MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

COST OF SERVICE STUDY REVIEW

HEARING

Before Board Panel:

Marilyn Kapitany - Chairperson

Larry Ring, Q.C. - Board Member

Hugh Grant - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

September 7, 2016

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1 APPEARANCES

2	Robert Gabor, Q.C.	)Board Chairperson
3	Bob Peters	)Board Counsel
4	Dayna Steinfeld	)Board Counsel
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6	Odette Fernandes	)Manitoba Hydro
7	Janelle Hammond	)
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9	Byron Williams	)Consumer Coalition
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11	Denise Pambrun	)City of Winnipeg
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13	Bill Gange	)Green Action Centre
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15	Christian Monnin	)GSS/GSM Group
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17	George Orle	)MKO
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21	Terrance Delaronde	)Manitoba Metis
22		)Federation
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24		
25		

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LIST OF EXHIBITS

1 --- Upon commencing at 9:02 a.m.

2

3 THE CHAIRPERSON: Good morning,

4 everybody. Ms. Fernandes, are you ready to go? Oh,

5 Ms. Hammond. Pardon me.

6 MS. JANELLE HAMMOND: Good morning,

7 Madam Chair, Board members Grant and Ring. In

8 accordance with Order 84/'16, Christensen Associates

9 Energy Consulting will be presenting its positions on

10 key issues for oral evidence today.

11 I would like to introduce to you the

12 consultants from Christensen Energy Associates, Mr.

13 Michael O'Sheasy -- he's just walking in -- and beside

14 him is Mr. Robert Camfield.

15 The CV and witness qualification

16 submissions of Mr. O'Sheasy and Mr. Camfield were

17 submitted pursuant to Order 84/'16, and they were

18 qualified as expert witnesses as described in the

19 Board's August 25th, 2016 letter. Manitoba Hydro

20 notes that the CVs have already been marked as

21 exhibits, MH-66-1 and MH-66-2.

22 Manitoba Hydro would like to mark the

23 presentation of Christensen Associates as an exhibit

24 for this oral proceeding. And I believe that is MH-

25 76.

1 --- EXHIBIT NO. MH-76: Presentation of
2 Christensen Associates
3
4 MR. KURT SIMONSEN: That's correct.
5 Thank you.
6 MS. JANELLE HAMMOND: Thank you. I
7 know that these witnesses were sworn in during
8 the Manitoba Hydro workshop, so I will proceed to ask
9 Mr. O'Sheasy a few preliminary questions.
10
11 MANITOBA HYDRO PANEL 2:
12 MICHAEL O'SHEASY, Previously Sworn
13 ROBERT CAMFIELD, Previously Sworn
14
15 OPENING COMMENTS BY MS. JANELLE HAMMOND:
16 MS. JANELLE HAMMOND: Mr. O'Sheasy,
17 was --
18 MR. MICHAEL O'SHEASY: Good morning.
19 MS. JANELLE HAMMOND: Good morning.
20 Was Christensen Associates responsible for the
21 oversight and preparation of the report titled,
22 "Review of Cost-of-Service Methods of Manitoba Hydro",
23 dated June 8th, 2012, filed as Appendix 5 to Manitoba
24 Hydro's Cost-of-Service Study review submission?
25 MR. MICHAEL O'SHEASY: Yes.

1 MS. JANELLE HAMMOND: As well as it's
2 supplemental report dated August 10th, 2015, filed as
3 Appendix 2 to the same submission?
4 MR. MICHAEL O'SHEASY: Yes.
5 MS. JANELLE HAMMOND: And does
6 Christensen Associates need to make any corrections to
7 either of those reports?
8 MR. MICHAEL O'SHEASY: No.
9 MS. JANELLE HAMMOND: Thank you. So I
10 think we're now ready to proceed with Christensen
11 Associates's presentation.
12 THE CHAIRPERSON: Thank you, Ms.
13 Hammond.
14
15 PRESENTATION BY CHRISTENSEN ASSOCIATES ENERGY
16 CONSULTING:
17 MR. MICHAEL O'SHEASY: Good morning,
18 Madam Chair, and Board members, and all participants
19 in this proceeding. I'm sorry I'm a little late. I'm
20 from the south, and it's true, southerners are slower
21 than folks up north, but I'm here.
22 My colleague Robert Camfield and I
23 shall provide our observations this morning on the
24 four (4) major subjects of this hearing. And if I can
25 work this clicker, I'm going to present first, then

