Commission Docket No: UE20943

Transcript of a Pre-hearing Conference before

The Island Regulatory and Appeals Commission

on September 22, 2016

In the matter of the *Electric Power Act* and in the matter of an Application by Maritime Electric Company Ltd. for an order approving an Open Access Transmission Tariff for the period beginning January 1, 2017 and certain other approvals incidental thereto.

Scott MacKenzie, Chairman: Good morning, everyone. For those of you who I have not met, my name is Scott MacKenzie, I am Chairman of the Island Regulatory and Appeals Commission. To my right is John Broderick, Commissioner; to my immediate left is Doug Clough, Vice Chair of the Commission; and to my far left is Mike Campbell, Commissioner.

Well, thanks very much for coming and thank you to Maritime Electric for offering this technical briefing which we'll go through today. You will see that the microphones are on and we are recording this. This technical briefing will form part of the record for the application to go forward further in October, so this is Docket Number UE20943, and it's dealing with an application by Maritime Electric for the setting of an Open Access Transmission Tariff. So the process today I think everyone is aware of, but just to clarify, this will be a less formal session. We're going to let the presenters make their presentations as they have provided them. The only questions that we would allow today would be questions of clear - just clarification only. In other words, we're not going to be, this is not a hearing where we're going to have any kind of cross-examination of people who are making presentations here today. But for instance, if someone hears the acronym FERC and doesn't know what FERC is, it's fair to, at an appropriate time, to say I don't understand what that acronym FERC is, what does it mean. That type of question, that's okay, but there'll be no cross-examinations of saying well, why did you use these types of calculations to come up with the formula. We're not going to get into that today. That's for the hearing. So if that's clear and okay with everyone, we'll just let the briefing begin and thank you very much.

SUBMISSIONS BY JOHN GAUDET:

Mr. John Gaudet: Good morning all, my name is John Gaudet. I'm president and CEO of Maritime Electric. I'm appearing primarily because of my connection with this file. I've been intimate with it for the last 20 years and I've come today to provide context. Maritime Electric is very appreciative of all that are attending and thankful to the Commission for enabling this information session.

Today we'd like to provide some background and context to the filings. We're not intending to introduce any new evidence or argue our case but it's a presentation of the situation. The OATT is, I said I've been involved in it 20 years but it is relatively new and we recognize that the Commissioners and the public, whoever is interested, could use some background information on how these things work, so we are really appreciative of that opportunity.

With me today is Bill Marshall who has assisted us greatly in the filing and has a wealth of experience in the industry in this area; with Bob Younker, our director of corporate planning; and John Cunniffe, senior planning engineer. The four of us are engineers so engineers and information sessions don't sometimes go together. We can talk acronyms and obscure techniques but we're going to try today. Maritime Electric's experience with transmission access really goes back to the beginning, when submarine cables were installed. Cables were installed in '77 and that enabled Maritime Electric for the first time to purchase electricity from someone else; namely, NB Power. Originally, the early purchase agreements were based upon formulas, comparing our costs with our costs of productions and splitting things down the middle. Eventually those formulas gravitated to marked-based pricing and there were some issues with what we felt were not competitive pricing. So our interests had been enabled to secure supply or at least get supply on equivalent terms and conditions and the record's full of those details.

In the 90s there was a push for market liberalization across the world, in particular the United States. Mr. Marshall is going to talk about FERC and the genesis of Open Access Transmission Tariffs in North America which led eventually to Maritime Electric developing its own OATT. Driven by the need to demonstrate reciprocity, we want to access energy supply from another jurisdiction. It was incumbent upon us to provide same level access in our system. So that was the genesis. Back in the 90s and early 2000s the government was also developing wind in its vision and, you know, in

2006/7/8, the ten-point plan was developed. PEI is gifted with a very robust wind regime and an Open Access Transmission Tariff is essential to provide the rules of engagement for merchant wind to move their product off of PEI through the Maritime Electric system in terms and conditions that were non-discriminatory and fair. And so those are some of the lead-ups. In addition we have had a wholesale customer very interested in transmission access and being able to get a competitive supply from others.

So contractually we agreed in the mid-90s to provide access to those eligible customers on PEI, to the same extent as PEI or Maritime Electric, pardon me, the same extent as Maritime Electric got access in and through New Brunswick. New Brunswick opened its doors for transmission access through a note, I believe, of - the *Electricity Act* was changed in 2003 so since then Maritime Electric has been able to move product through New Brunswick and so have other customers. The ten-point plan hasn't unfolded exactly to the extent, but there are merchant wind farms on Prince Edward Island availing itself of that opportunity using our transmission tariff. And I don't believe they're here today. So with that, I'll conclude and I would ask Mr. Marshall to start our slide presentation on the background that led up to the development of OATTS in Eastern Canada.

Chair: Thank you, and just for people, I forgot to mention this, there are copies of, for those who want, there are copies of the presentation here at the desk. Thank you. Come forward. That’s fine.

(Brief discussion regarding equipment)

SUBMISSIONS BY MR. WILLIAM MARSHALL:

Mr. William Marshall: Can we load up the first - Okay, good morning, Mr. Commissioners. As John said, this presentation is an overview on tariffs, where they came from, how they evolved, so next slide please? Oh, do I do it? How do I do that?

(Brief discussion re equipment)

Mr. William Marshall: So I'm going to talk about, you know, background, even before the tariffs, how it evolved, on the electricity industry in general and then we'll get into transmission access and how it evolved and to get to the FERC, that's the U.S. Federal Energy Regulatory Commission pro forma tariff and then also what have Canadian utilities done relative to that. Next slide please.

So this is back to the basic physics of electricity. It can't be stored and it's the only product in the world that has to be produced in real time as it's consumed. And because of that, supply has to equal demand continuously, otherwise the system will go out of balance. And so you need reserves and ancillary services in order to meet this changing demand and to provide back up in case there is any unexpected loss in supply. And the consequences of this imbalance can be simply minor frequency or voltage fluctuations or it could be a major blackout. The next slide please.

And the other point about electricity is it can't be economically generated and distributed at the voltages that we use it at. We want power at 120 volts in our house to run everything but it's not economical to generate electricity and distribute it at that voltage. So you've got to generate it a much higher voltages and you need it transmitted at even much higher than that, from 69 kV up to as much as 765 kV.

The other thing about it is, because of the balancing requirements, you need a central system operator that's got their eyes on the system at all times, to be able to see exactly what's going on and they need automatic controls that will respond to these fluctuations in the system in order to keep it whole. So the primary concerns: safety, reliability, and cost. And the key point here that I'm getting into is that reliability is paramount, and transmission access is more about commercial operation but it has to always respect the reliable operation. So tariffs involve both the reliability aspect and a commercial access aspect. Next slide please.

So there are three basic functions in the power industry. Generation, transmission, and distribution. And you can see here, there are dotted lines, show the division point between the three. The transmission begins after the synchronizing breaker so that the generator step-up transformer and the synchronizing breaker to connect to the grid are the responsibility of the generator. And the substation distribution transformers are the responsibility of the load. The transmission system runs from that synchronizing breaker to the high voltage side of the distribution transformers. Now that's generally the case in terms of definition. When we get to the very end, we'll see that in terms of allocation of the costs for these functions, there are some differences across Canada in terms of where those lines are, okay. Next slide please.

Now, you look at those components, integrated utilities which were, as John had said, Maritime Electric before the cable was certainly an integrated utility, owning generation, transmission and distribution assets, just as NB Power today has generation, transmission, and distribution. Then we have municipal utilities, usually are only distribution assets but they may have some generation. Now Saint John Energy is only distribution assets, no generation. Summerside as we know has some diesel generation plus some wind generation and all of the distribution assets. Now over time, generation ownership, it used to be primarily all the generation was owned by the integrated utility. But now, more and more, generation is becoming separated from utilities and is privately held, like the West Cape Wind Project, for instance. Now this bit on the cost profile just gives you a breakdown of the relative costs of most systems, that the, in our bill, when we pay for our electricity as customers, about 65 to 75 percent of that cost is for the generation. And that as I say is a mix, in the, across the industry it’s a mix of competition and regulation and it’s leaning more and more towards competition. On the distribution side, again 15 to 30 percent of it is the cost for distribution and that is mostly regulated, okay, through its costs that goes into rates that are regulated to get to customers. In some jurisdictions there is retail access at distribution so it’s competitive but in most areas it’s regulated.

Now that leaves the transmission costs are only 7 to 10 percent of our electricity bill and transmission now is regulated open access and that’s what we’re here to talk about. And those transmission costs are recovered through Schedule 7, 8, and Attachment H of the tariff. The last cost, system and market operations, can be anywhere from .5 to 2 percent. Now that’s because in some jurisdictions there are formal, large-structured markets like New England or Ontario or others, so the cost of operating them is much more. In a utility structure like Maritime - cost is much down at the bottom end; it's simply the control operators in the system. And the cost for that is recovered through Schedule 1 of the tariff. Next slide please.

Now, across North America there are essentially four synchronous electrical systems. There is the Quebec Interconnection which is only connected to the Eastern Interconnection through high voltage DC lines. So it's not synchronously tied, so when there is an imbalance in Quebec, it doesn't affect the areas around it. It only affects the Quebec system. So the Quebec system has to be balanced, the Eastern Interconnection that Maritime Electric is a part of has to be balanced. But it has to be balanced from the tip of Cape Breton to the tip of Florida to Saskatchewan to Louisiana. So it's one large electrical system that has to be balanced. Now as I said, you need one operator for the whole system. The key operator in the Eastern Interconnection is the midwest independent system operator located in Indianapolis so they're the entity responsible when the system, the whole interconnection is out of balance and it speeds up, they are the ones that will do the error correction to say you've got to change this to get the clocks back on line and keep the frequency at 60 Hz. so that a time error correction is done. So they are responsible for those things across the whole system. And you have Ercot in Texas and the Western Interconnection as well, separate systems, separate operators, we'll deal with the Eastern Interconnection. Next slide please.

