0:0:0.0 --> 0:0:31.270
Scott Chomos
Finally, in terms of housekeeping, you'll notice when the meeting started today that there's a little note that we are recording this. So just a reminder that before we get into the presentation for privacy reasons, I want to advise that the session is being recorded for future reference clarity as required. The recording will be stored on the cost of service methodology review web page at www.saskpower.com. It will remain in the site until it no longer serves a business purpose.

0:0:31.360 --> 0:0:42.910
Scott Chomos
And/or has met its retention period by staying in the teams meeting. You are consenting to being recorded for the purposes outlined. So after this session we will provide a link to the recording once it's downloaded and been saved.

0:0:50.260 --> 0:0:50.930
Scott Chomos
Next slide, rod.

0:0:54.130 --> 0:1:12.120
Scott Chomos
So a land acknowledgement. So this meeting is hosted from the traditional territory of the Treaty foreign nations and the home of the Metis. We make this acknowledgement and the spirit of reconciliation because we are all treaty people as we each make our homes in the traditional territory of the Indigenous people of Canada.

0:1:14.130 --> 0:1:32.340
Scott Chomos
And finally, for those of you who have participated in a SaskPower meeting in the past, you'll know that before we start any meeting with groups of five or more, we like to start it with a safety moment. So in this case, we're using a very timely one, just using electricity safety at home.

0:1:34.0 --> 0:2:2.350
Scott Chomos
A few of these are obvious, but just remember to turn off electricity at the breaker panel. If the repair is needed. This is something that again is quite obvious but is often easy to forget. Water and electricity don't mix, so if you ensure you don't plug anything in with wet hands or well standing on a wet floor, if you drop an electrical device in water while using it shut off the power supply or homes electrical panel before unplugging or retrieving this device and never use power tools and wet conditions outside. With people plugging in their vehicles, this is also a pretty timely one.

0:2:14.300 --> 0:2:32.0
Scott Chomos
Replacing freight extension cords, so inspect the extension cord regularly when we're moving a cord from the socket, hold the plug, not the cord, and pulling on the cord can wear out the cord and increase risk of an electrical shock or fire. Finally, the use of correct bulbs and light fixtures and lamps. You know, an example of this is using 100-watt bulb for a lamp rated for a maximum of 60 watts will draw more power through the wires than it can safely handle.

0:2:43.0 --> 0:3:6.590
Scott Chomos
And again, just a couple thoughts on when to call an electrician if you're having frequent problems with blowing fuses or tripping circuit breakers. If you have a tingling feeling when you touch an electrical appliance; if there's discolored or warm wall outlets or sparks coming from an outlet; if you see flickering or dimming lights; or lastly a burning or rubbery smell coming from an appliance. So, I think that's it for some of the introductory pieces. With that, I'm going to turn it over to Rod MacQuarrie, who's going to take us through a bit of an overview on what exactly the cost of service process involves.

0:3:26.420 --> 0:3:39.190
Rod MacQuarrie
Thank you, Scott, and good afternoon, everybody. Thank you for joining us this afternoon. I'm just going to give a very brief overview of cost of service. We felt that this was important based on feedback from our initial kickoff meeting. We wanted to give a little bit of a brief overview as to what caused the service actually is and of course, Elenchus is going to go into much more detail than this, but I thought it was a good idea just to give a brief overview. So, the cost of service is a methodology used by SaskPower to allocate our assets, what we refer to as the rate base and our expenses to each of our customer classes.

0:4:3.400 --> 0:4:19.790
Rod MacQuarrie
We use methodologies. Commonly it's a commonly used approach in our in the utility industry under the National Association of Regulatory Utility Commissioners. The manual that we use called NARUC, the majority of utilities use NARUC as a guideline for their approach to cost the service methodology.

0:4:20.750 --> 0:4:37.980
Rod MacQuarrie
And the model works under the assumption that any increase in SaskPower’s expenses are passed along to our customers. Assuming that we can achieve our target ROE if we're not allowed to pass through those expenses to customers, then we take a write down to net income and our return on equity is affected.

0:4:39.200 --> 0:5:5.710
Rod MacQuarrie
Our cost of service model is regularly reviewed by independent consultants approximately every five years to ensure that we are in accordance with industry standards and that's exactly what we're doing here in the session and the cost of service model is based on the principle that each customer class should be allocated its fair share of the total cost to provide them with electrical service. And this is the principle of cost causality, which is something that you'll be hearing about a lot more this afternoon.

0:5:6.750 --> 0:5:34.540
Rod MacQuarrie
It's the idea that customers who incur costs on the system are responsible for those costs. And so, if we were to visualize what cost the service is, if we were to just stay, take a look back and look at it, we really break our system down into four main functions: generation, transmission, distribution and what we call administration or customer services. From each of those functions, there is underneath each of those functions, a series of sub functions. Now, not all of them are listed here because there's too many

of them to put on a single presentation, but we break up the large functions into a smaller set of sub functions and this is used for rate design purposes.

0:5:53.910 --> 0:6:23.720
Rod MacQuarrie
We want to break down our rate base and our expenses down to a level of granularity so that we can accurately design rates appropriately. So the idea behind this is that if we have a customer who is served at 230KV, he's tapped off this 230KV line, that customer should not incur any downstream costs associated with transformation to 138 or any radial lines. So that's the idea as to why we subfunction down. And then from there we classify the costs as either energy related, demand related or customer related. So you can see that our generation function is classified both to energy and demand.

0:6:35.370 --> 0:7:5.240
Rod MacQuarrie
Transmission function is classified 100% to demand. Distribution is classified between demand and customer related costs and then our administration or customer services costs are all 100% customer related. So you can already see if you know a little bit about SaskPower's rate design methodology and how we charge customers for their power. We have a basic monthly charge which recovers customer related costs and we have an energy charge which recovers energy related and then demand. A demand charge which recovers demand related costs, and so the idea is how do we allocate these costs to our customers?

0:7:15.600 --> 0:7:45.630
Rod MacQuarrie
So the allocation portion of this is quite simple once we've determined what the energy requirement or the energy revenue requirement is, we allocate that to customers based on the class energy plus a provision of losses or for losses and for customer related costs, we allocate that based on the number of customers or a weighted number of customers. And for a demand-related costs, we allocated the customer classes based on the coincident peak, the class coincident peak and a provision of losses.

0:7:45.700 --> 0:8:4.640
Rod MacQuarrie
Now a coincident peak, just as a as a reminder, a coincident peak is not necessarily the customer's maximum demand or the class is maximum demand, it's what the classes contribution was to our maximum peak. So if SaskPower hits a peak, about 3800 megawatts, it's whatever that class's contribution is to that peak. It's not necessarily their maximum peak.

0:8:15.270 --> 0:8:32.970
Rod MacQuarrie
And one of the ways that we measure performance of our rates is we use what's called a revenue to revenue requirement ratio. And we use this to determine whether each class is contributing enough revenue to recover the cost of serving them. So, it's a commonly used metric throughout the industry. It's sometimes referred to as a revenue to cost ratio. We refer to it as a revenue to revenue requirement ratio and it's basically the revenue that we recover from a customer class divided by the revenue that we are required to recover from that class as determined by cost service. So, if you have a ratio of 1 or 100%, the class is paying its fair share.

0:8:53.840 --> 0:9:15.750
Rod MacQuarrie
If you have a revenue to revenue requirement ratio that's less than one, the class is receiving a subsidy from other classes. And if you have a revenue to revenue requirement that's greater than one, you're providing a subsidy to other classes. And what's really important to understand about cost of service is that it is a zero-sum process and it's been described in a lot of ways. I know that some people have described it as a water bed. If you push down on one end of a water bed, the other end has to come up. Other people have described it as a pie. It's a pie that we're just, we're just cutting up pieces of the pie. And if we give somebody a smaller piece of the pie, that means somebody else has to have a larger piece of the pie. So it's important to understand that any special rates that we provide to customer classes are paid for by all other customers. And that's the idea of the zero-sum process that we're just the pie is whatever the size of the pie is. And in order to remain whole, SaskPower has to allocate out pieces of that pie.

0:9:52.660 --> 0:10:22.630
Rod MacQuarrie
So our position on revenue to revenue requirements is that we try to set our ratios within a target range of 0.95 to 1.05 or 95% to 105%. And we get asked why a lot and one of the main reasons is it's utility standards. Just about every utility especially in Canada adheres to this range of .95 to 1.05. Some utilities have a little wider bandwidth - they go 0.9 to 1.1 so they have a little bit of a wider bandwidth in terms of their ratios, but the range is established due to the inherent imperfections of allocating common costs and expenses to each customer class. And the idea is that even though we're using the most recent information that we have, cost to service is not a perfect process. So there are inherent imperfections in this. So the idea is that there's no material levels of cross subsidization that are occurring within this range, so it's just a way to recognize the imperfections of cost of service methodology. It's kind of a standard deviation as well. If you're falling within this range, there's no demonstrable levels of cross subsidization that are occurring.

0:11:15.780 --> 0:11:45.870
Rod MacQuarrie
So just based on this last rate application that's going to be going to effect next month on April 1st, I thought I'd show you our target revenue to revenue requirement ratios are .98 to 102. That's traditionally where we've tried to line up our rates. Because of a lot of the things that have been going on, especially in the last couple of rate applications and changes to our industry and with the rate redesign, we have been exercising a little bit more flexibility and kind of reverting more to the .95 to 1.05 range. So this is our target range here .98 to 102 and you can see where the ratios are lining up as of April 1st, 2023 with the latest rate applications. So every class is certainly within that 0.95 to 1.05 and as soon as we are finished with our rate redesign exercise that we're currently undergoing, we're going to get back into this really, really tight bandwidth of .98 to 1.02. We're going to exceed industry standards and have some of the lowest levels of cross subsidization in Canada.

0:12:23.240 --> 0:12:26.560
Rod MacQuarrie
So that is just a brief overview of cost of service. Are there any questions? If not, I'll turn it over to John and he can get going. Does anybody have any questions for me? No. OK, John.

0:12:42.230 --> 0:12:47.460
John Todd
OK. Pleasure to be here. Good to see, well sort of see many of you again. And then, Gerry, I think we've been having these kinds of chats since the 1990s haven't we, when you were chair of the Manitoba Board.

0:12:59.590 --> 0:13:19.180
John Todd
So, these discussions have been going on for many years covering these topics and well everything's different across utilities. The basic concepts are the same. What I'm going to go through is covering some of the same ground as Rod covered, so you'll see a lot of familiarity there. The intent is to push the concepts a little bit further and to perhaps allow opportunity for questions that get more technical if you so wish.

0:13:35.840 --> 0:13:39.10
John Todd
So we're starting with the project description and then get into the background of cost of service study concepts. That's… going into a little more detail of what Rod has just covered and then we're looking at methodology and preliminary Elenchus recommendations, which is getting into what our work and ultimately the report that you will see in a few weeks will be covering. What we are particularly focusing on and we're encouraging any feedback you have of saying you know what about X or what about Y? If you think there's something else then what I mentioned that requires a particular look.

0:14:24.620 --> 0:14:30.630
Rod MacQuarrie
John, I'm sorry to interrupt you. Somebody is raised their hand here, Dwayne.

