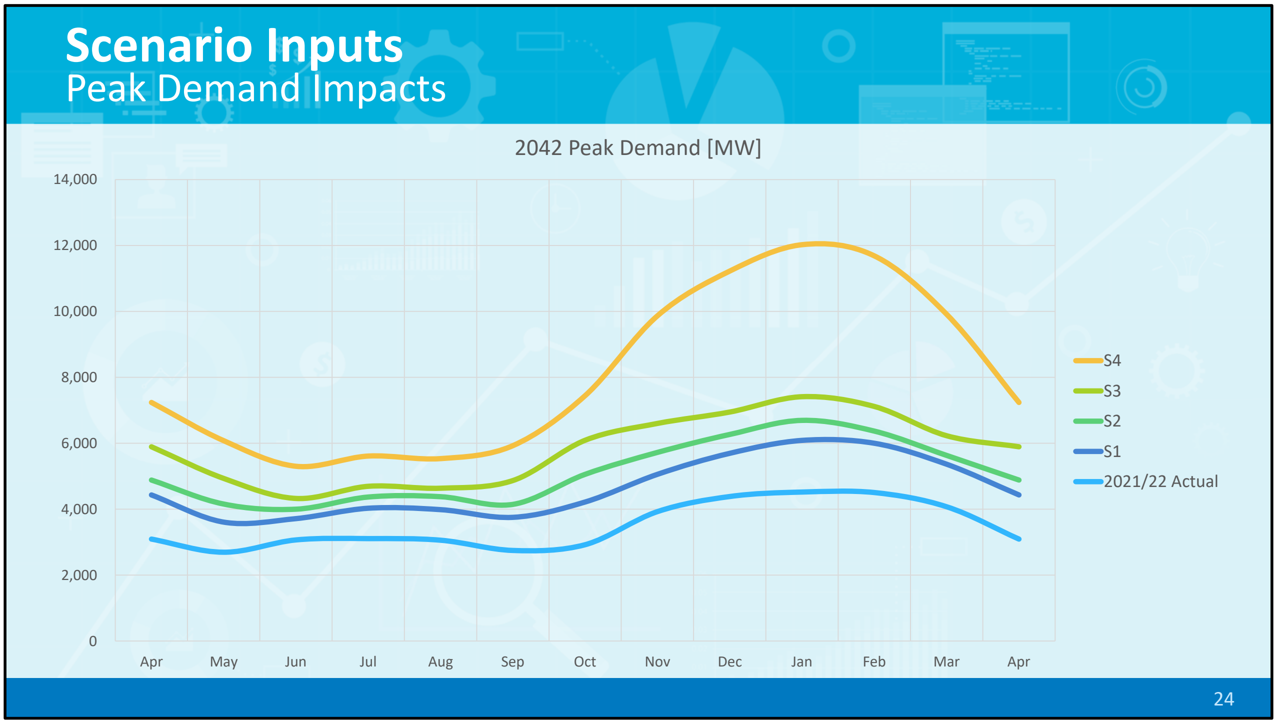
The left-hand graph shows the electric energy needs over the study period for each scenario, while the right-hand graph shows demand for each scenario.

In all scenarios, it is anticipated that our customers will use more electricity in the future, as they adopt electric vehicles and start to use more electricity to heat their homes and businesses. This is most pronounced in scenario 4.

Demand does increase between scenarios 1, 2, and 3, but there is a significant step change to scenario 4. This step change is because scenario 4 represents accelerated decarbonization and a pathway towards net-zero through electrification.

And, as you can see on the graphs, these assumptions for scenario 4 in 2042 result in our customers needing double the energy as today. More importantly, they also result in a peak demand in 2042 that is two and a half times the current demand. This has significant impacts on our system's capacity requirements.

One thing specifically impacting this peak demand is converting natural gas space heating to electricity. We explore that further on our next slide.

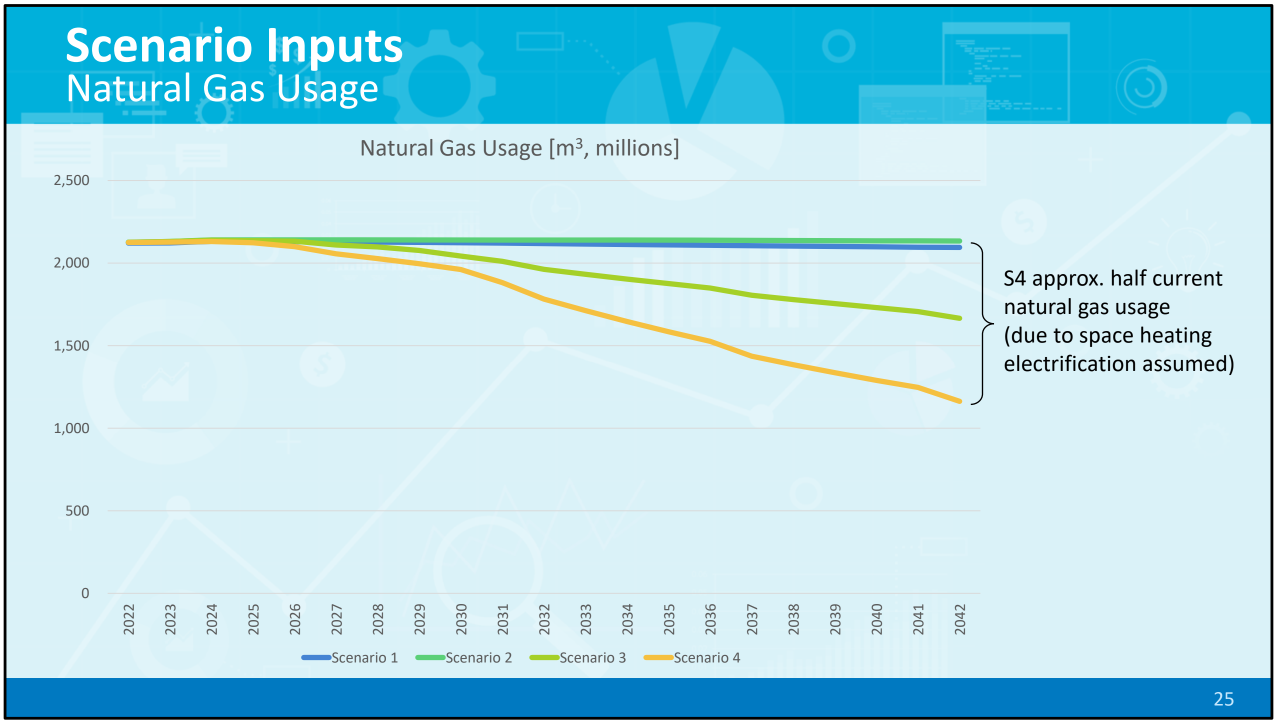


This graph shows the impact to peak demand for each scenario over a calendar year. Today, and in the future, the greatest amount of electricity is needed in January and February.

Manitoba's current winter peaking load is shown by the lower light blue line.

The 4 scenarios assume customers will switch from natural gas to electric heating at different rates, which results in a corresponding increase in winter peak demand. We can see that with the bumps that form on the right-side of the graph, between October and April.

Scenarios 1, 2 and 3 have relatively minor differences in the rate of change for the various electrification assumptions, while scenario 4 has a significant change. Again, this is shown by the step change increase to winter peak demand as shown by the top line.

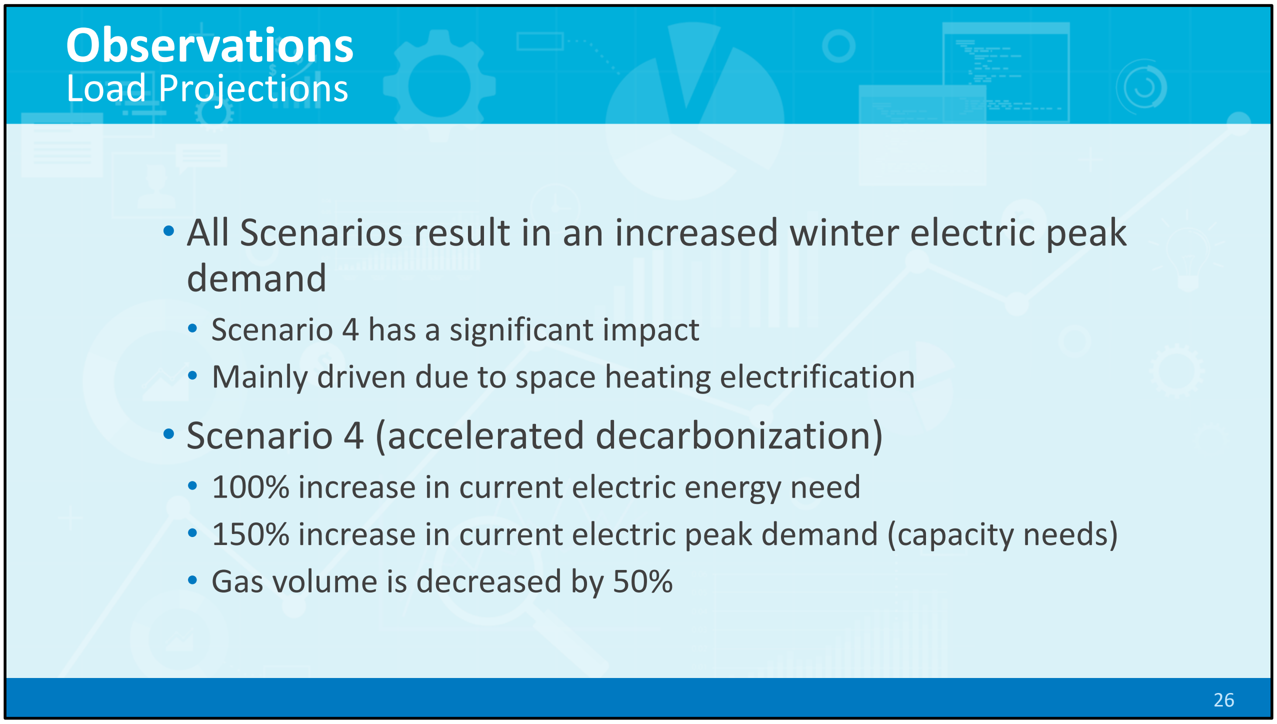


In addition to electricity, we also consider how we can meet our customers' future natural gas needs. These needs could change, particularly if there is greater focus on decarbonization.

Natural gas is primarily used for space heating in Manitoba, so as we study futures where customers switch to heat their homes and businesses with electricity, there is a corresponding decrease in natural gas usage.

In all scenarios, our initial modelling results anticipate Manitobans will still be using natural gas in 2042.

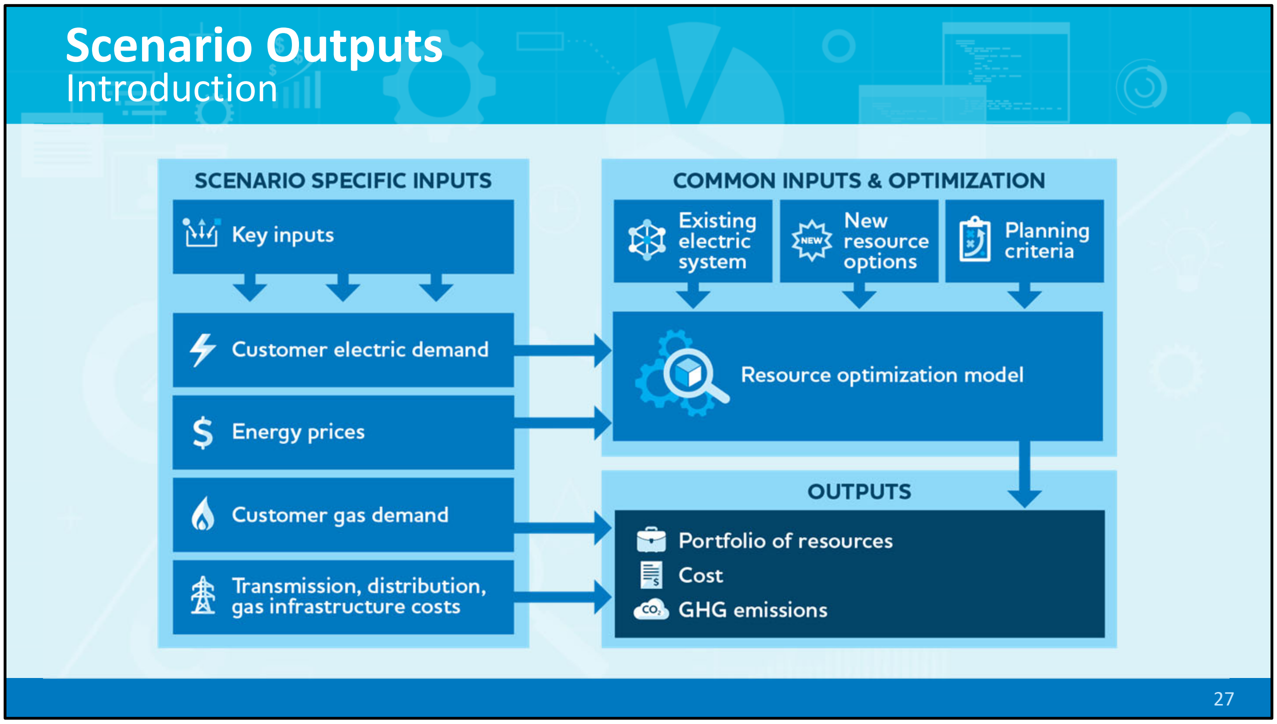
In scenario 4, natural gas in 2042 is used in industrial applications, such as for a process input or feedstock, with some natural gas still being used for space heating.