Now, reliability is an issue that, it's determined by the North American Electric Reliability Council, was formed in 1966. It has since become a corporation and its responsibility hasn't changed: promote reliability in the bulk system. It started on a voluntary basis, that utilities were voluntary members and voluntarily they developed the standards and they complied with them. And the standards deal with two things. Adequacy is - you know you have to build enough generation and transmission facilities and assets so that you can meet the requirements. That's a planning-type process. And then there's security. Security is an operational process. And it's will this system be able to be operated to continuously provide service? Now that N-1 that I put there in brackets is a key driver. Every one of these electrical systems, the synchronous system, has to always be at least one step away from failure. So the way they're operated is that you scan the whole system and say what's the worst thing that can happen. And then you have to back away from that and operate the system so that if it happens, the system will respond safely and continue to operate. Okay? That's the key driver and that's called N-1 criteria.

Now mandatory compliance began in 2007. FERC, the US Federal Energy Regulatory Commission, was empowered through the *Energy Policy Act* in 2005, became responsible for reliability in the U.S. NERC, reliability council, now formed into a corporation, became responsible and was designated by FERC as the electric reliability organization, responsible for reliability in the United States. But NERC is a North American organization so to deal with it, Memorandums of Understanding were required from the provincial authorities in Canada and so MOUs were formed, were done. New Brunswick did one with NERC and NPCC, so did Nova Scotia, so did Quebec, Ontario, most provinces. And in New Brunswick today, NERC standards that are developed, saying the (unclear) standard to meet reliability, they are then, NB Power applies and they go to the regulator in New Brunswick and are then approved and are legally required to be complied with in New Brunswick.

Now, PEI is not part of a bulk system today and there is some argument today as to where the line is drawn or not drawn. So it may become so in the future, but the issue is that the regulatory standards in New Brunswick of NERC and NPCC, which we'll get to, essentially Maritime Electric is required to comply with them through their interconnection agreement with NB Power. So, they're contractually obligated to meet those standards. Next slide please.

Now these NERC reliability standards, they require automatic generation control, which abbreviated is AGC, which, for balancing and frequency control. Now as I said before, in real time the system has to always be balanced. So we need generators to be under control to respond instantly to variations in frequency and errors in balance. That's a service that's required under the tariff, okay. We also require spinning and supplemental reserves. These are non-spinning reserves, they could be offline but they have to be available in ten minutes or thirty minutes, to respond to a contingency. They're also services that are required through the tariff. Reliability co-ordinator is the entity that's responsible to meet the standards for reliable operation in any specific area. And that, the reliability coordinator sets out the obligations of the area utilities based on load ratio share. And we'll talk about the fact that the

NB Power operator is the reliability coordinator for Maritime Canada and they designate the obligations to Maritime Electric for their share of what has to be met.

Now the, provision of these services that are required for reliable operation, they can be provided from generators that you own, the self-supplied; they can be purchased from some third party that has generation that's capable of responding; or they can be purchased through the transmission tariff. Next slide please.

Now, I mention NPCC, that's the Northeast Power Coordinating Council and now the Northeast Power Coordinating Corporation. There are five areas. It is the northeast region of the United States and Eastern Canada. The central operator is the New York Independent System Operator. They will be the entity taking the direction from myself to do error correction. They will allocate it out to each of the regional operators and they also are a co-operating agency with NERC. So they deal with implementing and monitoring the NERC standards in this region, okay? Next slide please.

Now in the Maritimes, we have the New Brunswick Transmission System Operator, is the reliability coordinator for all of the Maritimes and they would be the operator responsible, they would be in continuous contact with the Nova Scotia operator, with Maritime

Electric, with the Northern Maine Operator and they have to balance, ensure that the Maritime area is balanced against its inner-ties into New England. And just an interesting note here. You can see that the New Brunswick area is not just New Brunswick. PEI is part of the New Brunswick balancing area, as is Northern Maine, which is electrically only connected to New Brunswick. It is not electrically connected to the rest of Maine. You connect from Northern Maine into New Brunswick and then New Brunswick connects down into Maine. So that makes Aroostook County and parts of Washington County part of the Maritimes, electrically. Okay? Next slide.

And this Maritime Area, New Brunswick System Operator is one of eighteen reliability coordinators across the continent. Now you can look and you can see all of those, that this area is not, is not that large; whereas a lot of these others are very, very large. But the New Brunswick operator for the Maritimes would be probably the second smallest. Saskatchewan on its own would be smaller than the Maritimes with the combination of New Brunswick, Nova Scotia, PEI and Northern Maine. Next slide please.

Okay, so that’s it for the background in the industry. So we look at transmission access issues, I want to look at the evolution of it and regulation, how did that come about and where are we. Next slide please.

Well, as Mr. Gaudet had explained, utility access, you know, originally the transmission access was controlled by the utility that owned the transmission lines. And the access required contracts. So the only way you could get access to somebody else's transmission is you entered a contract with them in order to deliver power across it and some examples of that are Maritime Electric's contracts in order to deliver energy from Dalhousie and Pt Lepreau to the Island, or NB Power's contracts to deliver Coleson Cove and Pt Lepreau exports into New England and get it through Maine, to get it to Massachusetts. So those contracts started in 1977, actually at the same time these, when the cables went into place, the major interconnection from New Brunswick into New England was also operational and Colson Cove came on at that same time. So those contracts existed through the late 70s, 80s into the 90s, okay, up until the advent of open access. Next slide please.

Well, in the United States the electricity is governed by the *Federal Power Act*, and the Federal Power Act empowers FERC and the regulatory commission to regulate the Act. And it applies, and this is important, it applies to public utilities, but it doesn't apply to federal power authorities. So it applies to privately held corporations that were, you know, utilities essentially. But it doesn't apply to the Bonneville Power Authority, it doesn't apply to the Tennessee Valley Authority, which were federal agencies that were built to develop rivers and hydro power in the thirties and do irrigation projects and, but were, also became power utilities but they were owned by the Federal Government in the United States. So FERC doesn't regulate them, okay. Now, but in 1992 the U.S. Government amended the *Federal Power Act* to provide for competition in electricity at the wholesale level. And in that they defined wholesale as purchased for resale. So essentially it primarily provided municipal utilities the ability to go out and get power from other than the utility that they were connected to, that they could go out and contract for supplies across the system and would have access to deliver it through the transmission system of the utility they were connected to. So that became the law in 1992. So the transmission had to be available on a non-discriminatory, open access basis to those utilities. Next slide please.

So how was that going to be done? So it was the law for the utilities to provide open access so it opened up a whole new area of, well, how do you price transmission. So you've now got to separate transmission costs and how do you price it to make it available on a fair, non discriminatory basis. So FERC came out with their transmission pricing policy in 1994 and it said pricing is to be just and reasonable and not unduly discriminatory or preferential. But they left it open to the utilities to develop the pricing proposal. They simply set out some principles. The key one meaning that the traditional revenue requirement for transmission should be recovered. Now in the United States, FERC, regulating all these public utilities has a standard set of accounts so every utility reports their cost to FERC under the same set of accounts, so they were able to say these accounts are transmission so those are the costs that you've got to recover through the tariff. But the most important principle is the second one, that the proposal for pricing has to reflect comparability. Now comparability means it's the Golden Rule, as you treat others the way - you treat your neighbour as yourself, that's the rule. You make transmission access available to this third party customer on the same basis that you use your system to supply your load. That's comparability. Okay? That's the Golden Rule of transmission access. The other three are yes, economically, be efficient, be fair, be practical, but to be a conforming proposal it had to meet the first two.

Key ones, meet the revenue requirement and be comparable. Next slide please.

Now, in response to the U.S. *Federal Power Act* in '92 and FERC's pricing, it became very much of interest in Canada now to say, well, wait a minute, yes, we should have more open access in Canada. But the issue we have here is that electricity, being energy, is a provincial jurisdiction. There is no federal agency in Canada to deal with it. And the National Energy Board only deals with exports of electricity or transmission lines, you know, out of the country. So there was a movement to develop, you know, inter-provincial access. There was an energy committee that was formed, assisted by utility representatives. Federal and provincial energy authorities, and there was work through the mid-90s towards across territory transmission access and it was not successful, essentially because it was part of, going to be interprovincial trade on energy and there was no agreement on the offshore oil and gas, so the proposals for electricity never got agreed to. But it became irrelevant because most electricity trade in Canada is north/south so there were a lot of exports of electricity from Canada south, in the United States. And so the utilities in Canada had to respond to actions in the United States so when FERC came up with Order 888, the utilities selling north/south were subject to the reciprocity under that arrangement and that drove actions to develop open access in Canada. Next slide please.

So FERC Orders 888 and 889 and the major milestone in development of transmission access. They were issued in '96. Order 888 brought forth a pro forma tariff. Now, unlike the transmission pricing policy, which just set out principles and didn't give a, here's a standard; Order 888 developed a pro forma tariff and said here's the standard, do it like this, but you're free to do it differently but to do it differently it's got to be equal to or superior than the pro forma and it has to meet those principles. It has to be comparable, it's got to do the revenue requirement and it has to be, provide for reciprocity.

