Third Session - Fortieth Legislature

of the

Legislative Assembly of Manitoba

Standing Committee
on
Crown Corporations

Chairperson
Mr. Tom Nevakshonoff
Constituency of Interlake

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MANITOBA LEGISLATIVE ASSEMBLY
Fortieth Legislature

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LEGISLATIVE ASSEMBLY OF MANITOBA

THE STANDING COMMITTEE ON CROWN CORPORATIONS

Wednesday, September 24, 2014

TIME – 2 p.m.

LOCATION – Winnipeg, Manitoba

CHAIRPERSON – Mr. Tom Nevakshonoff (Interlake)

VICE-CHAIRPERSON – Ms. Melanie Wight (Burrows)

ATTENDANCE – 11 QUORUM – 6

Members of the Committee present:

Hon. Messrs. Chief, Chomiak, Struthers

Ms. Allan, Messrs. Briese, Dewar, Eichler, Graydon, Nevakshonoff, Pedersen, Ms. Wight

Substitutions:

Hon. Mr. Chomiak for Mr. Wiebe

APPEARING:

Hon. Jon Gerrard, MLA for River Heights
Mr. Scott Thomson, President and Chief Executive Officer, Manitoba Hydro
Mr. Bill Fraser, Chairperson, Manitoba Hydro-Electric Board

MATTERS UNDER CONSIDERATION:

Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2011

Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2012

Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2013

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Clerk Assistant (Mr. Andrea Signorelli): Good afternoon. Will the Standing Committee on Crown Corporations please come to order.

Before the committee can proceed with the business before it, it must elect a new Chairperson. Are there any nominations?

Mr. Gregory Dewar (Selkirk): I nominate Mr. Nevakshonoff.

Clerk Assistant: Mr. Nevakshonoff has been nominated. Are there any other nominations? Hearing no other nominations, Mr. Nevakshonoff, will you please take the Chair.

Mr. Chairperson: Okay. Our next item of business is the election of a Vice-Chairperson. Are there any nominations?

Mr. Dewar: I nominate Ms. Wight.

Mr. Chairperson: Ms. Wight has been nominated. Are there any other nominations? Hearing no other nominations, Ms. Wight is elected Vice-Chairperson.

This meeting has been called to consider the annual reports of the Manitoba Hydro-Electric Board for the fiscal years ending March 31st, 2010, March 31st, 2011, March 31st, 2012, and March 31st, 2013.

Before we get started, are there any suggestions from the committee as to how long we should sit this afternoon?

Mr. Ralph Eichler (Lakeside): Mr. Chair, I suggest that we ask questions for three hours after the final presentation of the minister, my opening remarks and the minister's opening remarks and review it from there.

Mr. Chairperson: Mr. Eichler has said–what is the rule of the committee? *[Agreed]*

Are there any suggestions as to the order in which we should consider the reports?

Mr. Eichler: I suggest we go by precedents of which–the earliest report to the final report.

Mr. Chairperson: Is that agreeable to the committee? *[Agreed]*

Mr. Eichler: We'll go global on the reports.

Mr. Chairperson: Is that agreed? *[Agreed]* We'll have a global discussion on the reports.

Committee Substitution

Mr. Chairperson: I would like to inform the committee that under our rule 85(2) the following membership substitution has been made for this committee effective immediately: Mr. Chomiak for Mr. Wiebe.

* * *

Mr. Chairperson: Does the honourable minister wish to make an opening statement? And would he please introduce the officials in attendance.

Hon. Stan Struthers (Minister responsible for Manitoba Hydro): We have with us the chair of Manitoba Hydro, Mr. Bill Fraser, and we have with us the president and CEO of Manitoba Hydro, Scott Thomson.

And I'm pleased that we're able to meet here today to talk about what I think is a very important issue to the future of our province. I look forward to suggestions that come from members of the opposition. My assumption is that their suggestions will be framed in such a way that it is to improve the delivery of Manitoba Hydro affordable, green, reliable power to the people of Manitoba and that we can continue to use Manitoba Hydro as a way to grow our province.

So, with those few words, I look forward to the– to advice and to the debate that we'll have.

Mr. Chairperson: Thank the honourable minister.

Does the critic from the official opposition have an opening statement?

Mr. Eichler: I do.

Mr. Chairperson: Mr. Eichler.

Mr. Eichler: I'd like to thank the officials and my fellow MLAs for being here this afternoon to review the operations of Manitoba Hydro electrical utility. In Manitoba it is owned by the citizens of this province.

Unfortunately, Mr. Thomson's review of Hydro's position, results, plans and prospects of this committee received when we last met, reflect the spin that are used to form from this NDP, rather than the straight-talk transparency needed for what would be ratepayer-oriented, critical service provider. What this committee needs is openness, transparency from Manitoba's major Crown corporation, electricity and natural gas monopoly that all consumers and industries have no choice but to rely on as we go forward.

In talking about Manitoba Hydro results, they have failed to acknowledge that rate hikes were higher than inflation since 2004 and the deferral of operating costs which provides much of which Hydro's net income. Rates and cost deferrals were much a factor in Hydro's net report since 1994 as good water conditions, cold winters, a few good years of Hydro has had were only experienced due to the then-escalating natural gas prices.

Natural gas prices soared after the horrific events of the hurricanes Katrina and Rita in 2005. This increase spot the export prices for electricity only for 2005-2006 physical year, causing them to be–barely exceed firm sale prices. The advent of shale gas occurred in that one good year in receding past. This has dramatically driven down natural gas and spot electricity exports, resulting in failing demand growth in the US since the accounting and rate hikes have kept Manitoba Hydro in the black ink.

Manitoba Hydro also ignored the fact that while redoubling the risk of drought and other events that are typical for a power utility, lacking diversity of supply by signing long-term export contracts and entering into the construction partnerships that involve billions of dollars, Manitoba supports this risky, expensive plan by imposing higher cost on Manitobans. They have also ignored the fact that government stands to reap the benefits from the gamble now under way regardless of census rate increases to have been inflicted on our customers and consumers.

Government plans to pocket 'maxive'–massive increases in debt guarantee fees, capital tax, water rentals, worker incorporating income taxes, additional PST, and rates and bills climb steeply.

The so-called preferred development plan will produce highest income flow to the government of any other alternative plans available. This includes alternatives not examined by the omissions, largely the result of contrived mandate that transferred PUB from consumer watchdog to a loading of government.

Given the shareholders represented since 1999 by the NDP preoccupation with revenue growth through taxation and fees, surprisingly intends to make it less–electricity rates another form of taxation. This presentation to committee by the Manitoba Hydro misconstrued the reality of Hydro's export business by assorting the utility is not losing money on exports. Right now exports, firm and spot, represent about 30 per cent of Hydro's generation. Those spot prices can be as low as 1 cent per kilowatt hour, which is way below the cost of generating and transmitting that power to the US, of which we all know is closer to 11 cents.

***** (14:10)

Spot sales at those prices confirm Hydro's role in the 'miscal' market as a price ticker. Low revenue generated when prices fall below 2 cents per kilowatt hour benefits only the government through water rentals. Wuskwatim was approved and built on the basis of a merchant plant. It was constructed to serve the export market.

Now Hydro asserts Wuskwatim is needed for domestic demand. This was not the story when the panel of the Clean Environment Commission–like PUB, members appointed by government–gave the counterproductive project the go-ahead. In its recent decisions going back to 2004 PUB has directed Hydro to establish an export class and allocate costs related to generation and transmission to that class.

When exports represent the virtual dedication of one third to total generation, it is no longer a by-product but a critical ongoing aspect of the utility's business. Exports are a large part of Hydro's sales and sales are the largest industry consumers or the general consumer component. Yet, in its subsequent rate application, Hydro stubbornly refused to follow PUB's direction which would have allowed the public to understand the scale of the losses being incurred on the export market particularly when the project cost of new generation and transmission lines is considered.

Manitoba Hydro loses money on its export class year after year and the losses will mount. This means higher rates for Manitobans as a result of the losses needed to cover a higher domestic rate. The fact that since the collapse of spotted energy prices Hydro has been losing money on experts and we, Manitoba ratepayers, are subsidizing American utilities.

Manitoba Hydro can cling to the fallacy that any revenue received from except market is profit, but as we must know only after new infrastructure is in place to this central–'intramical' income come into play as an important 'contribue' to hold rates from going even higher. The losses being incurred and, more importantly, likely to be incurred, the export market once Bipole III and Keeyask has come into service will be great. These account for part of Hydro's larger inflation rate increases.

Manitoba Hydro's superficial review also ignored the views of independent experts and knowledgeable Manitoban critics. None of these independents have anything to gain by pointing out the risk for a ratepayer that lay a development plan backed only by questionable assumptions and negligence as exploring less costly alternatives.

We also very concerned about how the government has drawn the Public Utilities Board and Clean Environment Commission into a 'cloca' plan now tested by two administrative tribunals that was put into action and partly paid for years before its mandated flawed reviews even took place. And, by restricting the ability of the Auditor General, the Ombudsman to review and protect, government again fails in responsibility to the public. Neither the PUB, the CEC, the Auditor General or the Ombudsman or Hydro board of directors, few of which have electricity utility experience in their background, have familiarized themselves with respect to the Hydro file. All these bodies are comprised of appointments made by the government without compensation or independence.

CEC concluded that Hydro made its environmental case for its preferred plan, yet recommended licences anyway. The PUB on its board being reconstituted in 2012 immediately withdrew a subpoena for Hydro's export contracts. These contracts should have been known–made known in detail. They granted an 8 per cent increase and hike in respect to the flawed mandate to review expansion plan that was unloaded and folded well before the PUB even sat down.

The PUB's in-fact conclusion expected–as expected were constrained and flawed by a mandate that left Bipole III off the table. The PUB ignored the mandate problem and seemed driven by the fact that Hydro already spent $1.4 billion on Keeyask alone.

The government is leading Hydro into a financial and economic disaster, a boondoggle of 'crafotsrophabic' nature. I sense that to meet the wide objectives of the government, Hydro's previously fine reputation with public has been put at risk. Rather than being a careful steward of critical function, the utility is driven by government, is risking the economic well-being of its ratepayers that they are there to serve. It is important to remind ourselves that Hydro, they were granted a monopoly to serve the public, not the other way around.

With those remarks, I would like to turn it back over to the Chair and listen to the CEO's recommendation and his presentation and move on from there.

Thank you.

Mr. Chairperson: Thank the honourable member.

Before we proceed, just for the information of the committee, you'll note there is a camera in the room off to my left. The camera is for Legislative Assembly educational purposes.

I understand the representatives from Manitoba Hydro-Electric Board wish to include a PowerPoint presentation as part of their statement to this committee.

Is there leave from the committee to allow the PowerPoint presentation? *[Agreed]*

Mr. Thomson, you may proceed.

Mr. Scott Thomson (President and Chief Executive Officer, Manitoba Hydro): Thank you, Mr. Chair. I'm just–*[interjection]* That's the one, thanks.

Well, good afternoon, Mr. Chair, ladies and gentlemen. I'd–I wanted to walk you through a brief presentation. I'm going to cover off a number of areas, briefly the corporate profile, talk a bit about the finances in the past year, our outlook moving forward. I want to address the NFAT regulatory review, provide you a short update on our major capital projects and then discuss some of the challenges that we face as we move forward.

For those of you who haven't attended this committee session before, the corporation currently operates just over 5,700 megawatts of generating capacity, and 5,200 of that is hydro power. But about 98 per cent of all the energy that we produce is renewable hydro power, and these come from the 15 generating stations. We do operate two thermal plants, but it's only in–on an as-needed basis.

Employment in the province is just over 6,400 people. Our customer base has grown to over 550,000 electric customers, and almost half of those customers are also natural gas customers. So we supply–we have the franchise for natural gas throughout the province, as well.

And we sell into three wholesale markets: the US Midwest, and Ontario, and Saskatchewan to the west of us.

Overall, the rates that we charge our customers are amongst the lowest in North America, on a weighted average basis.

Briefly, where are we today, how are we doing: Fiscal performance over the past year did surpass our forecasts, and we achieved earnings of $174 million. This reflects the ongoing improvement in the export electricity markets and a focus on cost, which continue to strengthen our financial position.

Income was up about $82 million or 90 per cent over the previous year. And as a consequence, our equity base, our retained earnings, reached just over $2.7 billion, which will be necessary as we move forward with our reinvestment plans.

All of these are all positive outcomes, but we can't rest on our laurels.

As we move forward, we–and we build the system out, a lot of what's driving our rates in the near term is reinvestment in the system, the aging infrastructure. And so our–while our profit picture was very favourable this year, we benefited greatly from–at more than normal water, and also the cold weather that we experienced, which was favourable on load for both electric and natural gas customers.

***** (14:20)

At the operating and administrative cost level, there's been a concerted effort put in over the last couple of years to manage these costs down. There have been–there's some noise in this in that IFRS accounting changes that are being adopted and must be adopted by the corporation as we go forward will shift the recognition of certain costs around overheads capitalized from being deferred costs to current period costs. But if we back that out and look at the directly controllable costs for operating and admin going forward, we've established a target of about a half a per cent increase over the next three years on a compounded basis for our operating costs. So we're trying to maintain that well below the rate of inflation.

The reality is that there's a great deal of variability in our revenue streams driven by weather events. If we have surplus water and cold weather, we'll tend to do better, and we can experience revenue shortfalls if we're in a drought situation or our throughput declines. We don't have any mechanisms to make up for those things. So the great focus has been on firming up export sales which–and maximizing the revenue potential of those over near periods of time as well as the long term and focusing on the controllable costs that we can manage.

On the rate picture, I'd mention we enjoy amongst the lowest retail rates in Canada and the US. In fact, if you go back 40 years and dial out inflation, they're essentially flat in real terms over that period of time. Even with anticipated rate increases as we move forward, we expect to maintain our favourable position relative to the rest of North America, and that's important to the cost competitiveness of Manitoba businesses. Knowing what lies ahead, we'll work with our customers to enhance conservation efforts and their ability to manage their total energy bills.

I've got a few slides that just show the comparisons from the lowest energy cost markets across North America, and these numbers are pulled from the US Department of Energy, as well Canadian cost comparisons, and they're done on a weighted average basis, so, of all of our throughput, residential, small commercial, large commercial and industrial customers, and when we compare on that basis, so Quebec and Manitoba are essentially neck and neck.

If we break down into individual customer classes, this represents an average residential customer who doesn't heat with electricity, so 1,000 kilowatt hours per month, we're No. 2 in Canada and the volumetric rate is actually very similar between Manitoba and Quebec, so the cost per kilowatt hour charged, but the basic charge, the basic monthly charge that's fixed, is a bit higher in Manitoba and that's what's really driving that differential.

At the heating customer load level, we're–it's virtually a dead heat, and then you move across the country and you see the dramatic swing and differential between some of the non-hydro-dominant provinces and Manitoba.

On a commercial customer bill, one that's at the 10,000-kilowatt level, that's where things start to widen out, and so business cost competitiveness benefits from this.

And then, overall, just to give you a bit of a retrospective on rates and what has happened over the last seven or eight years compared to some of the other jurisdictions across Canada, as I've said, Manitoba and Quebec are essentially–the rates are very similar. BC is about 25 per cent higher than us and pulling away from Manitoba in terms of their rate outlook. New Brunswick, Nova Scotia, Saskatchewan, all pay substantially higher rates than we do here.

Switching gears to the natural gas side of our business, as the critic noted, natural gas prices have been volatile over time and we have seen price spikes and swings, and market forces have benefited our natural gas customers in recent years. And it's important to note that we pass through the cost of natural gas at cost. We don't mark it up and–but as a consequence, in nominal terms the cost of heating with natural gas is lower now than it was at the turn of the–you know, in 2001. In real terms it's declined substantially and the rate–the outlook on natural gas, there is an upward trend in the forecast over the next five years, but it's not as dramatic as it was back in 2008, 2009 when North America anticipated that it would be running out of gas, we'd be importing natural gas, importing LNG, and now there's talk about building export terminals to export the energy from North America. That's going to have knock-on consequences to the price of that energy within North America, I believe, because the–instead of a continental market we'll–we have the–an expectation that over time we'll move to a world market in natural gas more akin to what we see in oil where you have a world benchmark price.

Again, we're fortunate in that natural gas is going to be around for a long time. There are abundant supplies, but the cost of production is higher than what we have experienced when it hit the lows in the last couple of years. So there's going to be upward pressure on natural gas more modest than it once–what we once thought, which is good for our heating customers. But that will ultimately put pressure on the cost of all energy as it moves up and as it sets the floor for electricity prices in some of the markets that we sell into.

I'd like to move now to the regulatory review process that was touched on earlier that the PUB review was one of the–I think it was the most extensive review that's been conducted in the province to date. There were 44 hearing days. The process took about 11 months. We responded to almost 3,300 information requests. There were 11,000-plus pages of transcript taken. Five intervener organizations were involved. The PUB hired eight independent firms to provide advice to it in looking at the various aspects of the review and, ultimately, it resulted in 14 recommendations that the Province adopted.

Some of the key recommendations were that the Keeyask generating station project and the US interconnection between Winnipeg and Duluth, Minnesota, move forward. There was a recommendation to halt Conawapa development and stop further expenditures pending the outcome of an enhanced integrated resource planning review and that the demand-side management model be examined and targets reviewed around demand-side management.

The Keeyask recommendations were echoed by the provincial Clean Environment Commission as well as the Canadian Environmental Assessment Agency. This is a–this project was licensed July 2nd and we moved forward with construction on July 16th. I'll talk a little bit more about that in terms of the project update.

So Keeyask, as most of you will be aware, is a 695-megawatt project at Gull Rapids on the Nelson River. It will have seven generating units of about 100 megawatts of capacity each. We've developed this project in co-operation with four Cree Nations in the region: Tataskweyak, War Lake, Fox Lake and York Factory. We expect to bring the first unit into service in November of 2019, and the remaining six units will be brought in in two- or three-month intervals thereafter.

***** (14:30)

The project–as I'd mentioned, we went through an extensive Clean Environment Commission hearing process resulting in quite a number of licensing recommendations which we're moving forward on. And the–we selected the general civil contractor earlier this spring. They've had early contractor involvement in the project. They were mobilized to site to initiate preparatory work that could be completed prior to the final licensing. As I mentioned, construction commenced on July 16th, and you can see rock that's being prepped for the cofferdams in the upper picture, and this is a picture in the bottom of the phase 1 of the camp which we–has been occupied now. There's about 500-person capacity. The camp is going to grow to 2,000 when the project is fully up and running. As of mid-September, the general civil contractor had constructed the quarry cofferdam and the north channel rock groyne, and so we've dewatered one of the channels and we're on track in terms of the initial construction schedule of the project.

The next project I wanted to update you on is Bipole III. As you're aware, this project has been in development for a number of years. We started our public consultation process back in 2008. There was–there were four rounds of public engagement. We had over 400 meetings that took place between 2008 and 2013. There were 137 open houses, 42 landowner information centres, almost 250 meetings with councils and RMs and other stakeholder groups. The information gathered at these open houses, feedback from various stakeholders and the environmental assessment processes helped inform and contributed to the final route selection and the environmental impact statement which was filed with the province in December of 2011. Subsequently, public hearing began in the fall of 2012. This hearing convened–which was convened by the CEC, was public and made available the opportunity for written or oral submissions from any interested individual.

We recently updated our control budget for the project. Construction started last winter in the form of line clearing. We've selected the consortium, the joint venture around the HVDC contracts, and that was the–those tenders closed in the spring of this year, and we anticipate finalizing that contract and having a signing in early October. Land–the land-securement process has been under way for some time now. We've secured easements from 216 landowners. We're in the process of working with the balance of the landowners on the project. And the line itself has been approximately 20 per cent cleared to date. We anticipate having the balance of the line cleared this winter. We've also started site prep on the northern convertor station, and work is well under way on the southern converter station, the Riel Converter Station, where we've been engaged in work there for some time because we've been sectionalizing the supply system around the city of Winnipeg, and that will be the location of the southern terminus of Bipole III.

Some of the key milestones to date: The construction power station at Keewatinoow, the northern converter station, was put in service in July, and as I'd mentioned, site preparation is well under way. The work at this site is on schedule. We drained it and it's been settled over the summer. We've moved over 800,000 cubic metres of material and fill over the course of the summer. And just some pictorials of some of the line clearing, up on the right-hand side, tower assembly on the left, and.

Another major initiative that's been under way for the last couple of years is the Pointe du Bois spillway replacement project. This project involved building a new spillway; the existing facility and powerhouse are over 100 years old. And we relocated the spillway to a new location; we'll be reclaiming the existing one. It's actually been decommissioned now, and over the course of next summer we'll finalize an earth dam, complete the earth dam construction by next fall. We're on track to complete that by next fall. We had weather events this year with the high water on the Winnipeg River system that actually came close to necessitating opening the spillway, the new spillway, prior to final commissioning. We were able to manage that, but we were at full discharge on the Winnipeg River, on the old spillway. That slowed us down somewhat, but we're continuing to manage to the control budget as we move forward.

As I'd mentioned, we placed the new spillway into active service in August of this year. The existing spillway structure, the gates were closed and sealed, and we had, as I mentioned, prepared it for emergency operation prior to final commissioning.