1 I'm going to turn it over to Robert, and he will
2 present two (2) of the major four (4) topics here.
3 My presentation is going to be concern
4 -- number 1, I'm going to talk about our role,
5 Christen (sic) Associates' role in this cost of
6 service proceeding. And then the two (2) topics that
7 I'm going to speak to are the treatment of exports,
8 including the number of export classes and cost
9 allocation to those classes, and then I'm going to
10 talk about net export revenues, often termed NER, N-E-
11 R, and how that should be treated.
12 Okay. First off, the purpose of
13 Christen (sic) Associates Energy Consulting and why
14 they were retained was to provide an independent
15 assessment of Manitoba Hydro's cost allocation methods
16 as presented within the perspective Cost-of-Service
17 Study. It's commonly called PCOSS.
18 This review was conducted using
19 accepted costing theory in North American electric
20 utility practices. We had three (3) major
21 deliverables in this process. Number 1 was a 2012
22 report in which we provided comments and
23 recommendations, some of which Manitoba Hydro agreed
24 with, some of which they did not.
25 The report also provided an overall

1 assessment, concluding that -- that accepted costing
2 theory was used and all the methodologies were within
3 industry norms and reasonally -- reasonably determined
4 the cost of providing service to the various rate
5 classes.
6 Secondly, we provided a supplemental
7 report in 2015 which further addressed three (3)
8 evolving and provocative issues, those being export
9 sales, transmission cost allocation, and generation
10 cost allocation.
11 And finally, the third deliverable that
12 Christensen provided in this effort is participation
13 in several stakeholder workshops and this current
14 hearing.
15 Now, for those of you who are -- may
16 have a hard copy in front of you, I've excluded the --
17 my third slide for the sake of expediency. The first
18 issue that I'm going to talk about is the treatment of
19 exports in terms of number of customers and the types
20 of sales, and cost allocation within PCOSS.
21 Now, as we heard yesterday, there are
22 basically two (2) types of export sales, you know,
23 what we call opportunity sales, and these opportunity
24 sales are of short notice, short duration. They're
25 when water conditions permit in excess of dependable

1 energy sales, these are non-firm sales and they're not
2 backed by Manitoba Hydro resources.
3 And as we've heard yesterday,
4 opportunity sales may have an influence along with
5 other factors in the technology choice for new
6 generation. Dependable sales, however, they're longer
7 in duration. They're longer in notice. In other
8 words, how long it takes before they begin.
9 They are served under low water
10 conditions. These are firm sales, and they originate
11 from Manitoba Hydro resources which we term dependable
12 energy resources. They can able advancement of new
13 generation to take advantage of markets for dependable
14 sales.
15 Now, the reason that the export issue
16 of the number of classes and the allocation matters,
17 why it's a big deal, is that it impacts the revenue
18 cost ratios differently for different rate classes.
19 Now, to demonstrate how these definitions of export
20 classes and allocators, how they impact RCCs, I'd like
21 to discuss three (3) possible ways in which we can
22 treat export sales.
23 Remember, we have two (2) classes. We
24 have opportunity and we have dependable. Now, one (1)
25 way to do it would be to treat the two (2) types of