Now the reason the U.S. Government went in with reciprocity in FERC, say reciprocity is required, it's a way FERC could get at those federal power authorities, because Bonneville and Tennessee Valley are large generators, they interact with utilities around them going, to say, if you're going to do business with them you also have to provide reciprocal access so they can do business with you. Okay, and similarly for co-ops like Eastern Maine Electric as a co-op, and other co-ops, you've got to provide reciprocal access if you're going to take service. Order 889 was the order that required how are you going to do this, how are you going to deliver these services? And it required functional separation of merchant and transmission operations. So the entities in the utility that are doing the buying and selling of power in the marketplace and with other parties had to be at arm's length, separated from the transmission operations people and they introduced a code of conduct that decided, here's how you have to be separate. So it set up Chinese walls between the operations in these organizations and it brought forth the requirement for an open access, same-time information system. Now that became an electronic bulletin board system so that the utility, if it was going to be doing any business with the tariff, it had to access the transmission through that same bulletin board system as any other third party. It couldn't pick up the phone and call their own transmission operator and say we want to do this. They had to be treated comparably to everybody else and they had to do their business the same way as everybody else. Now those orders were challenged through the courts and went through a series of cases and by 2000 the court of appeals ruled that FERC was, had legitimate authority and that the orders were upheld. Next slide.

So we'll look at the FERC pro forma tariff and what is in it because the application of Maritime Electric or its tariff is based on the FERC pro forma. So it is the standard tariff across North America today. Next slide please.

Well, the tariff, it defines the services available and there's transmission services and ancillary services. And those ancillary services are some of those reliability services we talked about earlier. It specifies the operating terms and conditions for how do you schedule, how do you differentiate what's firm or not firm, what, who has priority for curtailment, how much information do you need, how do you get it - all of the operational issues are specified in detail. It also sets out the rights and obligations of the transmission provider, for what services it has to provide and what obligations it has to expand its system in order to provide them. And it sets out the rights and obligations of a transmission customer for what service is available to it, and for its obligations to pay and its obligations to provide reciprocity. Next slide please.

Inherent in the service there are two types of transmission service. There's point-to-point service which essentially is delivery from one point of receipt, a generator, to one point of delivery, a particular load or a particular interconnection to another utility, okay.

Or for example, from the inter-connection at Murray Corner with New Brunswick to Summerside Energy, okay, that would be a point-to-point, from one point to another. The - it can be firm or non-firm, it can be long term or short term, it's generally the service that's used for short-term economy transactions between systems and across systems. And it's also used for long-term power contract supply. For example, for Hydro Quebec to deliver 300 megawatts through New Brunswick into New England, have a long-term, 300 megawatt, point-to-point contract. And as I say, it's analogous to a pipe, this goes straight through. Network service is multiple sources of supply to multiple loads. So it's a service that supports the economic dispatch of resources to supply load across a system. So it's generally used by the host utility to supply its load, as Maritime Electric uses network service to supply all of the loads across PEI. And it will use generation coming from New Brunswick or from Charlottetown or Borden or wind farms under contract to it across the Island. So in it, the system is analogous to a cloud and you can have, the sum of all of the sources is going to add up and meet the sum of all of the loads. And in this simple example, we ignore losses. Okay? This is a perfect system. But you, the reality is the sum of all the generators has to equal all the loads plus all the losses. Next slide.

Now, ancillary services are, there are three kinds of ancillary services in the transmission tariff and in the pro forma tariff. There are compulsory operational services that a transmission customer has to purchase from the transmission provider at system control and dispatch to operate the system, and voltage control, so because vars don't travel across systems, they've got to be provided locally. Voltage control across the Maritime system is the responsibility of Maritime Electric and they've got to make sure they have that capability so anybody buying transmission has to buy that service from Maritime Electric. And if you're in New Brunswick, you've got to buy it from New Brunswick Power. The capacity-based ancillary services are the ones we talked about earlier. They are the ones from generators that are needed for reliability. We need that spinning and supplemental reserves. We need load following, we need that load following to follow the variations in load, we need it to follow the variations in generation from wind farms, for example, that are not controllable. So you've got to have resources that are there to back those up. So you have got to have load following capability and you need to have that frequency regulation which is this automatic generation control that's going to sense any variations and automatically increase or decrease, to correct for any imbalance errors in real time. And again, as we said before, those services can be self supplied, from your own generation. They can be purchased from a third party, or they have to be made available under the tariff, they can be purchased from the transmission provider. And they may not be required for point-to-point. If you're doing a short-term, point-to-point transaction that's interruptible and non-firm, okay, you don't need to provide the services with it to supply it to the load, okay? So they're not compulsory there. They are compulsory for network service. Network service has to provide transmission service and the transmission customer taking network service has to provide all of the ancillary services needed to go with it to supply that load.

And the last service is energy and balance. Because the electrical system is always out of balance and is working always to catch up and get in balance and will go a little plus or a little minus; over time you want it to be, the sum of it all to be balanced; but at the end of a month a transmission customer may be scheduling to meet its schedule but there would be an imbalance and it won't be equal to what it said it was going to deliver. It delivers a little more or a little less. So there's got to be a financial settlement at the end of the month for any - the customer would have to pay if there's a short, because they've got to pay for the energy that was delivered that they didn't generate or they get paid some money for the surplus energy that they delivered that they didn't need to deliver. Okay? So that's Schedule 4 in the tariff. Next.

And finally this reciprocity obligation. So any. in the pro forma tariff, any non public utility that uses the tariff of a transmission provider, they must agree to provide reciprocal open access. Now, it has to agree to provide reciprocal open access to its transmission system if it's part of the same corporation. But it could be an affiliate corporation. For example, in New Brunswick, New Brunswick Energy Marketing is a separate corporation from NB Power but it's an affiliate of NB Power, being owned and controlled by it. So when NB Energy Marketing does a deal in the United States, okay, it's obligated that NB Power, its affiliate, provides open access, reciprocal access in New Brunswick, okay? And the other rules that drove this, that because you have these affiliates and you have different marketing entities, in order to participate in the United States and sell power at market prices requires that you get a power marketing authorization license from FERC and in order to do that, FERC requires that, and there were hearings for New Brunswick because there was a complaint against NB Power about selling into Northern Maine, there was a hearing before FERC, they looked at it. They had to show that they had no market power and they had to show that their tariff - they had open access tariff that provided reciprocity and met the requirements and FERC accepted that back in 2010 as a result of that hearing, okay. So you have to demonstrate no market power but you also have to demonstrate reciprocal open access of any affiliate utility. Next slide please.

So what happened, since - that was Order 888 in 1996 and a series of other orders - 888A, 888B, 888C - there were a number of re-hearings, you know, through the few years after that and then in 19, in 2007 there was Order 890 which is a major update on the tariff and it added a whole lot of changes from what was in the 1996 pro forma. Now I'm not going to go through all of those but the list of those essentially is dealt with in my evidence in the filing, going through, and looks at those Orders, you know, word by word. What are the sections, what are the changes reflective in Maritime Electric's application. And there were changes from other Orders, different ones, particularly the NAESB, that's the North American Energy Standards Board, and they had a lot of protocols and operating standards that are adopted by reference through Order 676 and are included in Maritime Electric's application. So next slide please.

So that's the pro forma. Where it started in '96, where it is today after all of these other Orders and updates. So how did Canadian utilities respond to it? You know, in terms of getting power marketing authorities and developing tariffs in Canada. Next slide.

Well, in terms of getting power and marketing access in the United States, virtually every utility in Canada with competitive generation assets now has achieved or is pursuing a power marketing authorization to sell at market prices in the U.S. Now many did it immediately in 1996 in response to Order 888. Like Hydro Quebec, Manitoba Hydro, Trans Alta, BC Hydro - they were - actually BC Hydro applied to FERC even before Order 888 was finally approved. They applied based on the notice of proposed rule making, you know, prior to it. Other utilities plus different marketers in Canada took a little bit longer but they today now all are power marketers into the U.S., and you've got Ontario Power Generation, Brookfield Renewable Power, Algonquin, Saskatchewan Power, Emera Energy, who has an affiliate in Nova Scotia Power; New Brunswick Power, New Brunswick Energy Marketing as its affiliate holds the license. And it's currently right now we have, Nalcor is in the process of developing and we fully expect that they will have power, they are actually selling into the U.S. today through Quebec. They have Emera Energy basically are their agent and conduct the business for them. But they are in the process of getting power marketing authorization and are expected to have a pro forma based tariff when Muskrat and the transmission projects come on line in a couple of years or so. Next slide.

Now, in terms of pro forma tariffs in Canada, the only transmission utilities in Canada that don't have a FERC-based, pro forma tariff are Ontario and Alberta. Now those two provinces don't have, their tariff is not based on the FERC pro forma but they have large markets in those provinces. They have open access. They were developing tariffs there even prior to Order 888, to move towards markets. They do provide province-wide open access. They allow access from outside the province in to provide to provide, to supply the loads inside the province. And the tariffs in both Ontario and Alberta have been accepted by FERC as equal to or superior to the pro forma in meeting the reciprocity requirement. Because FERC has granted power marketing authorization to Trans Alta, and Trans Alta is both a utility, generation-owning marketing utility and owning transmission assets that's part of the Alberta tariff. And similar in Ontario, Brookfield owns Great Lakes Power and its transmission is part of the Ontario transmission tariff as well and Brookfield are a marketing agent into the U.S. Next slide please.