Here's some depiction of work that's being done at the old spillway, and ultimately this will all be filled in. The–all that will remain of the old spillway will be the concrete, everything else will be stripped out and it'll go back to nature other than we won't actually demolish the concrete structure, but it will be submerged as we move forward.

Another major piece that came out of the NFAT review and that we're advancing now as the Manitoba-Minnesota transmission line project, this is the new line that will be constructed to connect the Dorsey Converter Station down to Duluth, Minnesota, and we'll be constructing the Canadian side of the line. It'll be a second 500 kV alternating current transmission line. We currently have one 500 kV line and three 230 kV lines in service. This will increase our firm transfer capability between Manitoba south by 883 megawatts. The project in-service date is summer of 2020 with a budget of–in 2020 dollars of $350 million.

Scope and early line selection routing is shown on this map. The line will cross the border south of Piney. It's approximately 235 kilometres long, and it will connect back to the line that Minnesota Power is constructing to the border on the American side.

We'll be doing station upgrades at Dorsey and Riel. A new 500 to 230 kV transformer bank will be installed there and some additional work at the Glenboro Station to support this project.

Currently, we've gone through the initial rounds of public engagement. Alternative routes and border crossings were reviewed in February of this year. The second round was completed in August where we refined the alternative routes and selected a preferred border crossing site. The third round of public engagement will start this winter in January to finalize the preferred route, and we've initiated preliminary design work for transmission and civil design on the project.

***** (14:40)

Just wanted to update you where we were on export commitments. With the existing sales contracts that we've entered into going forward, there's just over $9 billion of committed sales. Five billion of that is dependent on the Keeyask project, but these are contracts with extensions of contracts with Xcel or Northern States Power, the 250-megawatt sale that we made with Minnesota Power which caused them to underwrite the development of the US transmission line expansion.

Wisconsin Public Service: we've got diversity exchange agreements in place with Great River Energy and we signed our first power sale agreement with SaskPower this past year. We've got memorandums of understanding under–in place. We're developing–we're working on developing a sales agreement for 100 megawatts with SaskPower that we can serve from the existing system and up to 500 megawatts in the eventuality that Conawapa move forward. So part of what we're doing, we're continuing the sales effort and–around future export potential, but some of that will be necessitated by the ultimate development of a business case supporting Conawapa.

I wanted to touch briefly on export rates. We have existing long-term export contracts for what we refer to as firm energy. These contracts are at prices more than 50 per cent higher than the prices we charge to our largest industrial customers in Manitoba, which as a class of customers would be the closest approximation, the nature of the load and the service that we provide to them. So we are–our firm power sales–we are charging at rates that are higher than our domestic customers. Rates that we set for domestic customers reflect the cost of service and we don't build profit margins into the rates for domestic customers.

Spot market sales are often incorrectly cited as evidence that export markets aren't profitable because they're sometimes lower than domestic rates, and we've seen the change in recent years. It's important to note, though, that as we–when you build a hydroelectric system and you plan for the–your domestic requirements, you build the system so that it can meet the needs of the province in a low-water year. So most years we're going to have surplus energy and the cost of that surplus energy is essentially fixed in terms of operating the generating station and we pay a water rental fee for the use of the water. So any time I can sell power at a rate that's higher than my water rental fee, I'm making positive contribution to the system and to the benefit of our domestic customers. We obviously try and maximize what we get out of those sales, and you can see this past year, this past fiscal year, we've ticked back up from in the $22 range to the high $20s on spot sales–or opportunity sales, as we refer to them.

I'll briefly touch on some of the challenges that we face as we move forward. A key one is system renewal. Our system was built out in–a significant component of our existing system was expanded post-World War II and, eventually, that infrastructure starts to wear out and we've been seeing that. The–it impacts on the reliability of operations and, you know, a lot of–although our plant is long-lived, what we see is that after 50 and 60 years it's getting more and more expensive to maintain.

So we're at that point in the life cycle of a lot of our assets where we have to address them. Many of our assets are reaching the end of their service life and the risk of equipment failure is growing. Outages will become more frequent and they'll last longer if adequate investment isn't made to upgrade and renew these facilities.

I've talked–you know, I talked last year about pole replacement, and we're looking at about 120,000 poles that we're going to have to replace in the next 20 years, and that's going to cost about $400 million. And it's at a rate of replacement that's substantially higher than our normal or what we've seen over the last two decades. And, again, we didn't need to replace them because they had lots of life left in them.

We're looking at ways that we can reinforce existing wood poles. We're looking at injecting silicone into underground conductor to extend the useful life of that so that we don't have to rebuild and replace everything, but we're also seeing a need to modernize and replace substations within the city of Winnipeg. And we're looking at, by the end of this decade, we're well into the replacement program now, but in total there's–there were 20 stations at the start of this decade that were falling into a poor state of repair, and we're seeing a lot of pressure, particularly in downtown Winnipeg.

You've seen a lot of the development as you drive through downtown and new towers that are going up and the new police services building, the human rights centre. They're all fairly big power-demand scenarios, and so we're pushing past the capacity limits of some of the downtown infrastructure that we've got and we have to be–we have to be–able to meet that need as it moves forward.

You've no doubt seen traffic disruption this past year. We've got an aggressive program in place to start repairing and replacing manhole access for our buried infrastructure, buried electrical infrastructure, again in a downtown part of the city, and a lot of this infrastructure is–has been around 60, 70, 80 years. And the manholes themselves were crumbling. They were becoming traffic issues as well. So we can't–I think we prudently deferred replacement historically but we're now at the end of the life of those assets and we're in a position where we must do something about them.

We aren't alone in this. The Conference Board has done research that suggests that across the country over the next 20 years, we're looking at a requirement to invest $350 billion replacing electricity assets that were built out last century. So they've–utilities across North America are facing the same challenges and they'll put the same kind of pressure on electricity rates that we've seen. Like most energy utilities in Canada, we have to begin replacing these assets. As a consequence, though, we're going to be competing for construction resources for major builds across the country both in terms of material, the suppliers of a lot of these equipment. There are a number of named suppliers: ABB, Siemens, Alstom. We deal with all of these companies but, you know, when we look–when we think about the transformer contracts that we let for Bipole III, there's only three qualified bidders in the world. There's eight HVDC projects in development right now, and there's only so much productive capacity. So depending where you are on a calendar, that can have a dramatic impact on your ability to source and have companies bid.

The Chinese have started to emerge as suppliers, but the challenge that we face there is that they've licensed technology from the big three that–for domestic purposes and now they're trying to export that around the world, and there's intellectual property issues around that and concerns that we had. So we're limited to where we can go for some of these major investments.

Reliability: Weather plays a huge role in reliable service to our customers. This was–you can see what happens when we get ice on vegetation. Brings down power lines. This is transmission infrastructure from the ice storm last winter. Not only does it damage our system but it places huge demands on our workforce as well and has a role in operating costs because it drives overtime costs as we effect repairs on the system.

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There were outages caused by the floods last summer, so, you know, you can see the impact that that has, and these–we have to be in a position to respond to weather events around the province.

We also face–this is a picture of Bipole III back in 1996. You know, this could've been disastrous for the company had it happened at a different time of year. It was in the shoulder season, late September. We hadn't–we didn't see heating load come on. The system was down for a week. We've got a heavy reliance on one transmission corridor, being the Interlake, for both existing bipole lines, and a single southern terminus at the Dorsey station for those two lines. Tornadoes come through there. If we had a major wind event that knocked out infrastructure at Dorsey, the convertor station could be down for months. Two winters ago, we came close to losing 20 towers in the Interlake because of ice conditions. If they had come down, it probably would've taken four to six weeks to put the existing bipoles back into service, and we'd face rolling blackouts in southern Manitoba for that entire period just because of the dependence that we have on that one transmission corridor. I've–the economists have tossed around numbers on the order of a billion dollars of GDP a week could be lost if we lost the bipole system during the winter.

So Bipole III is a key reliability project. The new transmission line and the related converter stations will greatly improve system reliability and will eliminate our sole dependency on the Dorsey Converter Station. We've got a second converter station which will be built at Riel, and it provides another major point of injection to the southern system. As I mentioned earlier, we're finalizing land acquisition required for the project, and we're moving forward with construction to have this line in service for 2018. That gives us about a year's cushion before the Keeyask project starts delivering power.

A second transmission project that I mentioned earlier that has significant reliability benefits is the new US interconnection. We've got a southern transfer capability of that project of almost 900 megawatts, and we can transfer north 700 megawatts. Today, we've only–we can only import about 700 megawatts through the four existing transmission lines from the US, so that will double our import capability and provide a significant boost to the reliability of the system overall.

Having to deal with growing demand: At the same time that we're working on trying to maintain the reliability of our system, we also have to work to ensure that our future electricity needs are met in the province. Organic demand is growing by about 80 megawatts a year before the impact of demand-side management programs.

There's three basic factors driving growth of demand in Manitoba, the first being the growing provincial economy. We see that in the commercial-industrial load growth that we've been experiencing and we project going forward. The second is that the use per customer is going up. We're more and more reliant on electricity to power all of the gadgets that we use in our everyday lives, be it cellphones and computers and tablets and big screen TVs. We're also seeing a shift in demand for the use of electricity for space and water heating. And the final item is increases in population and the related services required to accommodate that growth.

So how are we going to manage the demand? First, we look to energy conservation to play a key role in meeting our future demand requirements. We've invested almost a billion dollars and are planning to invest almost a billion dollars over the next 15 years to help customers keep their energy bills lower. Our recent revamped plan targets an additional 250 per cent energy savings over our prior plan. And since the Power Smart program was launched back in 1991, Manitoba Hydro customers have saved almost $860 million in energy bills because of the conservation efforts.

So how do we get it all built? Hydro projects have incredibly long lead times. This illustrates when we started development of the Keeyask project. It's been almost 15 years and it'll be almost two decades by the time–from initiation to completion by the time that we're done. The challenge in planning and developing these large–it really illustrates the challenges that we have as we develop these projects moving forward. In Manitoba and other jurisdictions with abundant hydro resources, we often face criticism for undertaking necessary expenditures as we develop long-life assets such as hydro power generating stations, but it isn't unique to us. You look at the money that's been invested by Enbridge and by Kinder Morgan to develop pipeline projects in BC well in advance of getting regulatory approval to move forward. You just can't build major infrastructure without doing environmental studies, without consulting stakeholders, First Nations, and compared to alternatives, alternative power generation projects, hydro projects have lead times akin to nuclear power projects. So, I mean, we don't measure development time in years; we measure it in decades.

The projects we're undertaking are required to meet our fundamental obligation to meet the needs of Manitobans. In planning and developing them, we acknowledge that there are going to be impacts. However, through our planning processes, we analyze project options from diverse perspectives to attempt to reduce the impacts to a minimum. In doing so, we consider not only the natural environment but also the–what we call the built and human environment, the people and the economy impacts, and, lastly, the engineering or the technical environment. As we go through the various stages–see if I can drill down into this. Yes, as we go through the various stages of our projects, a key is to engage stakeholders and gain an understanding of their interests and concerns. Through respectful dialogue, we can gain information that will help us design better projects and avoid or reduce impacts.

At the end of the day, there isn't a free lunch. There are going to be impacts from any major infrastructure project that we do. So how do we deal with that reality? First, we design out and mitigate where that's feasible. Second, where there are adverse effects, we provide compensation, typically through offsetting programs or other financial measures. And finally, as we construct and eventually operate our projects, we have environmental protection plans and we seek to have ongoing dialogue with affected stakeholders.

Given the legacy of earlier northern hydro development, today we're taking a different approach to building these projects. We work closely with First Nations and communities to reduce environmental impacts and ensure local communities benefit from the development. This approach, which began with Wuskwatim and has been continued for Keeyask, results, in my view, in better projects to supply our growing demand, projects with reduced impacts, overall lower compensation costs through investigation of impacts upfront and dealing with those in advance, and greater local benefits.

By engaging with local communities, we build our understanding of Aboriginal traditional knowledge, and this also helps project planning and monitoring and developing environmental assessment programs. It also levels the playing field to ensure that these communities have resources to effectively represent their interests about projects and their impacts and opportunities around them. Over the years, substantial costs have been incurred to address the impacts of past development. We've spent a billion dollars in addressing the impacts of our past projects. And, you know, we touched on some people being critical about spending money to engage Aboriginal groups and going into communities, but, as I've said, you can't do anything these days unless you reach out to the communities that you're going to be building in.

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So one of the cornerstones of our approach to getting our projects built and to deal with some of the inevitable opposition from groups is to work with and treat impacted stakeholders fairly. I think this is exemplified in our landowner compensation strategy where we–where access to lands, as required for high-voltage transmission projects like Bipole III and the Manitoba-Minnesota transmission line, we enter into voluntary easement agreements where we can, and that's certainly our preferred approach. And these agreements, they include four key components. First, we offer a payment upfront of 150 per cent of the market value of the land that we require for an easement. We provide construction damage compensation, which we negotiate individually with each landowner because they are going to be unique to each parcel of land and the placement of towers. We provide structure impact compensation for each tower that's placed on the land, and then we will look at compensation for loss of production. And, again, we negotiate this with landowners, depending on the unique circumstances of each situation.

Another element of developing these projects is ensuring that we bring local benefits. It helps to build commitment in the communities. And, frankly, in a lot of the areas that–particularly the northern development, we're some of the only economic activity available to the local communities. So we look at training programs, ensuring jobs and employment preferences to people from the communities and business opportunities for

First Nations bands and other local businesses as we develop and move forward.

We've also dramatically increased our Aboriginal representation on our workforce. Back in 2001, it was about 7 per cent of our total workforce, and now it's reflective of the Manitoba population overall, which is about 18 per cent. Makes a really big difference when I visit northern communities and that the staff accompanying me when I visit these communities are from the communities. They–Aboriginal groups–and we have management representation in our Aboriginal relations department. And it helps to build bridges and it helps to break down barriers as we move forward. Forty-four per cent of our northern workforce is Aboriginal.

In the end, we got to pay for it all. Three factors are critical. First and foremost is a concerted effort to manage our costs down. I touched on that earlier. A couple of examples of how we're doing this: We've implemented a new mobile workforce management system, and it enables us to more effectively respond to customer calls and enhance field workforce productivity. So we know where people are geographically, we can match people up to trucks–sorry, people up to work, we can cut travel time down. And we're also evaluating positions that either have been or we anticipate are going to be vacated by retirements to determine whether we can eliminate work, change the way that we do that work so that we're not replacing people on a one-for-one basis. It's an opportunity that's created by the demographics of our workforce. So about 900 people are currently eligible for full retirement. We need to ensure staffing levels are adequate to continue to provide safe and reliable service. We also need to manage the loss of valuable experience and knowledge that can result from the retirement of key contributors.

But over the next three years I expect our workforce is not going to grow; it's going to contract. And that's deliberate, and we're looking–but we're looking at doing that in a way that we can utilize attrition so it doesn't result in layoffs. But it's how we anticipate controlling our operating costs down to the half of 1 per cent level of rate of increase. And that's–I contrast that with projected inflation, CPI, of about 2 per cent a year.

Second factor is export revenue. You know, the reality is we do have the lowest rates in North America, and a big reason for that is that a third of our revenue over the last decade has been garnered from export sales. So, if we didn't export surplus power, our rates would be a hell of a lot higher than they are.

So our past investments in developing hydroelectric facilities have paid big dividends over time for our existing customers and, you know, we have–we see rates, residential rates in places like California of 38 cents on peak energy. Their off-peak energy is more expensive than our rates.

So it's these types of investments and the cost certainty around it. Once you build a generating station your energy price is fixed for 50, 60, 70 years for the output of that. It's inflation-proof, and had we not made the investments that we made historically, our rates would be about 50 per cent higher today. And if we lost that export revenue we'd–we would see much higher rates domestically. So it's been a strategy that's worked.

That's why transmission interconnections like the Minnesota line are so vitally important as we move forward. Our system, as I mentioned, is designed to meet our load commitments even in low-water years. So in all but very low flow years we're going to have surplus power and that will contribute back to our customers. Just like, you know, agriculture relies on railroads and pipelines are essential to the oil and gas industry, we need transmission to connect generation to load.

The final factor is going to be rate adjustments, and I'll come out up front saying no one–and myself included, I don't want to have to pay more than–more for energy. I'd prefer to see us be able to avoid rate increases, but we simply aren't going to be able to do that. We're–our rates aren't being driven by operating costs. They're being driven by the fact that we've got to replace assets that we paid historic dollars for in today's dollars. They're fully depreciated assets and we've go to, you know, we've got to incur debt service on that new plant that we're putting in place that's worn out and we've got to recover the cost of that investment over time through depreciation charges.

So that is what's–over the next decade that's what's really driving the rates for our customers. When Keeyask is brought into service we'll have an increase in our cost of service. We'll start recognizing the carrying costs of that asset, but we'll also be matching that with new revenues that are dependent on that. This is a story that's repeating itself across North America as other utilities address aging infrastructure just like we are.

The BC government announced that their electricity rates are up 9 per cent this year, 6 per cent in 2015 and then, I believe, it's 4 and a half per cent and trending down to 4 and then 3 per cent. So they've got–they've already said what the rate increases are looking to be over the next five years.

SaskPower proposed rate increases of 5 and a half per cent this year and 5 per cent in each of '15 and '16.

In Ontario the long-term energy plan indicates residential customers will see their bills increase 10 per cent this year, 6 per cent in 2015 and 15 per cent 2016.

Like I said, I don't want to raise rates for our customers. But I can look forward and I can see the need, and we can manage those rate increases and we can smooth those rate increases and we can help our customers manage their overall energy bills through conservation initiatives.

So, to sum it all up, I guess the real challenge facing my team and I is to balance the needed investment in our system while maintaining the financial health of the corporation and providing quality service and stable, predictable rates to our customers. If we can meet this challenge, we'll ensure that the next generation of Manitobans continues to enjoy the benefits that this and prior generations have in the form of affordable, reliable and almost emission-free power.

I think I took less time than last time. So, Mr. Chair, I turn it over to you.

***** (15:10)

Mr. Chairperson: Thank you, Mr. Thomson.

Before we proceed, just a couple of points of clarification.

First, in my opening remarks, I'd mentioned that we'd be addressing the annual report ending March 31st, 2010, and that is not the case.

Secondly, the Clerk Assistant asks me to remind members that, as previously agreed, we will now proceed with questions for a three-hour period and revisit the discussion at that point in time. It is now three minutes–or three hours–or it's 3:11 p.m. So, on that note, the floor is now open for questions.

Mr. Eichler: Thank you for the presentation, Mr. Thomson, and certainly appreciate it. And we always like to get the updates from the department, and it's certainly useful and leads me into my questions. I hope you bear with me. We have a number of questions on various issues and might jump around a bit from here to there, but it appears that Hydro has spent approximately $3 billion on Bipole III, Keeyask and Conawapa before the issuance of the PUB NFAT report, C and C–CEC's environmental reviews and final approval of the projects by the government. What were the reasons for spending such sums well before government approval?

Mr. Thomson: Actually, I believe that the expenditures were lower than that in terms of prior to receiving final approval. The–our current expenditure to date on Bipole III is on the order of $600 million, and we received approval to proceed with that project last summer. And we've incurred significant costs through the first year of construction. So I can't remember off the top of my head what we had expended up to securing the approvals, but it was–I expect it was less than half of the 600.

Our total expenditures to date on Conawapa, and this includes early development costs, this project was advanced 20 years ago and then cancelled, but it–the cost hadn't been written off, so we're on the order of $300 million total cost incurred to date including interest for that. And we had expended, I believe it was about $1.2 billion subject to check on the development of Keeyask leading up to the time when final approvals were secured. So if I can do my math there, it was on the order of about 1.8 in total on the three projects, not $3 billion I–which I believe you quoted.

But, as I mentioned earlier, the–it's necessary in project development to engage communities, to do preliminary engineering work, to do project definition work in order to advance your understanding of what the overall cost of a project will be and to work through the actual processes. I mean, the environmental review process costs money preparing an environmental impact statement, and you can't build anything and go through a CEC process and a CEAA process federally without incurring expenditures. You just can't.

There is a trade-off. The more engineering you–work you do, the more project definition work that you do, the better understand and scope definitions, the better understanding you have of what the ultimate project will be and the–and helps you to firm up your understanding of the costs. You trade that off with the risk that the project won't go, you know, may not go forward, but you can't get a good handle on what a project is going to look like and what it's going to cost and engage with communities and Aboriginal groups and move it through to the approval stage without incurring significant spending.

Having said that, you know, overall if we were at $1.2 billion when we received the final approvals on Keeyask, that's roughly 20 per cent of the overall project cost. It's not insignificant but it's necessary, and I know that the gateway project, they–well before I moved to Manitoba three years ago, they were–they had spent in excess of $600 million on that project. It's likely a billion and a half dollars today, and they don't have approvals to proceed. Like, it's impossible to do major infrastructure projects without incurring some cost upfront.