1 sales separately. Opportunity sales would receive
2 variable cost allocation. Dependable sales would
3 receive variable and fixed-cost allocation. So that's
4 one (1) way.
5 Another way you could do it is you
6 could allocate variable cost and fixed cost to both
7 opportunity and dependable sales. And a third way to
8 do it would be to allocate variable cost only to
9 opportunity and dependable sales.
10 So we'll now proceed to the next slide
11 where we'll see some numbers. Now, these numbers are
12 not Christensen computations. They were extracted
13 from discovery that Manitoba Hydro had provided
14 through this process, and we've just repeated them
15 here. So don't -- and -- and I would also sug --
16 suggest don't take these numbers as gospel in that
17 they are based on major assumptions.
18 You change the assumptions, you change
19 the numbers. But they do give a good feel for
20 direction, and that's what I wanted to point out here.
21 These numbers will indicate how the -- the percentages
22 change and to -- to what degree.
23 The first column there represents the -
24 - an allocating fixed and variable cost to -- based
25 from your generating and transmission functions to

1 dependables only. So once again, you take your --
2 your fixed and your variable generating and
3 transmission costs and allocate those to dependable
4 sales only.
5 You allocate variable cost to
6 opportunity sales. So that would be scenario 1.
7 Scenario 2 is the second column. That would be you
8 allocate fixed and variable generating and
9 transmission costs to both dependable and opportunity
10 sales. So in this case, dependable and opportunity
11 are getting both types of costs, fixed and variable.
12 In the third column over there, we're
13 only going to allocate variable cost to these two (2)
14 types of sales. So opportunity and dependable sales
15 will get variable cost only. Now, let's just look at
16 the first row to exemplify what we're talking about
17 here.
18 If you did it based on the first
19 assumption where you split it such that dependables
20 get fixed and variable cost, opportunities get
21 variable cost only, you can see the residential RCC
22 there is about 100 percent. It's about 99.9 percent,
23 and all that's saying is that the revenues we get from
24 residential customers are pretty much covering their
25 allocated costs. Probably a good thing.

1 Then if you move over to the next
2 column where we take fixed and variable cost and
3 allocate them to both dependable and opportunity
4 sales, it drops the residential's RCC, revenue cost
5 ratio -- or coverage, down to 98.3 percent. Now,
6 these percentage changes many not appear great in
7 terms of percentages, but they move big dollars.
8 There is a big dollar impact by moving one (1) basis
9 point, for example.
10 The third column over there says, Okay,
11 what happened with residential when you allocated
12 variable cost only to both dependable and opportunity
13 sales? Well, in that case there, the residential RCC
14 went up to 101.7 percent. So some could argue that
15 favoured residential with an RCC greater than 100
16 percent.
17 Now, the point of this slide is merely
18 to indicate that the class -- the num -- the -- the
19 class treatment in the allocators matter in terms of
20 developing RCCs, inconsequential or eventual revenue
21 requirements for each rate class.
22 Now, some likely factors to consider in
23 deciding the PCOSS treatment of exports, very
24 importantly, a cost. And exports do influence
25 Manitoba Hydro's cost. For instance, they cause

1 variable costs to be incurred. Variable costs would
2 be stuff like water rentals, variable O&M, losses,
3 things like that, but they also can influence fixed
4 cost. For example, dependable sales are known to
5 advance in-service dates. So that would be a fixed
6 cost impact.
7 Also, as we heard yesterday, for recent
8 technology installations, new hydro, opportunity sales
9 along with other factors can influence the type of
10 technology that's used in that new generation.
11 The next thing I wanted to point out
12 that many ut --
13 THE CHAIRPERSON: Excuse me, Mr.
14 O'Sheasy.
15 MR. MICHAEL O'SHEASY: Yes.
16 THE CHAIRPERSON: Can you clarify what
17 you mean when you say, "the type of technology that's
18 used?"
19 MR. MICHAEL O'SHEASY: Yeah, I sure
20 can.
21 THE CHAIRPERSON: And the whole thing
22 we're trying to get at here really is cost causation.
23 And so if you can put it in that framework between the
24 two (2) types of exports you're speaking of.
25 MR. MICHAEL O'SHEASY: Sure.