To summarize our observations with the outputs of the load projections:

- All scenarios have an increased peak demand, driven by the assumptions around space heating electrification. Scenario 4 experiences the biggest impact, as this includes assumptions around the greatest pace of change.

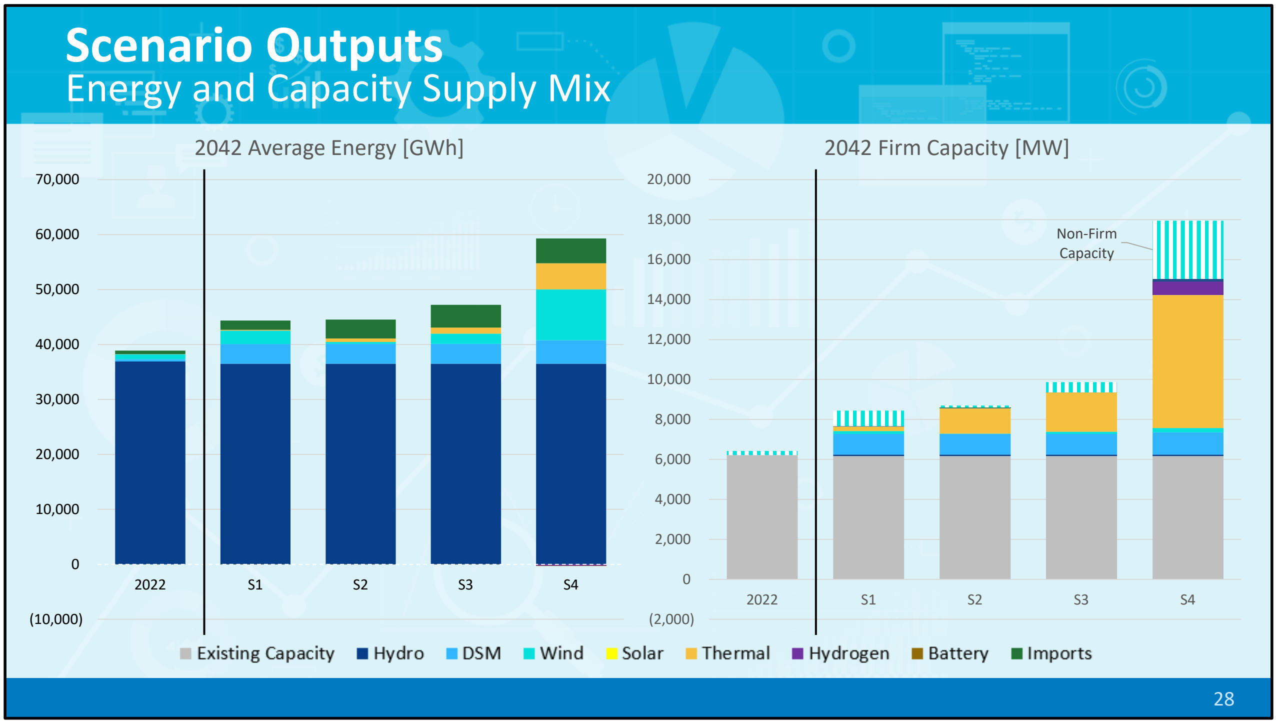
- And from scenario 4, we can see that those assumptions leading to accelerated decarbonization results in significant increases in our system for both energy and capacity needs, while also seeing a reduction in natural gas usage.



Now that we have our demand projections, we pair these with other projections, such as wholesale market prices and fuel prices, and run them through the resource optimization model.

The model is a cost optimization model, which means that it finds the lowest cost way to meet customers' future capacity and energy needs based on the provided assumptions and constraints.

We use the outputs of the model to find commonalities between the initial results, to identify least regret decisions, and to see where differences may need further exploration. We compare things like energy requirements, capacity requirements, relative costs and GHG emissions.



Here we are showing graphs of the model outputs for each scenario's new supply mix that represents the lowest net system cost at the end of the 20-year study period. We need to consider both energy and capacity when planning the system, so we are showing the capacity resources to meet customer demand on the right, and the energy produced by those same resources on the left.

There is a lot of information we can understand from these two graphs, but there are two key points:

1. First, that energy needs in 2042 for each scenario (shown on the left-hand graph), are still predominantly provided through hydropower. Existing hydropower is supplemented with wind and imports. The biggest differences between scenario results are the amounts of the new energy sources.
2. And second, Scenario 4 has a significant step change as compared to the other scenarios.

Understanding this step for scenario 4 is important. The peak load increase in winter, due to assumptions of space heating electrification, is driving the need for increased capacity resources for scenario 4 in 2042, as shown in the right-hand graph.

Within the capacity outputs for scenario 4, there is a significant amount of thermal generation – this is the yellow portion that is about 50% of all capacity resource outputs. However, when we look at the left-hand energy graph, we can see that this thermal generation contributes only about 10% of the total average energy used throughout the year.

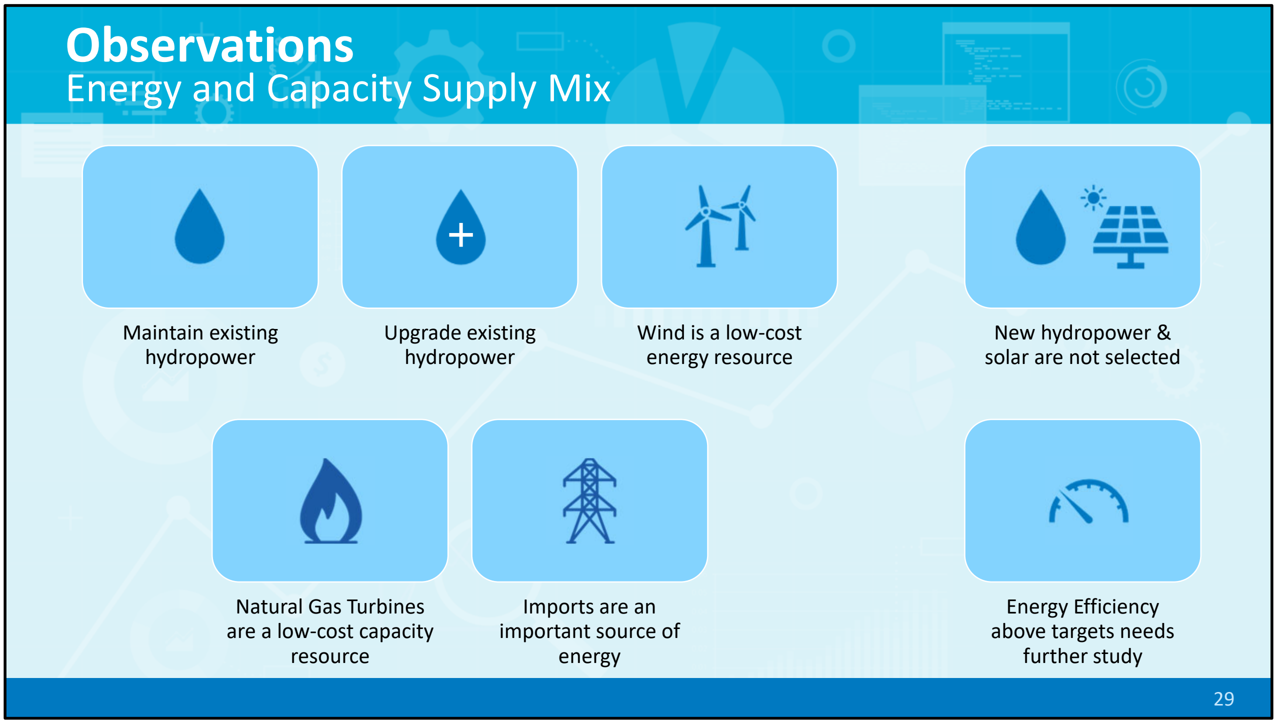
This tells us that for most of the year, energy is supplied through clean electricity, such as variable renewable resources like wind. However, as these resources cannot always be counted on when we have significant winter peak capacity needs, we need to pair these variable renewable resources with a dispatchable resource. In our results, this is thermal generation, fueled by natural gas, because it is one of the most cost competitive resources for providing capacity.

We also see, or in some cases don't see, other notable information on other resources.

- For example, there is no new hydropower generation selected. What is selected in every scenario, is an upgrade to an existing hydro generating station. (This is the skinny dark blue line in right-hand capacity graph). While this may seem insignificant as compared to other resources, it does comes into each of the scenario outputs and before other resources are brought in, indicating that it is a very cost-effective resource.

- There is also no solar generation selected.

- And finally, energy efficiency through demand side management, labelled as DSM on this slide, is very similar for all scenarios.



Again, to summarize some of the observations on the initial modelling results for the energy and capacity supply mix.

First, our existing hydro generation will still make up significant portions of the system, for meeting both energy and capacity needs. In addition, improving existing generating stations can be an economic choice to add capacity. Further study will help understand the true potential of expanding this resource option. What is also evident is that no new hydropower resources are included in the initial results.

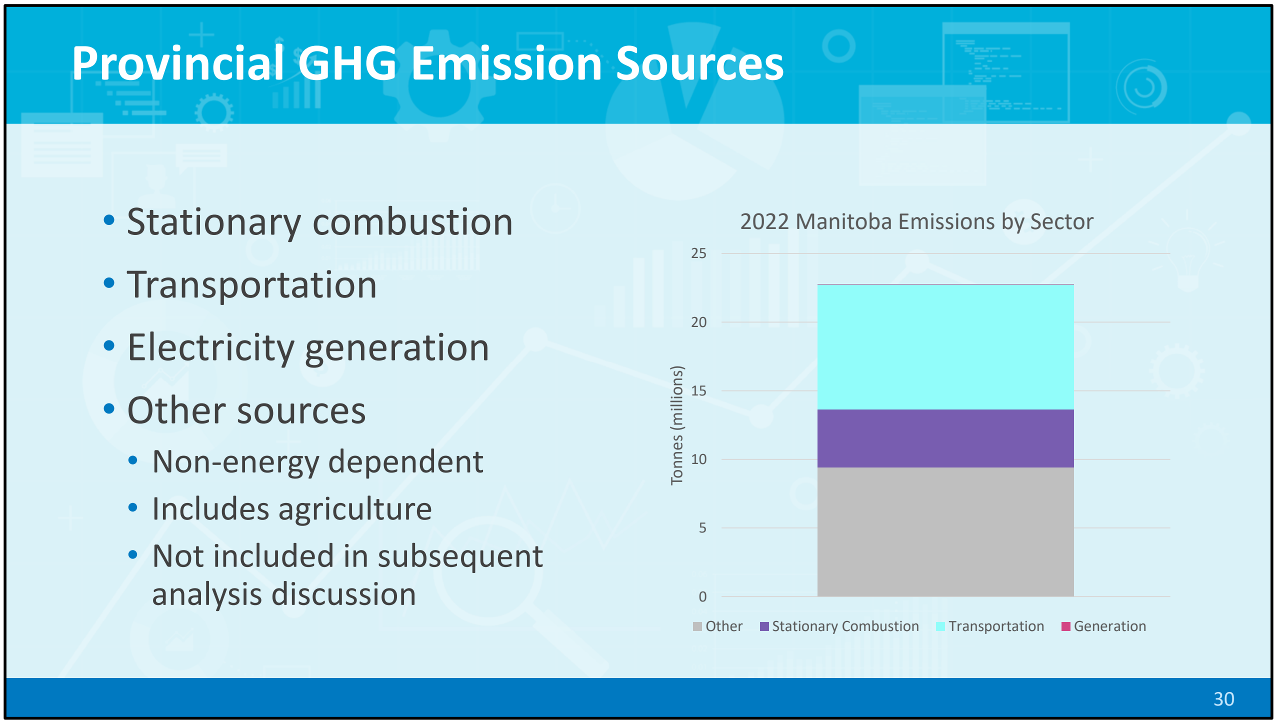
Next, wind generation is a cost-effective resource that provides significant energy. Due to its capacity limitation, other resources are needed to add capacity to the system to meet winter peak demand.

That leads to thermal generation. Thermal generation is an economic capacity resource, that can produce energy when needed. It also provides energy during a drought when other less costly resources do not provide enough energy.

Imported electricity from outside Manitoba can also provide energy during a drought or other extreme events such as weather disruptions. Such imports may also provide a low-cost source of energy.