0:14:30.830 --> 0:14:35.440
Duane Hayunga SRRP
Are we supposed to see your, the presentation? Because all I'm seeing is all of the participants on my screen.

0:14:41.790 --> 0:14:42.770
Rod MacQuarrie
You should be able.

0:14:41.990 --> 0:14:44.610
Duane Hayunga SRRP
And I didn't see yours either, right? Did you share it?

0:14:45.180 --> 0:14:51.360
Rod MacQuarrie
Oh really? It's shared on my screen. Is anybody else having this problem where they can't see it?

0:14:51.630 --> 0:14:55.360
Kim Hartl
I can see your PowerPoint. I have no problem.

0:14:55.660 --> 0:14:56.60
Rod MacQuarrie
OK.

0:14:57.250 --> 0:14:57.600
Duane Hayunga SRRP
OK. Maybe I'll drop out and come back in. Thank you.

0:15:0.730 --> 0:15:1.50
Rod MacQuarrie
OK.

0:15:1.350 --> 0:15:2.790
John Todd
Maybe a setting on the device?

0:15:3.590 --> 0:15:6.410
Bonnie G (Guest)
Yeah, I can only see the agenda.

0:15:7.80 --> 0:15:9.250
John Todd
Well, right now the agenda is what's on the screen.

0:15:9.310 --> 0:15:11.620
Bonnie G (Guest)
OK. Then then we're good. OK, perfect.

0:15:12.40 --> 0:15:17.740
John Todd
Is there anybody else who does not see the agenda but is seeing the participants? OK. If not, we're OK.

0:15:22.80 --> 0:15:24.310
Rod MacQuarrie
OK, alright. Sorry John. I'll let you go on.

0:15:23.830 --> 0:15:25.560
John Todd
OK, next slide. So first of all, an introduction, to myself and Andrew, is the consultants. Those of you who have been involved in these sessions will know elenchus from past reviews. I'm the president of Elenchus, which I founded in 1980 and the cost of service is often called cost allocation and when it actually comes to designing races it’s called rate design, so in many jurisdictions this cost of service review is actually called a cost allocation rate design C-A-R-D or CARD studies. And we have done these for regulators of various companies including the British Columbia Utilities Commission, the Ontario Energy Board, the Regie in Quebec and we've done this work for like we're doing for SaskPower from any other utilities.

0:16:28.650 --> 0:16:51.500
John Todd

We did do the reviews in 2012 and 2017 and you'll see as I go through a couple of references to recommendations that we made in past reviews that have been implemented and some comments on things we will be digging more deeply into and there's possible new recommendations that will come out of our completions of review this time around.

0:16:52.140 --> 0:16:54.260
John Todd
Andrew who unfortunately came out with COVID a few days ago. This was going to be a joint presentation. He is severely under the weather. He joined Elenchus in 2016. He's particularly focused on the modeling and has done lots of cost allocation models. He may be able to make it in later in the day, but he was in a bit of a COVID fog yesterday, so I think he's probably not going to be joining us next slide please.

0:17:26.470 --> 0:17:29.500
John Todd
So the project description that is our work. It's reviewing SaskPower's cost allocation methodology. I'm going to talk about this, but what we examine in doing that is go through the process that is used for cost allocation methodology, which is functionalization classification and allocation - three steps to the reviews before you get to the rate design stage. Part of what we're doing is we have in the past is doing an updated survey of some Canadian and US utility practices to ensure that SaskPower is keeping up with the time, shall we say, of developments in cost allocation or cost of service studies.

0:18:10.670 --> 0:18:19.500
John Todd
That will lead to recommendations. If there's anything that we see that is a problem, or if it's just a matter of keeping up. We're due to deliver the draft report April 28th which will be circulated. I forget, Rod, whether circulated at that day or whether there's a little bit of time for getting it posted on your website. Will people see it on the 28th?

0:18:46.490 --> 0:18:52.770
Rod MacQuarrie
I believe the draft report that's for us to review for technical. I'm not sure if I'm not sure if we're going to post the draft report to Scott.

0:19:2.740 --> 0:19:15.490
Scott Chomos
Yeah. I think the thought was, is that we would just kind of review the report, provide comments back to Elenchus and then once we have our meeting on the 17th, that's when the report will become available.

0:19:15.710 --> 0:19:25.760
John Todd
OK. So, we presented on the 17th and it doesn't have all the details in there, but parties or everybody on the call and other stakeholders will then address questions that we will respond to after the presentation of the report on May 17th. Those will be then be taken to be considered and the what will not be final until June 30th. Any questions on the process for either myself or SaskPower?

0:19:54.950 --> 0:20:6.200
John Todd
If not, this slide is the agenda. Again, just in bold is the background on cost of service study concepts. Just saying we going on to the next section of the presentation.

0:20:7.220 --> 0:20:14.470
John Todd
You've seen this picture before. I won't be going through it in as fancy way with the multiple stuff calling up as… Somebody's got their microphone on.

0:20:25.970 --> 0:20:28.310
Rod MacQuarrie
If somebody has their microphone on. Just a moment. Here, just a minute here. How's that? Better, John, OK.

0:20:41.280 --> 0:20:43.890
John Todd
Sounds fine. Yeah. OK, good for me. OK. So this is essentially the same diagram, and I may flip back to it when we talk about functions. But again, we're showing generation, transmission, distribution, customer service. And rate base you see down that blue box SaskPower has a rate base and has expenses. The basic concept there is that the costs, if you think of the financial statements of the company, capital costs are rate base, in other words, rate base are all of the investments current valued investments, net book value, that SaskPower has with on which they earn return in order to bring in the cash that's needed to pay debt interest and to provide a return on the equity portion which is where they end up with retained earnings which is an unnecessary part of the capital structure. You can't have zero retained earnings or there's no cushion there in case of unexpected events that cause actual cost to vary from forecast. Expenses as distinct from rate base are the payments that SaskPower makes, which are straight current year. So salaries certain materials. Things that are not capitalized rate basis, capitalized expenses are not capitalized. That's the simple distinction between the two.

0:22:28.670 --> 0:22:32.400
John Todd
As you can see, I think the other thing I want to point out in this diagram is you'll see in the… sort of in the center, there's a center at law across the bottom is a square box, large industrial customer. And you see it goes up to the line, which is at 72 KV radial lines. Those are part of the transmission function. You go the very top, you see transmission function across the center there. So large industrial customers are actually fed off the transmission system. And as you move further to the right, small industrial, large commercial, farm, residential small commercial… All of those these other classes are fed from the distribution system.

0:23:19.10 --> 0:23:48.240
John Todd
What that means is that large industrial customers pay their proportional share based on cost causality of the transmission system. But they do not use, they have no connection with, the distribution system. Therefore, their costs allocated costs do not include the cost of the distribution system. They are caused by the customers connected to the distribution system and so cost of the distribute distribution system

are allocated only to the customer classes that are connected to it. Now before we move on, is that clear? I'll just give a pause in case there's any questions.

0:24:0.260 --> 0:24:3.330
Rod MacQuarrie
I believe we have one question here from Peter. Peter.

0:24:2.240 --> 0:24:7.190
John Todd
OK, just before I go to it, my screen is saying the recording was stopped.

0:24:7.550 --> 0:24:11.590
Rod MacQuarrie
I saw that too, and I've gone in to look and it says that it's still recording.

0:24:11.990 --> 0:24:13.410
John Todd
OK, I'll ignore that then.

0:24:13.350 --> 0:24:17.240
Rod MacQuarrie
It's, you know, OK, so hopefully it's still going on.

0:24:17.10 --> 0:24:18.350
John Todd
There is a participant question.

0:24:18.570 --> 0:24:21.840
Rod MacQuarrie
Yeah, there is somebody here from Peter Chan. Yeah, go ahead, Peter.

0:24:21.590 --> 0:24:28.730
Peter Chan
Yes, thank you. My company taking most of the power from at the 138 KV. And we own our substation. So... So in the cost of service study, do you actually make another category before the large industrial customer who take the power at 72 KV because my company properly, should not be responsible for the for the costing the 72 KV line related.

0:25:0.530 --> 0:25:26.20
Rod MacQuarrie
Yeah, that's that. That's correct. The this is just an example here. Sorry, John, if you don't mind. We do have customers who are served at 138 KV. We have customers who are served at 230 and you're right, those customers would be tapping off at an earlier point on this graph so that they would only receive or be responsible for costs to the left of wherever they're tapping off from. So, they don't incur any downstream cost to the right. Yes, there are other categories.

0:25:29.440 --> 0:25:30.330
Peter Chan
That's all. Thank you.

0:25:30.710 --> 0:25:31.250
Rod MacQuarrie
Yeah. Uh, sorry John. We have one more question here.

0:25:31.450 --> 0:25:39.270
John Todd
In case so yeah, thanks for that question and that, that's good. And yes, so that this is a simplification. And, all of the different functions and subfunctions, each of them get separately treated through the cost allocation model. And as a result, each class is only being allocated the costs that cost causality principle cost that they cost. IE if you're not connected to that part of or that function or subfunction, you would not be bearing the cost of that function or subfunction.

0:26:15.360 --> 0:26:17.310
Rod MacQuarrie
John, we have another question here from Lonnie. Go ahead, Lonnie.

0:26:21.700 --> 0:26:48.870
Lonnie Kaal (Guest)
Thank you. I I'm appreciating the breakout question though, is capital as we all know that the cost of infrastructure and replacing that has become concerning for all of us. So as a city we're cognizant of how far behind we are in the investment we need to put into that. And I'm guessing as a utility you are as well. So, when I look at the rate base, which includes you say current value of investments and I look at the customer base. I'm… that part of it. It would be interesting to see what that is in relation to the operating costs as far as in my opinion what you're putting into investments and maintaining the grid, so to speak.

0:27:10.630 --> 0:27:17.460
John Todd
OK, what I'm going to do then is I'm going to take that under advisement to make sure… because they don't, we we're not doing numbers today. OK. So, I'll take the advice and to make sure that in the report. Then you can see that and you will because you know rate base. You know those are those are the first breakdown is what is rate base because it's treated differently in the model than expenses. So, I will make sure I'm sure it is. It always is completely transparent to you. They were going through the and today, though I'm not giving the numbers I would have to take a few minutes to go to the side because the because we have, we have not completed our review and we're doing the methodology discussion today is that OK for now?

0:28:11.650 --> 0:28:22.500
Lonnie Kaal (Guest)
Oh absolutely. I was just interested. You know what I'm thinking about the generating stations and to the large customers because for instance in our area we don't have enough… Our area does not have the capacity and so there would be there would have to be an investment in and around Yorkton in order to accommodate some of the industries that potentially could be coming on stream in the future.

0:28:39.870 --> 0:28:41.70
John Todd
OK so the cost allocation process is starting with SaskPower’s current financial statements, statement of

accounts, and this is not a planning exercise, but I think what you are flagging to the company which is true of each of these across the country is that there can be some anticipated growth. You are not paying for the assets of the future today. You will, when they come on stream and are used and useful, as the phrasing goes. And part of SaskPower's planning process is to look at what is going to be required in the future, make sure that they begin the process of putting additional assets as it is required so I suspect that SaskPower knows about the future growth concerns that you just raised. Is that fair to say?

0:29:38.940 --> 0:29:39.130
Rod MacQuarrie
Yes.