Mr. Eichler: In regards to those expenditures, according to the numbers that you just put on the record, my math tells me that's $2.1 million. Was there any of that written off prior to those numbers? For the totals are there–in particular Conawapa. Obviously, you didn't write anything off on Bipole III, but–or Keeyask. On Conawapa was that $300 million–anything wrote off before you used that number of $300 million? *[interjection]*

Mr. Chairperson: Mr. Thomson.

Mr. Thomson: Sorry, I will get that as we move forward.

Not to my knowledge.

Mr. Eichler: Did the board of directors sanction the approval–pre-approval expenditures? If so, on what basis would they base that on?

Mr. Bill Fraser (Chairperson, Manitoba Hydro-Electric Board): Management would come forward with recommendations to do certain things to let certain contracts beyond a certain dollar ceiling for approval of the board. So, certainly, the board was kept abreast of these projects as they were moving forward. And the financial spending, I mean, is included in the financial reports that the board gets and that the auditors look at, both the provincial auditor and the external auditor who is Ernst & Young.

Mr. Eichler: In regards to those expenditures, walk me through how that would look. So the staff would bring in recommendations to spend $1.2 billion just on Keeyask and $600 million on Bipole III. So they would make those recommendations to board and then board would approve it and then what happens after that?

Mr. Fraser: They bring forward the preferred development plan and every fall they do an update of that plan in terms of what they refer to as the IFF, which is a financial forecast going out 10 and sometimes 20 years in terms of the capital spending and the various projects that are involved in that spending, and they get approval of the budget or the budget gets changed–whatever. But, at some point, there's a budget approved and the financing requirements related to that come through The Loan Act and come through the Legislature. They're reviewed by the Crown Corporations Council as part of that process and by Treasury Board in terms of The Loan Act requirements on a comprehensive basis.

So, I mean, the information is in there all the way along. The costs are in there all the way along. In terms of doing the groundwork, as Mr. Thomson has indicated, is necessary to be able to plan these projects and get the impacted parties a line to agree to do certain things.

Mr. Eichler: Appreciate that feedback.

In regards to the line-by-line expenses that were spent before regulatory approval not only for Bipole III, Keeyask and Conawapa, would we able–would we be able to get a list of those expenditures prior to the, say, maybe the next month or so?

Mr. Thomson: Yes, we–we've provided updates and I believe that much of that information was filed in the NFAT proceeding. So I don't see any reason why we can't provide that.

Mr. Eichler: Was Hydro instructed to spend or commit ahead of the necessary reviews and approvals by government and, if so, how were the directions conveyed to the board or to the CEO of the Manitoba Hydro?

Mr. Thomson: Could I ask you just to repeat the front end of that. We're–

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Mr. Chairperson: Mr. Eichler.

Mr. Eichler: Was Hydro instructed to spend and commit necessary ahead of the reviews and approvals by government? If so, how were the directions conveyed?

Mr. Thomson: No, we weren't directed to spend. We've been evolving our development plans over the last couple of decades.

But, as Mr. Fraser indicated, we do an annual planning cycle, and each project has a Gantt chart, if you will, but work activities at each phase of the project, and we develop budgets for those. They're reviewed at executive committee, at my executive committee level. Where expenditures need to be authorized beyond certain limits, we take those to the board, pursuant to our authorization policies.

But we weren't directed by government. I mean, it was management's initiative, but with the authorizations required to move forward as we prepare our capital expenditure forecast each year and seek approval under the loan authority act to make those expenditures.

Mr. Eichler: Mr. Chair, $2.1 million is an awful lot of money. So you're telling me that–and the committee that Manitoba Hydro has the authority to go out and spend $2.1 million on the assumption that it's going to be approved, and analysis of those is what you're claiming that would be the direction that Manitoba Hydro derived on their own initiative rather than direction from government.

Mr. Thomson: Yes, that's correct. And, again, just to clarify, I believe that the preapproval expenditures for Bipole III were south of $300 million, so the 2.1 should be 1.8 in round figures.

Mr. Eichler: With respect to the route of Bipole III, was it, absent given the direction it received from government, Hydro's intention to proceed with the much shorter, less risky eastern route rather than a western route?

Mr. Thomson: Well, these discussions predated my tenure here at the corporation, but there–as I understand it, there had been planning work done. Ultimately, a decision was taken–again, before I had arrived–around routing and, actually, one route that had been excluded and management made recommendations, as I understand it, to the board and they were accepted by the board for the current preferred routing.

Mr. Eichler: The recent press release that was sent out on the original plan on Bipole III, the anticipated cost was $2.2 million. That was back in 2008; 2011 comes along and we realize that that's low. So the reality was that now went to 3.1 or 3.3 million dollars, and now recently that number is now $4.6 million cost for Bipole III. It is a high-risk route. It's through tornado alley.

What is the maximum number that we'll be allowed to spend or prepared to spend whether the–not this project and Bipole III is in fact viable on–based on rate of return based on the rate of which you negotiated this deal with mid United States?

Mr. Thomson: Well, I guess what I'd say is, as I had indicated earlier, when we started to receive the tenders on the major final components of the project, it became apparent to me that there were going to be cost issues this spring. So we did a full in-depth review and we applied the processes that we'd applied to revise our estimates of Keeyask and Conawapa that went into the NFAT proceeding.

The project definition is complete. We've been through environmental reviews. We've tendered over 70 per cent of the costs of the project and we know what the route is. We've got a high degree of confidence in our ability to bring the project in under the revised estimate.

So I don't anticipate, and my team is managing to–the control budget for the project. I contrast that to the estimate that was prepared three years ago before we'd selected a final route, before we'd gone through an environmental review process, and some of the project scope was yet to be finalized. So we're at a much higher, further advanced and level of maturity of the project. And it's kind of like that trade-off that we talked about earlier in respect of how much work do you do prior to getting approvals for a project, that the further you define the project, the more certainty you have around it, the better you've derisked it, that you've transferred risk to your contractors, you have a higher degree of certainty. So, again, we haven't defined a go, no-go because we're working towards the budget, and this is the most cost-effective option that we have as we look forward today is to continue on, complete the project and bring the asset into service to address the reliability issue that we have.

Mr. Eichler: Based on your presentation, you had told us at committee here that you have made or reached agreements with 216 of the stakeholders. So the current budget of $4.6 billion that all ratepayers and Manitobans are going to have to pay for, whenever we look at that and the outstanding numbers, what makes you think that that number is going to be realistic at $4.6 million when we have a huge number of outstanding issues and claims that yet to be settled as a result of that? Two hundred and sixteen is a small number based out of the $4.6 million currently used. So, when is that going to be addressed, and what is the–what's the timeline for the next budget? When is that going to come down?

Mr. Thomson: I'll address that in two parts.

The land-securing process where we've secured easements from about half of the southern landowners that we have to deal with, we recently communicated with them again looking to, on a voluntary basis, to complete the easement process by within the next few weeks. And we need to complete securing those–access to that land by next year in order to commence construction on the southern components of the project, so in foundations and tower placement.

So we've got time and a critical path, and we're still hopeful that we'll secure the lion's share of the easement agreements on a voluntary basis.

Mr. Eichler: And the second part of the question in regards to the next budget and what–when is that anticipated far as the total cost for Bipole III anticipated to be brought forward?

Mr. Thomson: We will–on an annual cycle we will continue to update our outlook for the project, and, again, my anticipation is that we'll reaffirm the project budget as we move forward.

Mr. Eichler: So, again, coming back to your previous comments in regards to the–your response on the total cost, what it stands at now is anticipated at $4.6 billion, and I asked you what the amount would be before it would no longer be feasible. The government, in 2011, made it very clear that neither the transmission line from Winnipeg to Minnesota nor Bipole III would cost ratepayers a cent. In fact, they made that an election issue. Why is that cost now not significant enough to–why was it not part of the plan when you sold the power to the United States as part of the cost analysis of delivering the cost of goods to that customer?

Mr. Thomson: Well, I think it's important to recognize that Bipole III is–we're not building Bipole III to sell power to the Americans; we're building it to address a reliability issue in the province. I can't comment on what happened in 2007.

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Mr. Eichler: Well, it wasn't 2007; it was 2011 when they made the commitment that it wouldn't cost Manitobans anything in regards to the cost of the transmission line or Bipole III. So, obviously, that moving target has moved, then Manitobans are going to have to pay for that.

So, coming back to your–you know that it's harvest season. In order to meet your goal to have these landowners sign off on their agreements, most of them are on the land right now, at least in southern Manitoba a lot of them are. What if they don't voluntary sign? What's the next step? Does that put a hold on Bipole III? Does it move that target? Does it escalate the cost? Where do we–where's–where are we, as Manitobans, going to be looking for Bipole III to move forward, or is it going to move forward if they say no?

Mr. Thomson: If we're unable to secure voluntary easements from landholders, we'll have to move to an expropriation scenario.

Hon. Dave Chomiak (Minister of Mineral Resources): I don't know how long the critic wants to go. I have a question or two I wanted to ask of the–I'll defer to the critic if he wishes to wrap up the series of questions.

Mr. Eichler: I don't understand what the member from Kildonan is asking. We've talked about three hours.

Mr. Chomiak: At this point I didn't want to interrupt the flow of the critic, but I wondered if it was all right at this point for me to ask a question or two.

Mr. Eichler: Sure, Mr. Chair, as soon as I'm done my questions. I only have about three hours, so if you be patient, we should be able to get to that.

Mr. Chomiak: Yes, I–okay. Mr. Chairperson, I understand the critic is asking one-sided, partisan, very political questions, and he wants to do it for three hours from his one-sided, very jaded perspective. I'll–I allow that, but I do want the critic to know that there is another side to this argument with all of Manitobans benefiting from this, First Nations benefiting from this, the lowest cost in the country benefiting from this, and there is another side to this story that the critic's totally avoiding, but that's fine. He can ask his three hours of questions, but we will ask our questions after he finishes his three hours of one-sided, partisan questions that only look at one side and don't look at the benefit to all Manitobans. But we're fine with that.

Mr. Chairperson: Okay. I've heard sufficient on this. My understanding, while the rule is the critic has the floor to ask questions–we have a three-year time–or a three-hour time period–he has that time to completion, and once he finishes his line of questioning, then others are welcome to join the debate. At this point, I return the floor to Mr. Eichler.

Mr. Eichler: Thank you, Mr. Chair, and, yes, we're more than happy to listen to what government has to say. Right now we're focusing on what Manitobans have asked us to bring forward and we're going to continue to do that. And, you know, we may not necessarily agree, but I also said that at the end of three hours we would take a look at the timelines and make a decision then on how much longer we would sit. So, we may not be done in three hours. We may have to sit longer. I really don't know, but that was what was agreed to on the onset, and if the member from Kildonan wants to be patient, I'd be happy for him to answer the–or ask questions at that point, and we're happy to move forward. But we're ready to go on with the line of questioning.

Mr. Chomiak: Yes, and again, I thank the member. I–we are prepared to ask questions after he goes through his three hours of one-sided, partisan questions.

Mr. Chairperson: Mr. Eichler, to resume questioning.

Mr. Eichler: Yes. We're ready to proceed. You know, Mr. Chair, in regards to the expropriation on this land, you had stated that Hydro has agreed that they would like to have that route established and the sign-off on those lands within the next few weeks. So, if there's not agreement, when would expropriations start taking place?

Mr. Thomson: If we're compelled to do that, then I would anticipate the process would be initiated in October.

Mr. Eichler: And the timelines for expropriation normally take what? Two months, three months, a year?

Mr. Thomson: At a high level we've worked back from when the land needs to be secured next fall at the outside, and it can take up to a year for the process to complete.

Mr. Eichler: So, based on that assumption, we know that not everybody's going to be in agreement and walk out hand-in-hand and singing Kumbaya about this is a great deal for Manitoba. Will those–what will that do to the plans to have that developed in as far as your timelines are concerned? Is it based upon the expropriation of that property?

Mr. Thomson: We've developed the overall project plan and the critical path on it, allowing for the possibility that we would have to initiate expropriation in some circumstances. It's not without precedent on projects in the province. Our hope is that as we move towards completion of the voluntary process, people will look at what's on offer and what we believe is a very fair compensation package. The Expropriation Act requires payment of fair market value for the lands, and we're offering a premium over fair market value of the land as well as compensation for lost production, et cetera, et cetera. So landholders have the opportunity to do a whole lot better if we can reach a voluntary agreement that if we're–than if we're forced into an expropriation scenario.

Mr. Eichler: Out of the 216 agreements that are already signed, what is the number or the percentage of claims outstanding and what number is that?

Mr. Thomson: Bear with me. I think I have that number. We've secured–there's a total of 449 landowners that we need to deal with. We've secured 216. We have a significant number pending and then we've had a number refused. And I don't have the exact breakdown of the refusals to date.

Mr. Eichler: We know that building Keeyask and Bipole III is a part of that deal that's been made. And the province has the opportunity to receive, according to the NFAT hearings, over $40 million annually. What is the breakdown to the province out of that $40 million that was brought up at NFAT?

Mr. Thomson: I guess I'd have to get you to cite–

Mr. Eichler: It was on page 189 of 306. Back–I can't tell you exactly what the date was, but that would be–give you enough to refer back to your staff, because I think this is pretty important that it's not necessarily all about what's best for Manitobans. Also a good deal for the government of Manitoba as far as the revenue, not only the water rates but PST, other costs that are going to be flowed back to the Province, of course, and the number that you–or that Manitoba Hydro had put on the record was $40 million just off the in service of Bipole III on an annual basis, so that's a substantial amount of money.

Mr. Thomson: In order to accurately respond, I think I'd have to see the documents being referred to.

So, if those can be produced sometime this afternoon, then I'll attempt to address it here. If not, then I can look to address it as an undertaking.

Mr. Eichler: I would be fine with that. During the NFAT hearings, it was clear in you–in your line of questioning, you said time and time again that Bipole III would not be something to be used for profit, neither by Manitoba Hydro or by the government.

***** (15:40)

How would that be, as a non-revenue-generating item, that would be based on a revenue, when you made those comments?

Mr. Thomson: I don't remember making those comments, but I think that conceptually what you're referencing is Bipole III is an infrastructure project, reliability project, and we don't seek to make a profit on it. We simply recover the cost of operating our infrastructure assets and our rates.

Mr. Eichler: So what you're trying to tell us, then, that there is no profit for Manitoba Hydro or the Province of Manitoba off Bipole III?

Mr. Thomson: No, our rates are set on a cost-recovery basis.

Mr. Eichler: Then coming back to my question several minutes ago in regards to the cost of which it would generate to export hydro to Minnesota, why was the cost of Bipole III and the transmission line not included in the cost of production cost when you negotiated the sale to western United States, in particular, Wisconsin and Minnesota?

Mr. Thomson: Well, the–we're building Bipole III to reinforce our system because it's vulnerable. If we lose one of the existing lines, we can't provide an adequate supply of power to the residents of this province. So we're building it to resolve that issue.

It can carry power, and we can utilize that, just like we utilize our existing system which was also built to serve Manitobans' needs. And we use it to export surplus power. But, whether we were exporting incremental power or not, we still need Bipole III.

Mr. Eichler: I know that in your previous presentations, not on this one, but in the past, in Bipole I and in Bipole II, my understanding, and I–correct me if I'm wrong–there's lots of line voltage left there that could handle Keeyask alone without building Bipole III at all.

Is that factual or not?

Mr. Thomson: My colleague was reminding me, the capacity of the line is utilized by the–our existing system, or the generation of the 3,500 megawatts or so that we have installed up north. And so the transfer capability to move the power of our existing system is used up.

We need Bipole III to reinforce that system. If we lose half the system, then we're short 1,500 megawatts of capacity to move power from north to south, and we can't meet Manitoba load in a–what we call an N1 event. If we lose one of our major assets, Bipole I or Bipole II, we can't meet the needs of Manitobans, even by running our thermal generation at full and importing to full capability of our system. That's why we're building Bipole III.

When we build Bipole III, we'll have the added benefit of being able to transfer additional new northern generation to the south. But, if we didn't build new northern generation, we'd still have a reliability problem. And that is why Bipole III is being built.

Mr. Eichler: In your presentation, you showed slides of the towers that were damaged on Bipole I and Bipole II and said that was out roughly for six days before you were able to get it up and running, so this is the justification for reliability, for predictability. In regards to that, my understanding was–and correct me again if I'm wrong–but during that time we were importing power back the from United States, again at a spot price in order to cover off that demand load. Is that correct?

Mr. Thomson: I believe that that would have been correct at the time, and there was voluntary curtailment. We appealed to the public to use–to conserve energy the week that we'd–that the system was down, and we managed to make it through because we were in a shoulder season. So our peak demand–we didn't have to meet our system peak demand at that time, so we could manage through.

Our load has grown a lot in 20 years and therefore our peak requirements are much higher than they were 20 years ago. And our system transfer capacity hasn't grown, so we've–we don't have that luxury any more. The current situation is that we're extremely vulnerable. Even if that event had happened in the shoulder season, we're vulnerable. If it happens in the winter, we've got rolling blackouts in the city of Winnipeg. You know, 30 per cent of our system we would have to shut down on a rolling basis, and that's–that–to me that's critical–a critical vulnerability of our system given the number of our customers, the percentage of our customers that rely on electricity for heating purposes.

Mr. Eichler: Coming back to when I had asked earlier in regards to the NFAT hearing, I'll just make it clear for you. It's 9.13.0, and it's Mitigating the impact of rate increases, and I can read it out for the record. About 15 per cent of Manitoba Hydro's annual gross revenue is paid to the government of Manitoba for water rentals, debt guarantee fees, capital tax. These direct payments are currently in the order of $250 million annually and would double, over $500 million, for the Preferred Development Plan.

In addition, the panel estimates that Bipole III in service will result in incremental government revenue of about $40 million annually based on incremental net present value basis. So the total benefits to the province are almost $2.3 billion for the Preferred Development Plan to the all-gas plant. So that's significant amount of money when you're saying on one hand that it's not supposed to be profitable for the province of Manitoba or Manitoba Hydro, but yet the record states very clearly that it is. So which one is it?

Mr. Thomson: Okay, I understand where you're going or you're coming from on your question, but there are a number of things that are mixed into the present value assessments of our Preferred Development Plan. And I think that that's in part getting mixed up in the question that you asked.

It's true that as we build out the Preferred Development Plan, that under the current structure we pay water rentals. So if we increase our hydro generation and if the water rental rate stays the same, then we're going to have more energy produced and we'll pay a water rental on that additional water flow through new turbines. That's entirely consistent with what other Canadian hydro jurisdictions do. BC does that. Quebec does that.

The capital taxes–we pay capital taxes. It's a relatively small component of that mix that you referred to in terms of the roughly $250 million that we pay today in transfers, and we pay a debt guarantee fee. We benefit from access to low-cost debt and we're utilizing the province's balance sheet, in effect, to access that low-cost capital or financing. So we pay a fee around that. If we–as we invest in the system and we borrow more money, all else equal, we'll pay the 1 per cent debt guarantee fee on new borrowings. And, as I said, our water rentals will go up, all else equal. That's true.

***** (15:50)

I would point out, though, that our transfers compared to BC and Quebec and Saskatchewan that I'm most familiar with are substantially higher than what we pay, and it's not unreasonable or inconsistent that a royalty or resource rent is transferred to the Crown for using the resource. But that's a–you know, that's a decision that the Crown makes and one that we comply with.

Mr. Eichler: So the debt that's incurred on Bipole III, Keeyask and other projects being brought forward by Manitoba Hydro, as you had mentioned, to the Province of Manitoba for borrowing that money from them, they charge you a 1 per cent premium over their current borrowing rate.

Did Manitoba Hydro seek out other financial institutions to see if they could get a better rate from another bank or another institution along those lines?

Mr. Thomson: Well, no, that's not–we don't have the authority to–or, currently, we don't have the authority to arrange financing outside that. But we have–we would benefit from a provincial guarantee. If we were sourcing debt privately then our cost of borrowing would be much higher.

Mr. Fraser: Yes, Mr. Chairman, the Department of Finance, Treasury Division, is responsible for all the borrowing, not just of–for general government operations but for all the major Crowns: MPI, Hydro, Liquor Control Commission if they needed to borrow money and so on, and the synergies and professionalism in terms of that Treasury operation is a saving to Hydro because they don't do that function. So, I mean, it's in part at least a payment for services. I mean, whether there's an exact match there, I mean, is debateable, but there is an expertise there that all of the Crowns draw upon, and Hydro doesn't have the authority to go out and solicit alternatives.

Mr. Eichler: Recently, as we know, the Moody report has come out and Manitoba's borrowing power is not near as good as it used to be. In fact, there's red flags being raised in regards to the Province of Manitoba and the amount of percentage per debt based on population. What checks and balances are we putting into place in the year payback plan if the rates increase and what impact will that have on the ratepayers of Manitoba?

Mr. Thomson: Well, we continually update our outlook–we've–in terms of our costs of borrowing and we have–we build in what the forecast rates are into our cost of borrowing. We've–subsequent to the Moody's report coming out, we recently this past month arranged an incremental $300 million and we saw no change in the costs or no discernable impact of the Moody's report in that and the outlook that Moody's has had. So–but we update our outlook annually in our long-term financial forecast, our integrated financial forecast and incorporate that into our outlook.