So every Canadian pro forma based tariff has been initially modelled on Order 888. And every one of them except Saskatchewan Power and Nova Scotia Power have since been upgraded to meet all of the changes in order 890 and all of the other orders. And that's the application here of Maritime Electric, is to do the same with the tariff in PEI. But none of them are identical to the FERC pro forma. They are not word for word identical and they do not have every particular aspect identical. Each have some minor variations. For instance, both New Brunswick and Nova Scotia do not build network service on coincident peak loads. They build them on non-coincident peak loads because they have metering limitations at all of their substations. So that they can't get what's the coincident peak load there. So the regulators in New Brunswick and Nova Scotia have said, okay, you can do that. So that's a deviation from the pro forma. All the other aspects are pretty much the same. There are point-to-point discounts for exports in a number of jurisdictions. Manitoba Hydro have a reciprocity agreement with MISO and don't charge any tariff for exports into the U.S. out of Manitoba. BC Hydro have discounts right in the tariff for exports out of their system. And again that's similar, Maritime Electric, in its application in the current tariff, provide a discount for renewable exports out of, so West Cape exporting out of PEI into New Brunswick use the off-peak rate for everything, not - so they get a bit of a break. But it's economic and it's good value for all of the other customers. New Brunswick has an open season for increased transmission capability. In the pro forma the open season only applied to the initial allocation of transmission and when some new stuff comes up, it's first come, first served, who's ever in the queue gets it. But that's not the case, you know, in New Brunswick. And then the last one we'll look at on the next slide here, there are some deviations in functional allocation of costs.

Now I must say, this slide, Mr. Chairman, this slide is not in my evidence. This information was prepared after I did my report and filed and gave it to Maritime Electric, but it's information that was developed in anticipation of questions you would ask, okay? So it's, I just want to make it clear, though, but it's not part of the record at this point, okay, but it is factual information that's available. You know, you can go online, you can get reports and you can get the information behind it in the tariffs of each of these areas. So what you have here is the, back to that slide where I talked about the functions, generation, transmission, and distribution, and here we'll even separate out the generation step-up transformers and synchronizing breaker and the distribution step-down transformers, so they're separated out in these slides and you can see that not everybody allocates these costs and collects them through their tariff in the same way. Now the Maritime Electric application, you can see that the step-down transformers are allocated and charged a distribution, the generation connection assets and the generation step-up transformers and charged (unclear) generators, the transmission tariff deals with the transmission network and the radial load-serving lines. And that is the same as in New Brunswick, Nova Scotia and Saskatchewan. The other provinces, British Columbia, Alberta, and Manitoba, can see the radial lines are not included in the tariff but in Ontario and Quebec, not only are they included but so are the substation step-down transformers and the generator step-up transformer. So there are some deviations in the cost allocation, you know, across the country and I just provide that information because that's where the world is at this point. And I believe that's my last line. I thank you for your time.

Chair: Thank you, that was very good. Questions? I don't have any questions. Anyone else have any? I guess not. That was very thorough, Mr. Marshall. That was excellent, it really was.

SUBMISSIONS BY MR. JOHN CUNNIFFE

Mr. Cunniffe: Thank you, Bill. Mr. Chairman, I'm going to just present right now an overview of the filing that Maritime Electric did in July with some background concepts to explain some of the terms that you would find in it. So overview, introduction, the time line for this open access tariff where, when Maritime Electric has filed it back in 2006 'til now, Bill's given the back-grounder on tariff development and so on and then we'll get into the transmission system overview and discuss some of the key concepts. I'll highlight a few of the concepts in the current filing or a few of the things that we have done. And description, more detailed description of the schedules and the services provided, although Mr. Marshall has described most of them, at least at a high level. We will get a bit more of the detail and then I'll show a few of the differences between the Prince Edward Island tariff and the New Brunswick tariff.

So back in 2006, April 2006, IRAC directed Maritime Electric to develop and file an open access transmission tariff under Order UE06-02 and this is in response to the - in the end it's in response to the U.S. electricity market deregulation, as Mr. Marshall has shown, and IRAC directed Maritime Electric to file it by November 2006, which was done. In early 2007, there were stakeholder sessions between Maritime Electric and various stakeholders on the system. Feedback came from those stakeholders so Maritime Electric in October 2007 filed an updated tariff based on the feedback and inclusion of comments from the stakeholders. And in March 2008 Maritime Electric received interim approval of the OATT pending resolution of some outstanding issues. We're still operating under this interim umbrella. Just to note that the costs from this interim OATT were based on a 2004 cost allocation study, 2005, sorry. And which brings us 'til today when Maritime Electric filed an updated OATT in July of 2016, which is based on costs from a 2014 cost allocation study which has been provided to the Commission.

The intent of this filing is to remove the interim label and have a fully functioning, standalone tariff. It was originally updated to specifically incorporate FERC 890 as the other, most of the other Canadian utilities have done; and it also aligns with all the other FERC orders - 888, 889, 1000 and a number of others that have been pointed out in the evidence supplied in the application - and it closely follows New Brunswick where New Brunswick Power has received New Brunswick Energy and Utilities Board approval for deviations from specific FERC orders and those are all highlighted in the application as well. This is the Island Transmission System, I'll take a minute to explain how, all the components and so on. Over here, right down to the bottom of the screen, is a substation in New Brunswick called Memramcook. It's located just south of Moncton. Into it is 345 kV lines coming from New Brunswick and there's also the connection line from New Brunswick into Nova Scotia. So those terminate in Memramcook substation. And in Memramcook substation the power is stepped down from 345 kV down to 138 kV and there's lines, 138 kV lines from Memramcook that feed up towards Moncton; there's also lines that feed down towards Nova Scotia. And then there's two lines that feed Prince Edward Island. Line 1142 and 1143 and I know the diagram I'm showing here is the Island overview at the end of 2017 so I'll talk about Cables 3 and 4 in another project, after. But as it stands today there's two lines that come from Memramcook down here and go up to Murray Corner, which, the Murray Corner substation which is located let's say right, it's on the other side of the Northumberland Strait. From there, there's two submarine cables, 138 kV submarine cables, Cables 1 and 2 right here, that come ashore at Richmond Cove and two lines from Richmond Cove at 138 kV come to the Bedeque substation. And in Bedeque we have two 138 kV lines heading out to Sherbrooke which is a substation in Summerside, just outside, well on the outskirts of Summerside, and from there, there’s the line that connects Sherbrooke up to the West Cape Wind Farm at 138 kV up here. So that’s about an 80-kilometre line that was built in 2008. Going back to Bedeque there’s also two, 138 kV lines that feed to West Royalty which is on the northern parts of Charlottetown and in 2017 when the line is finally completed, there’s going to be a 138 kV line from West Royalty along all the way out to the Church Road substation which is out here, which is just north of Rollobay, Souris area, and that will - and then that continues on down to the two Eastern wind farms, at Hermanville, Clear Springs, and at Eastern Kings. There’s also a couple of 138 kV lines from Bedeque that feed down to Borden which is where the new Cable 3 and 4 interconnection is going to land. I’ll talk about those again as that’s a future project.

Now, from the 138 kV, power step-down to 69 kV, number of substations, 138 kV is meant for large transfers of power, the higher the voltage, the bigger transfers of power. So right now it’s step-down to 69 kV at Sherbrooke right here, there’s a step-down at Borden and there’s a step-down at West Royalty and in 2017 there's going to be also a step-down at Church Road. So a step-down to 69 kV just sent out to all the load substations and at each load substation, it's further step-down from 69 kV in the rurals to 12.5 or 25 kV, in Charlottetown it's 13.8 kV and there (unclear) distribution lines feed all the different, all the customer loads. Now I'm going to refer back to this screen once more. Actually Cables 3 and 4 I'll just touch on that for your information. Cables 3 and 4 are going to be connecting to Memramcook as well and they are connecting into Borden. And that's the project that's ongoing right now and will be online the end of this fall. So most of these facilities are included in the open access transmission tariff, are recovered under the tariff. So the facilities included in the OATT costs and tariffs are all on Island 69 and 138 kV transmission lines except for a couple. So T23, T25, Y115, Y108, 112 and a portion of T8, I don't know if I can - oh, so looking at this, back to this map here, T23, T25 is the line feeding up to North Cape, dedicated generation line feeding from the four wind facilities at North Cape and that terminates at Alberton where the first load substation is. That line is not included in the tariff. The Y115 line from Sherbrooke, it is dedicated to feed the West Cape Wind Farm, that is also not included in the tariff. The line, essentially right now, starting at T8, so right around Dingwells Mills, the 69 kV line, Church Road Substation and the lines feeding the two eastern wind farms, that currently is not included in the tariff. Those are dedicated facilities so that is not considered part of the system. A portion of the Maritime Electric substations is not included the tariff.

Now Mr. Marshall kind of described the breakdown between distribution and transmission and generation. I've got a, the next slide I'll show that in more detail. The costs associated with operating, maintaining Cables 1 and 2, the existing submarine cables and the lines connecting the submarine cables to the Maritime Electric System, submarine cables and those connection lines are owned by the Provincial Government. Cost associated with that is included in the tariff. That's considered to be part of the Maritime Electric transmission system, although a portion of that is owned by the Province. And Maritime Electric or the OATT also covers costs associated with some of the New Brunswick system costs, which are costs dedicated to supplying energy to the Island. So a portion of the Memramcook substation, the Murray Corner substation, and a portion of the 138 kV lines which connect Memramcook to Murray Corner, so Lines 1142, 1143.