Additional solar beyond that included in Efficiency Manitoba’s plan, is not selected by the model. Solar cannot meet winter peak demand, because it does not provide the capacity needed in Manitoba’s winters when we need it the most.

Finally, additional energy efficiency programming helps to meet some future energy needs, but more study is needed to understand its’ potential role. We understand this is an area of interest for many people and we are working on that now.



With the increase in thermal resources in the scenario outputs, we can expect that Manitoba Hydro's generation specific emissions would increase, even though new thermal generation would be mostly limited to meet peak demand. But we also want to know if within these initial results, do they support a reduction in GHG emissions across the province, particularly in other sectors like transportation and space heating.

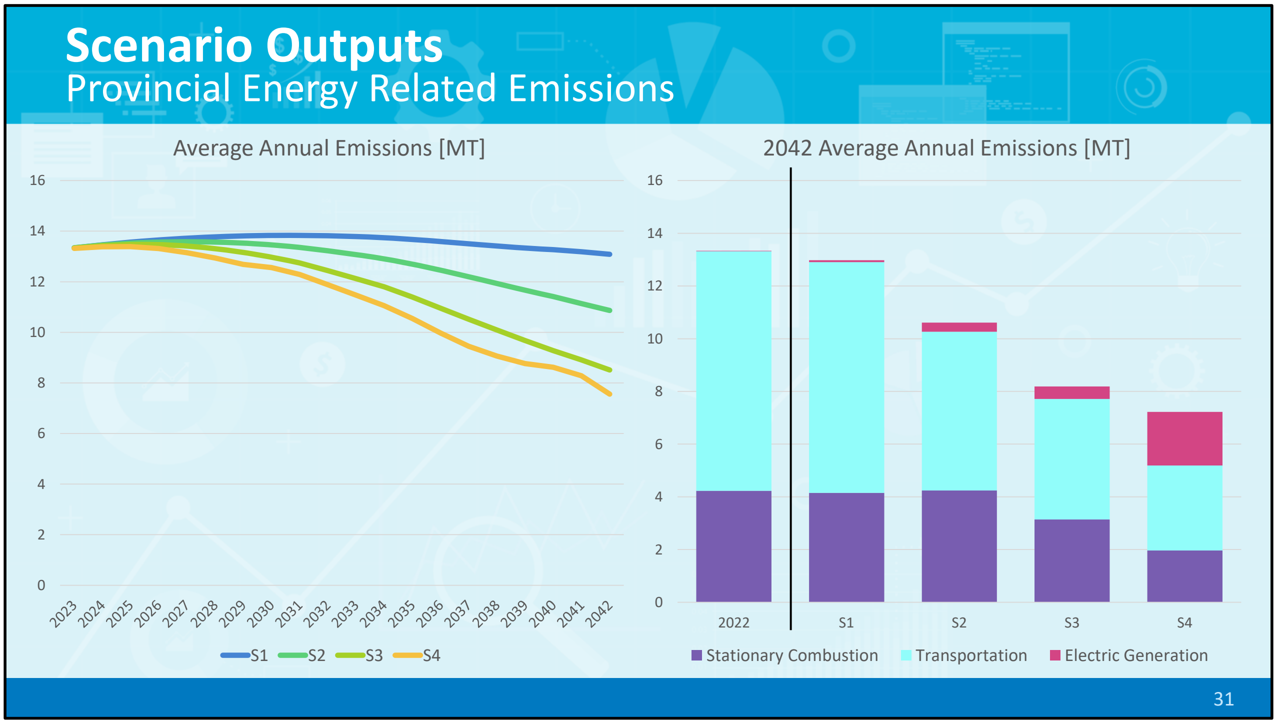
To answer this question, we first need to understand the sources of GHG emissions in Manitoba. Generally, they are separated into four categories, three of which are directly impacted by our customers' energy choices. These three categories are:

Stationary Combustion, as shown in purple, represents just under 19% of all provincial emissions and includes energy used for space heating, as well as industrial process

Transportation, as shown in light blue, represents around 40% of all provincial emissions. Moving from internal combustion engines to electric vehicles will directly impact electricity needs and future emissions.

And, **Electricity Generation**, as shown in pink (if you could see it at the top of the column), represents about 0.1% of all provincial emissions. Differences in generation fuel source may impact future emissions.

The “other” category, as shown in grey, are the emissions that are not energy dependent. These are generally GHG emissions from agriculture. Because these are not impacted by different energy choices, they are not discussed further.

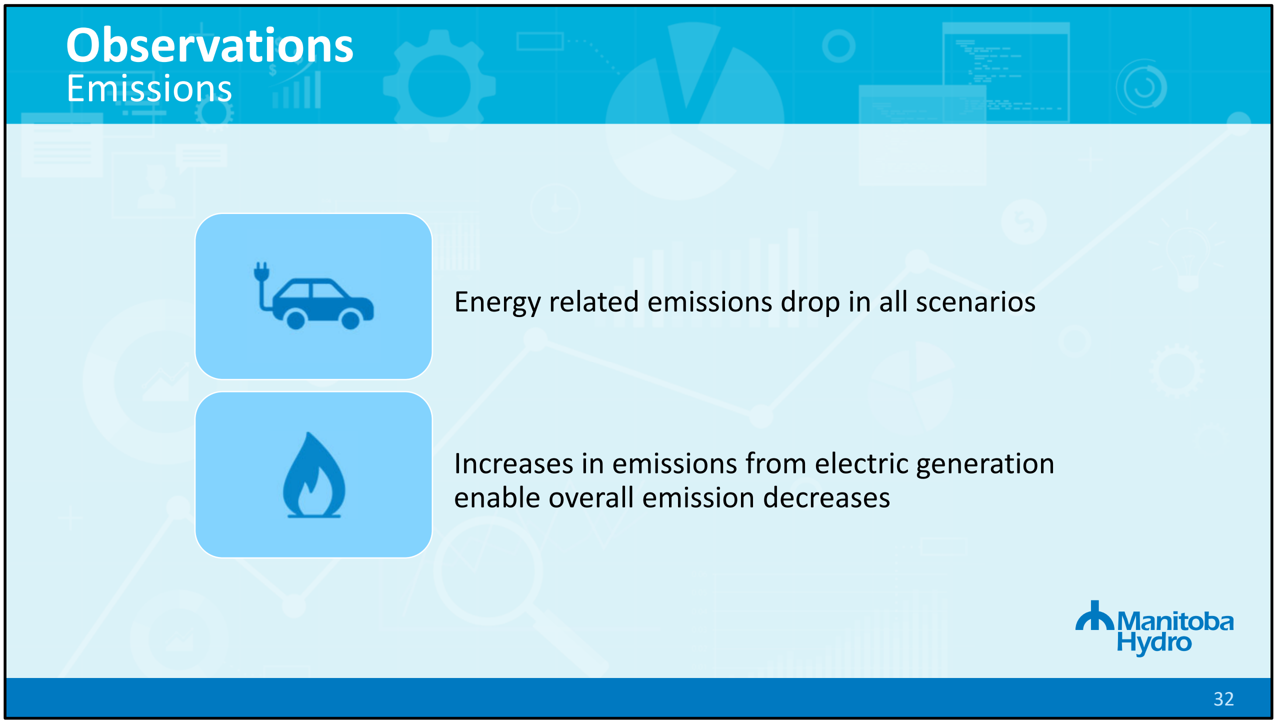


The left-hand chart shows the impact to the emissions in Manitoba from the initial modelling outputs, for the three categories of GHG emissions that are energy dependent.

As you can see, GHG emissions decline over time in every scenario, with scenario 4 representing the largest changes in energy use to reduce emissions.

While all scenarios use natural gas to generate electricity through thermal resources, overall provincial emissions still decrease. This is because emissions are reduced in other categories like transportation and stationary combustion (of which a significant portion is space heating).

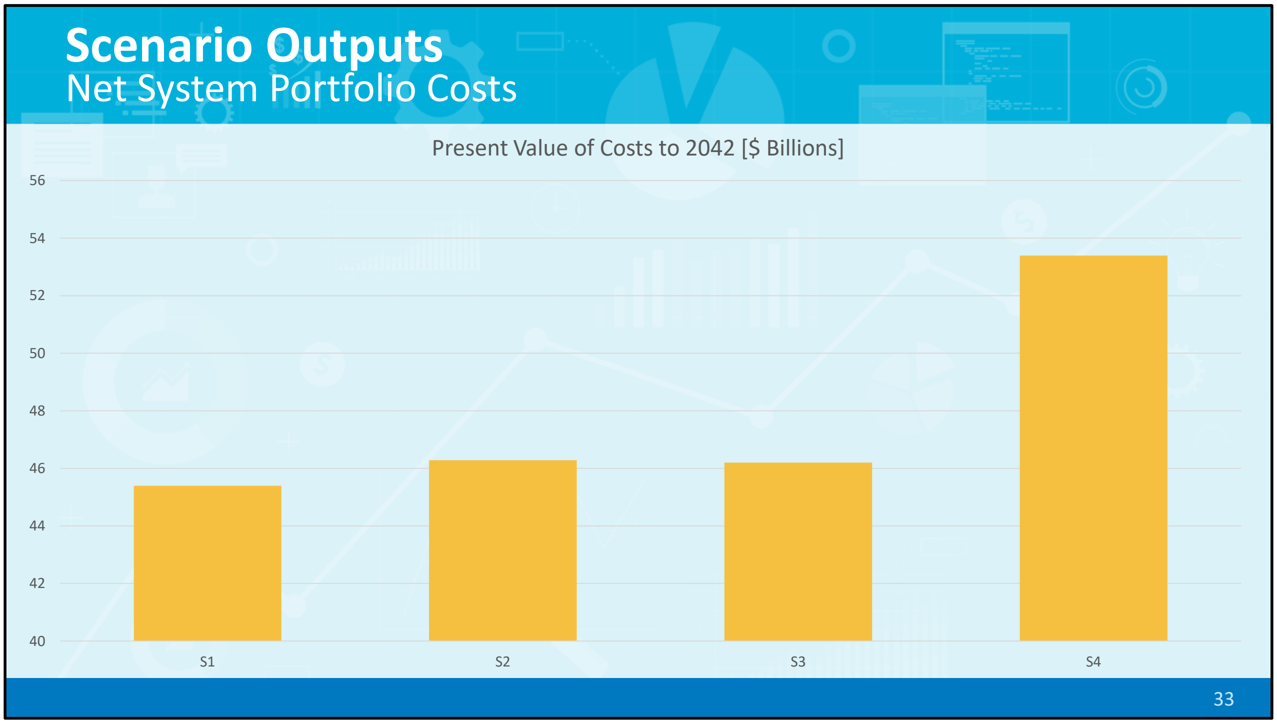
Again, while you may have more thermal resources they are run infrequently to help meet peak electricity demand. The majority of the time, when demand is lower, the electrification of transportation and space heating is served through clean electricity generation, such as hydropower and wind.



To recap, our observations on GHG emissions within the future scenarios:

First, total provincial energy-related emissions drop in all scenarios, even with the fact that the resource outputs include thermal generation, fueled by natural gas.

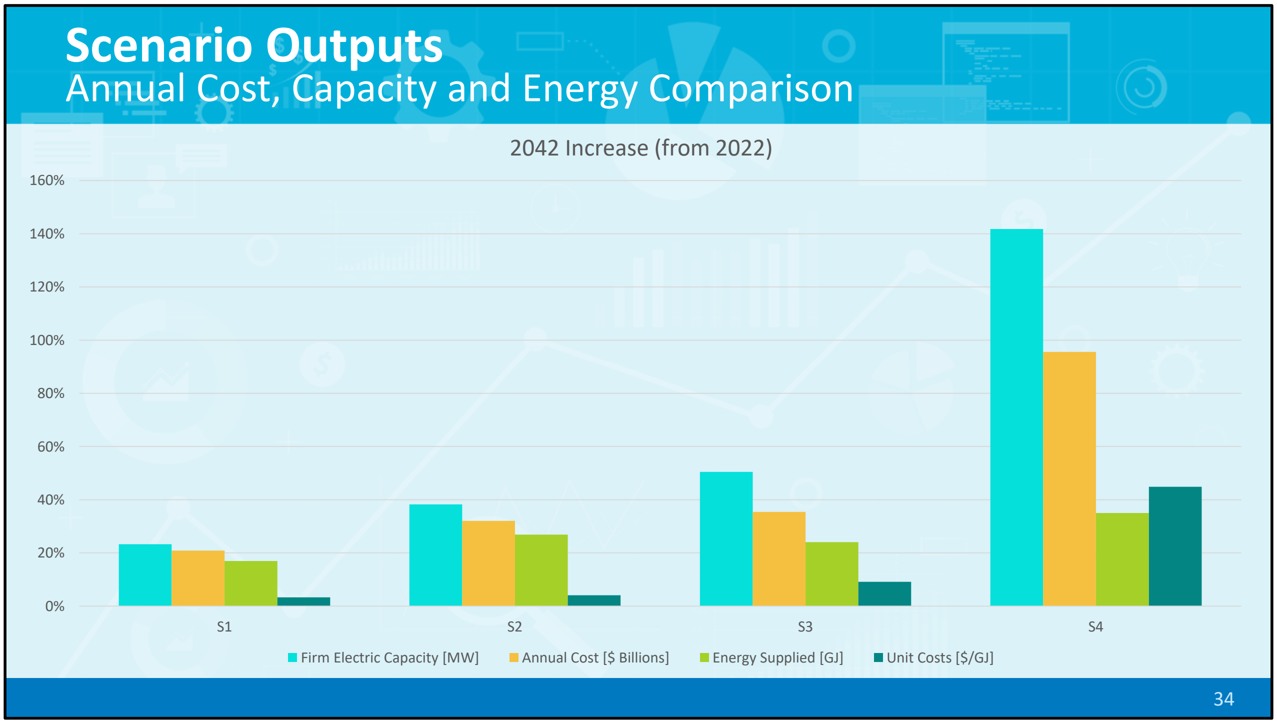
Second, a measured increase in emissions in electric generation, along with new renewable energy resources, can enable significant decreases in emissions from transportation and heating through electrification.