1 Utilities, when they have a need for new generation,
2 and that need is often times encouraged by growth on
3 the systems, kilowatt hour sales and so forth, they
4 look at the different technologies that are out there
5 to serve that.
6 Now, for simplicity sake, let's imagine
7 that Manitoba Hydro needs to add a new generating unit
8 in the year twenty thou -- 2023, they got to add 500
9 megawatts of new technology. Well, let's just
10 simplify it and say they've only got two (2) choices.
11 They could build a combustion turbine or there's a
12 hydro site up north where they could build a new dam
13 facility and generate it that way.
14 Well, what Hydro's going to do is
15 they're going to think through -- or at a hydro site,
16 number 1, tremendous fixed costs but very low running
17 cost and it has a lot of benefits to it, clean energy,
18 for example. It has water rental, revenue for the --
19 for the Province. More than likely, it -- it -- a lot
20 of the power from it initially can be sold export and
21 those export revenues can come in and reduce the cost
22 of serving domestic customers.
23 So that's one (1) type of technology.
24 Now, the other type of technology that they -- they
25 would consider in my simple example of combustion

1 turbines, and they can -- they can fit the amount of
2 cust -- combustion turbines to the load need in 2023
3 pretty closely.
4 If it's 500 megawatts, they could build
5 500 megawatts of CTs pretty easily. But when they
6 build a hydro unit, hydro units, because of their
7 technology and the topography that's required, more
8 than likely the hydro unit is going to be quite a bit
9 more than the 500 megawatts that's needed immediately
10 and the load for domestic will grow into that load.
11 But in the meantime, before it grows
12 into it, the excess hydro capability will be sold off
13 system. It'll be sold as dependable sales to other
14 utilities in the south. Those revenues will come into
15 Manitoba and lower the cost of serving domestic
16 customers.
17 So those are the two (2) types of
18 technologies in my simple example. Now, eventually,
19 Madam Chair, they will go into PCOSS. If it's the
20 year 20,000 -- 2023, they'll go into a PCOSS study if
21 they had one in that year. Now we've got to allocate
22 those costs out, and we will to the domestic classes
23 based on the generation allocators that we have.
24 Manitoba Hydro uses what's called
25 weighted energy to allocate out generating cost to

1 their domestic classes, so they'll have relatively
2 small fixed costs for combustion turbines that they'll
3 allocate back to the domestic class. But they'll also
4 have relatively large fuel costs to run those
5 combustion turbines that they'll allocate to the
6 domestic classes.
7 Or in the case of -- if it's a Hydro's
8 choice, technology choice, they'll have huge fixed
9 costs that they'll allocate back on weighted energy
10 and no fuel costs. Now, that's the way it's -- the
11 cost of those technology choices will be distributed
12 to the domestic classes. But some of it will also be
13 distributed to export sales.
14 We will -- we will require that export
15 sales pay for some of the cost to that new generation.
16 And you -- we'll have to make a choice, for example,
17 and we talked about this yesterday. We'll have to
18 make a choice.
19 Those fixed costs, whether it's
20 combustion turbines or hydro units, are we going to
21 allocate them to the export class based upon all the
22 sales we made, opportunity sales and dependable, or
23 are we only going to allocate those fixed costs to
24 dependable sales and just allocate relatively small or
25 variable costs to both classes?

1 So that's a long-winded way of -- of
2 trying to describe a complex issue. But those are the
3 -- when I talk about technology choices, it's which
4 choice you use to generate your future need.
5 And then once you get -- you get that
6 as a plant in service, how do you allocate it back,
7 and why that export responsibility that you've
8 allocated to it, how that's done.
9 But because this is owned by the
10 province, whatever earnings that come out of those
11 export sales, we're going to send those back to our
12 domestic customers to their -- for their benefit. And
13 that's what we call NER, and I'll get into this
14 shortly.
15 BOARD MEMBER GRANT: Just while we're
16 interrupting you --
17 MR. MICHAEL O'SHEASY: Quite all
18 right. Sorry, Robert.
19 BOARD MEMBER GRANT: -- on slide --
20 I've got it eight (8) in the hard copy, but the last
21 column where you present variable -- variable costs
22 only, this is strictly for illustration, I take it,
23 because I -- if I just listen to your description of a
24 Hydro dam as this lumpy, large investment good, then
25 dependable sales are -- at least dependable sales are