0:29:40.130 --> 0:29:52.990
John Todd
And therefore, and they would be involved in your planning process, which is very, very important, but it's not, because it's future expenditures, that's not included in rate making.

0:29:54.890 --> 0:29:57.800
Lonnie Kaal (Guest)
Thank you. I just had to get my point out there. We want more.

0:30:2.80 --> 0:30:2.400
John Todd
OK. Next slide. Oh so no more questions, first of all?

0:30:12.500 --> 0:30:13.110
John Todd
So, this is gets a little bit technical. Most of this we've covered in you know five years ago in the last review and in the previous one. But for most people they see it so seldom that I'm sure it needs a refresher. So first of all, there are what can be directly allocated costs. Those are something that is exclusively used by a single rate class. We'll come to an example as we dig into this a bit more deeply. Virtually all of the assets of electric utility such as SaskPower are shared use. Can you just, Rod, can you slip back to the previous slide for a moment? You can see that the generating station is producing power. Every customer class that's using power is sharing the use of the power generated by the generating stations. It's going in the wires. Similarly, the transmission line. Everybody gets their electrons down the same transmission line. Those that are only that are large volume that are connected to the transmission line do not use the distribution line, but everybody who's connected to the distribution line is sharing the use of the distribution. So, if you flip back to the next slide, Rod.

0:31:45.640 --> 0:31:49.700
John Todd
So that's what we're talking with the shared utility assets and expenses. The concept there for a monopoly like SaskPower is that we all benefit by having a shared utility. This lower cost for everybody. If you had two utilities running through the province and you had two sets of transmission lines and two sets of distribution lines, obviously things that are more expensive. Our primary reason for the benefit of sharing is because the electrons are flowing through common infrastructure. You incentivize two systems, you have one larger system.

0:32:24.840 --> 0:32:32.410
John Todd
Then when we're looking at how those costs get elevated costs, causality is the primary or the main criterion that we use. Most costs are apportioned across the classes based on relative use. There's a couple of concepts of relative use and get into that a bit more in a in other later slides, but the simple way to think of it is that when it comes to the energy use, everybody's meter measures the energy they're using, and so it is by totaling up the kilowatt hours used within each class, you get the proportionate use of energy and therefore the cost can be allocated proportionally to the classes.

0:33:6.760 --> 0:33:11.930
John Todd
The goal is to have a basis for establishing fair and reasonable rates. You start with cost causality. What costs are caused by each class that becomes the basis for the allocated costs. The allocated costs are used to establish the target rates. Once you've got your target rates, you adjust the current rates to move close to the targets, which was what Rod was talking about, and I will also be expanding on in a moment. Note that rate design is a subsequent step to the cost allocation because we come up with in the cost allocation process and the revenue to revenue requirement ratios is the total dollars that you need to collect from each class. Those total dollars are collected through multiple charges in part, it's a fixed monthly charge, in part for some classes. It's demand charge demand charge based on demand will expand on that to make sure it's clear as well and or pretty much all classes, there's also a kWh charge, which is the energy charge. OK, there?

0:34:20.140 --> 0:34:21.530
John Todd
And Rod, then we can move on. So, now we get into some of the technical terminology in cost allocation or cost of service reviews, cost of service models? There's a three-step methodology I'm going to start the high level and then substance slides will drill down a bit. And this is done… Rod referred to the NARUC electricity cost allocation manual and electric utility cost allocation model, I think it's fully called which dates back to 1995. It NARUC is the American organization, I think called the Canadian regulators or members of it. So it is, I refer to it as the Bible for cost allocation. Since 1995 there's been refinements, but it was meant to say here's what you can do and a lot of what's in there is rarely used. So that's why when we're doing our examination to say is SaskPower consistent with the industry. We're not just saying are they are consistent with the manual, which is a spectrum of basically everything that can be done. It has to do two things beyond that. One is, consistent with normal practices because a lot of things in the NARUC manual are not common practices and secondly, is it consistent with the way electricity utility costs are normally handled that are similar to SaskPower. In other words, when different utilities treat some of the costs differently, the reason for the differences should be the nature of their system. So that's an important consideration, and that's simply breaking it down into the four broad functions that Rod showed to you and we are in our slide as well.

0:36:29.130 --> 0:36:32.240
John Todd
Having functionalized you then categorize. And categorize looks at what is the cost driver, the standard breakdown for categorization or classification as it is sometimes called, is that it's energy related or demand related or customer related. More on that in a couple of minutes. Then the third step is allocation, where you actually take the costs, look at cost drivers. The kWh driver, corresponds to

energy. The kilowatt driver corresponds to demand. A customer count or weighted customer account corresponds to customer related costs, and that is the basis for your application.

0:37:16.130 --> 0:37:21.160
John Todd
I'll go into each of those steps. You know a bit more detail, but that's the overall methodology. Any question there? I hope everybody's with me.

0:37:27.190 --> 0:37:29.60
John Todd
No questions brought, so you can move on.

0:37:33.150 --> 0:37:34.440
John Todd
So functionalization. We're starting with SaskPower's system of accounts and by the way, every everything I say here is exactly what we do for every other utility that we work with across Canada. So, we group similar assets and expenses to but it's drawing some... we're actually using SaskPower's accounting, accounts. So, generation stations is one function. That's the function of generation, right? And that's simply thinking. But there could be subfunctions, so within the generating station there are different categories of equipment that do different things that all are part of the generation function. So the sub function simply says you can break that down.

0:38:27.510 --> 0:38:39.460
John Todd
Transmission lines. Basically the wires and towers or poles are all other transmission distribution and that's defined by voltage and the other slides it showed the voltage levels. And so at the high level, the function is transmission but in order to get the allocation right, it drills down a bit more deeply to look at the different voltages and the question earlier made a point of that, that the higher voltage may serve only higher voltage large volume customers. So, we keep the different voltage levels separate and feed the different segments or different sub functions of the transmission line or transmission function. It feeds through to costs to classes differently depending on the voltage level That voltage level also includes towers and wires because it's not just the voltage level, it's the towers and wires that operate at those voltage levels. They get assigned to differently to different voltage levels, which means different customers pay for different costs. Only those that they cause or use. Similarly, the distribution lines, there are feeders and I've just used…. This is quite complex, so this is grossly simplified. So again feeders and all the distribution system. There are different voltages, different customers that draw their power off the system at different voltages so it gets allocated out. That recognizes that. Customer connections meters. You know everybody's got a meter, but all meters are not the same. Larger customers may have interval meters, smaller customers may have non-interval meters which are cheaper meters. Those meter costs are allocated to the classes that use a specific kind of and there for specific cost of meters. So all these things, different types have different costs. That doesn't mean that if you have old meters and new meters, that you, different customers, pay a different rate based on whether they have an old meter or new meter. If they're essentially the same meters if it's residential meter, it's a residential meter and it goes into one pool and everybody shares in the cost of that. Customers with old meters will, when their turn comes, when it's necessary. We'll have a new meter. So that's… they're treated as uniform in terms of their use or their need.

0:41:17.280 --> 0:41:18.670
John Todd
Functionalization okay for here? So examples. At the generation level, hope I've got my numbers right. If I was looking something outdated, Rod, 17 stations and in terms of the generation capacity, 37% coal, 24% in natural gas, 60% hydro and more. So, there are different kinds of stations but all of them feed power into the shared system. Transmission, 72 KV I mentioned this is because these are examples, so somebody connected to the 72 KV system is going to share in the 72 KV costs, which of course includes higher voltages because the higher voltages feed 72. Transmission connects, generation to distribution, so that transmission is used by everybody uses the transmission system. You cannot get distribution without transmission. And it also connects large users. Large users do not necessarily use all of the transmission system.

0:42:33.790 --> 0:42:40.400
John Todd
The distribution system, that's the lower voltage, goes out to the residential, farm, businesses below 750 volts. So again, that gets broken down. Different classes of customers will have different level, if you want of the distribution system they use.

0:42:53.460 --> 0:42:54.630
John Todd
Customer services. Simply, basically everything other than the towers and poles and wires and generation. If you call SaskPower, if you call the sellers, the people on the line, the administrative offices, all of that is tied into customer service. Everybody shares in those costs from the President, CEO on down to customer service reps. Of course, when you look at construction people or people who maintain the lines, their costs are part of the distribution system or transmission system, not part of customer service. Customer service is the billing, answering the phones, things like that. Any questions on these examples?

0:43:48.740 --> 0:44:10.850
John Todd
If not, we move on. I keep asking ‘any questions’ because normally this type of presentation is done when I can actually see people and you can see people nodding or quizzical looks on their faces, and I can't do that today. So, I'm trying to make sure that you speak up with questions if you have any, since I can't see it from your faces.

0:44:13.30 --> 0:44:14.160
John Todd
The classification gets into the demand, energy, customer related costs. The demand related is a capacity function so the thing that probably people are more familiar with is garden hose. The garden hose is kind of pipe. It's analogous to the wire. The diameter of the hose affects how much water can go through it, although the pressure in the hose is analogous to a voltage. The higher, if somebody, if you require more water per second than somebody else, that means you have a higher capacity requirement. It's exactly the same thing for capacity for energy. So if you have a 100 amp service because amp or amperage is measuring the flow of energy, if you have 100 amp service when you're running that at capacity, 100 amps, you are going to be drawing less energy through the entire distribution system transmission system out of the generation capacity system, you'll be joining less

than somebody who is a 200 amp service and is using that full amount. So the capacity is equivalent to a flow of water or flow of energy or flow of natural gas and capacity is demand related because demand is a measure of your peak usage that was referred to by earlier by Rod. And so your demand is measured and then that's grossed up on a class basis, so the capacity, each generating has a capacity of the maximum energy that it can produce for the system. You put all the generating stations together and you have a capacity of the generation resources of SaskPower. Similarly, you have capacity for the transmission system and a capacity for the distribution system. And the capacity is what demand can be accommodated. If demand exceeds capacity. You've got a problem.

0:47:5.990 --> 0:47:11.820
John Todd
Energy related is to the cumulative flow. So if you've got your hose running, and if the hose has a capacity and you've got the pressure as high as it can go, and it can give you one litre per minute, in 60 minutes, you'll have 60 litres. Energy related is equivalent to the 60 litres of water.

0:47:31.420 --> 0:47:37.110
John Todd
Customer costs are costs which are determined essentially by the number of customers. The more customers you have, the more meters you need, the more customers you have, the more customer service agents she need. They differ by class. There's a nuance there where the model, the cost of service allocation looks at weighted customers, so that comes into play where you say, OK, we're going to allocate meters out the different classes. But one class, a larger volume class for example, may have meters there twice the cost of a residential meter. Therefore, the weighted meters would say, OK, a larger volume customer with a more expensive meter, those are weighted, so it counts as two residential meters. The full concept here is to say, OK, you should be, you shouldn't be paying the average cost of meter, you should be paying the cost of the meters used by your class. And that's why these costs differ by class. We're okay, there? Moving on Rod?