So as Mr. Marshall already spoke, essentially we have here, this is the Borden substation and Albany substation areas. The 138 kV lines would be included. There's some protection and isolation equipment called a breaker and switches, those are included in the tariff, the substation bus, which is essentially a pipe or a, some substations or you know, overhead wires hanging in the substations that allow different lines to connect to it, it's called a bus, that's included. Step-down transformer from 138 to 69 is included. But anything directly associated with the generation switches, transformer, breaker and so on, that is not included. That is excluded from the tariff. The 69 KV line connecting to the two substations is, the 69 kV bus in Albany would be but the distribution step-down transformer and any low voltage bus and lines leaving that substation would not be part of this transmission tariff. Now in as I mentioned, the PEI OATT, or PEI tariff also is responsible for costs in New Brunswick. It's, this red arrow here should be pointing at some of the breakers. We're responsible to pay a portion of the 183 kV breaker in New Brunswick because those breakers feed the lines feeding the Island. We're responsible for some of the costs associated with Line 1142. I don't believe 1143, that bottom arrow should not be there, we are not responsible for any costs associated with the second 138 kV line feeding the Island. But we are responsible for the costs, of the O&M costs and so on at the Murray Corner Substation, which is where our cables connect to so they are the cable termination point in New Brunswick.

So again, on-Island transmission facilities that are not included in the OATT are T23 and T25 lines which feed the North Cape wind farms; Y115 line which feeds the West Cape wind farm; Y112 and Y108 lines which feed the Eastern Wind Farms and a small portion of T8 which right now is only connected to generation but in future this portion of T8 when the 138 line is completed out to the east end of the Island, to Church Road, it’s now a part of the loop, part of the system loop. So that portion of line will now become part of the OATT, as well as a portion of the Church Road substation. The portion that is not dedicated for the generation will be part of the OATT, but the part that is dedicated for generation will still, will remain outside the OATT.

So my next few slides are going to be dealing at a high level with some terms and concepts from the OATT. Postage stamp, Mr. Marshall talked about this earlier, the costs to operate a transmission system are all bundled together. Per-unit rates are based on total operating cost divided by system usage and for a given level of service, all transmission customers pay the same unit rate for access to the transmission system and location or geography is immaterial, which is similar to the postal system. You mail a letter in Charlottetown to Summerside or Iqaluit, it's the same price. And just for example, all the local jurisdictions or neighboring jurisdictions, New Brunswick, Nova Scotia, Quebec, all use the postage stamp philosophy for rate setting.

Another term I'd like to talk about is the difference between energy and capacity. Energy is the amount of power needed to operate customer load in an hour. You see it on your electricity bills. It's measured in kilowatt hours or megawatt hours and from a system operator perspective, it's scheduled on an hourly basis. Capacity is the amount of transmission or generation capability. So from a generation perspective, if a utility buys generation capacity, just think of a pie and there's X amount of generation in the pie and the utility is buying a slice of that pie. Whether that pie is, whether that generation is operating or not, you're essentially buying your right to that.

Unidentified: You may not get to eat the pie.

Mr. Cunniffe: You may not like the taste of the pie. Yes.

Transmission capacity is how much of the delivery pipeline is reserved for a particular customer's energy to flow from the generator to the load. Transmission capacity, you have a choice to purchase an amount of that. Depending on the level of service you'd like. We've heard about, in the last six, eight, in the last couple of years, the availability of transmission capacity in New Brunswick has been an issue. And that's where this flows out. How much of that pipeline can the Island secure for its long-term purposes.

Another term I'd like to talk about is loop versus radial. Radial system is pretty straightforward, it's straight out. There's one line, say Line T10 here that feeds down towards Montague and then down towards Wood Islands. We have two stations, Victoria Cross and Dover. That's a radial feed. Another example is up to Souris or even the line that goes from Sherbrooke and feeds the Western end of the Island, one line, everybody's off that line. That's a radial feed. In Prince Edward Island we also have looped systems so there's a loop starting at Bedeque, going to West Royalty, back up through, a 69 kV system through the Hunter River area to Summerside and back down. There will be another loop here when the Y104 is completed; 138 kV out to Church Road, step-down and all the way back, that's another loop.

Now from, more from a customer application perspective, when a transmission customer applies for a new service or a transmission customer has a project that's going to have a material impact on the system, they contact, in our case Maritime Electric, and say we'd like to do this. So we take a look at it and if it's not going to - if we determine that it's not going to have a material impact on the system, say to the customer, no problem, go ahead. But if we make an initial determination that it is going to have a material impact on the system or it may have and we have to examine to see if it will, in the tariff there's a couple of procedures set up to do these kind of studies. First study is the System Impact Study. How is - is this going to impact the system and it's a determination to see if we, the system will need more transmission lines, where it should connect, what type of connection it will need, will it need new substation or can we just essentially tap onto an existing line. It's a high-level system overview saying, you know, at a high level this is what we need. That is sent back to the transmission customer and the customer says yes, we'd still like to proceed with our project and they, then Maritime Electric has to undertake a facility's impact study which is much more detailed. In the system impact study we've already determined kind of what line we need, where it needs to go; and the facility's impact is much more detailed, specifies the equipment, what kind of protection and control is needed, what kind of metering is needed, how we're going to communicate, if it's going to be wireless, if it's going to be fibre, commissioning procedures and so on. So a facilities impact study is often a much more significant amount of work for multiple departments because it's much more detailed. So when, let's say a new wind farm was to come on the system, big wind farm, western end of the Island. They would apply, they would need to go through the whole process because of the impact they would have on the system.

Mr. Gaudet: And the purpose in the end for that of course is if there are other costs that need to be incurred to mitigate those impacts, they would be attributable to the entity that causes those impacts so there's no cost shifting or increased cost on the other customers.

Mr. Cunniffe: And just to reiterate, what Mr. Marshall talked about, there's two different types of transmission service. Point-to-point which is delivery of energy from a defined point of supply to a defined point of load. Now that's not, that's not line specific. If you're on a point-to-point and there's multiple lines, you don't reserve a portion of X transmission line. It's, the transmission system has a path and if one line's out, the other paths can be served, or the other paths can be used to get it from Point A to Point B. And then secondly, network system, which is delivery of energy from a pooled group of supplies to a pooled group of loads.

Just going into firm service or into these two different kind of services a bit more, firm service, the customer has made a financial commitment to use the system for a stated time period. In the schedules you'll see, there's yearly firm or yes, there's yearly firm and all the way down to daily firm. And system facilities are built to meet long-term firm financial commitments. So if you as a customer are going to commit financially to the system long term, the system will build facilities to meet your requirements. Non-firm is typically shorter term commitment and it uses spare system capacity when it's available. System facilities are not built to meet non-firm obligations.

Pros and cons for firm service. Long-term firm service is guaranteed, so it's the top level of service. If the system encounters contingencies or issues such that service has to be curtailed, non-firm is cut first and firm, along with network, is cut last. And the system is planned, built, and expanded to meet firm commitments. The drawback, the biggest drawback to firm is that it's take or pay, you still have to pay if it's not being used. Non-firm, the pros, you can optimize its usage if the load is variable and if you have a good handle on your load you can use non-firm or you can use a combination of firm and non-firm to essentially economically optimize your transmission service. And it has potential to be less expensive than a similar amount of long-term firm. The drawback is that it's the lowest level of service. It's the first to be curtailed if there are issues and it's available only when there's extra system capacity.

Network service, the real reason network service is brought in, if you think of Maritime Electric, it's got wind farms in the east, wind farms in the west, supply from New Brunswick, 22 or 24 different load stations. It would be unmanageable to schedule energy from each of those points to each of those points. So network service was brought in and Maritime Electric is a very small utility compared to some of the other utilities which would have, you know, hundreds or thousands of load supply stations; so this was brought in just because it's far more manageable. The pros of network service, it's the highest level of service, it's similar to long-term firm, the system is planned, built and expanded to meet the projected loads, and the cons, it may be more expensive than an optimized firm/non-firm combined service, depending on the situation.

Now I'd like to highlight several of the updates to the existing tariff that have been made since the last filing. Minimum term for network service is now five years, the reservation priority for existing firm service customers, so in the existing tariff, if you're a long-term firm customer, I'll use an example. If you're a long-term firm customer that has a reservation for 100 megawatts and another customer comes in and says I would like a 10-year reservation for 200 megawatts, under the existing tariff, I believe it's one year, is it not? One year. If you're a long-term firm customer for one year you have the right to match their offering or lose it. Now, your existing contract has to be at least five years in order to be given the right to match a competing application. Conditional firm is now offered. It's firm service with the provision that it may be curtailed for a specified number of hours per year. Essentially this was brought in to, say, in certain situations, in certain systems. They are very reliable but in the very off-chance that there is a defined outage for a defined, specified number of hours per year, which may be maintenance or so on, the operator wants to give the highest level of liability for all the other hours of the year and the customers know that their exposure to curtailment is relatively limited. So it’s kind of a balance between the firm and non-firm, and as Mr. Marshall talked about before, reciprocity has been extended to all members of the power pool.

Another change since the last filing, Line T11 which is the radial line serving the City of Summerside which connects the Maritime Electric Sherbrooke Substation to the Summerside Ottawa Street Substation. In the past it was considered a direct assign facility and now in the current filing it is no longer being considered direct assign facility. It’s being considered part of the tariff so it’s being consistent with all the other Island radial lines. So in essence the line and its losses and all associated costs will be included in the pooled, in other words the OATT costs.

And another highlight from the current filing is that the system impact studies that I spoke about before, IRAC must be notified if the, if Maritime Electric isn’t completing the system impact studies in the time frame specified in the tariff.