Now, let's look at one of the other outputs from the model — net system cost. Costs shown are the present value of the net system costs to provide electricity and natural gas service over the 20 year IRP study period. The net system costs include both capital costs as well as maintenance and operation costs, natural gas costs, transmission and distribution infrastructure costs, fuel costs, and finally import costs and export revenue.

These costs are generated from very high level estimates, for the purposes of comparing modelling outputs between the scenarios, to help inform decisions on developing the roadmap and near-term actions. These are not intended to be interpreted to support specific project decisions.

We see from this graph that the cost associated with meeting energy needs in scenarios 1, 2 and 3 are similar, while significantly more investment is needed for scenario 4. These numbers give a sense of what is needed to get to 2042 for each scenario.



Understanding how different metrics interact between the scenarios helps to inform the decisions needed to draft our Roadmap and Near-Term actions. One way is to look at the cost outputs and compare them to our energy (in green) and capacity (in teal). Unlike previously, energy is shown here as a combination of electric and gas energy needs. As well, the costs do not include impacts due to inflation.

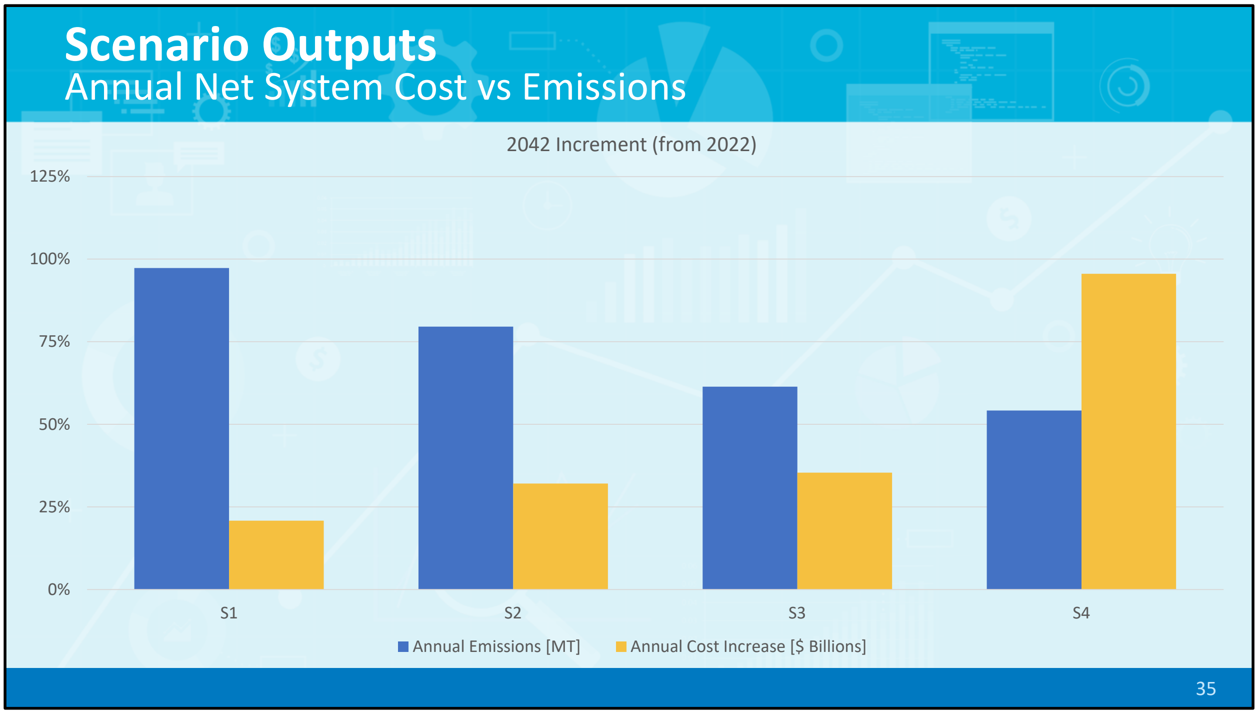
We are showing all values as of 2042, as a percentage of the value as of 2022. This provides a sense of the ongoing needs past our study period.

We can pull a few very key pieces of information from these graphs:

1. As we've seen before, scenario 1, 2 and 3 all have very similar results, with a step change to scenario 4. We can also see that the initial modelling results are showing that all scenarios will require some level of investment to meet future demand.
2. This step change also helps to illustrate that costs (in yellow) are driven

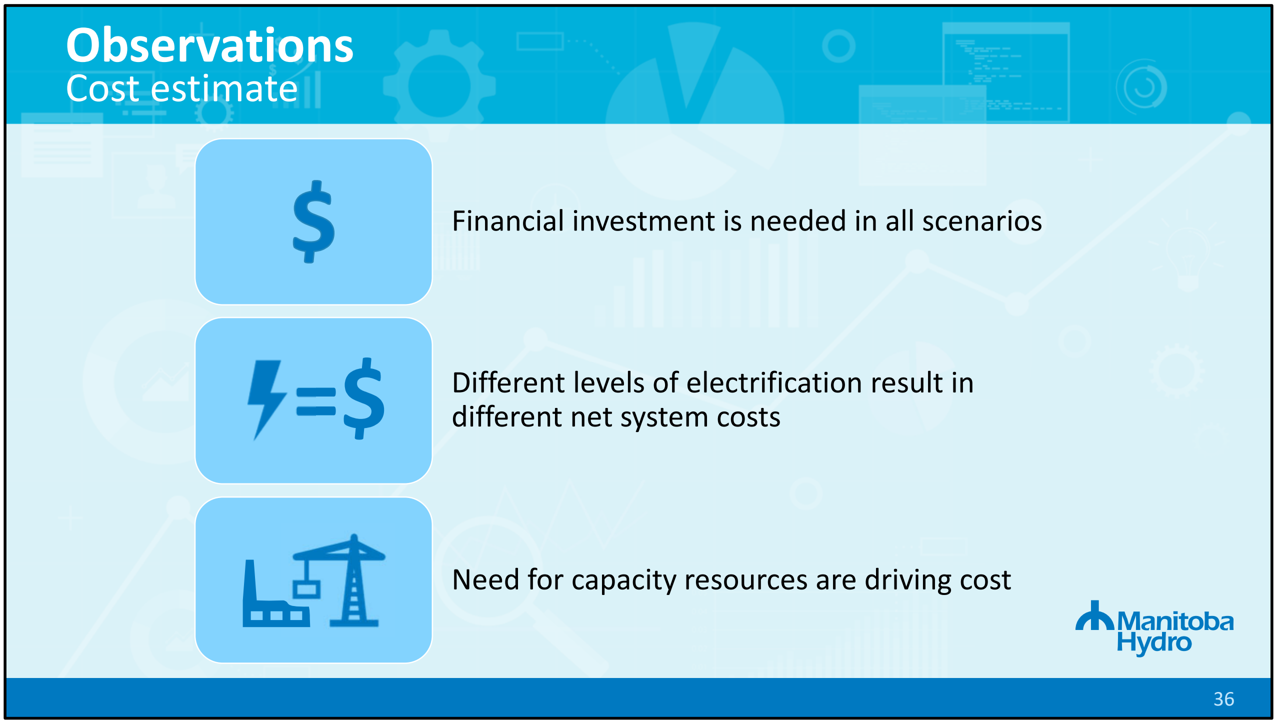
by firm capacity needs. This is because of the more proportional increases between capacity and cost in all scenarios, as compared to the energy increases.

We've also added in a metric for the unit cost of energy, which is the dark teal column. Here we take the energy in each scenario for both electricity and gas supplied and divide that into the net system cost. Even though in scenario 4 we can expect to sell more electricity, we can see from this result that the cost to serve that electricity is higher than in the other scenarios.

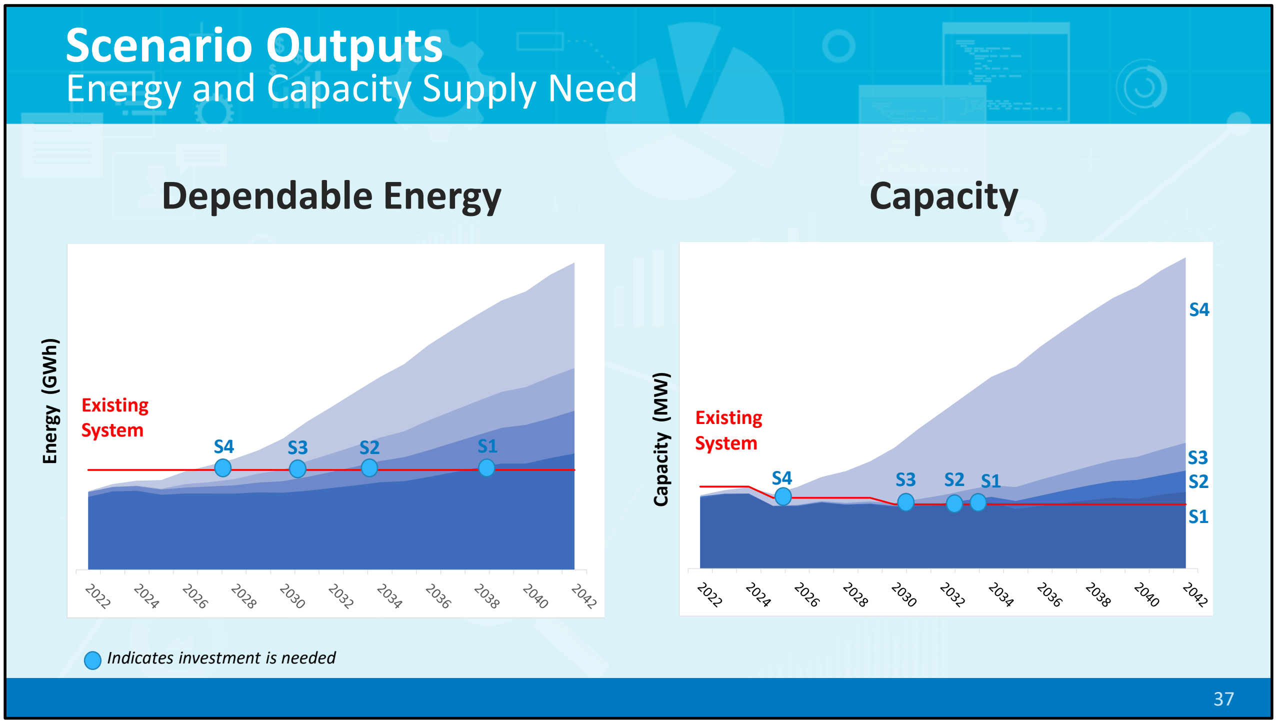


Another way to understand how metrics interact is through this graph that demonstrates how different customer energy choices in each scenario can impact system costs and GHG emissions.

While there is a steady decline in GHG emissions over the four scenarios, the change from scenario 3 to scenario 4 is important. There is minimal change in GHG emissions, but the net system cost increases significantly. This indicates that greater levels of electrification will be more expensive to support and alternative ways to reduce emissions at lower costs are needed. We'll talk about this more shortly.



From our initial modelling outputs, we can see that financial investment is need in all scenarios. However, the different levels of electrification we have studied within the scenarios result in very different impacts to the overall net system costs. These costs are fundamentally tied to these increasing levels of electrification that are directly increasing our winter peak demand and a corresponding need for capacity resources.