0:48:42.960 --> 0:48:47.480
John Todd
So corresponding in this, we've touched on this, cost allocated to SaskPower customer classes. The primary allocators, as we call them, which is used to share the costs proportionately, the kWh, or energy, the kilowatts of demand, number of customers, weighted number of customers and there's some direct assignment. The example there is streetlights, there are streetlight costs aside from the energy which says this is just directly allocated. So, you come up with an amount per streetlight. Nobody else uses the same thing. Nobody else uses luminaires that are, I think they are supplied by SaskPower. Part of that cost is actually the luminaires, the fact they're on poles and so on. So that just costs that nobody else shares in so those costs that nobody else shares in go directly to the class. And that all produces the total allocated cost by each class. And I'm using the term costs. The technical term is the revenue requirement. I usually talk about costs because that's something that… non electricity sector people understand cost. But what the hell is a revenue requirement? It's an, it's an expense. How can expense be revenue? Well revenue requirement is the required revenue to cover the cost. So, revenue requirement is identical to cost. So to compare those costs to the class revenues revenue over the revenue requirement or cost is the revenue to revenue requirement ratio.

0:50:32.290 --> 0:50:33.40
John Todd
The results. So I've referred to the revenue to cost ratios, that's the more common reference across the country. I should have adapted to the revenue to revenue requirement ratio for here using my habits instead of the specifics. So this is common. All utilities identify that ratio and that is the target. In some jurisdictions, and this is as you probably know, Saskatchewan is a little bit unique in terms of having the rate review panel. Review panel does a review and recommends to government, government makes the final decision. Other jurisdictions have a regulator who is essentially delegated the responsibility by their province to say yay or nay to a requested rate. Essentially the same regime, but a little bit different anyway. So on a jurisdiction specific basis, there's a decision made of what to do about the target ratio. How much above one or below 1 are, is acceptable within the jurisdiction. The most extreme is, for particular reasons, is Ontario has had ratio range of 80% to 120% over the years have become a little more complicated because it's different by class. Historically Ontario had 370 or something distributors reduced to 70, down to more like 60 now I think. There was a lot of uncertainty around what a revenue cost ratio meant, how accurate it was because everybody had different kinds of accounting methodology. So they allowed a very large range. In other jurisdictions, it's 90 to 110, is, I'll say double negative, not uncommon. But again, that's a matter of how much confidence you have in the actual allocated cost you're using to create your target ratio. When you think of it, because the actual sharing it's a mathematically precise exercise to allocate the cost out. But a lot of those costs are allocated based on what we call peak demand and get to that a bit more. And what's relevant is coincident peak demand. In other words, at the time that the utilities system is being used to its absolute peak. How much of that peak is every class using?

0:53:36.520 --> 0:53:39.480
John Todd
We do not know. Nobody knows, because in some classes like residential, we do not measure the actual demand that's taking place on an hour by hour or minute by minute basis. Therefore, it's a bit of an estimate. All, which is to say, when it comes to allocating costs, you're using a bit of a rough I mean a bit of a rough guide to get there so you know that the numbers you come up with in terms of the target ratio by class are not perfect. Therefore, it makes sense to allow some flexibility. In addition, the way demand and energy goes from year to year demand requirements, you know you have a you have a cold winter, you have warmer winters. It bounces around from here to here. If you were to react to every change on a year by year basis by saying, 'oh, gee, last year this is what we actually had. We need to change our rates to get 201.00 based on last year's demand', that won't be the right rates for next year's demand. And you're setting rates on a forward-looking basis.

0:54:52.620 --> 0:54:58.430
John Todd
So there, so it is appropriate to have some flexibility where the intent is that a narrow range will keep you closer to one. And what you're probably looking for is avoiding any serious deviations that take place year after year after year. So cross subsidy in one year is I wouldn't even call the cross subsidy. It's a variance. But if it becomes large enough and persistent enough, then it is a cross subsidy and you adjust the rates and that's exactly what SaskPower is doing. They've got the ratio of .95 to 1.05, but they're saying we're going to try to zero in on closer and closer .98 to 1.02. As we can, we can refine it.

0:55:44.970 --> 0:55:50.580
John Todd
So that's in here. I've got the range of 95 to 105, which is the dominant consideration on a year by year basis, as Rod said, they're getting more precise, but the caveat there is when the next year happens the ratios may be in the .98 to 1.02 range, probably some of them will slip outside just because of the nature of the changes of demand. So using the range reduces volatility in rates. If you're reacting, you'd be bouncing rates up and down all the time to get back to to one.

0:56:25.150 --> 0:56:39.870
John Todd
And it also means that if something does get out of whack, you avoid rate shock. In other words if something were it at 93% and you went to 100%, that would imply 7% increase for that class. Well, let's go more gradually. Let's support great shock. Let's avoid big rate changes and we'll just go to .95 and then gradually get ourselves up to .98. If that kind of deviation is persisting.

0:56:53.50 --> 0:56:56.940
Rod MacQuarrie
John, I'm. I'm sorry. I'm sorry to interrupt you here, but we do have a question here from Jonathan.

0:56:56.770 --> 0:56:57.990
John Todd
Yeah. OK. Thank you.

0:56:58.910 --> 0:57:1.600
Johnathon Rasmussen
Yeah, just a question on peak demand. Is there any consideration to the cost being associated back to the class group on the cause of the peak and what I'm getting at there is if I just decide to start up a bunch of wells, yeah, it's my, I'm demanding more. My peak goes up. But if there was a monstrous storm and the whole power grid goes out, it's not really quote unquote 'fault' is the wrong word. But it's SaskPower isn't able to produce and then all of a sudden all the power comes back. There's a massive peak. by everybody, are we all sharing that cost even though it wasn't necessarily our fault? And again, I know fault is the wrong word.

0:57:41.800 --> 0:57:42.150
John Todd
Right. No, I mean that is sort of unusual circumstance would not flow into the data. I suppose first of all. Tell me if I'm getting too technical here. When that happens, If it does not happen at the coincident peak, and you'll see while we're working for SaskPower. We actually have two coincident peak measures summer and winter. If that happened on a day other than the day that was anyway, coincident peak day you probably would not exceed the peak for the season. So, it probably would just disappear in the data. The point you raise is something a little perhaps more to SaskPower on an ongoing basis as they measure their peaks for use in this process. If there were a peak which was identifiable that it was created by an anonymous, an anomalous situation such as when you mentioned. Would that be ignored? Rod, do you know the answer to that question?

0:59:5.340 --> 0:59:5.830
Rod MacQuarrie

Well, I think the best way to look at it is, we don't just allocate costs based on a on a single winter or summer peak. We actually, when we're designing rates, we do what's called the tri-average peak. So we take the top three summer peaks and the top three winter peaks and average them together. So if something like that were to ever occur, and if it did happen on a coincident peak, it would basically be watered down or washed out because we're taking so many other… we don't want to just rely on allocating costs on a single incident. So we average the top three winter and the top three summer peaks together and we do that over five years. So we really have a large sample size of data to prevent that from happening, yeah.

0:59:55.890 --> 1:0:3.300
Johnathon Rasmussen
Sure. Thanks. Then the ratchet clause though is on the peak of every specific meter then though, right?

1:0:2.930 --> 1:0:28.320
Rod MacQuarrie
Yeah. Yeah. But you're… so that's the difference between a coincident peak and a maximum peak. So a coincident peak is whatever your contribution is to our system peak to our maximum peak. If we're peaking, whatever your contribution is, whereas you know your maximum peak is the maximum load you've drawn in a month or in a year, regardless of when it occurs, it doesn't have to be at the time of our peak. That's what your ratcheted on your maximum peak.

1:0:28.700 --> 1:0:47.60
Johnathon Rasmussen
So again, if there is, say, an act of God, all the power goes out and then you guys come back on, we need to restart all our wells. Our ratchet, we're going to be paying for that act of God for 12 months or for, yeah, 12 months, I think, right, because it's going to be a huge peak due to something we didn't control.

1:0:48.400 --> 1:0:50.170
Rod MacQuarrie
Of well, I mean if all your wells are tied in together, are these are all just separate individual wells? Like I I'm just thinking like, potentially yes if the power goes out and the whole system goes down and everybody automatically resumes their normal usage immediately when the power comes back on, yeah, there, there could be a demand spike for sure. It's good to know, because then yeah, we would stagger our well starts. Anyways. Thank you.

1:1:20.420 --> 1:1:21.160
Rod MacQuarrie
Yes. Yeah.

1:1:21.870 --> 1:1:28.450
John Todd
OK, so, Rod, from a cost of service perspective, the issue is watered down and not should have no effect from a billing perspective. I think that final comment is key. You should watch the way you get started again because that peak is going to be recorded.

1:1:41.860 --> 1:1:43.380
Rod MacQuarrie
Yes, exactly. Yeah.

1:1:42.280 --> 1:1:48.500
John Todd
And if you spread it out, you're going to trigger less costs than if you don't spread it.

1:1:47.410 --> 1:1:58.930
Rod MacQuarrie
Yep, yeah, that's exactly it. If you if you activate all your wells all at once, yeah, you'll probably hit a major peak, but if you spread out, starting them up over time, then you'll be much better off. Is that fair?

1:2:2.220 --> 1:2:3.870
John Todd
OK then. Yeah, to finish off this slide, the last point there saying that once you decide on the revenue that you need to get from each class to be within the revenue to revenue requirement ratio of .95 to 1.05 or whatever, then you actually come up with a monthly charge per customer the demand charge where relevant and the energy charges and that will generate the intended revenue or target revenue needed to give you the target ratio and that becomes your rate design, rate design being the actual structure of the rate that you see on your bill.

1:2:55.110 --> 1:2:56.160
John Todd
Next slide. So. Again, just for an understanding, we had from the past the 2015, it's called residential class load shape. Every customer class has a load shape. What this shows, which I think is, I find interesting here. I hope you do too. You see, across the bottom the hours 1 to 24. Are those the 24 hours a day. And this slide shows you two class load shapes and if my memory says right in the notes, what it shows is the average for that class, residential class, for each hour of the day to show how it differs through the day. This this particular curve does not show different times of the year. Obviously, there's a lot of other factors which affect the load shape, but this gives you a sense and there's two curves here so that you can see 2015 versus 2017. And 2017 is what's being used in the current cost of service model. As a… to help with the allocation, 2015 was previously used. It shows how little change there is in those curves. Within it you can see the demand is essentially those lines. That's how much is being drawn on hourly basis from the system.

1:4:50.750 --> 1:4:53.720
John Todd
Therefore, the area under the peak is the energy. You sum up what's drawn each hour and you end up with the total energy, as is drawn in the day. Just like, here's how. Here's how much water's coming through a hose in the hour you run that hose at different levels all through the day. Then that's the amount of water you get in total. The peak is hour 18, which is the highest demand. Now the highest demand for this class may not be the same as the system peak. The system peak is when you put all the classes together. When does the occur? It's probably around the same hour, but you look for example at 18 and 19, you know, six o'clock seven o'clock. They're pretty close. It's possible that due to the demands of the other classes, that the actual peak for the system as a whole is, it might be either those

hours. It might even be off something beyond those hours but this all makes sense you know once you're talking the first hour of the day.

1:6:3.120 --> 1:6:25.110
John Todd
Demand is really low, but it gets even lower through the middle of the night, so it rising in the morning going up and peaks around 6:00 o'clock everybody comes home and turns on their electric stoves and open the refrigerators and turns on their lights. And it's sort of heavy use in the evening, dropping off as people go to bed. So it's that load shape is used to help with the breaking down of the costs and we'll get to this between energy and demand.