Mr. Struthers: Yes, I would–I'm trying to help out here by suggesting to the member in his three hours of partisan questioning that he try to be accurate. There was no downgrade of anybody's ability and costs associated with borrowing on the part of the Province. The–so that won't have an increase on rates or anything else that the member would like to attach that to.

What would bump rates through the roof is if we took his own advice and his own leader's advice and not sell on the export market the surplus power that we produce in Manitoba. Then you'd see rates go through the roof.

But I would ask him to be accurate, try to be correct in how he characterizes the report that we received from Moody's.

Mr. Eichler: Back to my questions.

I thank the minister for his advice. We're here listening to Manitobans who want to make sure that Hydro is listening and they're held accountable as well. And we will continue to do that.

And we know that whether or not the government wants to believe it or not, 1 per cent increase in the borrowing rate would make a significant difference to the ratepayers in Manitoba. And those rates would, in fact, have to change.

There's only one ratepayer out there, and whether or not you wanted to rule that in or not is going to have–these rates aren't fixed–then we're going to certainly have a problem with that.

When we look at the overall cost, and we know that based on the information that you provided at NFAT, the information was tabled, the rate increases–when the next 20 years is going to at least double. And that's without any increases in the rate increase, if there is one, between now and the next 20 years.

So, out of the projections that you and Manitoba Hydro have put on the record through NFAT, what impact will 1 per cent have on the ratepayers if a 1 per cent increase was to come forward in borrowing cost?

Mr. Struthers: Well, yes, and the member says if. At least he's trying to be accurate now. He says if, and he's speculating on whether or not there would be a downgrade in the–from Moody's or anybody else.

He's asking a speculative question. But what is known for sure is the rate increases that would occur if his leader had his way and put in place market rates for Manitobans. If you want to see rates go up–I would suspect a lot more than 1 per cent–then you should actually question your leader on what he had said, as opposed to speculating on what Moody's may or may not do in the future.

Mr. Eichler: My question's still on the table.

Mr. Thomson: I would point out that our 20-year outlook anticipates that long-term borrowing costs go up based on analyst forecasts of borrowing and assuming that we continue to enjoy the benefit of the government guarantee on our borrowing. So we haven't fixed our assumed cost of borrowing in our long-term outlook.

A substantial component in excess of 80 per cent of all of our debt is long-term duration, and so the rates are fixed, and even on some of the short-term borrowings, we've swapped out for fixed rates.

So we've got a certainty around what the costs of our existing borrowing are. And we built in the escalation in borrowing costs that we see based on what the market tells us. And we update that every year.

So we haven't fixed our assumed cost of borrowing. We have reflected the best information available to us, and we update that every year. And that information's shared with the PUB, and they consider that when they set rates.

Mr. Eichler: The current agreement, I believe, is for a 10-year agreement with the customer in the United States that you made a deal with. And when we're looking at–and I know the minister don't want to acknowledge this, but borrowing cost is a significant part of what we're looking at for the rates for Manitobans.

And according to your forecast based on 2019: 2018, we'll break even; 2019, we're anticipating a

$55-million loss; 2020, a $19-million loss; 2021, a $62-million loss; 2022, a $45-million loss.

So, if there is cost overruns and we have this 10-year deal, what guarantees do we have in place to protect the real owners of Manitoba Hydro, the ratepayers of Manitoba, that our hydro rates are not going to go through the roof?

***** (16:00)

Mr. Thomson: Well, in terms of the outlook on revenue streams, we've got multiple firm export agreements in place, and they range out terms to–the most recent one that we've signed is out as far as 2035. And the recent Wisconsin one, 2036. And there's escalation factors built into those contracts that are driven, in part, based on inflation and other factors. So there's–they're formula-based, but there's–we've got some certainty around our revenue streams going forward, and it's over a substantial period of time.

So, you know, I mean, obviously, the greatest tool that we have is to–is project management and cost control as we build projects. There are factors that we have to respond to that are beyond the utility's control, and so there's no guarantees in life, but prudent management of the projects as we go forward will help to ensure that we deliver them on time and on budget.

And so, you know, the–and we review our cost outlook for rates with the PUB on a regular basis, so–and ultimately they're the arbiters of what rates do get set.

But, you know, as I said earlier, we build to meet the needs of Manitobans. We benefit–we attempt to maximize the value of the assets that we've built and utilize the export market to create revenue streams that help to reduce the rates domestically.

Mr. Eichler: In regards to the formula, then, what would–what does that formula look like? What do you base that on when you go back and renegotiate or say we're losing too much money or we're making too much money–which would be a great problem–but walk us through that. How does that formula look?

Mr. Thomson: At a high level, we've got a number of financial targets that we pursue over the long term. One of the benefits that we have of being–of public ownership and being a Crown corporation, unlike an investor-owned corporation that's chasing quarterly earnings statements and whose revenues have to respond immediately to cost of service impacts, we can plan over the long period of time as we, you know, as we set rates. So we, over the long term, we project what our revenues are going to be and we build the cost of service.

So we don't plan to make profit on our domestic operations. We have incurred windfalls at times, depending on export markets, but–and we do–we have firm export contracts in place, so we build the firm revenues into our revenue forecast and we build an assumed level of revenue in–each year into our rate setting mechanism for opportunity sales, spot sales, that are, in the near term, are driven by our outlook of our water availability, so what we project our surplus revenue to be for the next year, and over the long term we base it on what our average revenues are. So there's going to be years where we do better because we've got high-water years and there's years that we're going to not do as well because of having a shortfall in water or drought conditions. Over the long haul, it should average out.

But it's important when we're investing in the–in–reinvesting in the system, and like we are today and like we're going to have to over the next decade to refurbish the aging assets, it's important that as we move forward we don't say, oh, we had a windfall, we had a great year this year, you know, we made $174 million, so we don't need a rate increase. Because part of the advantage that we–that I was referring to that we have as a Crown, we can smooth rates over time. And so if we know that we need to recover a certain amount of revenue over a long period of time, we don't have to whipsaw the rates around and have a massive rate increase one year and that sort of thing. So we can smooth that out and reduce the impact on customers and, hopefully, provide them some forward indication of where they're going so they can plan their businesses around that, they can respond to that, they can, you know, they can implement energy savings options and take advantage of Power Smart initiatives that we have to help them manage their costs down.

But that's how–in–at a high level, that's how we produce our rate outlooks and how we–why we produce a 20-year outlook that we share with the Public Utilities Board. I know that if we had zero cost escalation in our operating costs, we're still going to have pressure on rates because, you know, we've got assets that we're taking out of service that are fully depreciated that we don't have any borrowings associated with that we're replacing with assets that are going to cost us money in 2014, and I have to service that debt and I have to recover that investment over the life of the asset as we move forward.

So that in and of itself is going to–think, you know, think about your first car that you bought. You know, you probably paid $2,000 for it. A similar vehicle today is going to cost you $30,000. You paid for that old vehicle. You changed the oil. You did–you maybe replaced the transmission, and as it got older and older, you were having to do more and more of that, and finally you said I can't keep putting baling wire and finder twine on this and you need a new car. Well, that's where we're at, and so the cost of servicing those new assets is what's putting pressure on our rates.

Mr. Eichler: So, just to follow up, and you've mentioned it a couple of times now in regards to the rate increases. So the increases that was tabled and your outlook for the next 20 years based on 4 per cent per year–and did that include the extra $1.2 billion that was recently announced for the increased cost of Bipole III? What would that increase look like then based on the new numbers?

Mr. Thomson: All else equal, it would impact rates by approximately a third of a per cent incremental to that 4 per cent.

Mr. Eichler: So the $280 million, I believe, is the number that, per year–no, I'm wrong. It's $400 million per year to service the 3.3 million, so you take a third of that so you're going to increase by another $120 million per year to just to service the debt. Is that correct?

Mr. Thomson: No, it's not–not–not correct. The assets themselves, the depreciation rate is approximately 2 per cent, and the cost of borrowing, you know, the most recent debt issue that we did was 362–so 462. So let's assume the cost is 5 per cent all in to borrow and 2 per cent, so your high level cost to carry at the front end of a long-lived asset is about roughly 7 per cent of the up-front capital cost. As you depreciate it, the debt component that you're servicing goes down because you're recovering the cost of the asset and your depreciation. So, over the life of the asset, you can approximate it that it's going to be half of that, so it's not as high as the number that you quoted, but, clearly, it's going to be–if you figured it upfront at 7 per cent carry on the 1.2–what's that, about $85 million?

Mr. Eichler: Based on the number of Hydro customers, what does that work out per household?

Mr. Thomson: You levelize that cost over the life of the asset.

Mr. Eichler: According to the presentation again that, through the impact, 9.80 impact to Bipole III on rates, when the project is completed and in service 2017-18, Manitoba Hydro's determined approximately $280 million will have been recovered through rates. This would require a one-time rate increase of about 20 per cent. So you add, according to your numbers, $1.2 million–billion dollars on top of that, you're trying to tell me that that really is not going to make much of a difference to ratepayers on the 20 per cent increase. That's going to be able to be absorbed in there when, a minute ago, you said it was not in there when, in fact, we're looking at a 20 per cent increase once this project is completed. So which is right?

***** (16:10)

Mr. Thomson: I think that what you–what you're picking up on is that the cost-to-service effect of Bipole going to service, if I heard you correctly, was quoted as being $280 million. So relative to our current revenues, domestic revenues subject to check, the math would suggest 20 per cent. But we're not raising the rates 20 per cent in a year. We're able to smooth the effect of that over a long period of time just like we'll smooth the effect of the cost, the update in the project control estimate would be, which is why I'm saying it would be an incremental amount over what we'll need to adjust rates, all else equal, what our outlook on rates is of about a third of a per cent. A domestic customer that pays $1,000 a year, that means about $3 next year and an additional $3 the year after that and an additional $3 the year after that. So, you know, a decade out the monthly bill would be $3 higher approximately–the monthly bill not the annual bill. The monthly bill would be about $3 higher, again, all else equal, and there would be lots of moving pieces as we move forward. But–*[interjection]*

Mr. Chairperson: Mr. Eichler.

Mr. Eichler: I wouldn't want to invest in it on a $3 return on $1.2 billion. That–those numbers just don't add up so we'll leave it at that.

An Honourable Member: Not enough profit, right?

Mr. Eichler: Well, $3, no, you wouldn't even do it, Dave. Not even that.

Mr. Chairperson: Order, please.

Mr. Eichler: In recent years Hydro has increased its 20-year forecast for normal capital expenditures from under $5 billion to $12 billion. The major jump apparently has taken place without an asset condition report, one that was called for by the PUB in the earlier rate hearings. What is the most recent update on that and what basis would you use, and you talked about a bit of it in your presentation in regards to some of those projects that needed to be upgraded and what impact will that have on our rates?

Mr. Thomson: Well, we've–we have updated our outlook on what our replacement capital requirements are, and it's on the order of five to six hundred million dollars a year. So over 20 years it would be 11 or 12 billion dollars, and that's been factored in to our 20-year rate outlook. It's already in there.

Mr. Eichler: So is there an asset condition report being developed or is that part of the plan or is that be coming at a later time?

Mr. Thomson: We've done ongoing assessments and do ongoing assessments of the infrastructure and the priorities, the replacement priorities. So we've got a plan developed for replacements of stations. We've–we're looking at, as I said, the poles, the underground infrastructure. Have we–I'm not aware and I'd have to check, we haven't wrapped that all up into a report what–a single report. We do it along the lines of business.

Mr. Eichler: Is there a cost analysis done on these projects before they take place? You had talked about the spillway in Pointe du Bois, and I believe that cost was going to be around $2.4 billion, $566 million for the spillway. So what analysis is done on a rate of return for investment or is there one done?

Mr. Thomson: No. Assets for internal or–you know, when we're replacing–the project that we're doing for the bipole–or, sorry, the Pointe du Bois spillway replacement, we compared the cost of rehabilitating, putting a new spillway in and rehabilitating the dam, reinforcing the dam with the cost of decommissioning and that and the loss of revenue associated with the existing powerhouse. So we compare alternatives to meet the need. We had a dam safety concern with the spillway and the dam structure, so the pictures that I showed you in the existing spillway will no longer hold water back, because it was unsafe and we're building something to replace that. A decision will be made a number of years out, whether we actually re-power the powerhouse, so whether we replace the 100-year-old–some of them are actually 100-year-old turbines that are there–whether we rebuild that or we decommission that. So it'll be a cost assessment: Is it going to generate enough benefit to offset the cost at the time?

With modern infrastructure, we can probably increase the production from that plant by about 50 per cent, so we would assess whether the incremental revenue benefit from that would warrant the replacement or whether we would simply run the existing assets to failure and then not replace them.

Mr. Eichler: Whenever we look at, you know, Winnipeg hydro or Pointe du Bois in regards to those cost and cost of repairs and maintenance on them as well, that's why I think it's important that we have a cost analysis done on them in order to see whether or not, in fact, it is worth the rate of return. And then–and that's what Manitobans are expecting, is to make sure that we do the right thing when it comes to investing their money. And whenever we look at those, I just am not clear on whether or not–how that would roll out. In particular, we know Manitoba Hydro has a lot of old buildings, old infrastructure, as you pointed out in your presentation, so how does that look for Manitobans? And, even though you're saying it goes over a five-year plan or a 10-year plan, how does that look for ratepayers in having input into cost recovery in order to return on that investment?

Mr. Thomson: It's–well, rates are established to recover the investment, to recover the cost of providing the service to our customers, not to earn a profit. And, again, that's a benefit to public ownership of the system, unlike an investor-owned utility that earns a return on their invested capital. And so, when I was speaking earlier about the cost, the incremental cost to service the Bipole III project over our previous estimate, we're not looking to earn a return of 9 or 10 per cent on equity that an investor-owned utility would require. We're simply looking to recover the cost of providing the service to the customers without a profit.

Mr. Eichler: Not that long ago, Manitoba Hydro had purchased Swan Valley Gas Corporation for SaskEnergy. What was the reason for that? And, following along the same lines, Stittco, who distributes propane through pipelines to Thompson, what's the variation there and how would the analysis look on that for the potential of why you bought those, and not Stittco? And what was the thinking whenever we made those investments and a–possible another investment with Stittco?

Mr. Thomson: We were approached by SaskEnergy, who were the previous owners of Swan Valley Gas. That system is isolated. It's on the Saskatchewan border, as you know, and it's actually supplied out of Saskatchewan, not off of the Manitoba pipeline system. So that was the genesis of it, and it had an industrial customer load that anchored the development of the system. The industrial customer changed their source of energy, and so about two thirds of the throughput on the system were eliminated.

***** (16:20)

The costs to the residential customers were about 50 per cent higher, in round figures, what Manitoba–Centra Gas Manitoba customers were paying for natural gas service, and, with the elimination of this industrial load, they were looking to go up by about another 50 per cent. So we entered into discussions, SaskEnergy approached us. They were about to make an application to the PUB, were preparing to make an application to the PUB that was going to have to have a big rate increase, and they asked us whether we would be interested in taking over that system and rolling it into our system. We have–and, in effect, that's what we did. We paid a dollar for the assets. They had a book value of about $1.8 million. We paid them a dollar. We assumed responsibility for operating it. We've got a gas supply contract in place with SaskEnergy. That's a part of our overall gas supply portfolio now, just to serve the load on that system, and those customers are paying rates consistent with every other Manitoban now. So it was deemed to be in the public interest for us to take that over rather than see that small group of Manitobans pay double what the rest of the gas users in the province did.

Mr. Eichler: In regards to Stittco? What's the–where's that sit now? Is that something along the same lines you're looking at to protect the northerners at the same time?

Mr. Thomson: We're not currently in any discussions that I'm aware of around those assets, and you indicated that's a piped propane system. So we don't have the ability to supply natural gas in–there's no pipeline. There's no supply. That's why it's a piped propane system. So we're–we don't operate piped propane, but.

Mr. Eichler: Coming back to the Swan Valley Gas, and, of course, we all know, you know, the benefits of the Bakken that's been for Manitoba and, of course, North Dakota's had a great wind slide far as revenues are concerned. Is there discussions in regards to harnessing some of the natural gas that's coming off those ventures in southern Manitoba?

Mr. Thomson: We have been approached by some producers, and we're at the very early stages of looking whether it would be feasible to have them introduce pipeline-quality gas into our systems, so as a potential supplier. An alternative would be for them to utilize by-product gas from their operations to do distributed generation, so to meet some of the generation needs. It's really in its infancy, but we're–you know, we're looking at things.

Mr. Eichler: In regards to the First Nations folks, Hydro has revealed that there's been several monies spent on northern mitigation and contract negotiations, First Nations training, and you talked about the number of employees there. It's my understanding that these costs incurred will be reflected in the rates and, of course, on the business and institutional customers as well. So what are the–what is the total amount of money expended in these measures present for ratepayers? What is the total cost that has been spent on First Nations training, negotiations and mitigation?

Mr. Thomson: I'd have to take an undertaking to provide that.

Mr. Eichler: In regards to mitigation, we understand that there is still a number of unsettled negotiations that are out there, and the contracts that has been entered to, they feel that they're just not what they need to be. So when are those negotiations going to be taken up again and what's the anticipated date for those to be written and agreed upon?

Mr. Thomson: I would need more specificity in what you're asking about to answer that question.

Mr. Eichler: Are the legal costs paid up front for negotiations for the First Nations, or they billed after?

Mr. Thomson: It depends. It depends on what the topic–you know, what we're discussing with them. We have a reimbursement policy that where we're providing resources to First Nation groups–and again it depends on the topic that's being discussed–we require that a budget be prepared and a work plan, and in most instances we reimburse. In–there have been instances where we provided some advances, and it depends on the cash flow and the specific circumstances.

Mr. Eichler: Recently, the Taxpayers Federation revealed a leaked document that was presented to Hydro's audit committee. The document suggested there was a number of problems with respect to inadequate support of some payments. What follow-up has occurred and have any questionable payments been turned over to the RCMP for investigation?

Mr. Thomson: Again, it's–there's not enough detail in your question to respond. I'm not sure what you're referring to–what documents, what incident.

Mr. Eichler: The payments that have been made to Manitoba Hydro–from Manitoba Hydro to First Nations communities–and some of those–some of that information has not been brought forward to determine whether or not those payments were actually spent in the right forum or with the right man, and there's been claims of fraudulent activities within those. Have those been referred to the RCMP or do you have evidence that they are now satisfied to meet the needs of Manitoba Hydro in regards to those payments made to First Nation communities?

Mr. Thomson: I understand that there's been an Auditor General report on some of these matters. I–we could undertake to provide that, and if there's specific questions for follow-up, we can deal with that. I'm trying to answer your question, but I don't know what you're referring to, so.

Mr. Eichler: So, to your knowledge then and the staff that's here, there's nothing been turned over to the RCMP for investigation as far as fraudulent claims are–been made aware of in your department.

Mr. Thomson: There may be a couple of situations where we've turned things over to the RCMP, so I will investigate that and I'll provide a response.

Mr. Eichler: In regards to the equity stakes for the First Nations–for example, Keeyask and the TCN partnership–those equity stakes, how were they negotiated and how–and who negotiated them for you or was it done on behalf of government or was it done on behalf of Manitoba Hydro or First Nations? Who did the negotiations?

Mr. Thomson: The project development agreements Hydro representatives negotiated with representatives from the band. In the case of Wuskwatim with NCM, and with respect to the Keeyask partners, we did that with the band representation, and that was Hydro management undertook those negotiations.

Mr. Eichler: So the percentages then of equity–how was that determined and what basis was it used on?

Mr. Thomson: I would again–there, it's evolved over time, so I would have to get back to you on that.

***** (16:30)

Mr. Eichler: Under the repayment schedule of the debt that's been loaned by Manitoba Hydro to First Nations for equity investments within Manitoba Hydro, what is the escape clause for those First Nations in order that–as we know, the first few years they've lost money and they want to renegotiate, and yet they still don't have to make the payments and yet they receive an annual profit and no payback. Would you care to explain how that works for us?

Mr. Thomson: The terms of the agreement are subject to–they're commercially sensitive and subject to confidentiality agreements. I don't think I can–I don't have it at my fingertips, but I don't believe I can make that available to you.

Mr. Eichler: Are you at liberty to tell us what equity is on Keeyask and also on Wuskwatim?

Mr. Thomson: The up to 33 per cent equity interest in Wuskwatim and the final determination on Keeyask has not been made.

Mr. Eichler: And the anticipated timeline for that to be made?

Floor Comment: I'm sorry?

Mr. Eichler: The anticipated timeline for that development agreement to be signed, what's the plan, the timeline?

Mr. Chairperson: Order, please.

Mr. Thomson.

Mr. Thomson: My recollection is that the final determination of the equity stake around Keeyask is on project completion, when the project goes into service. And we're in final negotiations around the Wuskwatim project currently, around an addendum to the project development agreement there.

Mr. Eichler: It's been reported–of course, through the media; we don't know how reliable that is nowadays, as we all know–that Hydro has spent $1 billion on mitigation and $250 million on negotiating partnerships with First Nations. With respect to the $251 million, what is the breakdown covering consulting and legal expenses for First Nations and payments to individuals within the First Nation on a community development program?