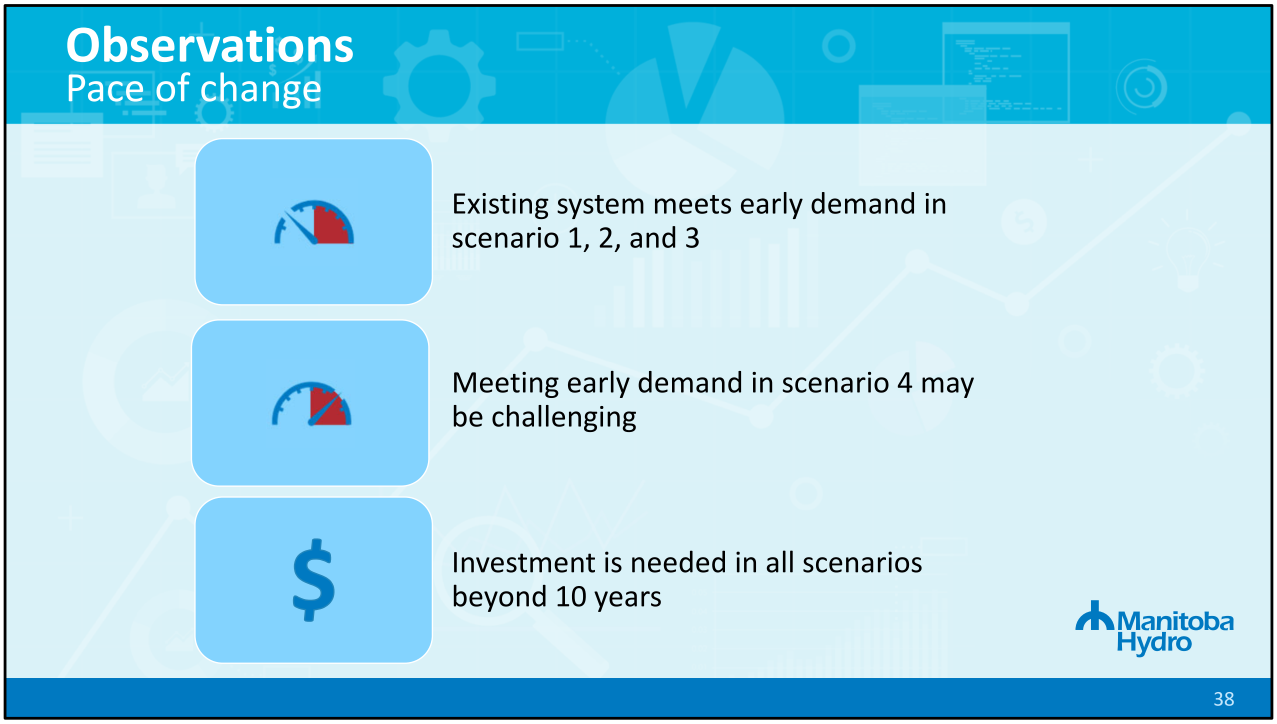


So far, the results shown have been focused on the end of the 20-year study period in 2042. There can be important observations relating to the pace of change over time to help understand the initial modelling results.

To show this pace of change, we've plotted the dependable energy on the left-hand side and capacity on the right-hand side, both over the study period. The blue area curves are what must be available for the four scenarios and the red line is what is available from our existing system. When the red line crosses the blue curves, is when new resources are needed to serve the required load.

For scenario 4, we can see on the capacity graph that new resources would be needed in only a few year from today. This poses a challenge because many of the new resource options being studied would required a longer time to plan, construct and put into service. Other solutions may need to be investigated.

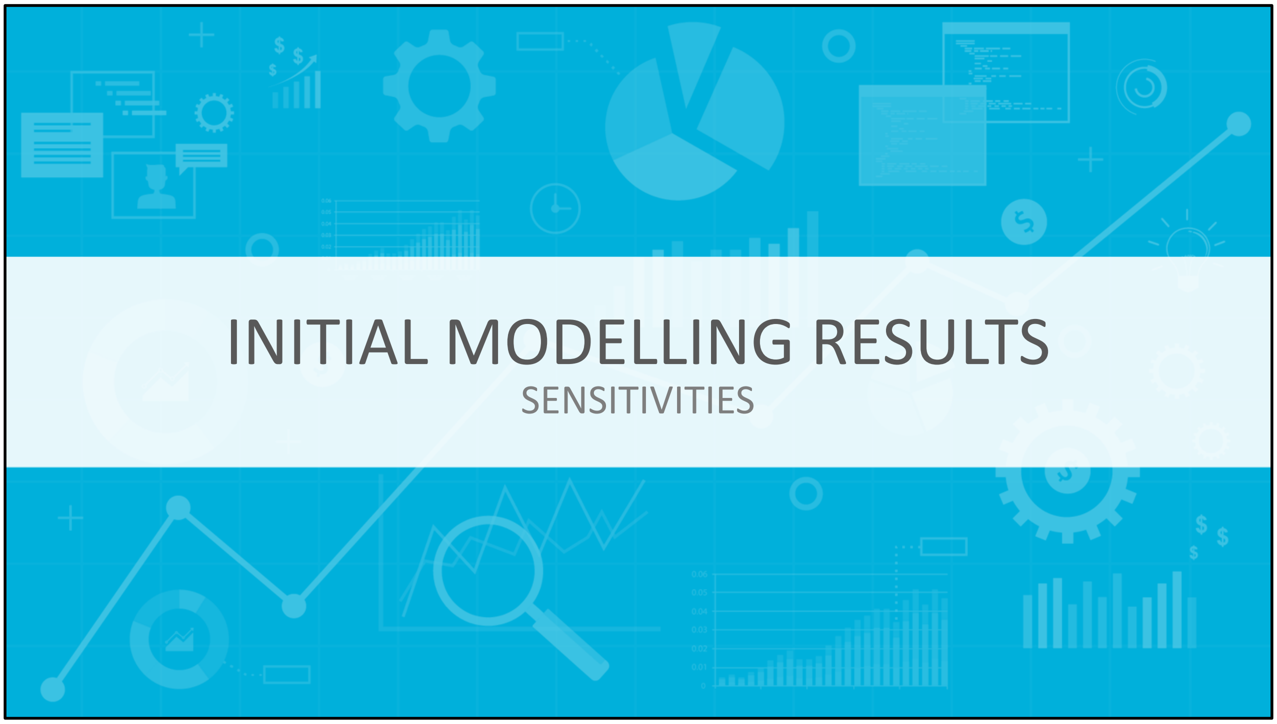
For scenarios 1, 2, and 3, the existing system continues to meet most of the energy and capacity needs. Some new resources would start to be required for these scenarios in the early 2030s timeframe.



Again, to summarize what we just discussed, the existing system continues to meet early years demand for scenario 1, 2, and 3.

Meeting the demand due to high levels of electrification in scenario 4, especially for heating, will be a particular challenge in the next 10 years due to the time required for approval and construction, or purchase, of new resources.

Beyond 10 years, all scenarios will need continued investment to meet demand, with a much greater requirement for scenario 4.



Thank you Lindsay. Hi, I'm Blair Mukanik.

As mentioned at the beginning of this session, some of the feedback we heard in our last round of engagement was that there needed to be different combinations of inputs between the bookends of the scenarios to properly model potential energy futures. We do this through our sensitivity analysis. We also used your feedback to prioritize some sensitivities for this discussion, so we could share how your feedback is influencing the initial modelling results.

Why do sensitivity analysis?

- Can explore "what-if" situations
  - Apply different constraints and interventions into a scenario
  - Understand how a select input or assumption impacts the modelling outputs
    - For example: resources, GHG emissions, cost
- Results of the sensitivity analysis help inform development of the roadmap and near-term actions

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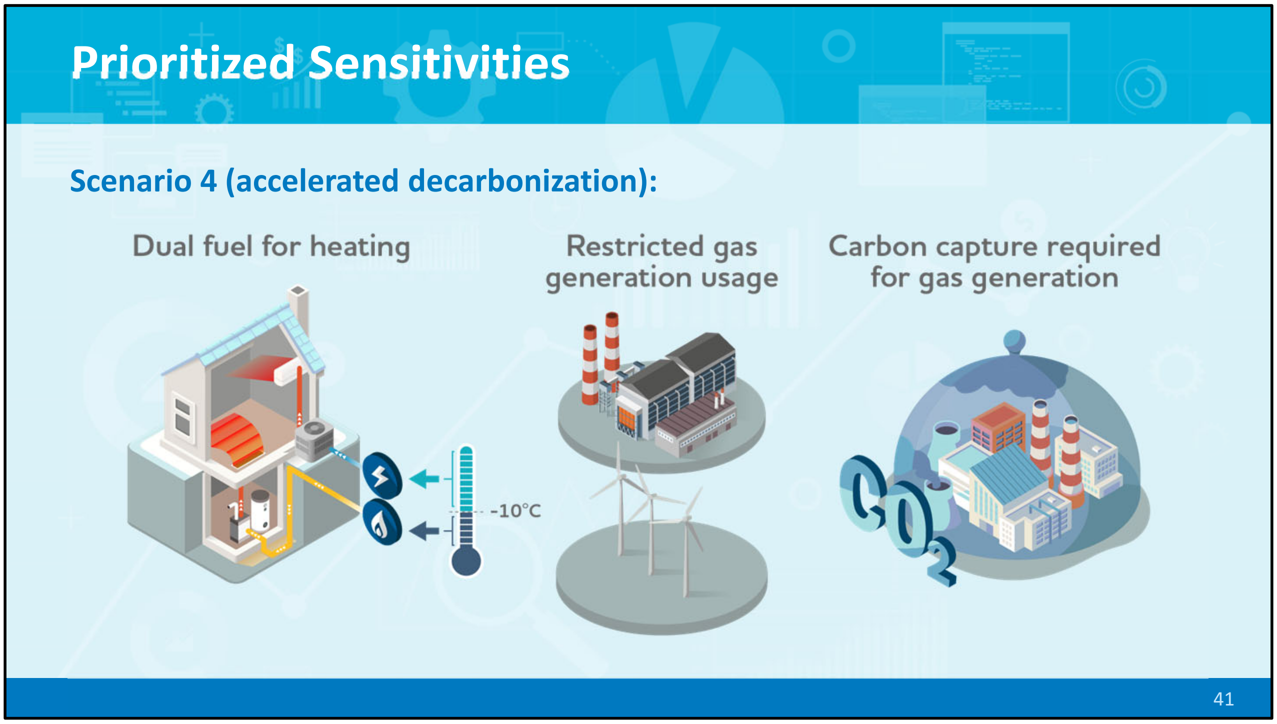
In sensitivity analysis, we make a change to an assumption or input in a scenario to understand how it might affect the model's outputs or results. We use sensitivity analysis, or "what if" analysis, to understand how individual inputs or constraints are driving output of the model.

Understanding this additional layer of information may help develop our roadmap and near-term actions. So, let's take a look at some examples of these sensitivities.



We’ve selected three sensitivities that we are going to present today. They are centered around costs and GHG emissions because these were key themes in the feedback from our prior engagement. There are other sensitivities we plan to investigate as well, and we’ll summarize those later.

For the purposes of this discussion, we will focus the sensitivity work around scenario 4, since it represents the greatest degree of change and provides the greatest opportunity to explore cost and GHG emissions impacts further.

4A. Dual fuel for heating

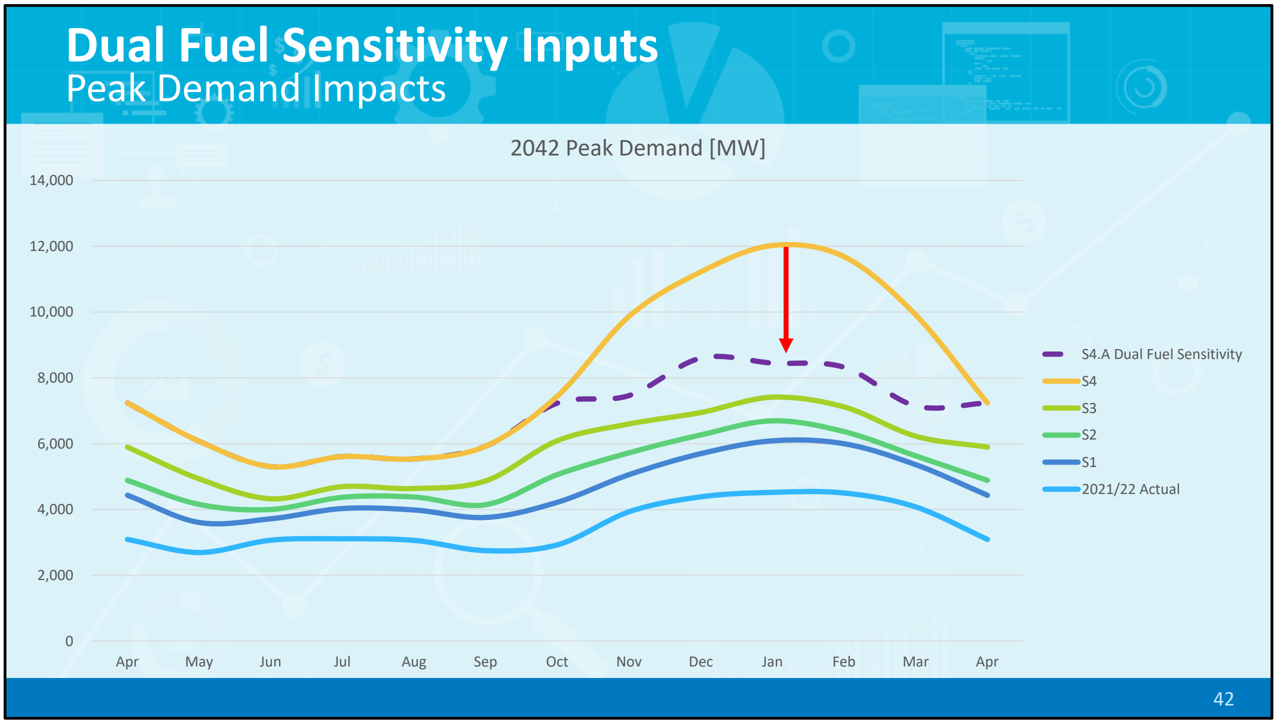
- This sensitivity explores a potential means of reducing the impact of electrification of space heating. Dual fuel heating systems use electric air source heat pumps to heat and cool buildings when above a certain temperature, and use natural gas for heating when below a certain temperature – in our case we’ve assumed -10C. This is something that’s also being explored in other jurisdictions. In our analysis, we assume that customers with gas heating replace their air conditioners with an air source heat pump when they reach end of life.