1:6:41.160 --> 1:6:42.90
John Todd
Load shape clear? Now I moving again as part of the background. There are well established principles I've got evidence going in Alberta right now that is running through here. The Bonbright principles you see there, Bonbright principles 1961, and the 2nd volume was published in 1988. And this is sort of the economic Bible if you want as opposed to cost allocation, this is just the principles of rate making and they're referred to as generally accepted rate making principles. And different regulators cast them differently, but they work across the country, they just have different labels for covering the same things. Sometimes they combine closely related concepts such as Bonbright, as an economist separates what's called static efficiency from dynamic efficiency. Some regulators say we care about efficiency, we're not breaking it down. That type of thing. Those are nuances, the theory. But as you can see, these principles that Bonbright called attributes of a sound rate structure, which he revised in 1988 compared to 1961, although actually he died before the 1988 was published. He had two coauthors. So, it was a joint update, but that has been the foundation of what constitutes a sound rate structure and there's three categories of attributes, so these are all things that are important to consider when you're establishing rates.

1:8:29.110 --> 1:8:41.790
John Todd
Revenue related attributes which basically says it has to produce the revenue that is necessary for the company to survive, have the income it needs to make investments to attract capital and so on. Then there are cost related attributes so the, I'm just in my notes here flipping through, and if anybody wants details, revenue related. In addition to yielding the necessary revenue requirement, it should provide a stable revenue. Again, this is part of the company focus. But also produce rates that are really stable. I mean what regulators want to avoid based on these principles is you don't want rates going up by 10% one year in down by 10% the next year and want to keep them stable over time. There are costs related attributes, so looking from the cost side, you want to make sure your rates encourage efficient use of electricity. So, for example, if you had if you had only the demand charge, people wouldn't care how much electricity they use when their demand is less than their peak.

1:10:1.320 --> 1:10:16.820
John Todd
So that speaks to the need to have an energy charge, to provide an economic motive for customers to be efficient in their use of electricity, not only in terms of demand, but also in terms of energy. That includes the issues of fairness as well, and Bonbright talks about avoiding undue discrimination or

excessive cross subsidies. Those are sort of being fair to all the different customer classes and the practicality of it is you're going to have something that's not so complicated that nobody knows what they're paying, why they're paying it. So you looking for simplicity and certainty and convenience and payment and hopefully you've got something that isn't controversial.

1:10:48.370 --> 1:10:52.840
John Todd
So the foundation of cost to service methodologies across the country and internationally is a well-established set of principles. And that's the essence of what they are. In our reports we always go through more detail than most people ever want in terms of those principles. It’s there if you want it when the report is available. If you're interested, take a look. If you're not, skip over that section. This slide may be all you need to know.

1:11:23.440 --> 1:11:24.560
John Todd
You know, SaskPower has its a version of principles which they which were originally based on Bonbright. You'll see there are six principles. That's a consolidation of the Bonbright principles. Bonbright listed 10. So for example, economic efficiency includes dynamic and static efficiency. Conservation of resources is tied in, so these are different labeling, but it covers all the principles that Bonbright laid out in 1988.

1:12:6.410 --> 1:12:13.70
John Todd
So I guess that's just saying that at the level of principles SaskPower is and always has been acting in a way which you consistent is consistent with the principles that are widely accepted and used in other jurisdictions as guidance in setting rates.

1:12:26.790 --> 1:12:27.840
John Todd
Alright, I think you he went on. OK, so now we're moving from sort of concepts to let's get into SaskPower methodology and preliminary Elenchus recommendations. The methodology in part we will get back to that narrow manual and there's a couple slides I'll skip through that if you want the details, it's there, so it's not strictly what SaskPower is doing, but it's getting down into the way the model works. For our review has mentioned, we will be surveying other jurisdictions. I'm not going to be walking through that today. That's for the report.

1:13:13.80 --> 1:13:17.70
John Todd
We are reviewing the model in the documentation that's well underway to compare it with any changes that have happened since last time but also then that gets linked to the survey of other jurisdictions to say are there any changes that, considerations you're given to based on evolving practices in the industry. Having looked other jurisdictions and reviewed the model, there's then exchange of information with SaskPower.

1:13:48.400 --> 1:14:6.240
John Todd
They may know some things that have happened and changed that we're not aware of, that exchange

information has already begun, not completed, and so we do not work in isolation. We make sure that we ask questions about what may have changed and issues that are of concern to us to see what's going on. It's not an audit, but it's our role is similar to an auditor. They come in and say, look what you're doing and saying why are you doing that? Now explain that to us. And as you've seen in past reviews, sometimes that leads to us making recommendations which I think SaskPower is always accepted to our recommendations in the past or it may lead to, “oh, now we understand. That's fine.”

1:14:41.200 --> 1:15:1.40
John Todd
So we compare with past practice based on the survey utility surveyed. Here's the survey sample as we go through it, if there's any problems with it or we think there's something else that's more relevant, it's possible that we will tweak that list to make sure that what we've got is survey that's representative and our good comparators.

1:15:8.820 --> 1:15:14.790
John Todd
So we can say clearly that that SaskPower follows the traditional approach. Everything's done is exactly the way you described, and is high level, exactly the same as every other utility across the country, and not a step. The second level bullet point is pointing out that it's currently using 2021 data, so that's quite current. Some costs of service models use the historic data once it's clean and verified and part of published financial statements audited financial statements. Sometimes forecasts are used. The advantage of using historic data is there's no controversy over not whether the numbers are right or not, they're audited. That's actually what's happened. So using the historical data is not universal, but is a certainly as credible, and I think a good thing.

1:16:18.980 --> 1:16:27.840
John Todd
You'll see there in terms of what's been documented in the past and will be here as well is the narrow manual which is fully cited there. The important thing in the manual and we're going to get into this a bit, is that there are many acceptable methods, so thought has to be given to drilling down and using the method that is most appropriate for particular utility. And part of that is not just a, does it make sense in isolation, but by looking at what others are doing. And there are many different opinions. What comes out as standard practice is a pretty good indication of what is reasonable.

1:17:3.560 --> 1:17:4.550
John Todd
Next please. So starting with functionalization. That's very, you know, you looking in in the electricity industry, how do you do it in a way that's different than generation transmission, distribution, customer service? It's that's pretty intuitive and obvious for the industry, pretty, pretty... I think we deal with cost allocation models in most Canadian jurisdictions and they all stick to this.

1:17:33.830 --> 1:17:35.590
John Todd
OK. And all the ones we survey.

1:17:36.520 --> 1:17:39.300
John Todd

Based in the system of accounts. So what that means is that actually, there's actually a model. SaskPower has a model, custom or cost of service model. It starts with SaskPower's costs. So 100% of the costs, whether they're capital investment, whether they're cost of capital which supports that capital or whether they're expenses, all of them go into the model. They get assigned to a function and then flow through the model. So it's an exact match to SaskPower's actual costs.

1:18:18.460 --> 1:18:26.20
John Todd
I know here that they'll be a little bit more on this. The carbon tax, which is relatively new, well new addition since the last review it's treated in what is essentially the same way, ie, the carbon tax is a cost which is incurred because you're running generation that uses fossil fuels. And so it can go through, it can be functionalized, go through the whole process. It is derived through a parallel calculation outside the normal cost allocation. As I understand it, because there's requirement provincial legislative requirement to present the amount of carbon tax being paid as a separate line item on the bill. That means you can't kind of bury it in with all the other costs. It is kept out so that you have the numbers you need as a carbon tax line item. Have I said that correctly Rod?

1:19:21.650 --> 1:19:22.920
Rod MacQuarrie
Uh, Yep, that's correct, John.

1:19:23.320 --> 1:19:24.610
John Todd
OK. And, we'll refer to that a little bit more, but it is the first time that we, Elenchus, have reviewed a cost allocation model. No, that's not quite true. It's only the last couple of years, I guess. Have we, have we seen some cost allocation models that include the carbon tax. There are different ways of treating it, but all methods used have the same end result, i.e., impact on customer bills as this SaskPower method which is parallel, others do bury it.

1:20:10.760 --> 1:20:16.620
John Todd
And that really comes down to a matter of government policy. Do you want the carbon tax visible or not visible? But the way it flows through in the end is essentially the same. This the functionalization approach is standard, uh. One thing we're looking at is that Saskpower, like everybody else in Canada except for Manitoba Hydro for rate setting purposes, has moved to IFRS. Manitoba is sort of split for financial reporting, IFRS, but it's not there for rate setting yet.

1:20:50.800 --> 1:20:54.30
John Todd
IFRS is increased componentization. That means that everything's been broken down in more detail. Probably that has no impact on the functionalization. I mean, you're not going move something from generation to transmission, but at a sub function level we want to check and make sure that we're comfortable that because of IFRS and the changes in the accounting system, has that created an opportunity for more precision in the cost allocation process. As far as I know nobody has modified their cost of service models to have increased componentization. What's done for financial accounting purposes is much more componentized than would make sense for a cost allocation model, but we are

addressing that to make sure we're comfortable that there's not something that would make sense to change there.

1:22:2.600 --> 1:22:4.160
John Todd
Classification allocation methods. They're sort of combined. We'll see why there's separate steps, but the concepts link. The one area that is difficult, first line, is that is generation costs. When you build a generation plant are you building the capacity to generate, ie, the plant has a maximum output. So did they build it to meet demand. Or are you producing it to generate an amount of energy over the year to meet the energy requirement?

1:22:44.60 --> 1:22:55.30
John Todd
So different jurisdictions, different companies split the cost of generation facilities that are related to capacity energy differently. Some energy costs, like fuel costs, are clearly energy. So how is fuel consumption caused? It's by the amount of energy you produce. But when you think of the plant itself there's been over many, many decades, there's been debate. Are you building capacity or building energy? What I'm going to skip through is some stuff that probably put you to sleep on here's what the NARUC manual says, but the splits, there are many different possibilities. I'll go through those very quickly just to make the point that there's a lot of possibilities.

1:23:33.550 --> 1:23:34.740
John Todd
And we'll get into SaskPower's approach, which is a pretty standard. There's a couple different things that are commonly used, but it's particularly for the system. It's an appropriate way to approach it.

1:23:47.590 --> 1:23:48.410
John Todd
Transmission. The standard approach is that you're building it for capacity. You're not building transmission lines and towers, while you do carry electricity, in the amount of money you have to spend on the transmission system is driven essentially by the peak demand, the coincident peak demand and therefore you design it from an engineering perspective. You design it to meet capacity. The peak capacity, therefore, is a demand item.

1:24:27.390 --> 1:24:39.810
John Todd
Distribution is also driven by capacity. How big do you need your wires? How did you dig in your posts in order to get the power through to people? What's interesting is that transmission, the transmission line essentially, not quite true, but there's one you know the transmission line. The main line is feeding everybody and it's the coincident peak because the overall peak of the system that drives transmission costs.

1:24:54.170 --> 1:25:11.800
John Todd
Distribution. There's a lot of local variation. You have to, you know, different parts of the province, different parts of the distribution system do not peek at the same time. Therefore, it is common to use non coincident peak measures to allocate the costs of capacity. And we'll see more on that.