The next couple of slides are going to highlight issues that were raised in the stakeholder process first go-round, so in 2007. This slide I’m just going to touch on at a high level, the next slide I’ll get into a bit more detail. Network service was an issue the first time around. It has been addressed, actually it was addressed I believe in the updated filing in October 2007 and any changes that have been made since then have been shown in the evidence. Imbalance penalties were an issue. That has been addressed. There were a number of issues raised about recovering costs for direct design facilities and the operating, maintenance and administration costs for the direct assign facilities. Those were addressed and are highlighted in Schedule 9 which we'll talk about at the end of my presentation and Mr. Younker will also talk about. The wind generation capacity value was raised; that's been addressed. Previous application for transmission service, that was talking about if there's other applications in the transmission queue for reservations or applications for service, how will those be addressed. Well that's been taken care of. As it stands now there's nothing in the transmission queue. So that's not really an issue right now. Cost of service study and provision of a cost of service study was questioned and that's been addressed. Our cost of service study was sent to the Commission as part of this application or appended to right afterwards. And the bypass application and that has also been addressed. And these I'll talk a bit more in the next slides so real power losses, standards of conduct, open access, same-time information system or known by its acronym, the OASIS and the transmission (unclear).

Chair: Mr. Cunniffe, I wonder if we could take about a five-minute break. Is this an appropriate time to -

Mr. Cunniffe: No, this is a good time.

Chair: Is that satisfactory? Okay. Let's, well let's take ten minutes. Is that good?

Mr. Cunniffe: Yes.

Chair: Okay. Come back at 11:15.

Recessed

Reconvened:

Chair: Okay, we can commence again. I think, I would take it that we can just push right through and finish, just keep going and finish. We're not going to break for lunch or anything like that, I - no? Okay. Whatever time you need.

Mr. Gaudet: No, and we're available. We're not back, excuse me, Mr. Chair, we're not back (unclear) so we're available so long as the Commission sees fit to entertain us.

Chair: Yes. Hopefully that's satisfactory to everybody else. Because it's probably the best thing to do is just keep going and take whatever time you need. Okay, Mr. Cunniffe, thank you.

PRESENTATION CONTINUED BY MR. CUNNIFFE:

Mr. Cunniffe: Thank you. So these issues were raised and addressed since the first filing but these four I'm going to get into a little bit more detail here. When it comes to real power losses, there's no change to the real power loss methodology. It's still a postage stamp application. Now as far as discounts go, reservations for off-Island electricity exports will continue to be discounted to the off-peak rates when the export paths are unconstrained. In the past that applied only to renewable generation and this has now been extended to all generation, not just intermittent renewable generation.

As far as the standards of conduct go, in our first filing, the standards of conduct were included as part of the OATT. In this filing they have been removed from the OATT and they will be standalone requirements, posted separately on the Maritime Electric website. They have been I believe filed with IRAC along with the OATT application for separate approval and this is all consistent with the New Brunswick OATT. Maritime Electric currently does not have marketing function employees. We are not - although we sell energy on the Island, we are not involved in selling into the energy market. So whereas Mr. Marshall talked about utilities having to separate the transmission function from the marketing function, as Maritime Electric doesn’t really have a marketing function, we don’t have that Chinese wall between the transmission and the energy people.

The OASIS, so that’s the Open Access Same Time Information System, there have been no significant changes. All the information and processing to be provided is to be provided manually through our OATT administrator. The Island has one network customer which is Maritime Electric, currently has two point-to-point customers, the City of Summerside and New Brunswick Energy Marketing, which is there on behalf of SUEZ and as I just mentioned, no internal marketing activity and automating, so automating the OASIS, as Mr. Marshall talked about earlier, for Prince Edward Island at least, is considered to be uneconomic. In the future if there are more market players, if Maritime Electric does get into the marketing energy field, the automation of this OASIS can be revisited. But as it stands today, it, we feel it’s uneconomic to automate the process.

The transmission planning process, FERC Order 1000, provided additional guidelines for transmission planning. In the original application back in 2006, Attachment K talked about the transmission expansion policy. That has been removed and has been replaced with transmission system planning which formalizes the planning process.

This is similar to the New Brunswick OATT. It's much more detailed and goes through all the steps and that's just been a replacement.

Now, how does the PEI OATT differ from the New Brunswick OATT because, you know, originally our OATT was modelled essentially on the New Brunswick OATT. There's minor differences in the system so I'm going to highlight here how ours is different than New Brunswick's. The initial allocation of available transmission capacity has been removed in PEI since the NB/PEI interconnection is unconstrained. Mr. Marshall spoke that one of the differences between New Brunswick and a lot of the other pro forma OATTs in Canada was that New Brunswick had kept this initial allocation of available transmission capacity in their tariff. Ours has been removed. We don't have any constrained interchanges. There's really no need to offer to have, to have a section in the tariff where it talks about how to allocate the constrained resources when there aren't any on the interconnection. So we've just removed it like most others have. As I mentioned before, there's no Island separation of the load serving entity and the marketing entity because Maritime Electric essentially doesn't market, so and the OASIS, as I talked about before, in PEI ours is manually done. In New Brunswick it's automated, they have many more interchanges, they have much more marketing activity than Prince Edward Island. There's only minor differences in the transmission planning process that I spoke about on the previous slide and that's essentially due to the relative size and complexity of the systems. And the last point, in Prince Edward Island Mr. Marshall talked about imbalance which I'll talk about in a few slides, under schedules, the PEI penalties for under scheduling of energy are higher so that's the imbalance energy. In PEI, actually in the New Brunswick area imbalance is settled, the cost for imbalance and balance energy is settled, the New Brunswick final hourly marginal cost and that is typically lower than the contract prices you see on the Island. So on PEI there would actually be an incentive to under schedule your energy, which would save you money, but the power system needs people to have accurate schedules so the penalties, there's a tiered band to the penalties. Essentially the tariff is trying to get everybody to schedule accurately. So we're removing the incentive to under schedule, based on the price difference between New Brunswick and Prince Edward Island.

Mr. Gaudet: Before you move on, I'd just like to recap that. Many of these changes, some of them are substantive, some of them are immaterial, have evolved from our operation of an OATT over the last ten years. Recognizing that when we developed the OATT originally, it was still quite uncertain how the system would react, the users would react, how things would pan out. So we've gained a lot of experience, we've listened to the market participants, and we're proposing a series of changes here that we think are, meet the needs of customers. That remains to be seen through the formal process but it's through experience-based key learnings that we've made those proposals that fit the size of the system that we are operating in. And also to address the complexities and the scenarios that occur here on PEI that may not occur elsewhere and vice versa. So a bit of a streamlining, so it's experience-based and that's the basis of our proposal in several of those areas. Along with conforming to the requirements of the FERC pro forma as it has evolved.

Chair: Thank you.

Mr. Marshall: I'd just add a comment to that. The issue of imbalance and penalties, what is in the application for Maritime Electric is what's in the FERC pro forma. It's NB Power that are, by using only the marginal costs, they are not according to pro forma.

Chair: Okay.

Mr. Marshall: But the regulator in New Brunswick at the hearing last year asked NB Power to do a study on what the effective costs and things are. So the issue of whether New Brunswick continues with that or whether they change is still up in the air and it could be revisited when they have to reapply in another two years. So what is in the application is FERC pro forma at this time.

Chair: Okay, thank you.

Mr. Cunniffe: Now I'm going to steer towards the schedules, so in the application there are ten schedules that deal with ancillary services and transmission reservations which are essentially where the costs to operate the system are recovered. And in the application, I can't remember what section it is but the cost breakdown has been included so the cost to operate the entire Maritime Electric transmission system is $9.1 million. This was based on the 2014 cost allocation study and these costs include the operating costs, amortization, financing, return costs, so it's an all-in cost.

Now as I pointed out earlier, several of the facilities are not included in the OATT calculations, so when you take those out, the OATT transmission facilities cost is $7.307 million and the costs and the schedules are based on that. And the ECC related costs, or the Energy control Centre related costs are $298,000 and all these costs are allocated to the transmission customer through the schedules, Schedules 1 to 10. So that's what I'm going to go through now.

Schedule 1 is the scheduling system control and dispatch. So this schedule, this ancillary service is required to schedule the movement of power into, within, and out of the Island transmission system and is provided by the Maritime Electric Energy Control Centre and all customers must procure this ancillary service from the Maritime Electric ECC. And the rates, I don't think there's any need to go into the rates but they're provided here. These are the rates that are included in the application. The time period that you see on the left - yearly, monthly, weekly and so on - the time period, you pay depending on the kind of transmission service which I'll talk about later, Schedule 7 and 8, that you take. So if you take yearly firm transmission you would pay yearly Schedule 1 rates. And if you took hourly, non-firm transmission, you would pay the corresponding hourly rate here. So that's how this is broken down. And if you take network services Maritime Electric does, you pay the network rate at the bottom. Schedule 2, the reactive supply and voltage control, this is for cost of online generators to produce or absorb reactive power as needed to maintain acceptable transmission system voltages. And again, reactive power can only be procured locally. It does not transmit very well. It has to be procured from on-Island so this service must be procured from Maritime Electric. We get real power, kilowatts and megawatts from off-Island and on-Island, but reactive power has to be procured in the local area. And again the rates are shown here. The third schedule, another ancillary service, so this is the regulation and frequency response, also known as AGC, automatic generation control, (Unclear) this is required to provide continuous balancing of resources so that's on-Island generation and the interchange with the Island or with the mainland, with load and for maintaining scheduled interconnection frequency at 60 Hz. This can be self-supplied or procured externally. If you are to self-supply you need operating generation that's controllable to be able to do that. Normally it's procured externally, so from New Brunswick or beyond. The New Brunswick rates are posted on the New Brunswick transmission system operator website if it's procured from New Brunswick; and if Maritime Electric gets a bill from New Brunswick on behalf of a particular transmission customer, the costs are flowed through direct to that customer with no mark up.