1 heart and soul of the calculation whether to go ahead
2 with the -- to make that investment, right? So it's
3 part of --
4 MR. MICHAEL O'SHEASY: Right.
5 BOARD MEMBER GRANT: -- the planning
6 process for --
7 MR. MICHAEL O'SHEASY: Correct. Yes,
8 sir.
9 BOARD MEMBER GRANT: So would it be
10 fair to say the description you just gave of the
11 investment decision of a hydro dam would sort of
12 preclude that third column from our consideration?
13 MR. MICHAEL O'SHEASY: Well, it would
14 on the surface, but I -- I wasn't as thorough in my
15 explanation as I should have been. What's happening
16 here is we're going to allocate out just variable
17 costs to the export class in that last column there.
18 Now, the revenues for exports aren't
19 going to change. They're the same, okay? So let's
20 pretend we've got a hundred dollars ($100) worth of
21 export revenue, and let's say fixed costs, if I had
22 allocated them to ex -- exports, they'd be eighty
23 dollars ($80). But variable cost is ten dollars
24 ($10), okay? Just -- just some round numbers.
25 So in that last case there, I've a

1 hundred dollars ($100) worth of revenue coming in from
2 export sales, and only ten dollars ($10) worth of
3 variable costs. So that gives me a ninety dollar
4 ($90) NER, net export revenue. But I'm going to take
5 that and send it back to the domestic classes to lower
6 their cost of service, okay?
7 So it's a zero sum game. Whether I
8 allocate dependables -- excuse me, whether I allocate
9 fixed costs to exports or fixed costs and variable,
10 the domestic class is going to enjoy the benefits of
11 those export sales.
12 But the trick or the reason that it
13 matters is the way in which we allocate cost does not
14 match exactly the way that we allocate that NER. And
15 that's why it affects classes differently. That's why
16 you saw this change in that last column is different
17 from the other columns.
18 Okay. Let's see. Which slide -- oh, I
19 wanted to demonstrate -- I'll try to do this quickly
20 because I've got to save Robert some time. I want to
21 demonstrate that this idea of export classes and
22 treatment it's common throughout the industry.
23 This is a very busy slide here. Turn
24 your attention please to that greyed column, that
25 greyed-in column on the -- the far right which is

1 called Wholesale Sales. This is a PCOSS study for
2 Georgia Power Company. It's for the year 2012.
3 You'll see their export sales in that last column
4 there.
5 And what they would have done is they
6 would have put their revenues for exports up -- up
7 front. That's on line 35, last column. It's roughly
8 $569 million. And they would then allocate fixed cost
9 on their equivalent dependable sales and variable
10 costs to their dependable sales, but only variable
11 costs to their -- to their opportunity sales.
12 Now, I would like to also point out to
13 you that if you go down to line 53 and you go to that
14 last column there, you'll see roughly -- roughly $73
15 million. That's the equivalent of their NER. They
16 don't call it N-E-R, but that's the equivalent of
17 their NER.
18 And that last line there, all that is
19 is rate of return. Rather than measuring the
20 performance of rates and covering costs with an RCC,
21 they look at it in terms of rates of return.
22 Now, on the next slide, I just wanted
23 to demonstrate to you that they too have opportunity
24 sales. They happen to call them economy sales. So if
25 you look at lines 9, 10, and 11.

1 MR. ANTOINE HACAULT: Sorry, for a
2 very brief int -- interjection, but I'd just like to
3 know where these slides are found in the evidence, or
4 is this new evidence?
5 THE CHAIRPERSON: Ms. Hammond, did you
6 want to address that?
7
8 (BRIEF PAUSE)
9
10 MR. MICHAEL O'SHEASY: This particular
11 slide is just illus -- illustrative of --
12 THE CHAIRPERSON: I think Ms. Hammond
13 is going to -- sorry, Mr. O'Sheasy. I think Ms.
14 Hammond is going to deal with this question.
15 MR. MICHAEL O'SHEASY: Oh, sorry.
16 MS. JANELLE HAMMOND: I was just going
17 to indicate, yeah, this is an illustrative example of
18 some information that was introduced at the workshop.
19 So it's not new evidence. It's just an example of
20 evidence that was already provided.
21 MR. MICHAEL O'SHEASY: Okay. So all I
22 was indicating on lines 9, 10, and 11, is these
23 economy sales are their equivalent of opportunity
24 sales.
25 All right. Now, so the issue on the