1:25:21.250 --> 1:25:26.480
John Todd
Customer costs. Completely standard. Use a weighted customer related allocations. Customer costs like the metering and customer calls are not caused by demand or energy. Through this process, as always, we'll be revisiting the classification alternatives. Not really expecting any change but, you know, flowing through from many changes to the functionalization, there may be some flow through things that we'll at least have to look at.

1:25:52.360 --> 1:25:54.580
John Todd
Anything further there? OK. So variable costs, fuel costs are energy related. Then how to classify capital and other fixed costs? We're talking generation classification now. So you drill down from the functionalization. Generation down to the classification of it. The NARUC manual identifies many different methods. There are several and see what it says here. Peak demand methods. There's five of them. Energy weighted methods? There's four of them. Time differentiated methods, another four. So there's a lot of things that the manual says in the right circumstances. This is a reasonable way to do it. And then next few slides, that I'm going to go through fairly quickly, just because they're showing you the range. So the two in the title just says second slide in this thing. So there's the five demand methods.

1:26:53.610 --> 1:26:58.980
John Todd
I believe we went through this in some detail. Last year's report, our last year's five years ago report. Just as information for information purposes. I don't think we need to spend time in that today. But those peak demand methods they take conceptually and say, 'oh if you are building your generating stations to meet the peak then these peak demand methods would clearly be appropriate ways to allocate those generation costs through classification methodology. Next slide please.

1:27:43.400 --> 1:27:47.380
John Todd
Going to the bottom, you know energy weighted methods, there's the for there and average in excess is a common one. Equivalent peaker used to be used by Saskpower and is no longer, which is that change that moved to average in excess. It's consistent with our recommendation and consistent with the way common practice has evolved. We've seen the move away from equivalent peakers in other jurisdictions as well.

1:28:18.740 --> 1:28:20.390
John Todd
Base and peak. In certain systems, that's also makes sense, but average in excess conceptually, and you can go through the details is what makes sense for SaskPower. All these approaches are when accepted because it's the recognize that you're building for both and to sort of say it's all demand, it's all energy, is somewhat arbitrary. Therefore, doing this conceptual demand energy split is perhaps a compromise, but it's more reflective of saying you know not at the extremes of right. So let's not use the bookends. Let's use something in the middle.

1:29:4.130 --> 1:29:8.560
John Todd
Next, I think there's one more on yeah and then time differentiated. These are rarely used, partly

because of complexity but some people attempt to use them in order to get more precise drivers of the costs production stacking. So that's sort of saying,OK, you have a dispatch order. Certain generation facilities run first and other ones you get to only in peak or in super peak periods and therefore it's appropriate to look at this by through production stacking or base intermediate peak loads, which is sort of a similar concept. Loss of load probability is something which I have to go back to my old engineering days in order to even understand it, but it looks at the system of that's a production cost related. Probability of dispatch links to the upper ones of when's it gonna be used? None of those are commonly used. They can be complex and if you're supply, mix is changing either we do different years or different generation facilities. It can cause some serious fluctuations from year to year in terms of how your costs get allocated.

1:30:33.50 --> 1:30:37.320
John Todd
So that's a quick run through of there's lots of options. Any question before you get into SaskPower's approach?

1:30:46.170 --> 1:30:51.270
John Todd
OK. So that next slide runs head. So SaskPower uses average and excess. You determine energy related and so that there are there's a split which says what's the what's the average demand, and the concept is that average demand you take the total demand through the year, divide by the number of hours, come up with average demand. If that's the way, if the system is being used exactly the same every hour, that amount of generation would be required to just to meet the energy requirement. So the average is a way of saying of defining what the energy is that you need out of the generation plants and excess is, okay when you take your peak compared to the average that's how much more capacity you've got in the generation plants in order to meet demand, which is above average. To me, that's a very logical way of splitting the energy related and capacity related generation costs and then the energy generation costs can get allocated in the base of energy i.e., the MW hours, or feeding down to customers that kilowatt hours of use. And the demand related generation is driven by demand.

1:32:24.530 --> 1:32:32.300
John Todd
We had very interesting discovery with the Sass power as we're looking at their peak periods they had which uses a two CP to win some peak method. And said, well, when you look at demand there's actually a winter peak is, you know, I think they're higher in the summer peak, but again, with talking engineers going back to my engineering days. Wait a second. Now those the wires that electricity come over actually have less capacity in the summer when it's warm.

1:33:6.220 --> 1:33:7.470
John Todd
And as it turned out the summer peak demand was pretty close to the adjusted capacity, or at least the amount by which the peak demand as a percentage of the capacity when the waters were warm was very similar to the peak in the winter when cold wires carry more electricity. So the logic of the two CP, coincident peak is to try to capture the sense that, well, OK, depending on the weather in the year. And I think climate change is particularly important here and the amount of air conditioning load and things

like that, both of those peaks are relevant to maintaining the integrity of the system, so operationally, there's two peak periods.

1:34:3.170 --> 1:34:21.30
John Todd
Those are used to allocate costs and as Rod mentioned, it's not just a one number for each season, It's all my notes in front of me. Remind me, I think it's five years in three peak days in each of those.

1:34:21.310 --> 1:34:22.320
Rod MacQuarrie
Yeah, that's correct.

1:34:22.620 --> 1:34:38.230
John Todd
Uh, so there's actually 15 incidents, if you want, of coincident, that go into determining those peaks. So it's kind of a normal or averaging peak if you want, but it shows what, looking at the cost causality, how are the costs being caused in peaking on the capacity of the generation system?

1:34:51.850 --> 1:34:52.270
John Todd
OK. When he moved to the transmission line against standard, I think I mentioned that the standard approach is to classify and allocate it based on capacity it's built there's really no consideration is given energy. It's okay, how big does it does the do the wires transmission have to be in order to accommodate the system? So it's a built for the peak, not energy. And when you're not at peak, you've just got spare capacity and since sitting empty so it's the peak that drives the cost so transmission is 100% classified as demand related.

1:35:37.120 --> 1:35:42.530
John Todd
It's allocated to the classes based on that two coincident peak method, same as generation demand related costs. Every generation, all the costs aren't demand related. There's a split between demand and energy, so this 100% of demand that is being allocated the same ways that demand portion of the generation costs. Okay?

1:36:7.70 --> 1:36:11.500
John Todd
We will, yeah, will document the main methodologies around distribution as well. Minimum system method for classification. There are two or three methods. Zero intercept, minimum system type of things that the, you know, they're all they're very technical and they both have advocates who say conceptually my way is better than the other way. From my perspective, it's angels dancing on the head of a pin. I mean, they're just conceptual differences, and both are reasonable arguments and, but it's all how you break it down between customer related costs and some transmission is almost arbitrary.

1:37:6.10 --> 1:37:14.140
John Todd
Your distribution system has to have wires going to every house, so part of it is based on customers, and here it has weighted customer numbers. That’s what SaskPower uses. And customer related and

customer count, different weightings and different customer accounts are used for different types of distribution assets. The weighting is there to say when you count customers causing some of these distribution costs, in some cases it's just a straight the number of customers determine the category of cost. In some cases different classes. A customer causes different costs. My example was meters maybe different in different classes.

1:37:52.420 --> 1:38:21.650
John Todd
Sub-transmission is, it's within the distribution system, but it's kind of like transmission, ie, everybody's using it. So still two CP, which is coincident peak, the NCP is when you get further away from the transmission line, it starts becoming more responsive to the localized demand. And so, using non coincident peak. So it's the peak of individual classes spread across different months, we're not sort of back to this two season thing. You use a different method which spreads it out more and recognizes that we're not all causing demand on all of the distribution system at the same time. The minimum system method basically says if we're talking about the pure customer costs of those poles and wires in the distribution system, what would you incur to just connect everybody? That's the minimum system. And then everything above that is to meet demand, either whether it's a two CP or an NCP.

1:39:5.660 --> 1:39:6.270
John Todd
Next. Uh referred to the carbon tax. It's unique in the cost allocation perspective, particularly for Saskatchewan, but only because it's kept, it's tracked separately to come up with the number pulled out of the cost allocation model. It is caused by generation. So it's the functionalization, the classification essentially it's an adder to the fuel cost. If you use no fuel, you have no carbon tax. So it's also an energy related cost caused by coal natural gas production. So it's essentially markup on fuel. One could do that within the model, but you wouldn't have a separately tracked result, so it's done as a separate tracking process that produces the same result, So the end result is the same as if it was an all-in fuel cost. And in some other jurisdictions, they viewed as that. And as I say, it's as I mentioned a couple times, it's done to get the parallel allocation to get a transparent line item.

1:40:25.240 --> 1:40:26.510
John Todd
Next, we getting close, aren't we?

1:40:27.450 --> 1:40:36.20
Forkast
John, just before you leave that, excuse me, Gerry Forrest speaking. I think it's important to remind the customer, especially the large use customers, that the dispatchable rules that SaskPower uses in in order to dispatch energy at the time it is needed includes the cost of the carbon tax so that the lowest cost including carbon tax is the one that first comes on to the system to supply that demand. It's just an important reminder that while the carbon tax is then incidentally changed or different ways managed in SaskPower versus others, but at the end of the day, the dispatch rules are the same.

1:41:16.330 --> 1:41:22.870
John Todd
Uh, yeah. Thank you for, raising that and yes. So inside the cost allocation model you can separate it and it makes no difference from a dispatch model perspective you have to have them combined. Otherwise,

you'd be dispatching, you could dispatch something with low carbon cast behind something which is a high carbon cost. So you've got for dispatch purposes, it's an all in thing, right. So that's a good point. And yes, it's important that customers understand that yeah, SaskPower is dispatching so as to minimize costs. Having done that dispatch, it does a calculation which then produces the carbon cost which get allocated in the cost allocation model and dispatch irrelevant in cost allocation.

1:42:5.480 --> 1:42:7.640
Rod MacQuarrie
John, we have a question here. Uh, Davis.

1:42:10.860 --> 1:42:22.160
Tavis Reeder
Yeah. It's just the Tavis here on the token of carbon tax. Now I'm assuming that's federally outlined percentages factored in and you guys are just passing that along to us.

1:42:27.320 --> 1:42:31.550
Rod MacQuarrie
Yes, that is, that is correct. The federal government sets the price and sets the threshold levels for us, and it is simply treated as a pass through to customers.

1:42:46.410 --> 1:42:46.830
Tavis Reeder
OK.

1:42:46.290 --> 1:42:49.420
John Todd
Yeah, and there's no actual measure of the carbon being produced, so you say that it's the dollars. What's important there, the dollars that are peeing passed through are the actual dollars that SaskPower's incurring, right?

1:43:0.420 --> 1:43:0.780
Rod MacQuarrie
Yes.

1:43:1.590 --> 1:43:9.360
John Todd
And the way that dollar amount comes up is, as the questionnaire described that it's by federally mandated carbon for coal and natural gas which are the primary source of the carbon as far as generations concerned.

1:43:22.0 --> 1:43:22.170
Rod MacQuarrie
Yeah.

1:43:22.260 --> 1:43:39.840
Tavis Reeder
And your dollars or percentages that you outlined there at the beginning, beginning stages of your slides are percentage of hydro, coal as well as natural gas. Now that's an average of seasons cause of course

our input or import I suppose from neighboring provinces would vary season by season. Now that that's factored into that as well.