Now, I posted the existing rates and the proposed rates here. Before you get sticker shock on the, what looks like a major cost increase, the way that the rates have been calculated has changed. These are the New Brunswick rates, as we said we flow them through. And the next slide I've got in here shows how that's broken down and I'm going to ask Mr. Marshall to talk about that because he knows more about the New Brunswick system.

Mr. Marshall: Yes, what, these ancillary service rates are based on, the billing determinant is the load that is served. So the, in order to do at the current rate, is in the tariff, the 51.9 dollars per megawatt month, is based on load being served. But the service, the actual service comes from capacity of generators that are required to provide the balancing.

So in the New Brunswick tariff, what was back in the 2008 application that was here, the actual cost per megawatt of generation behind the New Brunswick tariff was $88.31 a kilowatt year. So that's the cost of the generator to provide, you know, a kilowatt year of that balancing service. Okay? In the tariff hearing last year in New Brunswick, NB Power had applied again to do the same thing and there were intervenors, I being one of them, and the system operator from Northern Maine as well intervened because it was very difficult for them to, in buying a service they had to, they knew how many megawatts they had to buy but then they had to go back and get their non-coincident peak loads of different customers in the Northern Maine market in order for them to allocate. It was very difficult. So I advocated and they advocated that this service should be priced based on the megawatts of generation capacity you're buying to provide the service, not on the amount of load that it's supplying. So the New Brunswick regulator agreed with that, and changed it so that it's now based on the megawatts of capacity.

So for a situation if Maritime Electric's obligation is 5 megawatts of balancing out of the 70 megawatts required in New Brunswick in the area, if it's 5 megawatts, it's 5 megawatts; in 2008 it would have been 5 megawatts times $88. In 2015 it's 5 megawatts times $99.89 and the difference is these are escalating costs of generation year by year in terms of what they are. So the difference from 2015 from 2008 is not a change from $51 to $99, it's a change from 88 to 99. That's the reason for the difference. So it's actually, it's simpler. It's easier for Summerside to know what they, you know, in terms of their allocation, this is easier for them to know what it is they have to pay and what they have to do.

Mr. Cunniffe: And as it says at the bottom, there's a similar approach for Schedules 3B, 5, 6A and 6B, so in each of those you'll see that there's an obvious difference in the way the calculation is being done. And I should have mentioned earlier, as I'm presenting these schedules, I'm showing the, in the second column I'm showing what's currently charged in the existing tariff and what's being proposed to be charged in the tariff that we filed in July, in the update we filed in July. So that's the existing and the proposed.

So load following rates again, this is the rate that's being charged currently, this is the proposed rate that will be charged, that's been applied for in the application. These are flow-through numbers from New Brunswick. And at the bottom you'll see there's an AGC and load following charge for non-dispatchable wind generators which is a charge that the NBTSO has applied, each megawatt hour of output from a wind generator, due to their intermittent nature, and it's 29 cents per megawatt hour.

Mr. Gaudet: Just for added information, that is the number that's subject to change by NB Power if they experience difficulties in back stopping wind in the future. Right now at 29 cents per megawatt hour, it's not too bad but they have mentioned that those costs are subject to potential significant escalation in future with additional wind.

Mr. Cunniffe: Schedule 4 is the energy imbalance which we have spoken about before. This service is, an ancillary service is provided when the actual hourly energy flow across the interconnection differs from what was scheduled. It's based on the New Brunswick (unclear) hourly marginal cost. The cost is based on that. Maritime Electric looks at all Island customer schedules and looks at the imbalance and determines the responsibility of each transmission customer for that imbalance and bills them accordingly. And in the application there's a tiered penalty band approach that will negate the incentive to under-schedule as I've discussed before. Now, in line with what FERC has used, or FERC has approved in recent rulings, there is some relief for the intermittent generators, essentially the wind generators, they are exempted from the penalties of the third band, for under-scheduling there's three bands of penalty in the imbalance. They are, intermittent generators are subject to bands one and two but the most punitive are the third band, they're exempted for and that aligns with what's been done elsewhere.

Another ancillary service, Schedule 5, the operating reserve. So this is spinning reserve service. So this is a generation service where there's a generation that's already on line that has capability left in the event of a system contingency, so it can immediately serve, cut a load in the event of a system contingency. So it's typically provided by dispatchable generators that are online and loaded at less than maximum output. This applies both to Maritime Electric in Summerside and this can be self-supplied or it can be procured externally and on-Island we typically don't have dispatchable generators operating. So it's usually procured externally. And what I mean by dispatchable versus non-dispatchable generators is, dispatchable generators is generators that you can control the energy output. And another way to think about it is if you can control the fuel in, you can control the output. So coal, hydro, nuclear, gas - you can control what goes in the front end, therefore you can control what goes out the back end. But things like wind, solar, tidal, you can't control the fuel so you can't really control the output so those we consider non-dispatchable. And the rates are shown here, the existing rates, proposed rates, and again going back to what we showed in Schedule 3, these are the New Brunswick rates and these would be flow-through if these are procured from New Brunswick. Schedule 6, operating reserve, supplemental reserve, it's also referred to as non-spinning reserve. So this is needed to serve load in the event of a system contingency; however it does not have to be immediately available. There's two categories. There's ten-minute and thirty-minute reserve. Maritime Electric in Summerside typically supply their own Schedule 6. So as Schedule 5 talked about spinning reserve generators that are already spinning and can immediately react. The generators on Prince Edward Island, Maritime Electric has combustion turbines at Borden and in Summerside has their diesel generators. Those can be brought on line and up to speed full output in ten minutes, so those could be used for non-spinning because they are cold start to full load in ten minutes and they can also be used in thirty minutes. In contrast, the Charlottetown plant can't be brought up in thirty minutes. That's days - hours or days or weeks, depending on the time of year, so that cannot be used as this kind of reserve, just can't be brought on line quickly enough. And I'm showing the ten-minute supplemental rates and thirty-minute supplemental rates and these are again, New Brunswick Power figures and these will change as the rates change in New Brunswick.

Schedule 7, now we are out of the ancillary services and we're now talking about transmission services, so Schedule 7 and 8 are transmission services. Schedule 7 is long-term firm and short-term firm, point-to-point. So this is charged for firm, point-to-point service and as I mentioned before additional system resources will be added when the system cannot meet all firm obligations. And it shows the existing rates and the proposed rates. This is an on-Island figure. This is not a flow-through from New Brunswick so that's calculated from the costs of the Prince Edward Island transmission system. And the network service is shown down here, network service equates to, is essentially the same as one month of monthly service. So those are the firm rates. As you can see, it's anywhere from yearly to daily, you can get in firm. Schedule is non-firm, point-to-point transmission service, charge for non-firm point. And again it can only be provided when it can be accommodated using existing system resources and non-firm can be acquired from monthly down to hourly. Firm was yearly to daily, non-firm is monthly to hourly.

Schedule 9, I've briefly talked about this before. This is the non capital support charge rate. So direct assign facilities are built and owned by Maritime Electric but they were paid for by the transmission customer. Y115 line, which is the line serving the West Cape Wind Farm, is a prime example. This line was built to, it's a dedicated line built to service that wind farm. Maritime Electric built it, Maritime Electric owns it, West Cape paid for it, in Maritime Electric's accounting the, there’s offsetting contribution for the cost of the line from West Cape to Maritime Electric so it doesn’t appear on the Maritime Electric rate base. The transmission customer is charged indirect operating maintenance and admin costs on a direct assign facility. The existing rate today is 1.92 percent. The proposed rate is going down to 1.79 percent. So this is a fee that is charged based on the upfront cost of the transmission line. In addition Maritime Electric also charges the transmission customer, at cost, labour and materials for work completed on a direct assign facility. So if tree trimming needs to be done, if line repairs need to be made, Maritime Electric undertakes those as the owner and it charges the facility, so West Cape, it charges them at cost for those repairs.

Mr. Gaudet: And this is a point of difference with the NB Power OATT. NB Power collects an amount of percentage which is higher, I think it’s currently about 5.88 percent. Back when we had stakeholder consultations, one of the users suggested that that was a large amount. We also had a comparable calculation. So what Maritime Electric has done, is separated these non-capital support charges into two groups. One is an amount that you see here that represents all indirect costs that will have to be recovered and we rely on actually billing them when we do tree trimming or when we do maintenance on that line. Rather than putting in an average amount for a proxy for that amount. We've come to appreciate that in dealing with New Brunswick on new assets being required for the interconnection upgrade. We too find ourselves thinking about the same argument the wind developer made to us, that we're paying a larger percentage up front, we would rather pay the actual freight, if you will. We're not looking to get out of paying an amount but it's just the timing of the collection. New Brunswick Power captures all of its costs theoretically by the application of a larger percentage. We've broken it up into two percentages; one for the indirect which are, you know, the cost of supporting that; and then we will bill as incurred the costs for that facility and again the overall goal is to not impact the pooled customers by any costs associated with this direct assignment facility.

Mr. Cunniffe: And the last schedule in the tariff is Schedule 10, residual uplift. It essentially provides for a periodic settlement of expenses and revenues not reflected under other schedules, penalties for deficiencies, unrecovered replacement capacity costs, and recovered purchase and sale of emergency energy. These are charged directly to the impacted transmission customers that was, had the deficiency to cause this and they're calculated each settlement period but historically the charges for this have been (unclear - coughing).