Mr. Thomson: Sorry. The community development program is a specific program. The CDI is a specific program associated with Bipole III. The overall cost of that program is about $6 million a year, although we haven't concluded agreements with all of the affected communities yet, so we haven't been expanding at that level.

Mr. Chairperson: Mr. Eichler.

Floor Comment: We can provide information on–

Mr. Chairperson: Sorry. Mr. Thomson.

Mr. Thomson: Sorry. We can provide information on that.

Mr. Chairperson: Mr. Eichler.

Mr. Eichler: I thought there was something else coming.

In regards to the expenditures and commitments to First Nations governments, communities, residents and firms, are those subject to independent audits or they fall through Manitoba Hydro's own audit process?

Mr. Thomson: We have our own internal audit process. Again, we have approximately 100–or sorry, 500 agreements of various types with 21 First Nations in this province. Some of them are around project development; some of them are around mitigation; some of them are adverse effects; some of them are relationship agreements. There isn't a one-size-fits-all, and the specific provisions are dictated in the individual arrangements.

Mr. Eichler: Has there been any audits other than Manitoba Hydro, then, on the amount of monies that's been paid to those First Nation communities? And, if so, when?

Mr. Thomson: I believe there was an Auditor General review of some contracts, some agreements with First Nations. We can, again, provide that information to the committee.

Mr. Eichler: On those commitments that's made by Manitoba Hydro to First Nations, those contracts are an ongoing contract, is my understanding. So they're renegotiated and reviewed on an annual basis.

Is that correct?

Mr. Thomson: No. I don't believe that's correct.

Mr. Eichler: How many contracts are still outstanding that have not been settled in regards to the dam projects in the North?

Mr. Thomson: We have the northern affairs–sorry, the Northern Flood Agreement that covers the five major communities up north and subsequent comprehensive implementation agreements around that, so of the dam projects up north, we've got the Joint Keeyask Development Agreement with the partners around the Keeyask project, which is being constructed.

We haven't concluded agreements around Conawapa, but that project isn't in development at this stage. So we're not pursuing agreements around that.

So, for the projects up north, I think they've all been dealt with.

Mr. Eichler: With respect to Hydro employing members of the First Nations and First Nation contractors, would you indicate the volume and expenditures not subject to personal or corporate income tax due to the workers and contractors being on reserve land? Is there any?

Mr. Thomson: The–I don't have an analysis of that, although most–none of the project development is on reserve land. It's on Crown land. We've got, you know, we've got title to Keeyask. We've got title to all of the generating stations. So the–it's possible, it's conceivable that construction agreements with First Nation bands–they wouldn't pay–I don't believe they're subject to income tax on that, but I don't–I can't produce a number for you.

Mr. Struthers: I want to ask if there's willingness on the part of the committee to allow for a 10-minute break, so folks who are stuck at the table can have a break.

Mr. Chairperson: Ten-minute recess has been requested. Is that agreeable? *[Agreed]*

We are in recess for 10 minutes.

The committee recessed at 4:39 p.m.

The committee resumed at 4:54 p.m.

Mr. Chairperson: Order. We'll resume. The floor is open.

Mr. Eichler: Mr. Chair, I appreciate the minister suggested a short break there. I think it did us all good, and I got some more good questions as we prepare, and, when we had talked about the leaked Manitoba Hydro document, we–it gave us an opportunity to bring that forward, and I'd like the–

Hydro to comment on it in regards to mileage claims that did not match pay to staff–$78,500 to $108,000 estimated overpayment of airfares; that was on page 9. Two hundred and fifty thousand dollars on a Keeyask advance where staff were trying to reach an agreement on reconciliation or repayment of the 250 in advance; that was on page 10. And there was five other non-compliant items with an estimated value between $29,995 and $105,495, and that was on page 9.

So I would like a response on this and whether or not any of that money's been paid back. And, if not, is there legal claims that are going to be taking place to recoup that money that rightfully belongs to Manitoba ratepayers?

Mr. Thomson: If the critic will provide a copy of the report to us that he's referring to, we'll produce a response for him as an undertaking.

Mr. Eichler: I would be most happy to do that. We'll get it to you by tomorrow sometime. You don't need to do it now; tomorrow's fine. We have enough to do tonight.

In regards to the allocation of revenue and expenses and those partnerships, without getting into the nitty-gritty of the contracts that are putting Manitoba Hydro at risk or the government at risk, how are those calculated and what formulas do you use on those calculations? Is it based on depreciated value of cost? Is it based on revenues that are generated? For example, you had referred to the $174 million of profit this year. Is it net profit, gross profit? What checks and balances are in place in that process of which you make payments to First Nations based on profits through the agreements?

Mr. Thomson: Well, the only arrangement that's in place that's in operation is the Wuskwatim arrangement with NCN, and they have an equity interest in the–an equity ownership interest. So there is a preagreed definition of revenue and the cost of service for operating–the actual cost of service for operating the facility, and that produces an income statement, and they have a–their equity interest in the earnings of that business, and the other arrangements are part of the agreement that I'm not at liberty to discuss.

Mr. Eichler: So would expenses paid to First Nation members for travel, for other expenses that are incurred by those members, taken off the return of those revenues as part of that calculation?

Mr. Thomson: Cost of operations of the facilities don't include that. I think that what the critic's probably referring to is costs incurred in the development of the project and those were costs of the project itself, so they form cost of–the capital cost of the project that the equity owners will recover. You know, that will come out of the–that will be part of the cost of service of operating the facility, and both sides will pick up their respective share.

Mr. Eichler: Based on the agreements with the First Nation communities, what is the anticipated payback to those First Nation communities far as the number of life years that they're into that agreement with Manitoba Hydro?

Mr. Thomson: If that's not proscribed from me talking about it, I'll provide you with an answer to that as an undertaking.

Mr. Eichler: I'm fine with that.

In regards to Hydro extending the grid to remote northern communities which are currently left off the grid, how are they–you know, they're dependent, obviously, on diesel generation. There's health, economic, environmental issues in regards to those communities.

Taking into account the cost of fuel transportation to get that fuel there, what is the subsidy being provided to those ratepayers in those four communities that receive diesel-generated electricity at a provincial-wide rate? What is the overall cost for ratepayers in Manitoba to subsidize those four communities?

***** (17:00)

Mr. Thomson: Residential customers in those communities pay system rates and small commercial customers pay system rates on, I believe it's the first 2,000 kilowatt hours of consumption a month.

The band and government–federal government customers pay–cross-subsidize the rates of those. They pay rates that are set by the PUB but that are–that pay for the lion's share of the shortfall of those customers. So it's less about the broad Manitoba customer base subsidizing them as you framed it, but the–all of our rates are homogenous. We–our cost to serve rural customers is different than our cost to serve urban customers, but all of our customers pay the same rate. So there is a recognition in setting the diesel rates that the cost of operating those systems are higher, and effectively the federal government, through transfers to the bands, pick up the costs of the remote–the incremental costs of the remote service.

Mr. Eichler: So am I to understand, then, that it costs the ratepayers in Manitoba nothing as far as a subsidy through their hydro rates then, and it's absorbed through transfer from the federal government and the ratepayers of Manitoba have no cost. Is that correct?

Mr. Thomson: A substantial component of the cost of operating those systems in the diesel communities are paid by the federal government. They make a large capital contribution to the diesel generation, and the refurbishment and update, I think it's 70 per cent of the direct costs of that we recover from the federal government.

I can't say that there's no shortfall, but I wouldn't characterize it as a subsidy because we don't–we have the same rates. We have postage-stamp rates across the province for our grid customers. They're–it–so if you characterize diesel communities as being subsidized, then there are rural customers that are being subsidized by urban customers because we pay the same–we–all residential customers pay the same rates and, you know, the cost of our–the–and, again, that's a benefit to all Manitobans that we share the cost of operating the system.

Mr. Eichler: What was the losses of uncollected hydro revenue that has been charged out to residents in those four communities? Has all that money been collected and, if not, what is the percentage or the dollar amount that is gone delinquent and not paid to Manitoba Hydro as a result of not being able to meet those needs of those in that community that don't have the ability to be able to pay? What is the dollar amount?

Mr. Thomson: I'm not sure that I can provide you by–well, I will see if I can provide that on a community basis, but because the residential rates are consistent across the province whether they're in diesel communities or not, I'd–not–that's a–that's more a socio-economic issue. It's not a rate issue. It's not driven–you know, they're–they–whether their ability to pay for their energy consumption isn't driven by whether they're supplied by diesel generation or not because they pay the same rates as–you know, a Shamattawa customer pays the same residential rate as a TCN customer as you do for their consumption of electricity. So I'm not sure that it's particularly germane to whether it's diesel service or not.

Mr. Eichler: Has there been a cost-analysis study done on whether or not it'd be viable to bring in a line to those four communities based on the environmental cost, the other costs as involved into transporting diesel to those communities?

Mr. Thomson: Yes, the most recent estimate to serve–to connect the four communities to the grid is about $400 million, and there's, I–on the order of 1,000 total customers served. So we've–our assessment is that that's cost prohibitive. We are looking at–and there's a study under way right now of alternatives to meeting the energy needs of the customers with lower emitting or non-emitting energy. But, at present, and that's under way and we're doing work on that, it's certainly our desire, and I believe the government's desire, to move the communities off diesel. There's–across Canada there's about 160 remote communities that are served by diesel.

And, you know, there are a number of options being explored, but, you know, some in the west are–they're looking at LNG generation. You have to be able to get it there, and one of the challenges for us here is you can only move fuel in for a short period of time over the winter road system that we've got.

And so–but we're looking at other technologies and seeing whether we can at least–we can reduce the dependence on diesel initially and, hopefully, eventually eliminate it.

Mr. Eichler: Has solar power been one of those options that's been explored there with a revenue-generating–or a expense-generated analysis on whether or not that would be feasible for those communities with a limited supply of generated power?

Mr. Thomson: We were–there's about 25 proposals that have come forward in our request for expressions of interest, and those are in the process of being evaluated. I believe there were solar elements to that. I don't believe solar can–there isn't enough ability to meet all the needs from solar in those communities at present.

Mr. Eichler: I want to switch over to the Minnesota-Manitoba transmission line, and we know that that project is, you know, critical to Keeyask and, of course, part of Bipole III. What is the total cost for that project, and what portion is Manitoba Hydro responsible for?

Mr. Thomson: In my presentation, our expectation is that the Canadian portion of the line, in

2020 dollars, I believe it was $350.2 million, and it's in your materials that I handed out, and I may have the US component with me as well, if you bear with me.

The–in July–Minnesota Power, who's constructing the US portion of the line, has estimated that the cost, the construction costs, will be $676 million US in 2013 dollars. So that would be subject to escalation and capitalized interest. We're responsible for 54 per cent of that, which would be about $365 million, plus interest.

Mr. Eichler: And the Manitoba side, what's the cost from, I believe, Dorsey, you said, to the Minnesota border, what is the anticipated cost for that line?

Mr. Thomson: Our anticipated in-service cost is $350 million in 2020 dollars. So that includes financing, interest during this–during construction.

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Mr. Eichler: When you look at the cost on these things, and we know that, you know, in the discussions we had on Bipole III and the cost of going across land and farmland and so on is not only a burden for farmers and those irrigation systems and so on, converter stations, has the department looked at the towers and transmission lines that go down along the side of the road rather than across farmland and that type of thing and the impact that would have and the cost analysis that would be saved or the additional cost that would be used to create that line?

Mr. Thomson: We went through extensive environmental review process of–and the routing and the impacts, and the final route selection being recommended to and approved by the Clean Environment Commission. So, yes, that's been costed in. We've looked at the most cost-effective way to build and we've responded to the recommendations of the CEC and the licensing conditions that were placed on development of the project and, for the most part, on farmland as it relates to Bipole III. The–we were directed to go on the half mile and–but we've been accommodating in terms of owners' desires, where we can, with tower placement on their land so as to minimize the disruption to their activities.

Mr. Eichler: So on the prime agricultural farmland that this line in Bipole III would be going through, the DC transmission towers and that line technology where the prime land would not have to be impacted, what cost was estimated for Bipole III and the Minnesota transmission line to follow those guidelines rather than by land and going across the prime agricultural land and using instead the roadside DC transmission towers?

Mr. Thomson: Well, that technology doesn't work functionally with the existing bipole systems. It doesn't have protection on it. We'd be subject to–given, as I understand it, upwards of 150 outages a year due to lightning strikes. That technology is still being in development and it operates on different voltages than the bipoles. So it doesn't function with our system. It's time has yet to arrive. So it's not practical for us. It's not a viable alternative for us at this stage.

Mr. Eichler: So when you take land out of production, it's out of production usually forever when a transmission line, bipole line, and Bipole II–both grew through my riding and I know the impact that it has on our ratepayers there and the land owners and you never get that back and, obviously, from what you've just stated, the technology's not there yet. Is there any other countries or states or provinces that use that transmission line, that type of transmission line that you're aware of and, if so, what data is being used to determine whether or not it's feasible or not or workable?

Mr. Thomson: I'd have to get an engineer's explanation for you, and I'm not one of those so I'll have to undertake to get back to you on that one.

Mr. Eichler: I would appreciate that, and it's about landowner rights as well, and when you look at what Saskatchewan, Alberta have in regards to protection of that land–*[interjection]*–what are they using to protect their landowner rights?

And I know the member from 'Kindolan' is, you know, a bit sensitive about this, but we're here to hear what Manitobans have to say and bringing those ideas forward, and it's too bad the member from 'Kindolan' can't seem to get that under control.

But we're going to continue to ask those questions, and I think it's important that we have that debate and look at all the alternatives when we talk about using up land, valuable farmland that will be out of production forever. We need to have that debate and we want to make sure that we're covering all those off with the best ability that we can.

So I think it’s important that we have that discussion and I would like an answer whether or not you will commit to finding out whether or not the DC transmission towers will in fact work in some of the areas but not in Manitoba, and if so, why? It just doesn't make sense to me if that is in fact the case. And I'm open to the interpretations based on engineers. There's far smarter people out there that know how to do this than me and I don't pretend to be an expert at any point. But I think it's important to try and protect our farmland if there's an alternative that we can use to do that without having to go through farmlands and other parts of the communities, that where there's an alternative, I think we should try to be able to use that.

Mr. Thomson: As I indicated, I will endeavor to get an explanation to him, but I do know that it was considered and it was considered not to be viable in this application and it hasn't been used for this purpose and wouldn't work with the balance of our system.

Mr. Eichler: In regards to the CSC–not CSC, CEC approvals and the federal approvals for the environmental licence, has that been a barrier for Manitoba Hydro in any way? Have they reached out and got those approvals or is it something that Manitoba Hydro's exempt from?

Mr. Thomson: Environmental approvals for, sorry, which project?

Mr. Eichler: For Bipole III or the Manitoba transformation line, has the environmental–federal environmental licence been issued or does Manitoba Hydro require one?

Mr. Thomson: We'll have to go through environmental process. We haven't gone through the environmental processes for the US transmission line. The federal and provincial processes we attempt to co-ordinate those and–but we have received all of the environmental licensing approvals we require for Bipole III.

Mr. Eichler: What I'm talking about is the National Energy Board in terms of the routing of the route, and my understanding is that there has to be approval from them. Is that correct?

Mr. Thomson: We have to get export permits approved by NEB for export contracts. The transborder interface, I believe there's a federal requirement around that as well. We're not at that stage yet in the project place.

Mr. Eichler: Well, one would think that, you know, that would be a significant step that one would take before we spend billions and billions of dollars. If that could be a roadblock is that something that we're not concerned about at all in the development of the sales agreement to the United States, whether or not we can have that approval?

Mr. Thomson: The export agreements, which is the federal threshold, is the power needed domestically, and if not over the term of the agreement, can it be–is it reasonable for that to be exported and generate export revenue? That's the threshold test that the federal government looks at. We have never had a problem securing those approvals on our contracts, don't anticipate that to be an issue. I believe there's an interest at the federal level to bolster trade, just as the provincial government has an interest in maximizing trade revenue as well. So we–it's a necessary–there are necessary approvals to get but we don't anticipate that we'll have difficulty with that.

Mr. Eichler: When we were talking about the cost of the Minnesota line, you had stated that there was 600–Minnesota cost was $676 million of which we would be paying 54 per cent of that, roughly $365 million. So we own the line, is my understanding, because we have 54 per cent of the cost of that.

***** (17:20)

Do we maintain the line? Do we retain ownership of that line? And, if the deal goes south with another customer down the road, do we have the ability to negotiate contracts on that line with other states in regards to transmission of hydro through those lines? I know it's three questions in one, but I'd like clarity on it.

Mr. Thomson: We're finalizing the ownership model or the contribution model. Ultimately, it looks like we will make a contribution–analogous to a contribution in aid of construction on the project. We will control the use of the line. We'll have transmission rights on the line. We have arrangements like that in place on the existing US transmission system that we use to move our–move energy to market and–just like our customers make contributions toward our capital costs–so it hasn't been finalized. It looks like–but for tax reasons and for managing risk around those elements of the project, looks like we will have a contribution to that and we'll have transmission rights in return. We'll also affect–it's a point-to-point transmission line and we control what goes down to the border. No one else can get on the line so we essentially have that over the life of the term of the arrangement.

Mr. Eichler: Under the terms of that agreement, is the cost that Manitobans are paying to build this line calculated in the recovery of that loss–of the line cost–in the rate of return coming back to ratepayers of Manitoba?

Mr. Thomson: The–we've factored the cost of holding that asset in to the economic analysis that we did when we were evaluating alternative development plans, yes, and that had been reviewed by the PUB and it was their recommendation that that project proceed.

Mr. Eichler: So what we're talking with the $355-million cost of the 54 per cent on the Minnesota side and then the cost on the Manitoba side, is Minnesota and Wisconsin picking up the balance of the cost then of the 365 to the 676 then?

Mr. Thomson: Minnesota's picking up the balance of the construction cost, yes. They will hold–they require–in order–they've contracted with us for 250 megawatts of supply and they've also entered into another arrangement with us for an energy sale for another 133 megawatts. So that comprises the balance of the capital cost or percentage of the transfer capacity on the lines. So that's why they're picking up that cost.

We will recover the cost of holding our share of the line through the sales arrangement with Wisconsin and the other deals that we do to utilize the additional capacity of the line.

Mr. Eichler: So the expense that Minnesota's putting out, how do they get their money back for the investment?

Mr. Thomson: They'll include that in rate base and they'll recover those costs from their customers.

Mr. Eichler: The line that–you know, and I appreciate the minister and your staff, of course, and you joining us last Monday on the corridor of which you're looking at the various alternatives, and we know that there has been some concerns in regards to the route. On the US side, who determines what crossing would be determined to be used so that the Manitoba line connects up with it? Who makes those decisions? Is it the province–or the state of Minnesota? Is it the US government? Who makes those decisions?

Mr. Thomson: Well, both utilities. We've zeroed in, as we discussed last week, on a number of alternative sites and then we–between us, we agree on the preferred one that we want to move forward. And then we each have our respective regulatory requirements to get the approval for the final route selection. But we're–we ultimately are both applying to be able to connect.

Mr. Eichler: So what stage is that at at this point, then, in negotiations with the United States on the power grid and us as a province?

Mr. Thomson: I would have to–I'll have to undertake to get back to you on where exactly we are on the timelines on both sides. As I'd indicated in the presentation, we're looking to go through our third stage of public consultation on the final route selection starting in January of next year. So it's not imminent, because we still have work to do on that.

Mr. Eichler: The consultation process, as we all know, is very important. We know that on Bipole III, you know, there was a number of years and days and months and weeks that took part into negotiating that, and we're still a ways away yet on it. Part of that process is going to take some time, of course.

What's the anticipated timeline before Manitoba Hydro will make that decision after your public consultation and the feedback from them in regards to getting a environmental licence to move forward and start building that line?

Mr. Thomson: For the Manitoba-Minnesota line, I believe that we're expecting to commence construction in 2017. I can get the specific dates for you.

Mr. Eichler: The consultation process, we know that, through the presentation, there was a number of meetings that was held. Winter months is always tough; it's the time when the farmers, of course, have a little more time, you know, and of course the summertime is when they're busy and people are gone for their cottages and so on and the holidays.

What's the anticipated timelines for those public consultation meetings for feedback on that transmission line?

Mr. Thomson: Starting in January of next year.

Mr. Eichler: The development of that line, is it going to be similar to that of what Bipole III is used far as construction's concerned, or will it have a different format?

Mr. Thomson: Well, it's an alternating current line, so it's a–it'll be–it's different technology that's being used.

Mr. Eichler: So the area that's used for transmission, then, is it going to be less of land that's going to be needed to transmit that rather than a DC power line, is or it the same?

Mr. Thomson: I believe the right of way width is approximately the same, and there's 235 kilometres or so of line on the Canadian side.

Mr. Eichler: I know on Bipole I and Bipole II the farmers were allowed to use that land through gratis of Manitoba Hydro. That has since changed. They've been signing contracts with farmers in order to rent that land.

What does Bipole III and the Minnesota transmission line agreements state for those land-owners that are using that land, and what impact will it have on them to use that land if it's farmland or pasture land, hay land, that type of thing? What does that agreement look like that you're trying to move forward in regards to those negotiations with the producers that are impacted by Bipole III and the Minnesota transmission line?