1:43:46.120 --> 1:43:54.560
John Todd
Those percentages? Uh, am I? My recollection is I used capacity, so it's a I think instead of how much.

1:43:53.640 --> 1:43:57.670
Rod MacQuarrie
The boilerplate rating of the of the units, right?

1:43:57.540 --> 1:44:2.390
John Todd
Yeah. Yeah. So it's like it's the capacity, what, what they can produce just to give it relative scale. Now of course because of dispatch differences, the actual production of energy would not be the same as that. Because some plants run, the lower marginal cost plants, you know that for example if you're not incurring fuel costs on a production basis, it's cheaper.

1:44:31.910 --> 1:44:32.140
Tavis Reeder
Right.

1:44:32.570 --> 1:44:35.640
John Todd
Then the next step is, you know, prior to carbon tax, generally, coal would be cheaper than natural gas to run a coal-fired plant, so coal would then get dispatched ahead of natural gas, and natural gas tends to be peaking plants. Carbon tax has adjusted those costs a bit, but I'm not sure your numbers Rob, but I'm sure the carbon tax is not flipped that to make you, although natural gas produces less carbon than coal, I don't think that's made natural gas with the carbon tax cheaper than coal. Is that correct?

1:45:11.130 --> 1:45:32.300
Rod MacQuarrie
I may have to refer to Scott on this one, but I believe there was a time last year when natural gas prices spiked to a level where that price of fuel combined with the carbon tax actually made coal a cheaper alternative for us. Is that correct, Scott?

1:45:30.830 --> 1:45:47.380
Scott Chomos
That is correct and fortunately, as many of us know, we have seen those natural gas prices come back down. So we've kind of seen the switch back to the cheapest alternative being natural gas generation, including the impact of the carbon tax.

1:45:49.680 --> 1:45:54.610
John Todd
OK, so bounces around and what from the cost allocation perspective you don't care about how it's produced. We just care about the dollars to pay for it.

1:46:2.930 --> 1:46:33.410
Rod MacQuarrie
Yeah. Our, fuel and Environment Group determines or estimates what SaskPower's annual carbon expense is going to be in a year based on how they feel the units are going to run or how they're going to stack the units. So they go from lowest to highest cost and they provide the finance, my area with a number that says, OK, this is this is our estimate of our fuel expense for the year. And then from that we take that dollar value and derive the rate writers from that based on the forecasted energy use for the year. Does that help?

1:46:41.50 --> 1:46:42.440
John Todd
Questionnaire you're happy? Yeah.

1:46:43.80 --> 1:47:2.340
Tavis Reeder
Yeah, yeah, I mean it's obviously quite a quite a jump. You know, I'm looking at a fairly hefty bill, which I mean as we all are across the board, hence why I'm joining in on this. But yeah, it's more just to get a bit of information on it because I understand it's a blend and I understand that there's, you know lots of different things to consider. It's just a. Yeah, some of this stuff yeah, it's it is what it is.

1:47:12.850 --> 1:47:13.100
Rod MacQuarrie
No. I agree.

1:47:18.120 --> 1:47:19.430
Tavis Reeder
So you're double taxed, yes.

1:47:19.490 --> 1:47:19.700
Johnathon Rasmussen
Yeah.

1:47:22.320 --> 1:47:22.680
Tavis Reeder
But, fun of it.

1:47:29.970 --> 1:47:33.30
John Todd
Which of course GST's provincial.

1:47:33.790 --> 1:47:34.260
Rod MacQuarrie
Federal.

1:47:33.840 --> 1:47:39.940
John Todd
Well, the GST is federal. So you do have provincial or you don't have HST. I'm thinking different provinces.

1:47:39.350 --> 1:47:43.400
Rod MacQuarrie
We have PST it's but it's not on the carbon tax, just GST.

1:47:44.800 --> 1:47:44.990
Rod MacQuarrie
Yeah.

1:47:42.890 --> 1:47:48.460
John Todd
But it's not harmonized, right? OK, so yeah, so only the federal level. You're paying tax on.

1:47:48.910 --> 1:47:49.180
Rod MacQuarrie
Yep.

1:47:49.880 --> 1:47:51.910
John Todd
OK. So you know who to complain to. Which politician. OK. Are we OK with this slide then?

1:48:3.140 --> 1:48:3.910
John Todd
Rate design. SaskPower uses fixed and variable charges. Fixed charge. The basic monthly charge is fixed. It's a fixed on a monthly basis. Each customer pays you know that monthly charge. And everybody's got an energy charge, which is cents per kWh and that's the basic monthly charge and the energy charge is all that's on the bill for residential and energy billed, small commercial customers. The other classes, it gets… there's different rate designs as it is referred to. These like diesel supplied customers have monthly charge and inclining energy rate which goes up, which means as you use more the actual cost per kWh goes up. Farms and large commercial customers have demand meters they referred before that that everybody has a demand right. But not all customers are metered for their amount of demand, and if you're not metering customers to see how what their peak usage is within a month or within the year, you can't build them on the basis of demand. If you're not measuring their demand.

1:49:27.520 --> 1:49:47.570
John Todd
So as you get to customers with demand meters, then you can have basic charge, a demand rate and the above 50K VA per month is when they get into having what are called interval meters, which measure demand. And then there's an energy rate and for farms and large commercial it declines once the demand rate is applied is in effect recovering in when you don't have a demand meter. You're recovering demand charges in the energy rate. It's sort of a proxy for demand. Larger customers with a monthly charge, and that demand charge, energy charge, which is more directly reflective of the way you allocate costs because we can for them allocate out fairly clearly, here's what the demand related costs… set the demand charge on that basis. Here are the energy related costs. Set the energy charge on that basis. And here's the monthly charge based on the customer data costs.

1:50:31.260 --> 1:50:31.710
John Todd

OK. For those you have been following this so for the past decade, you've heard reference to the Bary correction. Used since 2000. Essentially, without interval meters, you don't know what a class's coincident peak demand is, and so the company, SaskPower, has since 2000 was trying to make a correction for the fact that it couldn't identify coincident peak and the concept there was if there's high demand, are you fairly constant throughout the year? You're probably going to have more coincidence with peak demand and so it's an adjustment to... It was an adjustment to be a proxy for not being able to measure coincident peak. And starting in 2022, It's being phased out. The Bary correction was imperfect that way and it produced a high price signal, higher energy price, which is a fault spread signal and what essentially said was even though the customers were not causing costs based on the amount of injury they're using, the Bary correction overstated that. They had a high energy rate which said you will save money if you yourself generate. But the amount of money they could save was more than the revenue from the energy charge.

1:52:39.570 --> 1:52:52.750
John Todd
Sorry, they would say do the energy charge was more than the causal costs, causal and related costs and therefore the loss of revenue was significantly higher than the reduction in costs if you self generate which created a an anomaly that across jurisdictions is a challenge for all utilities, and everybody's finding ways to get rid of this, of an artificial signal, sometimes just because demand charges are collected in terms of energy charge. So electricity markets are changing, have been. The industry has been reacting to that and in the case of SaskPower, it's a phasing out of the Bary correction.

1:53:39.500 --> 1:54:3.610
John Todd
That and another incentive from a regulatory and company perspective is that the change in the very correction or the similar types of changes elsewhere facilitates unbundling of rates. In other words, the industry across jurisdictions and across countries has been moving for many years toward rate structures that more closely match customer and cost to the customer charge, demand charge to recover demand costs, demand related costs and energy charge for injured costs which allows unbundling and everybody pays or more closely pays what costs they cause.

1:54:22.980 --> 1:54:42.570
John Todd
This change in the Bary correction we recommended in 2017, the company accepted it. It was not a simple thing to do as I understand it. So that's why it's starting now and it's a phased adjustment to eliminate the very correction to avoid large, large changes in customer bills is my understanding correct Rod?

1:54:55.650 --> 1:55:11.860
Rod MacQuarrie
Yes, that is correct. We started phasing that in just with the last rate application starting in 2022. So, it's going to take us probably another three to five applications potentially to completely redesign the rates.

1:55:14.740 --> 1:55:30.410
John Todd
So it is, it is disappearing. It should be gone completely before the next review. But this is a move which is consistent with the industry trend and from my perspective as a cost allocation and analytic person

you've gotten rid of something which is kind of an anomaly and is a false price signal and moving toward a more analytic approach.

1:55:45.90 --> 1:55:50.980
Rod MacQuarrie
OK. Yep. No, that's great, John. I think I'm going turn it back over to Scott here as we go through the next steps, if there's no questions right now.

1:55:52.640 --> 1:56:6.190
John Todd
Yeah, that's the that's the end of my part. I think the last slide actually is sort of questions generically. So it can be anything. So if you want to come back with a question with me, I'll be here for the next couple of slides. So ask them now or ask them at the end.

1:56:6.540 --> 1:56:10.320
Rod MacQuarrie
Yeah, actually we have a question from Mitch here. Mitch, go ahead.

1:56:11.790 --> 1:56:15.860
Mitch Minken
Yeah. Just wondering if you could comment on how you're allocating demand for how you're allocating demand to customers that you don't know the demand at coincident peak. I know you've talked about this before, but residential customers, even commercial customers that have demand meters, aren't necessarily yet metered at time of use, so just wondering if you could make a comment on how you're allocating demand to those customers.

1:56:52.350 --> 1:56:54.900
Rod MacQuarrie
I can. I can handle that one, yeah.

1:56:51.790 --> 1:56:59.0
John Todd
Rod, can you get back, I think it's helpful if you go back to slide 14 that curve.

1:57:0.670 --> 1:57:1.310
Rod MacQuarrie
14.

1:57:1.800 --> 1:57:4.360
John Todd
Yeah, that was the slide 14 was the curve.

1:57:6.210 --> 1:57:6.710
Rod MacQuarrie
Or was it?

1:57:5.470 --> 1:57:7.80
John Todd
Umm, I think it's sort of helpful.

1:57:7.720 --> 1:57:9.580
Rod MacQuarrie
Was it 14 uh?

1:57:8.760 --> 1:57:10.500
John Todd
Yeah, 14 shows the curve. And what's?

1:57:11.780 --> 1:57:14.530
Rod MacQuarrie
I think I might little bit different here. There we go.

1:57:14.660 --> 1:57:28.790
John Todd
For there OK. Oh yeah. Because they're sorry. It was fourteen of mine. So let me lead into you, Rod. I mean, first of all, these curves are residential curves based on a sample. So the company does load research and they have residential customers. A sample of residential customers representative, sample residential customers that actually have internal meters that are forward research purposes. So this curve reflects the load shape for those customers that they actually measure the hourly use. And then essentially they scale it up to be representative of the total demand of the class. So this is an estimate of demand but most utilities across the country do load research, and so they end up with an estimate if you want if the peak.

1:58:22.340 --> 1:58:47.540
John Todd
But it's not just sort of the number pulled out of the air. It's based on a good understanding of what customers use because that load research, which is measuring a random sample, it's like doing a survey, an opinion survey. This is a data survey. It's a survey of a random sample of customers to come up with the shape and that shape to the extent that it accurately reflects everybody's use. This load shape you see here, which is used as the indication of demand, is going to be pretty accurate. One reason why I asked to compare 2015 and 2017 is that the sample, some people have left and no longer have interval meters and the sample is a bit smaller. I was curious to say OK, should we be concerned that we do not have a good estimate of peak demand? And that comparison of the two, which is going to be affected not only by the disappearance of some of the interval meters but also by random factors like changes in weather, changes in overall demand.