4B. Restricted Gas Generation usage

- This sensitivity explores reducing the contribution natural gas generation could make to meeting planning criteria. Specifically, it assumes natural gas generation is not included as a resource to satisfy dependable energy planning criteria, rather it can only be used to satisfy capacity planning criteria. In practice, this should mean natural gas generation is run less often than in scenario 4.

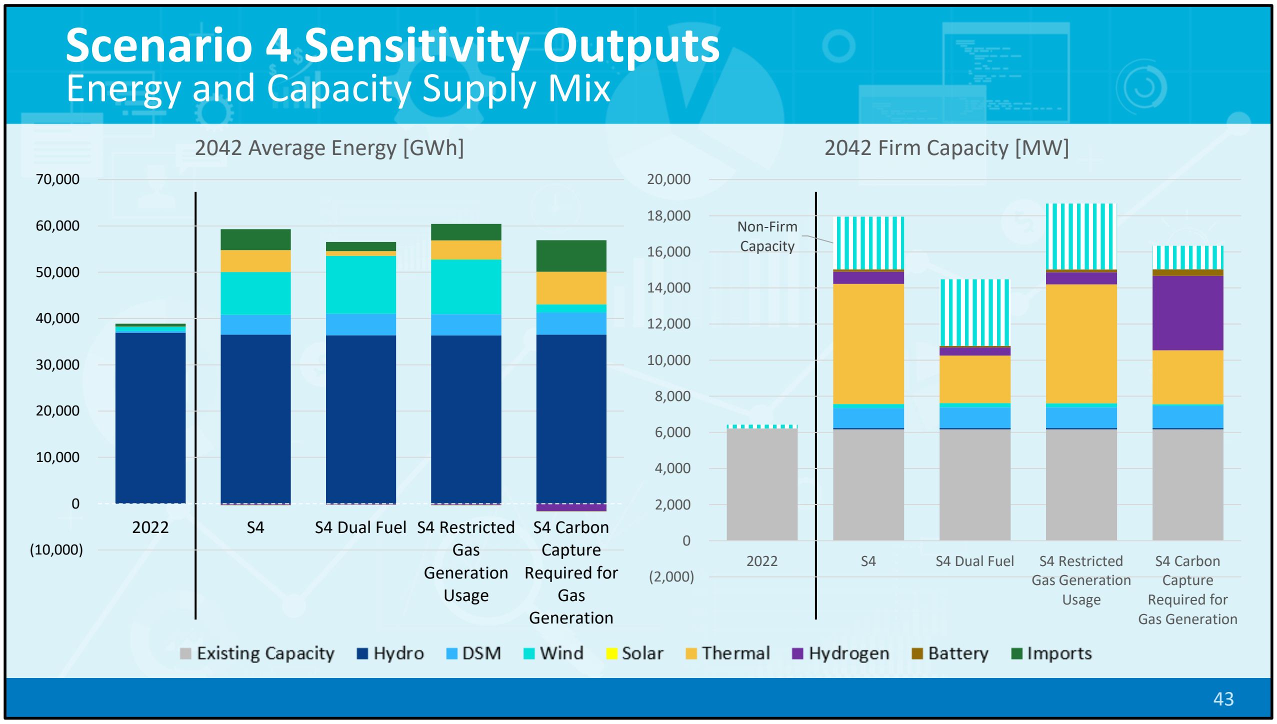
4C. Carbon capture required for gas generation

- This sensitivity explores a potential future requirement to capture and store carbon emissions from natural gas plants. This has been talked about in early proposals for federal Clean Electricity Regulations.



This graph is a repeat of the peak demand curves shown earlier in the presentation, but here the dashed line shows the impact of the dual fuel sensitivity on demand in scenario 4. If customers chose to use dual fuel heating systems, there would be much lower winter peak electric demand than in scenario 4 where we assumed natural gas heating systems would be converted to electric heating systems at end of life.

The other two sensitivities do not impact demand, only resource options, that is why they don't show up as separate lines in this graph.



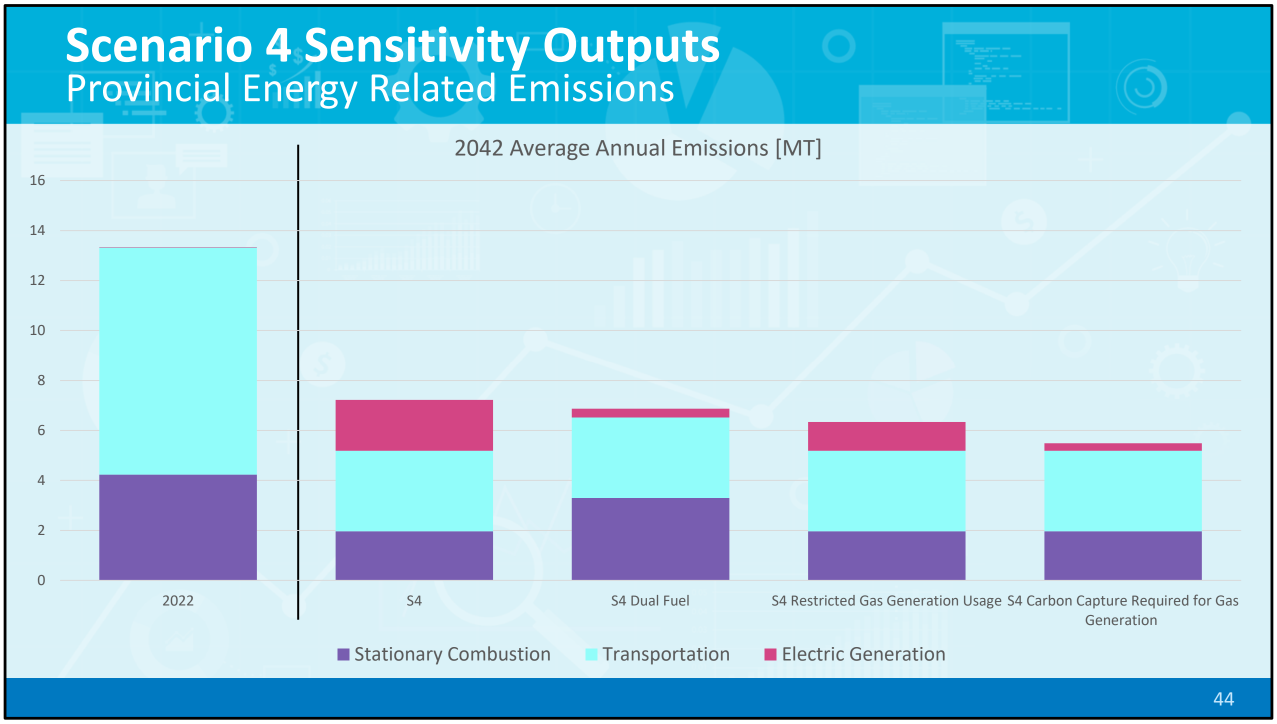
These charts provide similar information to what was provided earlier for scenarios 1 through 4, but focus instead on scenario 4, and the 3 sensitivities. This is how the supply of energy, at left, and capacity, at right, could look in 2042 for each of the 3 sensitivities, as compared to scenario 4 and to 2022.

Starting with capacity, at right, we see a lot less new capacity is needed under the Dual Fuel heating sensitivity than in scenario 4. When looking to energy, at left, we see less thermal generation, which should result in lower emissions from electricity generation. The resulting total emissions will be looked at shortly, including those from both electricity and natural gas use.

Moving to the restricted gas generation usage sensitivity, we see less difference between it and scenario 4. Generally, a bit more wind would be built to provide energy, and gas generation would be run less often.

Lastly, the Carbon Capture and Storage (CCS) sensitivity reflects a significant change compared to scenario 4, where the yellow segment represents natural gas generation with carbon capture and storage, and the purple is hydrogen generation. These two resources largely meet future capacity and energy needs, with carbon capture and storage providing both capacity and energy, and hydrogen primarily providing capacity. The purple bar for hydrogen in the energy graph which is below the zero line shows that hydrogen takes more energy to produce than it provides in electricity. Once an investment is made in carbon capture and storage, it is economic to run the resource for energy, rather than to build additional wind.

Once again these results are based upon a lowest net system cost resource selection.

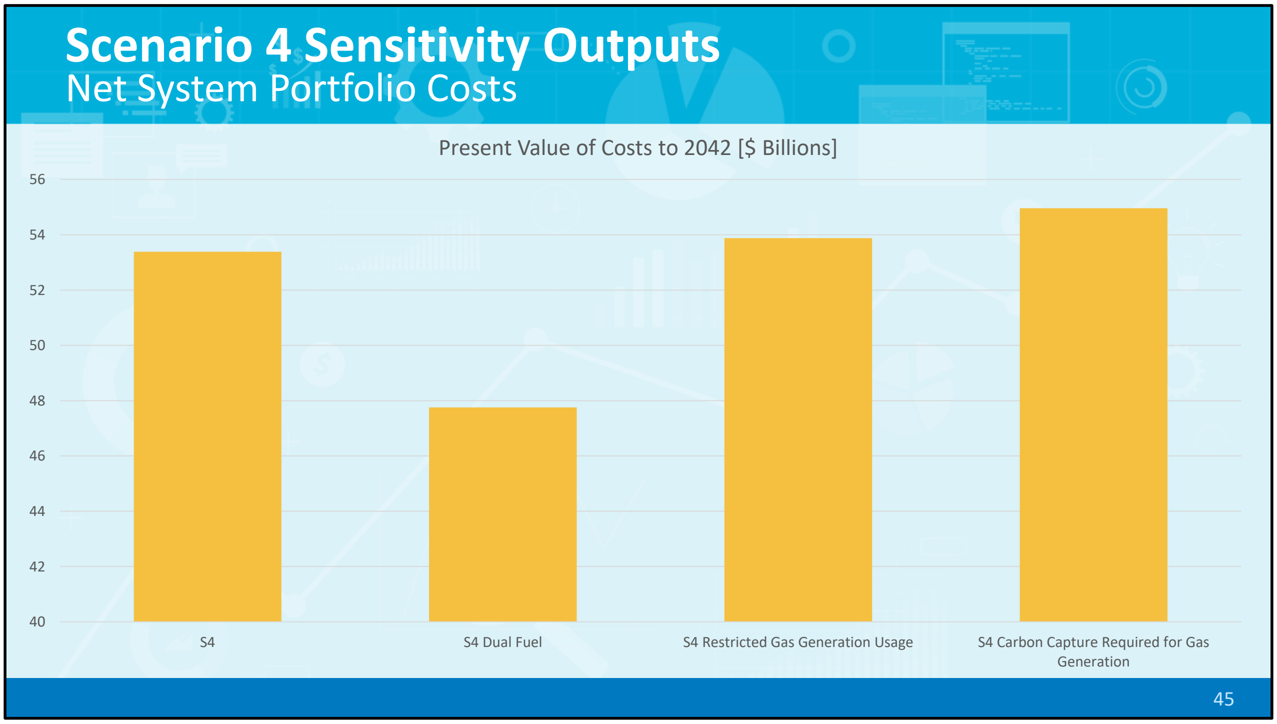


In this chart, we compare emissions amongst the 3 sensitivities to scenario 4 in 2042 and to 2022. We see again, that scenario 4 represents a significant reduction in emissions across the 3 sectors presented versus today, with the sensitivities showing the impact of a change in assumption.

An interesting finding is that there is little difference in emissions due to Dual Fuel heating as compared to the base scenario 4, rather there's a trade-off between emissions from natural gas for space heating (part of purple), and emissions from electric generation to electrify space heating (pink).