Mr. Thomson: Well, in the case of the voluntary easements agreements, they're easements, so we don't have any issues with the farmers continuing to farm the land around the towers.

Mr. Eichler: The liability, then. Is the farmer responsible for the liability if they're farming around those towers if there's damage to those, or is that the responsibility of Manitoba Hydro?

Mr. Thomson: No, the–as I understand it, if the farmers damage the towers, they would have the liability. They're–we've paid for easements 150 per cent of fair market value. We've paid compensation for the placement of the towers and the lost production for the footprint that the tower takes up. So my understanding is that the liability rests with the party that–if they damage the Hydro asset. They've been compensated upfront.

***** (17:30)

Mr. Eichler: So, in regards to Bipole I and II, then, why the change in policy in regards to leasing that land to them now rather than maintaining the land basically free of charge for Manitoba Hydro, and now they're paying a lease on it? What was the change of attitude there? Why?

Mr. Thomson: I'll have to make inquiries about that.

Mr. Eichler: I had brought this up several times prior to the previous two ministers and now the Premier of Manitoba (Mr. Selinger), and he made a call to Manitoba Hydro when I first brought it up, and it kind of dropped off the face of the earth, and now it's resurrected its head once again, and I know there's been a number of producers that have now signed the contract out of fear and intimidation from the legal gurus at Manitoba Hydro for being placed on land they didn't own. So there is some concern out there. Also, the concern if they don't maintain the land, what that would do to the rest of the crop that they have and leave that with, and who would be responsible for maintaining that.

So it's a significant issue for those producers, particularly on land that's good arable land that still has the ability to produce a crop. So I would appreciate it if you would look into that because I think it's something that Manitoba Hydro should have a look at rather than dictating policy to the farmers, they need to reach out and find out why the change in that policy.

Mr. Thomson: I said I would.

Mr. Eichler: In regards to the benchmark in asset condition, you know, of course, Hydro's been criticized by PUB at the hearings and the Consumers Association not having prepared and submitted benchmarks review of Hydro's operation, when will such a study be available to the Legislature, and why has this not been submitted before?

Mr. Thomson: Well, Hydro does do benchmarking, industry benchmarking, but I'll have to make some inquiries on that.

Mr. Eichler: To your knowledge, or the staff here, can you remember the last benchmark that was tabled in the Legislature?

Mr. Thomson: I don't know. I'll have to look into that.

Mr. Eichler: Hydro has more recently emphasized a need to refurbish and upgrade its existing infrastructure in an effort that the utility forecast to involve an expenditure of $10 billion over the next two decades, is that correct?

Mr. Thomson: I'm not sure what you're referring to, so I'll have to look into that, or if you can provide more specifics.

Mr. Eichler: You touched on it briefly in regards, and I'd asked some questions earlier on that. Basically, what we're trying to confirm is the fact that over the next number of years–in fact, the PUB has brought this forward as well–in regards to the refurbishing of a number of existing facilities. What they're asking, in my own interpretation, not theirs, because I'm not on the PUB as you know, but I think it's important that we know what infrastructure projects, how they look and the methodology used to determine those projects as we go forward. And I think that's what the PUB was trying to get at. So I was just following up on that recommendation from them in that regard.

Mr. Thomson: Understood.

Mr. Eichler: The PUB has long called for a filing of asset condition report that would assess condition of the utility's existing infrastructure, and I know that you have committed to doing that. And the bottom line is reliability, of course, and you've mentioned that several times, and we know how important that is. What was Hydro's last outage experience over the last three physical years where you would have an–have not been able to meet that demand? Has there been any?

Mr. Thomson: Yes, we track–we have a number of indices that we track and report on: frequency of outages, duration of outages. So that information is in the annual report, and it's made available. Our–so, yes, we've been–we've had outages and we can show the historic trends there.

Mr. Eichler: In your presentation–slide presentation, you had talked about staff, and you're anticipating–and some of us are there, baby boomers, and you're planning on losing 900 employees. I wasn't mentioning who was there, but there is somebody there, and, you know, you'd never know to look at me. But what type of a recruitment plan–or is there a recruitment plan to meet those demands? I know you said that it was not part of your plans when you were looking at your 900 staff increment loss due to retirement. Is there a plan in place to keep the staff levels where they are? Are you planning on downsizing or upsizing? What does that look like for the next five to 10 years?

Mr. Thomson: We've been looking over the next three years and our attrition rate's on the order of 300. We've been experiencing about 300 departures a year out of the organization. So, while I refer to there's 900 people eligible for full retirement today, they're not all taking advantage of that.

We've targeted reductions. We're being able to take advantage of that attrition, and over the next three years. So that's part of our cost management plan.

Mr. Eichler: So the number of staff–I forget the number, but I know it's in your presentation–are you–is the plan to keep that level about what it is at this point in time even though you're going to have more lines to maintain and an aging infrastructure? Do you think you're going to be able to do it with the complement that's currently there?

Mr. Thomson: Yes, the adjustments that we anticipate making will–or will–are not across the board, so there will be–we're able to–where we can utilize technology to improve productivity, we can take on more work, you know, that accommodate the growth in the assets.

And I think that it's important to recognize that a lot of the capital work that gets done is done by third parties for us, so we contract to have those assets refurbished. So we don't have to–we're not using our operations people in many respects to do that type of work. So, while that level of activity is going up, it won't necessarily be done by Hydro employees because it doesn't make a whole lot of sense to staff up to address it and then have to staff down when the peak requirement goes past.

Again, over the next three years I could see up to a 5 per cent shrinkage in the overall complement, and it'll depend on how things unfold and how we can harness this attrition as we move forward. We don't anticipate layoffs, and I think because of the level of turnover in staff we can take advantage of that selectively so that we can manage our cost profile as we move forward.

Mr. Eichler: I understand that the PUB has directed Hydro to create an export class and allocate revenues and costs to it. These costs would include operating costs associated with exports and an allocation of fixed annual costs arising out of generation and transmission infrastructure. Is that correct, and if so, how you planning on addressing that?

***** (17:40)

Mr. Thomson: What I can–I'm–we're not working on doing a rate class for export customers because the–we don't have regulated rates for export customers. The contracts that we enter into–the term contracts that we enter into are negotiated. They're–we charge what the traffic will bear. And opportunity sells. We take what the market gives us. There's no utility to creating a rate class around export customers.

Mr. Eichler: So, again, it's hard to determine what the PUB was trying to get at in regards to that classification. So is there different types of classification other than the export market that we've been looking at or been mandated to follow through the PUB?

Mr. Thomson: We have numerous rate classifications for our domestic customers: residential, small commercial, large commercial, industrial, high-load factor customer. So there are a number of different classes of service. And in its mandate to regulate the rates that we charge, that is the PUB's jurisdiction and they look at cost allocations from time to time on the cost drivers that relate to these homogenous classes of customers or distinct groups of customers.

Mr. Eichler: So, with that in mind and following that same formula, why would it not make sense to have an export class based on cost of those, like the transmission line, the cost of producing hydro. Why would you not want to follow a plan like that? Is it just not workable or why is it not relevant to your business plan? I don't know why that would be a problem.

Mr. Thomson: Well, I guess I'd frame it this way. The–first, we identify the need of and the expected throughput on our system for our domestic customers and we look at, over any period of time, what available firm surplus that we have that's the highest value export product we can have. Customers that can get energy in their peak demand periods and count on it as reliable supply, they're–they–they're willing to commit to long-term or short-term arrangements at attractive pricing. So we–and we know the term arrangements that we have in place when we set rates. So that's a given as reducing the overall revenue requirement from our domestic load and we also anticipate a certain amount of opportunity sales which we build into our revenue forecasts.

We–the PUB doesn't have the jurisdiction to establish a rate for export customers. The export customers are either going to contract with us because it's worth it for them to do it, we can fulfill a need for them and it makes sense for them to enter it into. But the PUB doesn't have jurisdiction or no practical way of establishing a rate that we would charge. We'll charge as much as we possibly can on export sales. We take the overall cost of running the system, reduce the contribution to that that we get from export revenues and then the remaining revenue requirement is what goes into establishing the rate that we charge for our domestic customers, and again, that's something that the PUB reviews each year or at each rate application.

Mr. Eichler: Based on that comment, then, on the export sales what would be our low, not counting spot prices, would we–be around the 3.3 cents, and what would be the high? Would that be around 10 cents, then, for export costs based on past sales and current contracts?

Mr. Thomson: Well, I–all I can disclose to you, because those are commercially sensitive arrangements, is the aggregate revenue that we get from exports and the average pricing. It's disadvantageous to the corporation and our customers to disclose pricing arrangements that we have with individual export customers, you know, and it can be damaging to those customers. They have to get regulatory approval to recover those costs in the rates they charge to their customers, and if we're seen to be getting a really good deal for our customers at their expense, their regulator might disallow costs as being for them to pay. They're paying too much.

So it's–that's the commercial rationale for why that is confidential. They don't want it disclosed publicly. We don't want it disclosed publicly because it could potentially damage our customers' interests and our ability to negotiate arrangements with new customers there–going forward.

Mr. Eichler: Yes, just for the record, I wasn't asking for a 'pecific' case sales or jeopardize any of those deals. I was simply wanting to know, you know, based on your numbers, you know, for your financial report, it went from, just on export sales, 3.7 to roughly 4.1 for revenue generated on the sales to–on export sales. So obviously you got some lows, you got some highs, and I was simply asking, you know, what is our low, what is our high, without implicating any of the deals that you made. Certainly, we don't want to put any of those at jeopardy, but I think it's important to know that we're getting a good value. And I know that spot sales are not included in that, so that's a different calculation entirely based on those sales. And, of course, we know that's a supply that we have built up but not able to use, so I'm not including those into that. I'm including only what we have for contract sales.

Mr. Thomson: It's the slide 32 in the package I think gives you an indication of the existing firm sales pricing, again, on average, and within a range that's–you know, there is some variability of the different contracts around that, but the top line that you see on slide 32 gives you a good indication of current pricing in export arrangements.

What I can tell you is that the pending contracts for future sales that will be delivered from new generation that's being constructed today are substantially higher than that and cover the full cost of production of–and then a contribution beyond that.

Mr. Eichler: Thank you. I appreciate the openness and certainly know the sensitivity of the issue, and we know, as Manitobans, we want to get the best deal we possibly can and, of course, get the best bang for our buck.

We know that Hydro has allowed new high-consumption operations that are providing new jobs to Manitoba and new demands for the cost of new generation and transmission at rates well below what is required to fully fund those costs for the new infrastructure. So, when we see a new business that comes in and starts up in Manitoba and they're going to create some jobs and we know they need that ability, and, of course, we know a number of those companies, we all meet with them. And so what is the formula? How do we determine when that cost or what cost is going to be provided to provide hydro to those new customers in Manitoba and the rate of return at which time we need to get a return on our investment?

Mr. Thomson: Well, I–we don't get a rate of return on our investment. We recover the cost of operating the system from our customers. We have a mandate, a legislated mandate to make supply available to domestic customers, so we don't have a choice. If someone locates their business in this province, we need to meet the load that they'll generate. And so the–if there are incremental facilities, there are certain contribution arrangements or certain types of costs that depending on the nature of the business, that the customers may have to directly reimburse the corporation for. But, in general, to make supply available to them, they become a system customer. So within their rate class, they pay the rate that that class of customers pays.

If the last customer in is the straw that breaks the camel's back and requires us to add a new resource that will cost more than the system average, then we don't charge that customer, you know, a higher rate because they were the tipping point that required us to invest in new supply for them. That gets folded into the overall cost of service and it–over the last number of years, those costs have been distributed at the same–like, cost increases have been–rate increases have tended to be blanket across all the rate classes. It doesn't have to be. That–the PUB has some jurisdiction around cost allocation and can differentiate, but the orders that we've received spread those costs across–new costs across all customers.

***** (17:50)

Mr. Eichler: So the mandate is from the government, then, on these initiatives. The formula that's used based up on that customer, how is that determined?

Mr. Thomson: There are cost-of-service studies done, and, again, it's more science than art, but there's–it's not a precise science. Assumptions have to be made in terms of cost drivers that allocate certain types of costs across different rate classes. For instance, a high-volume billing system that is largely driven by the mass market customers, the residential, small commercial, well, the cost of that–the overall cost of that might not be shared with an industrial customer who has one meter and, you know, and one point on a pro-rata basis based on volume. It might simply–you know, so there's different methodologies employed to allocate those costs, but we periodically file studies with the PUB, and they make determinations of whether those cost assessments or cost allocation studies are reasonable. And then, broadly speaking, they try and establish rates on a cost-causality basis in order to have that class of customers pick up approximately 100 per cent of the costs allocated to them. And, again, periodically they might make adjustments between rate classes to how much of the overall system cost they pick up.

Mr. Eichler: So we're clear on establishing those rates, then. You said it's more of a science than an art, but are those rates set and approved by the PUB, then?

Mr. Thomson: Yes, they are.

Mr. Eichler: Staying on the PUB, they recommended that energy efficiency be extracted from Hydro's responsibility and transferred to a new agency, recognize the apparent conflict of interest that lays with the utility seeking higher load growth, not lower. What's Hydro's response to the PUB's recommendation and, of course, the reasoning that they used? What is the response from Manitoba Hydro?

Mr. Thomson: Well, I think–my understanding is that the government has adopted the recommendations of the PUB and the NFAT report and they're looking at models. They're studying that at the present time. And, as I recall the wording in the NFAT report, it was there may be a perceived conflict of interest there. I think that what I would offer is that, you know, we've been running these Power Smart programs and delivering value to our customers for 20 years or more on conservation programs, and we have a big understanding of our customers and the opportunities that exist. So we have been successful in running Power Smart programs. Ultimately, we don't determine the outcome of the model that might be used going forward. I believe that there's benefits to the corporation continuing to run those programs.

In the NFAT proceeding, there are models out there where separate agencies have been set up. They're typically in jurisdictions that have multiple distribution companies, and, you know, especially in the US where there's local distribution. We have–we supply all of the customers in this province with their electricity. One of the shortcomings in those multi-utility jurisdictions is trying to provide consistency in the programming across–and, again, I think that was one of the drivers why it was adopted in places like Vermont, for instance. We don't have that issue. We can and we do deliver programs consistently to all our customers in a number of areas. So, again, ultimately, we will work with the direction that comes out. We don't make the final determination on that, but I'm hopeful.

I think that there's a lot of synergy for the utility to run those programs and I don't believe that–my view is that there isn't a conflict of interest. It's in our interest to meet our customers' requirements in the most cost-effective way to avoid having to invest in assets and avoid load growth. So I think we can manage that, but as I understand it there's studies being taken by independent experts around that, or there will be, and recommendations made.

Mr. Eichler: Just to follow up on that then, did decide–or demand-side management programs–and of course we've been studying that and you've been studying that in regards to, you know, the Power Smart program. And what we've seen is actually a decrease–there could be a possible decrease by 2028 based on the demand-side program. So what is Hydro doing in order to accommodate decide management in regards to those loads that are going to be actually saved as a result of the demand side? What is Manitoba Hydro's take in regards to cutting back on some of those services and how does that look once we move forward down the road?

Mr. Thomson: Well, we've built in–we've accelerated our plan activity around demand-side management. I referred to it in the presentation. And our targets for savings have been increased substantially, so that creates room in–you know, that creates breathing space and flexibility in our system as we move forward.

In the near term and the timing of when new other sources of energy are required, we can take advantage of that to the extent that it creates additional surplus, to sell the power and generate revenue. It also is a bit of a shock absorber for load that may be lumpy, that comes on the system. You know, you referred to new high-load customers coming in, and there are a number of businesses that we've been in communication with that are considering locating in the province, and that's incremental load–the pipelines and the Energy East project in particular, so we've got Enbridge and TransCanada that are talking about expansion in pumping. If all of their plans come to fruition, that could accelerate the need for new resources by up to five years. So doing more demand-side management is beneficial and can create value for Manitoba Hydro and for our customers.

Mr. Eichler: So the impact, then, for Conawapa, what is that look like following the demand-side management program based on savings and, of course, the return on investment? Do you see that as a problem moving forward on Conawapa?

Mr. Thomson: No, I don't in that we examined a number of different levels of potential DSM, and when we looked at three incremental levels of DSM and the cost-effective programs that are available to us to pursue doing Conawapa, based on the analysis that we did, was still beneficial. Again, there's lots of things that have to happen between now and an eventual project, and a key element to that is securing sales for upfront, to support that project moving forward. In effect, what we'd be looking at is buying down the initial and fixing the initial cost of ownership because an asset that can get built, permitted and built today, in today's dollars and the high depreciation front-end period can be picked up by export customers, for instance. It locks in the cost of that project as our demand grows into it and the domestic need is there for it.

***** (18:00)

Mr. Eichler: I'm glad you brought up the TransAlta pipeline, and I know that when we look at energy projects of any type, whether it be oil or gas, you know, airlines to transportation, they're all very important.

What is Manitoba Hydro's role in–looking at a national grid program across Canada?

Mr. Thomson: Well, we're–we've been–we have ongoing discussions with utilities in other jurisdictions, in Ontario, in Saskatchewan to the west of us, and ultimately there's–the approach that we've taken to it is that we see there will be incremental builds that will increase transfer capacity to initially Saskatchewan, if the opportunities exist, to Ontario to the east of us. They're–to connect long-distance transmission is a big investment. You need to have load to secure that.

So, you know, there's been lots of discussion about well, why don't we build an HVDC line to the oil sands, for instance. Well, that would require a long-term commitment to buy power that would cover all the costs of building new generation and transmission to get it there. But, you know, in that case–and provide a return to the Province if we were doing it on a merchant basis.

So I think that what we'll see, absent a federal-mandated program and federal dollars to support the construction of transmission, we'll–incremental assets will be built to connect supply to load where it makes economic sense to do that.

Mr. Eichler: So that I'm clear in regards to, you know, a national grid program, when we look at–you used Alberta, for example, and the oil sands. So what would have to be the agreement other than just the cost of recovery? Have those discussions taken part in regards to whether or not it's even feasible down the road, or what would that look like in order to make it part of a conversation that–say, Saskatchewan, Alberta and BC, Manitoba–what would that look like if that discussion was to take place?

Mr. Thomson: Well, in my view, in order that–to underpin it, you would have to have a customer, an anchor customer, a utility customer that would be willing to enter into a long-term supply agreement that would cover the full cost of building facilities and a return to whomever's going to build those facilities. Like, it's not in our mandate to build infrastructure on Manitobans' backs to supply energy to Alberta or anybody else for that matter.

That–one of the challenges around Alberta in particular is they're sitting on a pool of energy that–now, it's fossil-fuel based and they use coal and they use natural gas to generate their electricity in the province of Alberta. There'd need to be an incentive for those users or consumers to be willing to pay the cost of new generation and transmission to take it across the country. So whether that ultimately came in a form of cost to carbon or, you know, a legislated mandate or what have you. I don't think the conditions exist today to support it.

Mr. Eichler: I want to come back to Conawapa for just a few minutes in regards to the stages that would take place. At the beginning of your presentation you had stated that roughly $300 million had been invested in Conawapa to date. What are we doing to preserve that investment, and what rate is being charged to Manitoba Hydro customers out of that $300-million expenditure to recoup some of those costs and what steps are being taken to preserve that so that whenever we are ready to move forward on that, whenever that may be–you know, there's been a number of dates suggested, years suggested–so what does that look like for us?

Mr. Thomson: There're a number of parts to that question. I'll try and remember them all. It–and I'll answer them probably in reverse order.

I think that there was some work in progress on developing the project that–around environmental work that we're concluding. We're finishing up some engineering study work and we're in a sense winding it down, but winding it down in a way that it can be put on the shelf and we can pull it back off the shelf. So we're also continuing to do environmental monitoring around it because that work, I think, is necessary even in the event that we didn't move forward with the project. But it will certainly be helpful having that data as if the project is–goes further into development.

We're not recovering the costs previously invested in–to date, you know, in the initial generation of Conawapa that was shelved and then the current development of it. I–we're not writing it off. We're not depreciating it. We're not recovering it in our rates from customers. We are effectively servicing the debt on it. It's hard to match the dollars, but if you look at our overall capital structure, currently about 75 per cent at 25 per cent equity. We don't charge an equity return to the projects, but the cost of debt service, that's in–the interest cost on the project is–we're accruing it. We're paying it, but that is accruing to the project. So we're not recovering those costs from customers, either.

And if, you know, over some extended period of time, we're hopeful, because we–the river's going to be there. The generating potential will remain there, and my hope is that as we move forward and we do the integrated resource planning work and the broad public consultation that was recommended in the NFAT report and we continue to talk to our prospective US customers and Saskatchewan in particular who we've got a memo of understanding for up to 500 megawatts of supply over the long term because they've got needs to–that they need to replace, as well, that there will be a sales base to support the business case to move forward on that.

So we're not writing it off and we're not charging the cost of carry currently to our customers. That's not in rates. If at some point it–we determine we'll never develop that, then when we would look at, likely look at what we have often done or what utilities traditionally do if a project that's in development looks like it can't move forward, then you amortize that into rates over a period of time and you recover the cost. So that's a long-winded answer, but that's what we're doing on it.