Now, just to highlight from a, differences with NB Power, this is more relating directly to the schedules and the costs. The system costs are different, completely different system charges so that's for the energy control, the local area reactive power needed to support the voltage because those are both Island-supplied services so those will be different than NB and Schedules 7, 8, and 9 relate directly to the PEI transmission system so those will be different from NB. Schedules 3, 4, 5 and 6 which can be procured from New Brunswick if they're not supplied on Island, so those have the same charges in New Brunswick. And as was just mentioned in Schedule 9, the Schedule 9 charges are much lower in Prince Edward Island. As it stands now we charge only overhead up front and then maintenance and labour is charged at cost, so our - the proposed rate is 1.79 percent. If we were to calculate it in the same manner as New Brunswick, the all-in costs would be 4.19 percent which compared to, which compares to New Brunswick's Schedule 9 charge of 5.88 percent. So theirs is considerably higher than what's on Prince Edward Island.

And lastly, just to go over the time line and process, the updated OATT was filed in Juy 2016, technical conference is today, the hearing is scheduled for October 17th to 21st. The goal was to get IRAC approval in the fourth quarter of this year and the targetted OATT effective date is the first of January in 2017. And that ends my portion of the presentation and I'm going to pass it on to Mr. Younker.

Chair: Thank you.

SUBMISSIONS BY ROBERT YOUNKER

Mr. Bob Younker: For calculating the charges for recovery of transmission costs under the OATT, the cost allocation study also sometimes referred to as cost of service study is the starting point. The Commission will be familiar with the cost allocation study as being a part of our general rate application, most recently last fall; and basically its main function is to help in designing rates and to provide an assessment of whether each class of customers is paying their fair share of the cost of running the system. You can easily, utilities' records are kept so you know how much you're collecting from each class of customers from adding up all the bills, but the accounts are not kept in a way that you can easily say this is the cost of supplying a given class of customers, such as the residential.

So the purpose of a cost allocation study is to take the utility that counts and allocate appropriate portions to each class of customers and then with the total cost of supplying service to the residential class, for example, and the total revenue collected through bills, you (unclear) ratio and if you're close to one that's good, that's where you want to be. So the indication that the rates are recovering the costs, which is what they're supposed to do. So in the, the first step in doing a cost allocation study is to look at - starts with the company's annual income statement and you look at, for each line item, assignment to one or more of the functions in providing electricity service and functions such as the power supply which is, you know, also the generation or purchase, transmission function, distribution function. And for the purpose of the OATT, we're interested in the cost assigned to the transmission function, so we start that, after that first step in the cost allocation study process, we have the transmission function costs and we sort of take those and go away and then use those in calculating the rates. As a bit of an aside, this slide shows our 2014 costs by function, this is a summary version of Table 3 from the cost allocation study that was filed last fall.

As an aside, if you continue on with the cost allocation study process, under each of those headings you do a breakdown between demand costs, energy costs, and customer costs. Demand costs being costs that vary with the size of the peak load; energy costs being costs that vary with the amount of energy used or the number of kilowatt hours used, and customer costs being costs that vary with the number of customers on the system. So that's Step 2 in the cost allocation process and then Step 3 takes those costs and for say a customer cost, you would allocate it to each class of customers based on the number of customers in each class. So there's a three-step process in the cost allocation study process and we are taking the result of Step 1 in for the purpose of the OATT, we are taking the costs assigned to the transmission function. So in this slide, if you think of a typical income statement for a business, the first line item is cost of goods sold. Well in this case it's the operating, maintenance, and administration expenses that are somewhat analogous to that. The next line, major line item in an income statement is the amortization or the depreciation expense and then you'll see interest expense, income taxes and net earnings and the line of financing expense includes those three numbers just for the sake of trying to not have too many numbers on the slide. So for our purposes it's the, I have $9.195 million as the cost of the transmission function in 2014. Next slide please.

So this is now looking at just those transmission function costs. There's a couple of small adjustments to the $9,195,000 number to get to the $9.1 million number that you saw previously on one of Mr. Cunniffe's slides. So having identified the cost of the transmission function, we'll go on to look at who uses the transmission system and I think this has been well described by the previous presenters. The only other thing is in addition to supplying the load, both Maritime Electric and the City of Summerside can also use the transmission system to export the excess wind generation off-Island if needed. Not all of those transmission costs are OATT related or will be recovered through the OATT and when Mr. Cunniffe had the map of the PEI system he was showing, for example, in the eastern part of PEI there are lines that are connecting the Hermanville and Eastern Kings wind farms to the system. The output from those wind farms are used only by Maritime Electric customers for their load. They are not used by the City of Summerside to supply their load, they are not used by the Eastern, by West Cape Wind Farm. So those are not recovered through the OATT, they are recovered through Maritime Electric’s rates. And that’s the second line, the MECL-related contract to wind, the first line from that would be, for example, the generator connection facilities for the generators at the Borden plant as an example. For the West Cape Wind Farm, again there is a dedicated line that all its costs are recovered from the West Cape Wind Farm. The number there relates to just the Schedule 9 charges for 2014 because as Mr. Cunniffe described, the West Cape Wind Farm made a contribution in aid of construction to provide for the capital cost of the wind farm and the Schedule 9 is then recovering the ongoing costs for the wind farm. Again, the objective being that that's a dedicated line for that facility and all the costs associated with that line are recovered from the West Cape Wind Farm. So then that leaves $7.3 million for transmission service to be recovered through Schedule 7, 8, and Attachment H and the $298,000 of energy control centre related costs and the about, I guess 25 percent of the cost of the Energy Control Centre is allocated to the transmission function. The other 75 percent is allocated to generation function and also distribution function activities. And those schedule, the Schedule 1, the Schedule 7, 8, those again are all the part of a pro forma tariff that FERC had laid out. These are the schedules and this is what you recover from each of these schedules. This is all again, just following the pro forma format that FERC laid out. So we have, we've gotten the costs and at any rate, the rate is, you know, dollars per unit of usage, so we've got the dollars, that goes in the numerator so the next step is what is the usage, what goes in the denominator and it's based on what was the firm service supplied by the system during the year and we have Maritime Electric taking network service and that 189 megawatts is the average of the 12 monthly coincident peaks on the system.

Summerside takes a combination of short-term firm and non-firm service and the West Cape Wind Farm takes non-firm service. And those non-firm service amounts have been converted to an equivalent firm amount such that if you multiply by a firm rate times the equivalent firm amount, you get the same number of dollars as were actually collected through taking of the non-firm service. That's what is meant by firm service or equivalent. So given for our Schedule 7 and 8 transmission service and for Maritime Electric, the network service charge is the same as point-to-point. We have, based on the 2014 costs, a denominator, a cost of 7.3 million, sorry, a numerator of 7.3 million; a denominator of 239.4 megawatts which gives the rate of $30,523 per megawatt year. So that's the, that's where that number comes from. Similarly, Schedule 1 rate is calculated the same way, the $298,000 allocation of the energy control centre costs forms the numerator; the firm service or equivalent amount is different here. It's a little higher and I'll get into that in a minute and we get a rate, dollars per megawatt year in the same fashion. The, Mr. Cunniffe talked about a discount for, to the non-firm hourly rate for exports off-Island, so that applies to Schedule 7 and 8 but it does not apply to the Schedule 1, so in working out what the equivalent firm amount is, you get a different denominator and you get to that end result, so there is no discount for Schedules 1 and 2 for exports for off-Island. And that's why the firm service or equivalent amount is different than the calculation.

For non-firm service, normally the rate for use during on-peak hours is higher than for off-peak hours. And it reflects the higher demand for the system or higher loads on the system during on-peak hours. And the methodology for calculating that higher on-peak, non-firm charge is referred to as Appalachian pricing, for obscure historical reasons, based on a specific case decades ago. So what we do is for the hourly on-peak rate, it's the dollars per megawatt year rate divided by the number of on-peak hours in a year. So on-peak hours are typically from 7 in the morning to 11 in the evening, during a day, so that's 16 hours in a day and just for the five weekdays. All weekend hours are considered to be off-peak and there's 52 weeks in the year so we have 4,160 hours of on-peak hours in the year so down at, near the second line from the bottom, we divide that annual charge per megawatt year by the 4,160 hours and you get $7.34 per megawatt hour for on-peak, for somebody who wants to use the system just for, on an hourly basis, that's the on-peak charge. The off-peak rate is the annual $30,000 divided by the full 8,760 hours in the year. So that's - and at, for a daily rate you would divide the $30,000 by five days per week times 52 weeks per year. Then again you get a higher charge on-peak for daily, non-firm versus off-peak.

So then moving on to Schedule 9 as we've explained, it's not enough for someone who wants to have a transmission line built out to their new wind farm to pay for the upfront capital cost. There's also ongoing operations, maintenance, and admin charges associated with that line and Schedule 9 is the vehicle through which those ongoing costs are recovered and explained, we look at just the general expenses component of the ongoing OM&A, and the maintenance is charged on a 'pay as you go' basis. And this shows the calculation of the, how we get to the 1.79 percent from the cost allocation study we have general expenses. In the study the insurance and property taxes component that was allocated to the transmission function was on a, was shown, or is not included in the general expenses so adding the two gets to a total general expense of $1,576,000 and then the gross transmission assets of 88 million becomes, is the denominator, and $1,576,000 is 1.79 percent of that $88 million. So if the, whatever the cost of the transmission system was to, or transmission line to the wind farm was, that 1.79 percent is applied to that capital cost and that's the annual charge for the overhead portion of the OM&A expense. And that's it.

Chair: Thank you very much. Do you have any questions? Okay, we don't have any questions on that. Anyone at this time? Mr. Lanigan, is there anything that you feel -

Mr. Lanigan: No, I don't think so.

Chair: I don't see - thank you very much. That was excellent, lot of information there that we'll digest. I'm sure things will, questions will arise out of it once we get to look at it a little bit deeper and think about it, but that was excellent, it really was. It was most illuminating so we appreciate your submissions. Thanks very much. Right, we are adjourned.

Hearing adjourned

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