1:59:33.900 --> 1:59:48.160
John Todd
It shows a lot of consistency, so to the extent we can we don't have full data. There's some comfort there that what we got is a good basis for estimating the load shape and there for the peak of the class.

1:59:48.660 --> 2:0:17.590
Rod MacQuarrie
Yeah. I just want to add to that, John, if you don't mind. So, Mitch, we have for our power class customers like our large industrial customers, our large oil fields and our resellers. Of course, you and the city of Saskatoon, we do have you connected to MV 90 meters. So we do have your interval data. So for power class customers, large oil field and resellers, we do have coincident peak data and we have

many, many years of it. So there's no uncertainty surrounding the coincident peaks and the profiles for those classes of customers. The issue is the mass market customers. So that would be residential, commercial, standard oilfield and farms. And what we've done here is exactly what John had mentioned is that we have a representative sample of interval meters out there and then we take that representative sample and we extrapolate it to the larger billing class to get an idea about exactly how the class is operating. So, the issue is that while we're transitioning to AMI, once we get more AMI meters installed and we feel comfortable with the data, the interval data that we're receiving from that system then we can start to use those load shapes going forward with a with a greater level of confidence. So just so that we're clear, we're not exactly guessing here. We do have data for power class and large oil fields and resellers. We know that the mass market is a little bit more foggy, just simply because as we're transitioning out to AMI some of this interval data that we're using in the past it's representative and it's consistent but it's just we just need some newer data, so does that help Mitch?

2:1:40.120 --> 2:1:49.700
Mitch Minken
It does and you did answer my second part of that as AMI rolls out. Will you be able to be even that much more accurate?

2:1:49.920 --> 2:1:59.920
Rod MacQuarrie
Definitely. That's the plan. As we get more and more meters out there, we are going to start mapping out these load profiles and getting the information as up to date as possible.

2:2:3.450 --> 2:2:17.200
Forkast
John, Gerry Forest again. In your presentation you talked about using your data source as 2021. Is that 2021 fiscal or two actual 2021 calendar year?

2:2:17.640 --> 2:2:18.290
Rod MacQuarrie
It's fiscal.

2:2:18.800 --> 2:2:22.420
Forkast
Fiscal and that's really the latest that you have then, Rod?

2:2:22.770 --> 2:2:28.570
Rod MacQuarrie
Well, that's the latest base file that we've completed. We're just we're just finishing up 2022 fiscal base right now. So yeah, that's the last base file that we have for 2021.

2:2:35.920 --> 2:2:42.840
Forkast
John, of course, we've known each other for a number of years, so, and we probably not surprised. What I'm concerned about going forward and it isn't specifically for this particular cost of service study and your methodology and then the subsequent rate design which we used to call rate phase one and phase two. The issue for me is that this cost of service model will be probably implemented in 2024.

That is your recommendations if they are accepted and they would apply through to 2029. And as we well know, as a result of the federal government's policies and initiatives, first to move SaskPower towards the net Zero and 2035 we also… I don't think it'll be a surprise to anyone that for size power to get to that objective that natural 2035 is not likely to happen. But certainly from our point of view, there's a high cost of decarbonization.

2:3:45.380 --> 2:4:16.880
Forkast
And we will be moving through it through the 2024 to 2029 year and I just challenge you to use your bright mind to think about when you're recommending changes here that you take into consideration that the universe is likely going to change dramatically over the next few years. We have the electric vehicle policy that the Government of Canada has also implemented, which is not going to decrease the demand. It's likely going to increase the demand. And how is all of this going to flow through so that ensuring the customers at the end of the day, whether it's a large industrials or the small domestic consumers are paying the right signals or have the right signals so they can make the right decisions as to how they use electricity?

2:4:36.310 --> 2:4:37.900
John Todd
Good point, Gerry and I will make a generic comment and I'll make a self-serving comment. The generic comment is yes, there are changes. You make reference to price signals and that's where… so the comments around the Bary correction, which we're not really very Bary correction specific, but getting more in line with the true cost, getting price, better price signals is the very getting rid of the very corrections. One thing in that direction more can be done around great design. But what I think your concern is you're getting one cost of service study being done now which becomes the base even if things change and of course, the self-serving comment is well, SaskPower may need to get somebody to do a review of the cost of service study sooner than five years.

2:5:42.660 --> 2:5:43.590
John Todd
Whoever that may be. But I think more practically, it may, it's worth a discussion with SaskPower of how do they monitor things over the five year period because what most utilities do is say it is not uncommon to sort of do an update to cost service study every five years. And it's usually done in other jurisdictions. They only have rate applications every several years. So you do one with part of a rate application.

2:6:14.390 --> 2:6:16.660
John Todd
But the same time from a legitimate regulatory perspective you want to monitor and say, well, we may have to do an update sooner if the fundamentals change. And once and what we are Elenchus are dealing with is the model. To the extent that the input data changes, that model will be updated and that may change changes in the rates. And those changes in the rates may address your concerns. Right. Because you're not updating the design of the model, but you're updating the data into the model. And I think, Rod, you made reference to, you know, you got a target range and you keep moving toward that. I believe that's based on your updates, updated data in the cost of service model and so some of that's gonna be picked up. In addition, presumably you would be looking at is our model still correct given

those changes? Is it the data that's changed? Or is it the structure of the model that has been impacted? If it's just data that's easy to deal with.

2:7:37.760 --> 2:7:37.960
Rod MacQuarrie
Yeah.

2:7:38.170 --> 2:7:47.100
John Todd
Consistent with, you're saying, well, Rod into the response. If they're responded for you from my perspective and Gerry, you know this stuff really well. Is that sort of what you're looking for?

2:7:51.150 --> 2:8:21.140
Forkast
Yeah, yeah, I just am it certainly from my perspective in my career the changes that are going to occur in the next decade for electric utilities in Canada is going to be significant and much more significant probability than anything in the past. And I just want to make sure that all stakeholders, whether it's the users or the utility themselves as we move through the stormy weather in the years ahead that we are well prepared and we do it fairly. That help?

2:8:25.720 --> 2:8:31.390
John Todd
Absolutely. Yeah. Yeah. No, I understand where you're where you're coming from and I think and what I might take away is make sure we think through what will be addressed by updating the data and doesn't require sort of going back and saying is the model right and are there things that may actually drive a need to revisit the model, which would be left with SaskPower and it's possible that there are some changes that can be anticipated where the model could even be, in a sense of flexible, so without going through a long and expensive exercise, there may be some tweaking that may be needed. But that's if it's based on data, then that will happen.

2:9:20.490 --> 2:9:28.310
Forkast
Yeah. Thanks, John. And that's just, I just wanted you to be aware that there were some of the thought process that we may want to consider going forward.

2:9:28.710 --> 2:9:30.660
John Todd
OK. And appreciate that because you know we will when we do the that first report for the 28th and then it goes to the public meeting on the 17th. We'll be presenting that. There will be a questions coming in and what we're doing and so a heads up and if anybody else has anything you'd like to say as a heads up, the best process is that if you have concerns they're dealt with in that first report, that's not waiting for a comment to say, oh, did you think about in case we say no, we didn't now you're halfway through the process and we have to add to it, it'd be great to make sure those kinds of issues are up front. So thank you, Gerry. I'll make sure that's including the first report.

2:10:20.170 --> 2:10:37.70
Rod MacQuarrie

OK, I think we're… I appreciate everybody staying on who stayed with us. We're 15 minutes over on our time. So if there's no objections, I'm just going to pass it over to Scott here to go through the next steps and then we can open it up to just an open conversation or session here.

2:10:37.570 --> 2:10:59.20
Scott Chomos
Yeah. And I'll be really quick with this. So the end goal is to have the report completed by the end of June. And so I'm just going to touch on kind of the next three milestones. So to John's point, what we'd like to see or like to have is that if you've got further questions or if there's certain topics you'd like to see addressed in the report, again, we'd ask that you put that into writing, e-mail it to the e-mail address that you see on the right, which is COSreview@saspower.com. And we've put in some target dates here that obviously they'll be a little bit of flexibility on. But just as a goal, if the request is to either SaskPower to Elenchus or comments on what to include in the report if they were submitted by the 22nd, we would target having them back and posted on to the website by the 30th and then from there we'll do a very similar forum to what we went through today where we'll send out meeting invites and switch the focus of the presentation to Elenchus's draft findings in the report and then we'll proceed from there. So those are kind of the next three milestones.

2:11:54.540 --> 2:12:25.150
Scott Chomos
And if we go to the next slide, Rod, just going forward, this is a screenshot of where you can find information relating to this review process. So if you go right onto SaskPower's website and click on Accounts which you'll see in the top left hand corner and then down in the far right hand side, there's a separate page for the cost of service methodology review. So we'll put a copy of this presentation underneath that link. And just one other note, in our last meeting, somebody was asking about a copy of the previous report, which was done in 2017. So we've gone ahead and added that report under that link as well. So that's where information will be shared going forward.

2:12:42.270 --> 2:13:11.720
Scott Chomos
I think that was all I wanted to touch on. So again, I'd like to reiterate Rod's comments. Thank you for participating today and and sticking with us as we went into a little bit of overtime. But that said, I think if there's any other additional questions that you wanted to clear up now, I think there's still a few minutes available that we'll stick around for. And if not, we look forward to possibly hearing from you through the process on the 22nd and again you can expect another invite from your key account manager or through the website for a meeting on the 17th.

2:13:27.680 --> 2:13:35.150
Scott Chomos
We'll kind of pause for just a couple minutes to see if any other questions come in. If not, again, thank you and we'll chat again soon.

2:13:36.250 --> 2:13:45.750
John Todd
And I'll add my thanks for your tolerance. I ran this overtime because this stuff is probably more interesting to me than they're anybody else I think call. So thank you for sticking with it. As I drove us a little bit overtime.

2:13:53.270 --> 2:13:58.30
Forkast
Rod and Todd, John, very well done. Thanks.

2:13:58.590 --> 2:13:59.150
Rod MacQuarrie
Thank you, Gerry.

2:13:59.490 --> 2:13:59.920
John Todd
Thank you.

2:14:1.70 --> 2:14:4.920
Rod MacQuarrie
I'm not seeing any questions or anybody raising their hand here, so if no one has any questions, I think that'll be it. Right. So thank you very much everybody. Thanks, John and everyone who attended. And we'll see you next time. Bye for now and we will be getting together again next time. And I think it's going to be in person. And finally we'll get back out to see the beautiful province.

2:14:33.230 --> 2:14:33.590
John Todd
OK.

2:14:29.430 --> 2:14:36.570
Scott Chomos
We might do it again in this format, John, I think. We'll discuss that one.

2:14:37.90 --> 2:14:41.870
John Todd
OK, whichever is this, the post covered world. We're all staying virtual, right? Don't fly those airplanes. OK.

2:14:46.450 --> 2:14:47.630
Scott Chomos
Good bye.

2:14:47.130 --> 2:14:48.840
Rod MacQuarrie
OK, thanks, John. Take care.

2:14:48.280 --> 2:14:49.80
John Todd
OK. Bye bye.