Mr. Eichler: Is there any agreements or licensing that will be impacted by the cancellation of Conawapa at this time that's going to have an impact on the rates for ratepayers in Manitoba, say it be a First Nation community, Clean Environment Commission, any of those licensing agreements or agreements that would be a cost to Manitobans or would be put at risk by stalling the Conawapa project?

Mr. Thomson: No, I think the–there'd be lost opportunity if the project–there's some windows in and some regulatory cushion, if you will, built into the agreements that we've currently signed that would be dependent on Conawapa in order to deliver the supply. Like, there was the 308-megawatt extension sale to Wisconsin Public Service that commences in the '20s. If that, you know, if we don't get the project built and in service, I think it's by 2030 or 2031, then they're not obliged to, you know, they can walk away from that sales commitment. So they're not, you know, they're not locked in forever. If we can't deliver–like, they–the reason why they're entering into agreements is to meet their long-term needs. If–at some point in time, they've got a walk clause on that. So it would be a lost opportunity.

***** (18:10)

So, again, you know, it's probably going to take 18 months to go through a comprehensive integrated resource plan process. We're continuing to talk to them. We're hopeful that the conditions will be right 18 months, two years from now. The assumptions will play out.

But what we're not doing right now is we're not doing detailed engineering work. We're not doing–we're–we've turned the tap off to those types of expenditures in–and respecting the NFAT recommendations that the Province adopted. So we're winding up–winding down programs so that we can preserve the value of the study and the engineering work that we've done and we can mobilize it again. But, again, that will become stale dated at some point in time. Like, it'll have to be refreshed and–but, hopefully, that, you know, we'll be able to work within the next couple of years and the conditions will be right to move forward.

Mr. Chairperson: Order, please. It is now 6:11 p.m. We agreed to revisit our activities at this point in time. What is the will of the committee?

Mr. Eichler: Let's sit 'til 8 and we'll review it then. I'll turn it over to my colleagues here for a few minutes and I'll reorganize my questions, and, hopefully, we can try and review it at 8 o'clock and have another review at that time.

Mr. Chairperson: Mr. Eichler has suggested 8 p.m. Is that agreeable to the committee? *[Agreed]*

Mr. Blaine Pedersen (Midland): Over the course of the afternoon, there's been a few things brought up, and I would just like to come back to a couple of these, if I may. Earlier you spoke about legal costs to northern First Nations and you talked about a reimbursement policy. Is this policy–are you able to supply or provide me with this policy? Is it something that you have that we could–that you could send to me and so I could review it?

Mr. Thomson: Our reimbursement policy is on the public record, so that can be supplied.

Mr. Pedersen: And it will be supplied in a timely manner, I would assume, Mr. Chairman.

Mr. Thomson: Yes.

Mr. Pedersen: Thank you.

Another question relates to Bipole III. Is the surveying complete for the entire line?

Mr. Thomson: I believe substantially so, yes, including the final route adjustments. I believe so, subject to check.

Mr. Pedersen: So would you just check on that and, in particular, Crown lands. We've had this discussion over the summer about Hydro on private lands, but I'm particularly asking about Crown lands, if the surveying is complete on there.

So another item, and it relates to recently Moody's investment downgraded the Province's credit rating–

Floor Comments: No.

Mr. Pedersen: –adjusted the credit rating. How does this affect–Manitoba Hydro is looking to borrow a great deal of money in the next number of years in their development plan. How will this affect the Crown corporation's borrowing and repayment?

Mr. Thomson: Moody's didn't downgrade the Province's credit rating. They changed the outlook from stable to negative, I believe, so we have issued debt subsequent to their report. Moody's is one of three rating agencies that opine on provincial credit, and it hasn't impacted our access to the debt markets, and there's been no discernible change to the credit spreads on provincial debt.

Mr. Pedersen: So it hasn't–obviously, it hasn't affected to date, but going forward, do you expect it to affect your cost of borrowing?

Mr. Thomson: No, I don't. If, based on this new–based on this report, typically, borrowing costs change if credit ratings are downgraded, and that hasn't taken place.

Mr. Pedersen: I'll move on to–if I was to say the cost of bipole will be built into the price of product being sold to the customers south and to the west of us in the future, it will be paid by the customers, not by Manitoba ratepayers, would you agree with that statement?

Mr. Chomiak: Just–I'm–can the member kind of–is the member indicating his personal opinion? Is he quoting something? To throw out a statement and ask someone whether or not he agrees with him, it's not exactly what the purpose of this committee is, Mr. Chairperson. Can the member at least quote where he's getting that quote from? It may be that I have to answer the question.

Mr. Pedersen: I said that, and I–do you want me to repeat it? If I said that, would Mr. Thomson agree with that?

Mr. Chomiak: Yes, I think Mr. Thomson already referred to that in answers to his response to the member Mr. Eichler. That question's already been asked and dealt with, so can we move on because there's a lot of people that want to ask questions of this committee, and Mr. Thomson's already answered that question.

Mr. Pedersen: Well, Mr. Chairman, perhaps I missed his answer. Could he repeat his answer now?

Mr. Thomson: I was going to say, could you repeat the question, please?

Mr. Chairperson: I'm sorry. I didn't hear that, Mr. Thomson.

Mr. Thomson: Could you repeat the question, please?

Mr. Chairperson: Mr. Pedersen, to repeat the question.

Mr. Pedersen: If I was to say the cost of the bipole will be built into the price of the product being sold to the customers to the south of us and to the west of us in the future, it will be paid by the customers, referring to customers south and west of us, and not by Manitoba ratepayers, would Mr. Thomson agree with that?

Mr. Chomiak: As I understand from previously asked questions by Mr. Eichler, that matter was canvassed. But I think it's my understanding that the customers pay for everything in Hydro. And that's why we have a Public Utilities Board. That's why you have decisions made by the Public Utilities Board. So it seems to me like a redundant issue raised by the member, which has already been canvassed previously.

Mr. Pedersen: I just asked, does the–does Mr. Thomson agree with that statement?

Mr. Chomiak: Again, with all due respect, this is not a question of opinion of whether Mr. Thomson or whether a Hydro president agrees with an opinion offered by the member. The member has his opinion. The president's entitled to a fact, to answer facts, not opinions. That's actually part of our parliamentary procedure.

Mr. Pedersen: So will Manitoba ratepayers be paying any portion of the Bipole III line?

Mr. Thomson: Yes, they will, just like they pay for all of their other assets that are installed to serve their needs.

Hon. Jon Gerrard (River Heights): Mr. Thomson, the estimated cost of the Bipole III at one point was $2.2 billion, and then it was $3.3 billion, and we've heard recently that it's now $4.6 billion. Compared to $2.2 billion, that's missing the target by $2.4 billion. That's the largest missed estimate that I'm aware of in the history of Manitoba.

Floor Comment: No, no.

Mr. Gerrard: I'm telling you that it's the largest one that I'm aware of. Now, you may be aware of others, and you can–*[interjection]*

Mr. Chairperson: Order, please. Order.

The questions should be addressed through the Chair, and I don't want to have a debate amongst members off the record, so Mr. Gerrard has the Chair to put his question.

***** (18:20)

Mr. Gerrard: I think it's pretty important for all of us because those initial estimates need to be close to what the real numbers are, and that, in the future, because, I mean, we're having debates in the Legislature about what those estimates are and what the planning is and what the alternatives are, what measures are–is Manitoba Hydro taking to make sure that in future, estimates come in closer to the mark?

Mr. Thomson: I made reference to it in my comments, but we've developed a more robust estimating procedure. The estimate–the prior estimates were done quite some time ago, and, as I understand, the in-service date for bipole in the original estimates was assumed to happen sooner. So, with the passage of time, their inflation gets built into costs, and so that is a cost driver, and the level of definition of the project at the time and the scope of the project is different now than what is was at those times. So I've–you know, we've identified the drivers, the main drivers for the change from the estimate that was produced in 2011 and what we're calling our control budget now that we're building to and the level of both precision, definition of the project and risk assumption in terms of entering into contracts with companies that have committed to pricing and building within a timeline. That exists at this time. You know, we're–we've permitted the project. We're in construction. We've done clearing. The major contracts have been–so there's a higher degree of certainty because of where we are in the project with the control budget that we're building to.

Mr. Gerrard: From my understanding, this missing the estimates for projects happened with the Wuskwatim dam, and, in fact, one of the results was that the partner, right, the equity partner, NCN, Nisichawayasihk Cree Nation, right, has been put in a pretty difficult position because of the final number ended up a lot higher than the initial number. And my understanding is you're going back and renegotiating that and trying to work that out, but they're not as–you know, they don't have the deep pockets that Hydro does and the ability to borrow in the same way, so it puts them in a really, really difficult position.

Now, in the situation with the Keeyask dam, what approach has been taken with the four First Nations so that they're not put in a similar situation as NCN has been put in with the changing cost of Wuskwatim?

Mr. Thomson: We're–yes, the–well, the arrangements that we've negotiated with the Keeyask partners are different. We've learned from experience, and Keeyask is a bigger project, so there are a couple of potential options in the way that their partnership interest or their ownership interest could be structured. And, similarly, as we've learned from the Wuskwatim project, we're–if as in when we get back to negotiating a project development agreement with the five First Nations partners on Conawapa, it will look much different as well.

The risk tolerance of our First Nations partners is different, and their capacity to assume real commercial equity risk is not the same as the company or–you know, so we're not looking at a equity ownership interest in Conawapa. We'd be looking at something that provides upside potential for them and a benefit based on the production of the facility, which is much different than the scenario that we've got with NCN. And, again, it's–we've learned from experience. We're not locked–and we're not locked into a model for that. The size of the project is much bigger. The–you know, if a similar model on Conawapa to Wuskwatim would require on the order of eight or nine hundred million dollars of equity to be put in by the First Nations. Well, they don't have access to eight or nine hundred million dollars of equity. So we're not considering that. It's just not workable, it's not realistic, and, hence, they're–the reward potential won't be as great, but the risk that they assume, they won't assume anywhere close to the level of risk, they'll be–they'll benefit to the extent that the production from the facility is higher and they'll–they won't do as well if it's lower. So there's skin in the game, if you will, from that standpoint, but it's–we have learned from our experience.

Mr. Gerrard: On the issue of demand-side management, Manitoba Hydro has come under a lot of criticism in the last little while for not progressing in the way one would expect in terms of demand-side management targets, and one of the critics was Mr. Dunsky, who wrote a report and, you know, I have a copy of a figure here. I can share this, Mr. Chair, if that's of interest. But, basically, what it shows is that Manitoba Hydro, in terms of the target for savings as a percentage of demand, is way below, you know, a whole host of other jurisdictions in terms of their demand-side management targets. And I know that you've already spoken about the need to improve it. What I'm asking is, you know, what's your current goal in terms of your savings as a percentage of demand, presuming that you've moved it up from what it was earlier on, which was about 0.5 per cent?

Mr. Thomson: At a high level, I can tell you that the most recent plan that we've put forward would meet 84 per cent of our load growth over the next three years.

Mr. Gerrard: Would that continue on beyond the three-year time?

Floor Comment: We wouldn't be able to–

Mr. Chairperson: Mr. Thomson, I apologize.

Mr. Thomson: The overall component wouldn't be quite as high. There's diminishing returns on programs over time.

Mr. Gerrard: Yes, some jurisdictions have found that they've been able to maintain or even increase demand savings, so that may or may not happen depending on, you know, what happens.

One of the technologies which has been developed, put forward, in fact, by Mr. Dennis Woodford, was this compact line technology, where you could put the–have the capacity to take the amount of power going through Bipole III and put it through compact lines, which would be potentially run along a road. Now, you had referred to earlier, some technology that would go along a road, but that apparently is different from this compact line technology because the compact line technology, first of all, has less problems with lightning because there's not as much of a–they're not as tall, right, and so that you have less likely for them to be hit by lightning to start with. They also have less problems with wind because, again, they're not as tall. And, apparently, the outages, according to Mr. Woodford, you know, with the current Bipole III, there may be, I don't know, millisecond outages or what have you, with lightning strikes. But this would be very similar with compact line and very different from the, you know, what you were describing before with the problems of lightning strikes with some other type of line.

***** (18:30)

So I'm just wondering what you have–Manitoba Hydro has done in terms of looking at compact line technology and how it can be applied to, you know, Bipole III and helping farmers and so on.

Mr. Thomson: Actually, I was referring to compact HPDC lines when I made my earlier remarks, and we have looked at that and it's incompatible with the system. And the shielding is ground shielding on those lines. It's not shielding above the lines and which is why it's susceptible to lightning strikes. They've estimated that we would have 150 outages a year if we adopted that technology for Bipole III. The–instead of four towers per mile, we'd be looking at 12 to 16 towers per mile so that the footprint, albeit they're shorter towers, there's a lot more of them.

So, from a cost standpoint, we don't–my understanding is that the work that we've done, there wouldn't be an expected savings, and the reliability benefit wouldn't be there because it would be subject to a great number of outages during the storm season where lightning occurs. I'm not an engineer, but that's the information I've been given.

Mr. Gerrard: I'm not an engineer either, but Mr. Woodford felt that there was some concerns with, you know, how you had presented it and I will let him respond in due course, in whatever fashion he chooses.

The–one of the things that you referred to is the need to replace approximately 120,000 wood poles, and the International Brotherhood of Electrical Workers have, you know, been front and centre in saying that their people have the capacity to do this. The–but there's concern that this may be contracted out to some organization out of province. What's going to happen with the–who's going to be doing the replacement of those 120,000 poles?

Mr. Thomson: That is a program that will take place over the next decade. All the decisions haven't been made on that, but we're looking at optimizing the utilization of our existing staff and there's some benefits to entering into contracts with other Manitoba organizations to do that work and not taking away from the skills. Planting poles, replacing poles isn't particular high skill, so the grand plan has not been evolved. We continue to work with the IBEW on resourcing plans.

Mr. Gerrard: I think that you mentioned in the presentation that there had been something like 173,000 sturgeons stocked in, I presume, the Nelson River. There's a fair amount of concern that that dam, Conawapa or Keeyask, may interfere with the movement of sturgeon and may have a really detrimental impact on the numbers of sturgeon and on the ability of the sturgeon which have been stocked to survive. I wonder if you would comment on that.

Mr. Thomson: Yes, I mean this was a subject of extensive discussion at the environmental hearing, the CEC hearings and was built into the licensing conditions of the project. So we've got protection plans in place. We've got the sturgeon stocking program and the monitoring program, and we're mandated to monitor that over 50 years for its efficacy. So I believe that we have plans in place to deal with and address that and the work that we're doing with the–I forget the exact name of it–but the joint committee around sturgeon. So we have measures in place that should protect the sturgeon and, in fact, enhance the recovery of the sturgeon.

Mr. Gerrard: Yes, in the most recent Manitoba Hydro report of–there's a reference to the fact that there were contracts to Manitoba companies of $675 million.

What's the amount of the contracts to non-Manitoba companies, just as a comparator?

Mr. Thomson: I don't have that at my fingertips, but I can–we can find it. I can provide it for you.

Mr. Gerrard: I wonder if we could put that on the record as something that could be followed up. Thank you.

You mentioned earlier on in your discussion that in the spot sales to the United States that there was an increase from something like $22 to the high 20s, and I wasn't sure what that was referring to. That's not a cents per kilowatt hour, but it's–maybe you could–*[interjection]*

Mr. Chairperson: Mr. Thomson.

Mr. Thomson: Per megawatt. So the average–our average revenue per megawatt on opportunity sales, and it was on the slide–the graph over–from about 2005–I think it was on page 32.

Of course, my version of the slides is so small, I can't see it. But it's–that's the growth since 2012 to 2014, the average revenues from opportunity sales.

Mr. Gerrard: In the most recent annual report, one of the things that was reported was that the residential sales were $606 million and that the kilowatt hour that that represented was 7.9 billion and that would be an average cost for residential customers of 7.7 cents per kilowatt hour. That would compare with what the average out-of-province sales is about 4.2 cents per kilowatt hour. So residential customers are paying almost twice, not quite, but almost twice, what power is being sold for out of province.

I just want to make sure that I've got the calculations correct: Is that right?

Mr. Thomson: Subject to check, I think you're right, because it's the volumetric charge for the energy, plus there's a base–there's a fixed monthly charge. But you're comparing the wrong customer classes. The–a residential customer class drives cost differently than an industrial customer class, which is as close to an analogous customer group as wholesale export customers. And we don't, you know, we charge 3-ish cents to–3 to 4 cents to our industrial customer classes, depending on whether they pay demand charges and the total volume and demand.

Mr. Gerrard: I appreciate the difference in customer, but most Manitobans will just think about, you know, what they pay versus what, you know, out-of-province customers are paying.

But my question really focuses on this, that with the shale gas situation in the United States, which I'm sure Manitoba Hydro is monitoring, it's been responsible in part for keeping electricity generation costs low in the United States, and is it expected, based on the still very large reserves of shale gas in the United States, that the costs will continue to be low for quite some time in the North American market?

Mr. Thomson: Yes, the five-year outlook trends up, based on the consensus forecast that the industry produces. That's a lower outlook than it was a few years ago. So while it's–it increases over time in real terms, the–it's from a lower starting point. And I think that's indicative of the supply situation.

There's a couple of things that I think that will influence that because it changes every year. The five-year outlook changes every year. We've got the EPA announcement that's going to drive reductions in generation from coal on an accelerated basis. We'll see that have to–that production have to shift to something, and a lot of it's likely going to be natural gas.

***** (18:40)

I also see more and more development, certainly in the plans, for export terminals for LNG, and I referred to that earlier. I think that has the potential to create more than a continental market for natural gas, which, I mean, Europeans are paying $14 a gigajoule for, Asians are paying, you know, the Japanese are paying 12 to 13 dollars currently for natural gas. So we've got locked-in commodity in North America. As outlets are created for that, that has the potential to create, you know, significant push on those costs.

I mean, the benefit, the flip side to all this is that heating costs for Manitobans have been quite reasonable over the last few years, so it's not all bad news, but it does impact our export pricing, and it certainly has in recent years.

Mr. Cliff Graydon (Emerson): Does–has Manitoba Hydro done a current impact assessment if one of the bipoles were to go down, understanding that the summer is your high risk with extreme weather, so that's actually your low load on the lines, it's not the peak time of the year for power? Have they done a current impact assessment? You talked about rolling outages and so on and so forth; in the wintertime, I wouldn't disagree with you, but in the summertime it's a little bit tough to understand.

Mr. Thomson: Yes, we have. The short answer is, yes, we have. And you're quite right. Our system peak is a winter peak, and demand is lower in the summertime than in the wintertime because we've got a heat load component in the wintertime, but we're still–we would still be short if we lost the bipole in the summer.

Mr. Graydon: So, in that situation, we have an agreement to source power from other sources like the United States?

Mr. Thomson: We have the capacity to import power, and we have–we–the–we export our power–the demand is high in the US, in our US markets, in the summertime. That's their peak because they have a cooling load component in the Midwest market. So we have high demand there, but we do have the ability to bring power in on–like, import power over the US transmission lines.

Mr. Graydon: Do we actually import any power? And I'm thinking more specifically of the wind farms in North Dakota. We know that Manitoba and North Dakota have some of the best winds for wind power in the world. Obviously, there's no storage capacity for that, and it may not be that they can utilize it all when they are producing it. Do we import some of that power?

Mr. Thomson: Yes, we arbitrage that power, so we–oftentimes we are paid to take power and we'll take it at night and we'll hold back water and then we'll generate and sell back into the US market during the daytime when it's more valuable.

Mr. Graydon: So how are we paid for that? Are we paid for that in exchange for what we're selling them, or is it a cash payment?

Mr. Thomson: It can be all of the above. We have certain arrangements where–financial arrangements where, prospectively, we'll provide some storage benefits to US customers so that they can take advantage of or store wind power, but we–that produces a revenue stream for us as well. So it all speaks to how we can optimize the system and take advantage of the benefits of hydro storage, and, again, we–if–it works to our advantage if we are in a position to take power when it's very cheap. A lot of–and it's not just wind; it's must-run facilities in the US. Coal plants can't be turned off and on on a dime, so if they–and the electrons have to go somewhere, which is why pricing can be negative, i.e., we can be paid to take power at certain times of the day, and we do, and because of the nature of our system, we can ramp our production down when that–when we're being paid to take power and use it domestically. And then that stored power that we've got, we can turn around and sell it when it's more valuable. And we're not the only Canadian hydro jurisdiction that does that, but it's a benefit of hydro.

Mr. Graydon: Do–does Manitoba Hydro, then, when they're spilling the water and we're taking power from United States, do we pay for that water that we're spilling and the generating that we're not doing, even though the water is–the water's going, I mean, we pay–Manitoba Hydro pays for water. Do we pay for what we could generate?

Mr. Thomson: No. We pay water rentals on power production.

Mr. Graydon: The impact, the environmental impact of 'keesiak,' can you speak to that? Is there any concern of any of the environmentalists about the impact?

Mr. Thomson: Sorry, which?

Mr. Graydon: The environmental impact of 'keesiak' on the environment and on some of the–like sturgeon, for example, or caribou. Has anybody voiced a concern about that?