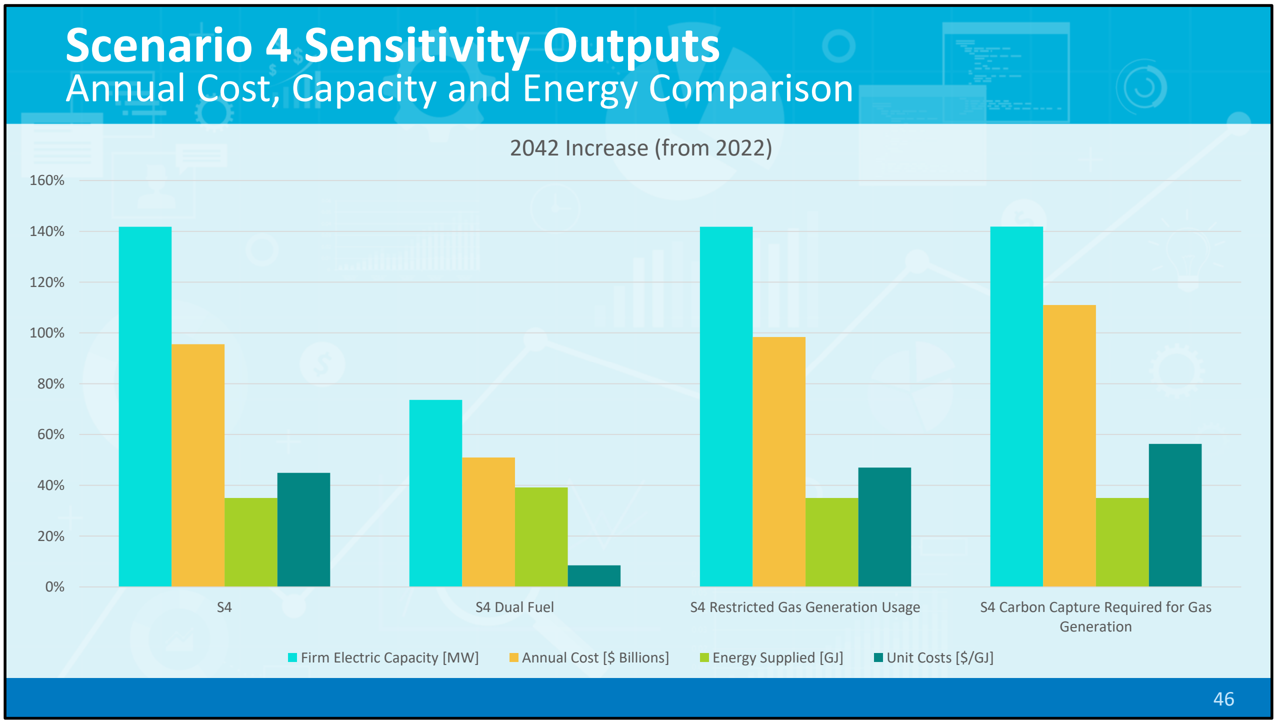
The other two sensitivities show that an impact can be made to total emissions by changing assumptions around future natural gas generation options.

We can also see that in 2042, at the end of the IRP study period, GHG emissions remain. To achieve net zero emissions by 2050 within the emissions sectors shown, for scenario 4, and its sensitivities, customers would need to make further changes to the energy they use for heating and transportation in the remaining 8 years, as well emissions from electricity generation would also need to be reduced. It is possible that in the future, clean fuels like renewable natural gas and Hydrogen, and other emerging technologies, may be available to as additional tools to reduce emissions.



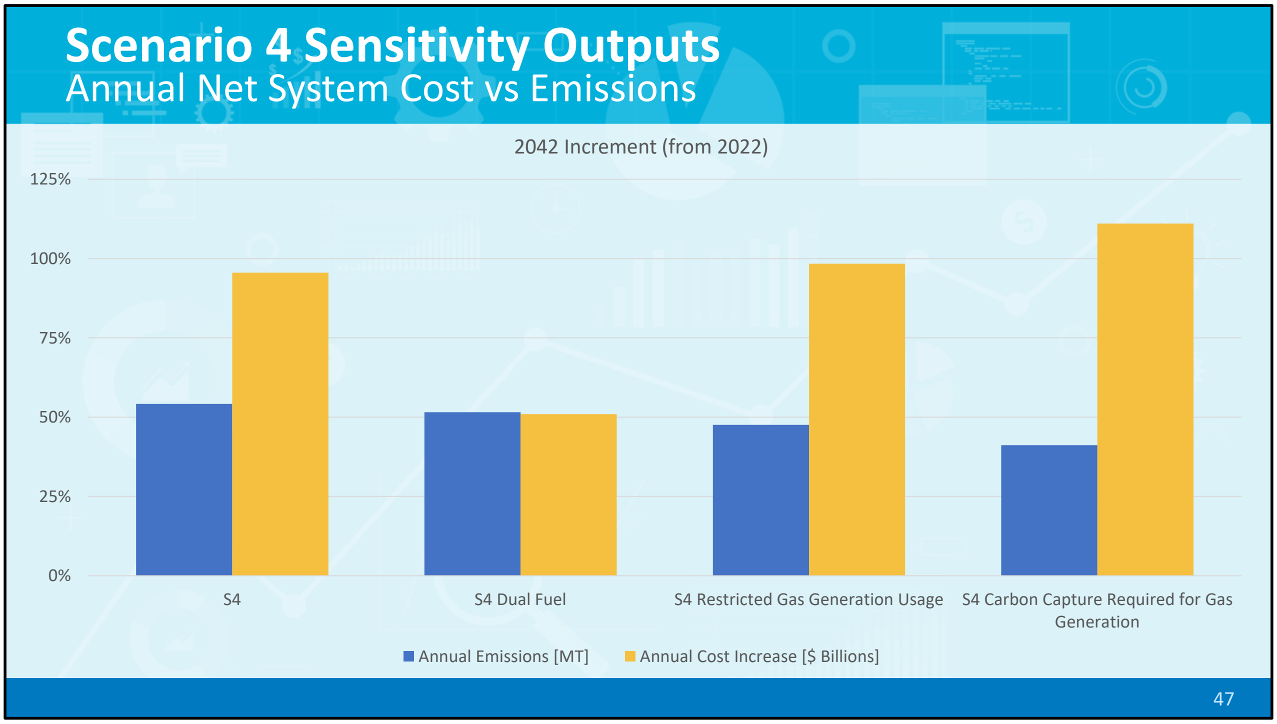
This chart shows the present value of net system costs to provide electricity and natural gas service over the 20 year IRP study period.

Again, these are considered very high-level indicative estimates intended to allow for comparison between scenario 4 and the three sensitivities. It should also be noted these are utility costs, and don't factor in costs or benefits to customers related to their future energy choices, such as cost to customers of equipment they may need to purchase.



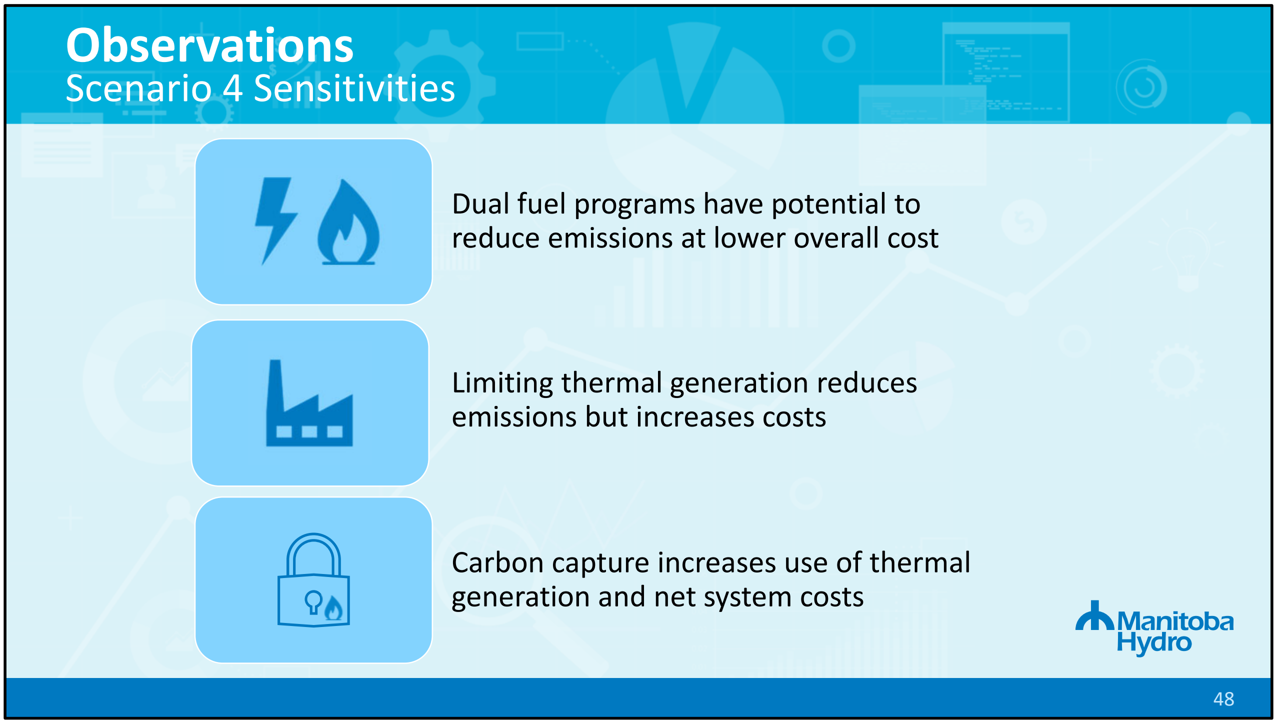
This chart shows similar information to what was presented for the four scenarios previously. Focusing first on the left two columns for each scenario, we've shown total capacity and annual costs for 2042 and compared them to 2022. Here we see a similar relationship as we did when looking at the four scenarios, that electric capacity and total cost are closely tied, this is particularly evident when comparing scenario 4 with the dual fuel sensitivity where both capacity and cost are significantly reduced.

The second two columns for each scenario show energy supplied, including from electricity and natural gas and cost per unit of energy. Here we see the cost per unit energy for the dual fuel sensitivity is substantially lower, while the unit energy costs for the two sensitivities related to natural gas generation result in increased cost. Again these percent increases do not include the impact of inflation.



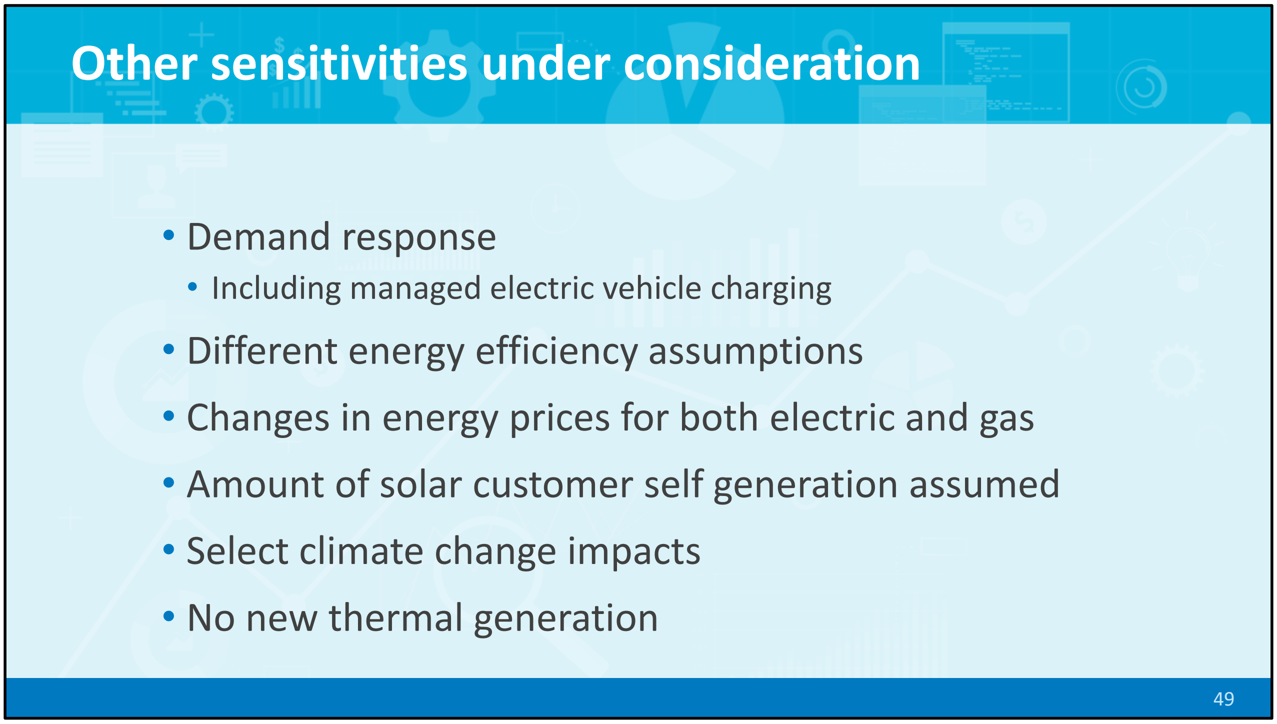
One more graph for sensitivities – this graph shows the general relationship between emissions and cost when comparing the 3 sensitivities with scenario 4 in 2042 vs 2022. Of note with this chart is that there is a significant difference in cost between the dual fuel sensitivity and scenario 4, with little difference in overall emissions. This analysis suggests that dual fuel heating may be a cost-effective means of reducing Manitoba's emissions because it can avoid costs associated with new electricity resources that provide capacity. This is consistent with findings in other jurisdictions.