Mr. Thomson: Did you mean Keeyask? The Keeyask?

Mr. Graydon: I'm sorry, yes. Sorry about that.

Mr. Thomson: Well, yes, there was an extensive hearing on the environment as it relates to the project and licensing conditions placed on the project which were, you know, and which we're complying with. So, unchecked, there would be impacts, and we've developed programs to mitigate the effects of that on the environment.

Mr. Graydon: What types of programs have you developed?

Mr. Thomson: Specifically, there's a sturgeon enhancement initiative that's under way. We got a stocking program and a monitoring program, and we're looking to not just maintain but actually positively recover the stocks of sturgeon in spite of the construction of the facility. So there's–that's one example of that.

Mr. Graydon: Where do you get your product of stock sturgeon?

Mr. Thomson: We run a hatchery at Grand Rapids.

Mr. Graydon: Have you got any data that would indicate the success rate of stocking?

Mr. Thomson: I believe all that information was filed in the Clean Environment Commission hearing, yes.

Mr. Graydon: I can't seem to find that, but I do know that the wildlife organizations in Minnesota have been stocking the Roseau River for a number of years now with a huge, huge number of sturgeon with, I'd hate to say, no success, because of the low, slow growth rate of the sturgeon. But we do know that the sturgeon did access that Roseau River; that's where the largest sturgeon in Manitoba was caught. In fact, it was caught on my father's property.

But we know that the success rate is not great, and so what happens if, in fact, that success rate doesn't work and a stocking program doesn't work, and how do we keep the sturgeon from becoming extinct, and how do you answer to the bands that are involved in a situation like that?

Mr. Thomson: As I said, the licence conditions require us to stock and monitor, and if they're ineffective, to develop new measures.

Mr. Graydon: So, then, you have some adverse effects agreements?

Mr. Thomson: Yes, we do.

Mr. Graydon: Can you explain to me what those are?

Mr. Thomson: Well, we entered into adverse effects agreements with the Keeyask partners. Those–what we attempt to do is mitigate the effects of our projects, so they're multifaceted. They–at the design stage, they look to avoid the potential effects of projects; where we can't avoid them, to enter into offsetting programs, that sort of thing. If, for instance, during construction, if it disrupts the flow, if it was expected to disrupt the travel of animals that are hunted by the band, we might put a program in place where we assist hunters or trappers to move to areas where they can trap, for instance.

***** (18:50)

And then in–and there can be monetary compensation for unavoidable effects and those have been negotiated and agreed to with the partners.

Mr. Graydon: From what I can read in the report is the monetary contributions will be ongoing for the life of the project for three of the partners. One partner is limited to 2025.

So we really don't know what the cost of that will be at any point now, do we?

Mr. Thomson: I believe we've costed that out and we've provided for it in our financial statements.

Mr. Graydon: The pipelines in Manitoba are built on private property. Manitoba Hydro owns two bipoles and are now signing agreements for the property that they own.

Do you think it would be fair that they, Manitoba Hydro, pay tax the same as the pipelines do?

Mr. Thomson: Well, Manitoba Hydro is a Crown corporation and doesn't pay taxes–pardon me?

Mr. Graydon: The question was, should they pay a tax?

Mr. Thomson: Well, I mean, that's really not for me to dictate government policy. But we pay other resource rents, so.

Mr. Graydon: You suggested that Manitoba Hydro could find efficiencies by attrition in the system, that there would be 900 jobs that wouldn't be filled.

Can you guarantee that the services will still be maintained?

Mr. Thomson: I actually said that we've got 900 people that are eligible for retirement and that we're looking to harvest some of that to manage our costs going forward. It's our goal to maintain services and, in fact, where we can, enhance them.

Mr. Graydon: You alluded that–alluded to the fact that you would be–that overtime would be cut back in travelling, and so on and so forth, and yet you've closed a number of offices or proposed to close a number of offices throughout rural Manitoba.

How do you answer to the people that are going to be in the dark for four, five, six hours by the time people get there, where before, they were there? And I can see that your colleague sitting behind you is laughing, but the fact is it's a–that is a reality that is happening and has happened out there when someone has to drive from Manitou to Woodmore–*[interjection]*

Mr. Chairperson: Order, please. Order, please. Mr. Graydon has the floor.

Mr. Graydon: So the question is, how do we maintain–or what do you consider a reasonable time that someone should be out of power?

Mr. Thomson: Actually, what I can tell you is that in the period since we initiated the rural office closures, and for those towns, our actual outage performance and our duration has improved by about 10 per cent on both.

So it's–the reason–we can better manage the utilization of the resource, and we're responding, on average, quicker to those. There's going to be outliers, but the statistics, the data that we've tracked, indicate that our performance has improved.

Mr. Graydon: I would suggest that that's a self-assessment, but at the same time I don't have all of the facts to dispute it, but I do know that there has been some fairly serious outages and there's been some serious wait times.

I have one more question. Will Bipole III be paid for by export sales?

Mr. Thomson: I believe that's been asked a couple of times. Export sales will go to reduce the overall cost of service for Manitoba Hydro's system, and our domestic customers pay for the residual of the system. So Bipole III will be paid for by Manitoba customers just like Bipole I and II are, just like the distribution lines in towns are. We need the asset to serve our Manitoba customers and they will ultimately pay for it.

Mr. Chomiak: I appreciate the chance to ask a few questions after five hours of questions, and I know the member is a little bit embarrassed by the last line of questioning, but that's fine.

I wonder if Mr. Thomson can tell us what rate of consumption is hydro growing a year in Manitoba. That is, how many megawatts do we need every year to go forward in Manitoba?

Mr. Thomson: Our load forecasts suggest that, prior to demand-side management programs, our demand is growing about 80 megawatts a year.

Mr. Chomiak: We've heard a lot about fish and we've heard a lot about water rental rates and we've heard about various comparisons and we've heard the members to suggest we should be making profits on Hydro. We know what members want to do with Hydro, but the question I think that's really salient to Manitobans is, can you again repeat who in Canada has the lowest electrical rates in the country? Which top–which two provinces have the lowest electrical rates in the country and intend to in the future?

Mr. Thomson: Manitoba and Quebec.

Mr. Chomiak: Now, recently there's been an outage–it's been my understanding in this–in the field that transmission is a significant issue. Stranded assets is huge around North America and the ability to transmit power is extremely important. Recently, there was an outage on a pipeline that provided power to rural Manitoba. Can you indicate to me how long the power was out and what was the ramifications of a pipeline disruption on infrastructure and how it affected that community?

Mr. Thomson: Just point of clarification. Are you talking about the Otterburne, the TransCanada incident? Our gas service was disrupted to about 4,000 customers for about four days. We were fortunate in that backhanded way that it was as cold as it was because we were in a position to overload our electrical system and provide enough energy through that so those customers could keep some heat in their homes and avoid the pipes freezing.

Mr. Chomiak: And Bipole III's built–is being built to back up Bipole I and II because in–as I understand it, in 1996 or '97 there was a breakdown in the system, and potentially an outage of the system could cost Manitoba a billion dollars–is it week or a day for an outage in our system?

Mr. Thomson: I understand that the estimates have been on the order of a billion dollars a week to GDP.

Mr. Chomiak: I know that some of the members were with me when we were in the United States recently for committee hearings and heard how impressed the Americans were with the delivery of hydro service and hydroelectricity from Manitoba. In fact, there's a quote today from someone in the United States saying that Canada's a clean energy leader and that three quarters of our energy is renewable and clean, and that quote came from the climate change conference in New York, and the quote was from the Minister of the Environment for Ottawa, Mrs. Aglukkaq, and she was talking about hydro.

And I wonder if you might talk about, just briefly, of the advantages of having the battery operation hydro and the wind transferred between United States and Manitoba and how that functions to help both and how that fits in with President Obama's plan for clean energy.

Mr. Thomson: I guess one of the benefits that we speak to when we go to the US and we talk to US regulators and–is around the fact that we can assist the US in meeting their renewables requirements. Wind is intermittent, solar's intermittent, so you need some firming energy in order to–some supply to back it up when the wind's not blowing or the sun's not shining, so hydro complements it very well.

***** (19:00)

We've integrated a couple–250 megawatts of wind in our system, and, as I was talking to previously, the wind often blows at night when the US doesn't need it. So having the capability to, in effect, store that wind by taking it and utilizing it in the system and holding water back and then flowing it, we can enter into an exchange agreement with US utilities that have wind on their system so we don't have to build wind, we can take advantage of their wind and vice versa.

Mr. Chomiak: So some of these issues we're talking about today have gone through public hearings, they've gone through the CEC hearings, they've gone through PUB hearings, they've gone for NFAT hearings, through all experts of which Hydro's paid millions and millions of dollars for consultants to provide independent–dozens of independent reviews, and they've all suggested we go ahead with Keeyask. Am I correct in that assumption, Mr. Thomson?

Mr. Thomson: Well, yes, we've gone through extensive reviews, and everything that we're building has been permitted and licensed.

Mr. Chomiak: Just a final question. One of the things I think that's really good about having a Crown corporation like Manitoba Hydro is not only is it a good corporate citizen and not only does it not make profit and works–keeps our rates low, but they do things like equalizing rates between urban and rural Manitoba. Now, do you know how much money urban–pardon me, rural Manitoba has saved since the equalization process was put into place with respect to Hydro and which is why the rates are equalized in rural Manitoba? Do you know how much money has been saved?

Mr. Chairperson: Order, please.

Mr. Thomson.

Mr. Thomson: I'd have to take an undertaking to give you that. No, off the top of my head, I don't.

Mr. Eichler: Back to real questions, not comments. But what is the status of the two converter stations on Bipole III?

Mr. Thomson: Well, we've–we're about to sign a contract for the supply of the converter stations' equipment and related buildings with Siemens Mortenson. We made the announcement last week that we had selected them and we've been working with them. I anticipate that the contracts will be completed early next month.

Mr. Eichler: So the Riel Converter Station, walk us through what that's been used for. Is it–my understanding is the Bipole III is going into Dorsey station first and then–*[interjection]* It's going into Riel first? Walk us through it, then, so I don't embarrass myself any more. Obviously the–what's the purpose of the Riel station and the Dorsey station in regards–and what costs is going to be impacted as a result of the Riel station?

Mr. Thomson: Okay, the–they're–Riel has two elements to it: (1) We're sectionalizing–independent of Bipole III–we were sectionalizing the–and building a ring system around the greater Winnipeg. So all of our northern supply terminates at Dorsey and exists to supply the–from that one location. So what we're basically doing is building multiple points of entry anchored at the Riel station, so there's switchyard–switchgear there, and that project's been ongoing for a couple of years and is substantially complete. It will also be the southern terminus of Bipole III, so it will be–it will come in and come around the south of the city into Riel, it will connect to this ring system so that we've got redundancy in the system as well. And the–we already have the existing 500 kV line to the US that comes out of that side, so we're–we will terminate the new US transmission line from Dorsey.

Again, we've got multiple backups, we're creating a situation with multiple backups, so we've–site prep's been done as part of the initial project to sectionalize, so that's work that's already complete, and it's in a greater state of advancement of site prep at, then, the Keewatinoow converter station site up north, which is the northern initiation point for Bipole III.

Mr. Eichler: Thank you for that clarification. Mr. Chairman, in regards to the northern converter station and the Riel station, are those converters included in the cost of Bipole III at the $4.6 million?

Mr. Thomson: Yes, they are.

Mr. Eichler: So the anticipated costs, the way it stands right now, is 4.6, including those two converter stations. Is that correct?

Mr. Thomson: That's correct.

Mr. Eichler: In regards to the cost on Keeyask, then, if I'm remembering correctly, it's around $6.5 million. What assurances have we in place and what was the last time those costs were looked at and when will they be looked at again?

Mr. Thomson: Those were reviewed and updated as part of the NFAT proceeding this spring, the Keeyask project cost, so it's a live current estimate.

Mr. Eichler: So, as we move forward, in 2020, when the switch comes on, if all goes well–and we know that past history has a tendency of repeating itself, and Oxford University has done a number of studies on cost on dams–are we fairly confident in the $6.5-million figure, that it's going to be awful close, because past history has shown us that it's usually double, not all the cases, but a number of cases? So I think that Manitobans want to be assured that we are fairly close in this estimate, at least at this point. And what would come about to make those changes get outside that $6.5-million figure?

Mr. Thomson: Yes, I believe that we're–again, we've got a high degree of confidence. The PUB had hired Knight Piésold, an independent consultancy with expertise in this area, to review our costing methodology and the work that we did around the estimates for both Keeyask and Conawapa. Their assessment was that they were world class, and we've also–again, you know, we've got a general civil contract in place, and the same–the lead contractor on that consortium, Bechtel, was the lead on Limestone. We had success with that. They actually brought it in under budget and on time, so we've got the risk resting with the appropriate parties in terms of the major contracts on Keeyask.

So we are working to–we're calling that our control budget. We're working towards that, and the gentleman on my right is going to hold me to that, and I'm holding my executive team to that. And we–I created an executive position and brought in someone from the outside to lead and oversee the major capital projects, including Keeyask, Bipole III, Pointe du Bois, so that it has that focus. It's not fractured across the organization.

Mr. Eichler: Is there a penalty clause incorporated into the contract for deadline–time deadlines, and is there protections in the contract to prevent us from having cost overruns?

Mr. Thomson: Yes, there's risk sharing. In the various different contracts, we've got risk sharing components and incentive arrangements to encourage and cost-share overruns. They're not all–it's not cookie cutter across the board, but we've got mechanisms in place in a number of the major contracts.

Mr. Eichler: In regards to one of the questions was asked by the member from Emerson, and you had mentioned about the trapping and relocating some of those trap lines, what is the methodology used to establish compensation for those and what basis do you use to determine how successful or unsuccessful that trap line was? How does that roll out, and what organizations do you deal with? Is it just the First Nations communities? Is it the Metis? Walk us through how that looks.

***** (19:10)

Mr. Thomson: Yes, we're–we've negotiated arrangements with trappers. It's based on provincial production records and the, you know, the–some of the negotiations are alive right now, but what's–what it's based on or predicated on where there's been a permanent diminution in the production. What we've done is we've looked at what they produced over a period of time, what the commercial value of that is, and that has been offered up in exchange for.

Now, in certain circumstances, the trapping market–or the market for certain types of furs collapsed in the '80s–but, for instance, around the Grand Rapids project. So we looked at the reduction in production post based on the provincial tracking–the production records that were kept prior to and post the initiation of the project over the period of time until the market fell apart, and we offered compensation on that basis.

Mr. Eichler: Are the Metis a part of that negotiation for compensation on traplines?

Mr. Thomson: Not exactly. Many of the trappers were Metis.

Trapping is a commercial activity. It just so happens, in one of the settlements, the lead negotiator happened to be the president of the Manitoba Metis Federation, but he wasn't acting in his capacity as the leader of the MMF. He was just acting in–on behalf of all the trappers in the group. They weren't all Metis. There were non-Aboriginal, non-Metis people that were trapping as well, and they were all offered compensation if they were impacted.

Mr. Eichler: Just to follow up on that just a little bit more, then. Some of the contracts or the traplines that were negotiated earlier on, how many of those are still outstanding?

Mr. Thomson: My–I don't want to–why don't I provide you our estimate of the outstanding? It's on the order of about 1,500, I believe, that–remaining trappers that we need to deal with.

Mr. Eichler: Just one last question on that. And thank you for agreeing to get that to me.

Is it transferrable from one generation to the next generation, as far as compensation, for a provider of a family who will no longer be able to provide for his family through a trapline–for his siblings to be able to take advantage of that in order to provide for their families?

Mr. Thomson: Different arrangements–over time, that–the arrangements have evolved. I will have to get back to you on that, but my recollection is, subject to check, that provided that the descendants of a trapper could demonstrate that–at least in one of the settlements, could demonstrate loss, that they were entitled to that person's share. Now there might be five kids, so it would be distributed amongst the family, then.

Mr. Eichler: Thank you, and I appreciate that and look forward to the information.

The compensation based for organizations, municipalities, community development, how much money has flowed and what is the budget for that to move forward? And when will that compensation be paid to the organizations and municipalities?

Mr. Thomson: Our budget for that is $6 million a year. Three point nine million–we've entered into arrangements with a substantial number of the eligible communities, and about $3.9 million has flowed.

Mr. Eichler: The $6 million per year, how many years is that eligible for compensation, then?

Mr. Thomson: The plan–the arrangements that we're signing are 10 years and subject to review at the end of 10 years.

Mr. Eichler: The municipalities or organizations that don't sign on, is there an appeal mechanism for them to come back on, or how is that settled in regards to value for compensation for those municipalities that don't feel they're getting a fair value? What does that look like as far as an appeal mechanism and fair value for that particular municipality or organization?

Mr. Thomson: I think it's important for me to point out that these aren't compensation payments; they're–one of the, you know, one of our objectives was to ensure that benefits were provided broadly from the project. And so, by and large, the municipalities have been quite happy to be able to participate in the program, and so they're–you know, and we're providing a period of opt-in. The first two years of the program if–we're giving people time to sign on–

municipalities, I should say–to sign on, or communities.

And we anticipate that–we anticipate they all will, because it's in their interest to do so. But it's–we're not providing compensation for impacts–negative impacts, so there really isn't an appeal mechanism; it's a gift to use–to be blunt. So.

Mr. Eichler: How many municipalities have yet to receive compensation or have not agreed to the 'compensensation' program?

Mr. Thomson: To date, 55 communities have signed on. There are 17 more eligible.

Mr. Eichler: Thank you. I appreciate that.

In regards to administrative expenses, they have rose by over $9 million from 2010 to 2011 to $472 million, while your net income has gone down $89 million to $61 million. Can you explain what had happened there and why the administrative costs have escalated?

Mr. Thomson: Well, yes, the–we–about 70 per cent of our operating costs are labour based. We have negotiated labour settlements in place that provide for annual increases; there are varying terms and maturities. But approximately 2.75 per cent labour inflation on 70 per cent of our costs, so, overall, over the last five years, our control of the LO&M has risen at less than the rate of inflation; I think it's about 1 and a half per cent over that period. So that's a key driver, and those costs are largely fixed. They're–our revenues, as I'd talked about earlier, fluctuate–can fluctuate dramatically, dependent on weather. But, actually, our earnings have increased, not gone down in over–successively over the last two years.

Mr. Eichler: In regards to energy intensive industry rate, is there any indication that Hydro will be bringing forward a program within the next five years in regards to that initiative?

Mr. Thomson: We're continuing to evaluate that. We had brought some proposals forward to the PUB, and they deferred looking at them at the last GRA. But, yes, we'll be looking at rates as we move forward, for industrial customers.

Mr. Eichler: What is the detailed analysis that you go through in order to establish that program, and what are the timelines to bringing that initiative forward? You know, when we think five years, is that real–a realistic timeline in order for that to come about, or is it a longer term proposition? What do we have to go through to get that established?

***** (19:20)

Mr. Thomson: I referred to it a little bit earlier in terms of what typically will underpin a change in rate classifications is a cost allocation study, and we'll be, you know, we'll update cost allocation analysis that we'll file with the PUB, and it–historically, I think it's been periodically. It–they don't address it at every rate–general rate application. But, periodically, the PUB will examine that. And we–they have deferred looking at that in–the last time we brought it forward. So, again, it's a matter of doing the prep work and the analysis on it, and filing it. Generally, we'd expect to file it with the rate application.

Mr. Eichler: I want to take this opportunity to thank Hydro staff, of course, for your indulgence. I know it's been a long afternoon, and I appreciate the opportunity to be able to bring these questions forward. And we've been calling for a Hydro committee for a while, and I thank the minister for allowing us to meet and do that.

And I think it's important–taking the politics out of it. I know that we're all in the best interest of Manitobans. We believe that a strong Hydro and a strong Crown corporation is beneficial for all Manitobans. And we want to just make sure that we as opposition ask those questions, even though they may be a bit sensitive. I thank you for your indulgence and the other members of the committee.

I know it's getting late, but we're prepared to move on. I don't know if there's any more questions from my side, but that concludes my questions for this evening.

So thank you very much.

Mr. Chairperson: Seeing no further questions, shall the Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2001 pass? *[interjection]* 2011–correction. Shall it pass? Sorry, allow me to repeat the question. Take my glasses off, too, here.

Shall the Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2011 pass?

Some Honourable Members: Pass.

Some Honourable Members: No.

Mr. Chairperson: I hear a no.

The report is not passed.

Shall the Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2012 pass?

Some Honourable Members: Pass.

An Honourable Member: No.

Mr. Chairperson: I hear a no.

The report is not passed.

Shall the Annual Report of the Manitoba Hydro-Electric Board for the fiscal year ending March 31, 2013 pass?

Some Honourable Members: Pass.

An Honourable Member: No.

Mr. Chairperson: I hear a no.

The report is not passed.

As the reports have not passed, I please request that the members leave those copies of the reports on the table for future meetings.

This now concludes the business before us.

The hour being 7:23 p.m., what is the will of the committee?

Some Honourable Members: Committee rise.

Mr. Chairperson: Committee rise.

COMMITTEE ROSE AT: *7:23 p.m.*

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