Emissions could be further reduced through Restricted Gas Generation Usage, or the use of carbon capture and storage technology, but it would cost more to achieve these lower emissions.



In summary,

- First - Dual fuel programs have the potential to:
    - Reduce emissions at a lower overall cost
    - Avoid the level of investment associated with scenario 4
    - Make better use of existing grid infrastructure
    - Allow for future advancements and availability of alternative fuels or application of other space heating technology to facilitate further emission reductions
- Second - Emissions from electricity generation can be reduced by limiting thermal usage for energy or by using carbon capture however this would increase Net System Costs.
- Third - The economics of carbon capture result in the increased use of natural gas thermal generation rather than building wind resulting in increased Net System Costs.



As I mentioned in our earlier discussion there are other sensitivities we plan to investigate as well.

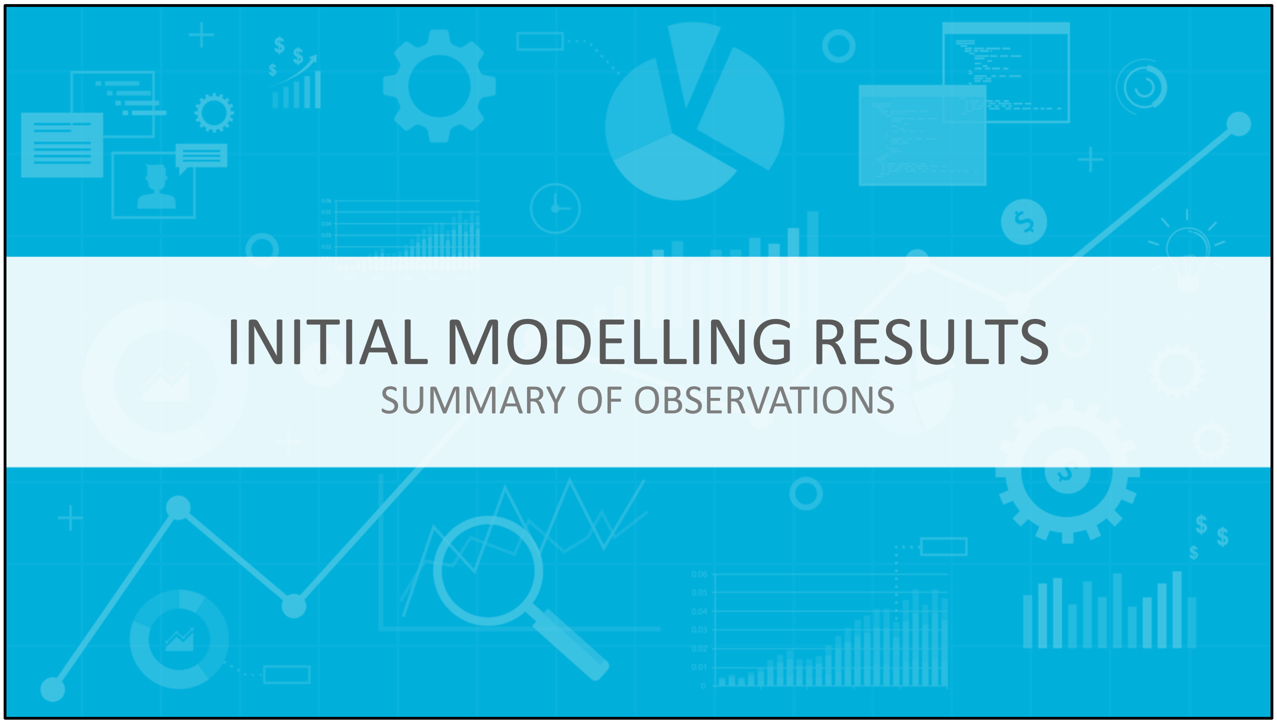
The first of these is demand response. Demand Response measures are being explored to assess the cost effectiveness of reducing electricity use during peak demand hours in the winter. Examples of Demand Response Measures include managing EV charging loads, Time Varying Rates, and Controlled Thermostats for Electric Heat.

Further analysis of Energy Efficiency Measures is also planned using different assumptions about costs, for example.

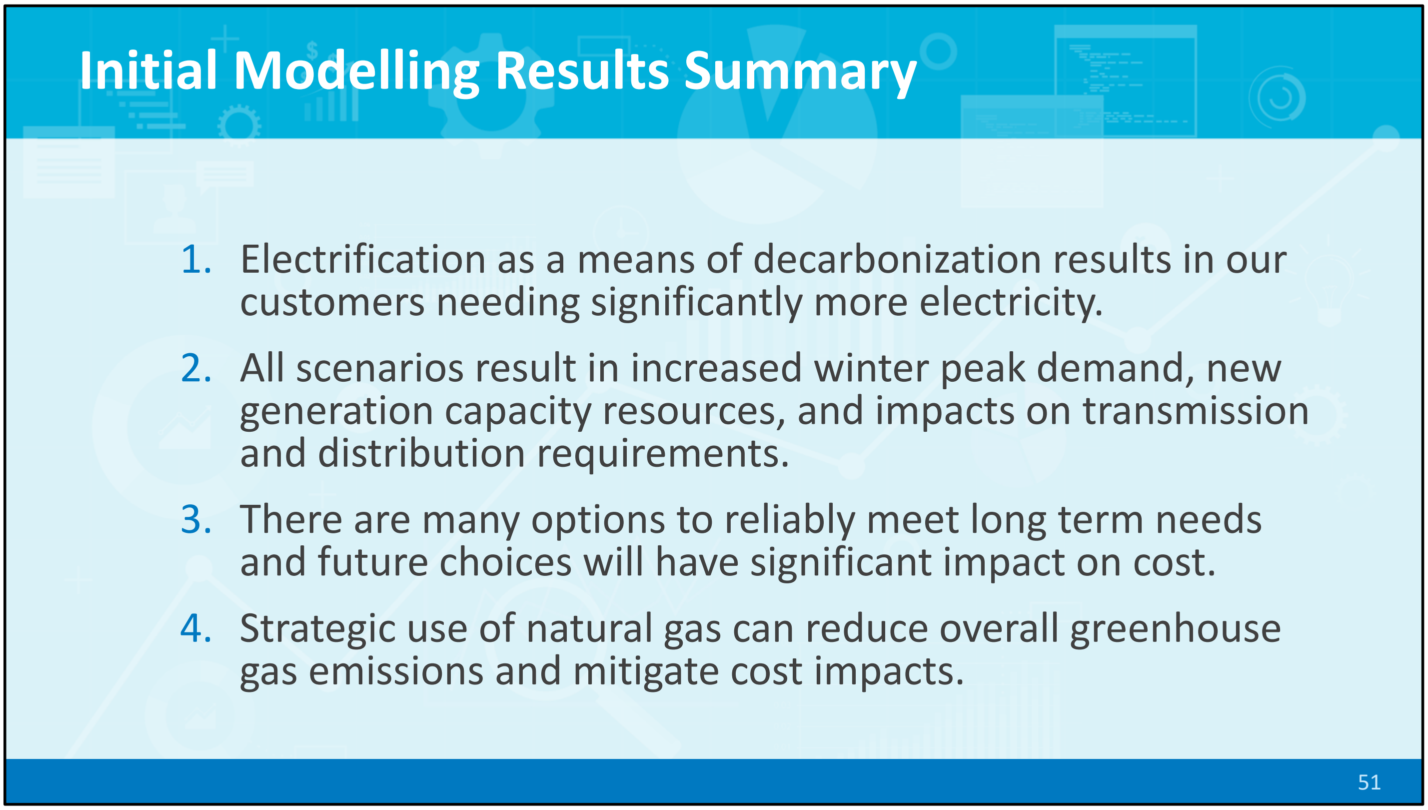
Examining the impact of market price projections will help to understand impacts to exports and imports, as well as gas commodity costs.

We're also planning to look at different levels of solar customer self generation, as well as select climate change impacts on the physical environment like warming temperatures and changes to water flows.

The impact of not building any new natural gas generation is also of interest and something we’re looking into.



We'll now review a summary of observations of our initial modelling results.

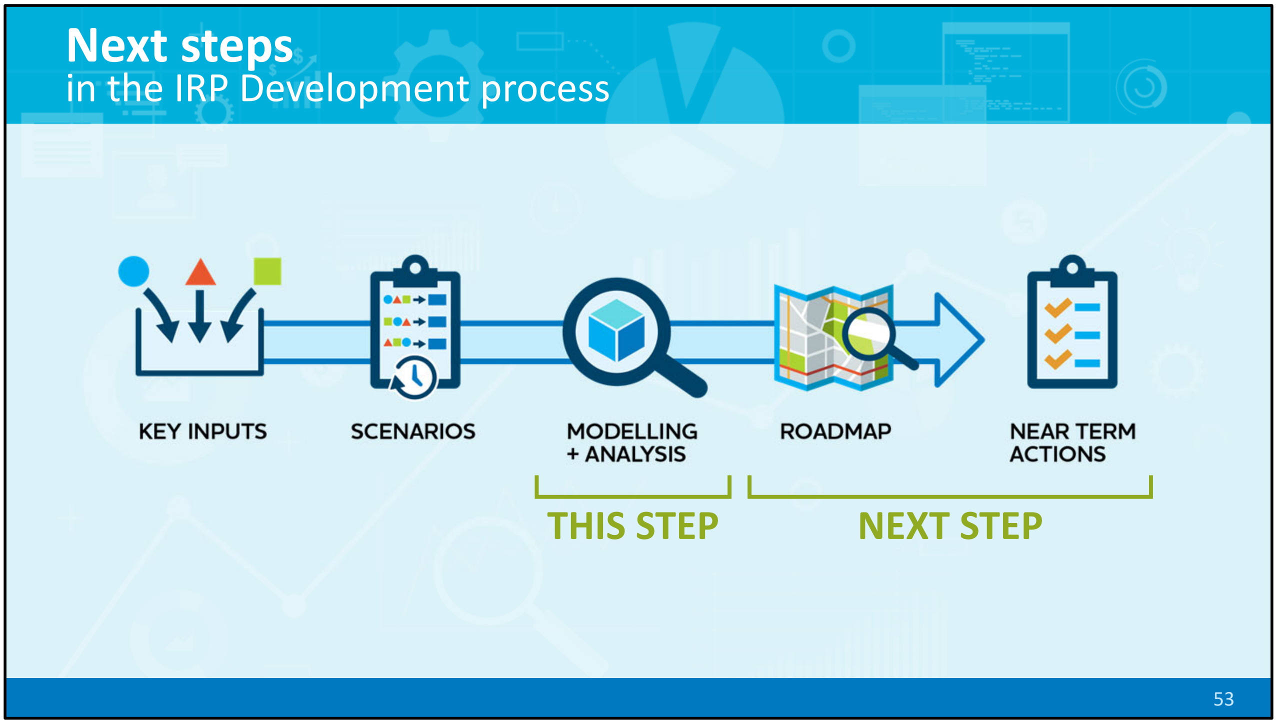


We've summarized the information presented on the Initial Modelling Results into four high level points:

1. Electrification as a means of decarbonization results in our customers needing significantly more electricity. This was shown in the electric and natural gas load projections for each scenario, particularly Scenario 4.
2. All scenarios result in increased winter peak demand, new generation capacity resources, and impacts on transmission and distribution requirements. This was shown in the initial results for resources and cost.
3. There are many options to reliably meet long term needs and future choices will have significant impact on cost. This was shown through our sensitivities around future resource options and customer choice on dual fuel.
4. Strategic use of natural gas can reduce overall green house gas emissions and mitigate cost impacts. This was shown through investigation of the sensitivities.

I want to thank everyone again for their participation in the discussions today.

Before we close out this session, we wanted to share the next steps in our IRP Development process.



As we move to on next step of developing our roadmap and near-term actions, we first need to finish our current step of modelling and analysis.

We will be taking your input and feedback gathered from today to help shape any additional sensitivities to model. We will also complete our post modelling analysis.

We will then use this information to develop our roadmap and near-term actions.

The next round of engagement is planned for next spring. We are expecting to have our preliminary outcomes by that time, ahead of publishing the final IRP Report in the summer of next year.

The development of an IRP is a repeatable process – it is not a one-time occurrence and is expected to be completed on a recuring basis.

The 2023 IRP, Manitoba Hydro's first comprehensive IRP, is a foundational step towards planning for the future energy needs of our customers and Manitobans – it will not provide all the answers. It will be critical that the IRP roadmap has the flexibility to adapt as the future unfolds, so we can continue to leverage new technologies and solutions.

When specific investments are needed to meet future energy needs, these will be incorporated into the analysis of future IRPs. Existing processes to review and approve investment decisions and actions will still be followed.

QUESTIONS

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