1 table is whether to consider, first off, exports as a
2 separate class. And it seems like listening to the
3 discussion yesterday, all parties agree that exports
4 should be considered a separate class, and we also
5 agree to that.
6 And we agree to it for a number of
7 reasons. Number one is the sheer magnitude of the
8 export sales. Two, we feel like having an export
9 class it reveals the importance of export sales to
10 Manitoba Hydro and it also demonstrates that exports
11 influence resources and cost by having exports as a
12 separate class in Cost of Service.
13 Now, we recommend -- so Christensen
14 Associates recommends that there be separate cost
15 allocation for the two (2) types of sales.
16 Opportunity sales we recommend would receive variable
17 cost allocation due to the reasons that we've put down
18 there, short sales notice, they're non-firm, they're
19 not backed up by Manitoba Hydro resources, they occur
20 only after dependable sales have been satisfied.
21 These -- opportunity sales, they do
22 have a history too and they're likely to continue, but
23 it doesn't change the nature of the product in each
24 opportunity sale contract, which is of short duration.
25 And bottom line, they're of lower

1 quality and status than a dependable sales in the
2 marketplace. Now, dependable sales we believe should
3 receive variable cost and fixed cost allocation.
4 The sales are much longer, of a much
5 longer notice and duration than an opportunity sale,
6 they're based on long-term contracts, and their
7 revenues of -- are of more certainty. The firm sale
8 is provided by Manitoba Hydro's firm energy resources
9 and they're of a higher quality status than
10 opportunity sales.
11 All right. Now, I'm going to switch
12 gears quickly and talk about NER, N-E-R. Now,
13 remember NER is the residual of all export sales after
14 subtracting off the assigned cost in PCOSS. But --
15 and this NER that you end up with is trad -- is
16 traditionally allocated back to the domestic rate
17 classes.
18 Now, an important point that I want to
19 point out here is that there's really no cost
20 foundation to NER. NER originates from revenues that
21 come from a competitive market. They're -- they're
22 bidded out based on supply and demand.
23 The -- the costs that are allocated to
24 exports has all -- has already been removed. So
25 what's left over is a pot of dollars that we'll call

1 it super margin. It's the difference between what
2 those sales could command in the competitive market
3 minus the embedded cost of providing that via PCOSS.
4 So what we did in our reports is we
5 provided several -- half a dozen different ways that
6 you could indeed allocate NER back to the domestic
7 rate classes. However since there's really no cost
8 foundation to this NER, and there's really not a
9 single objective basis for how you allocate it, I
10 think there's some that are worse than others, but we
11 didn't see any compelling reason to make a major
12 change in the allocation of NER from what Manitoba
13 Hydro has been traditionally doing based on total
14 cost.
15 So what I've discussed, and we'll turn
16 it over to Robert now, but what I have discussed is we
17 do recommend that exports be treated as a separate
18 class in PCOSS. We do recommend that dependable sales
19 get fixed cost and variable cost allocation treatment,
20 and that opportunity sales get variable cost
21 allocation. And finally, we didn't see any -- any
22 compelling reason to change the allocator for NER back
23 to the domestic classes from what it has been.
24 So with that said, I'm going to turn it
25 over to Robert.

1 BOARD MEMBER GRANT: Can I ask -- I
2 ask all the naive questions, so. I thought you were
3 building up to an explanation of why, the logic to the
4 N-E-R, why isn't it allocated on a -- on a basis
5 equivalent to how costs are allocated?
6 So if -- if you and I were sharing a
7 house, and I was paying two-thirds of the rent, and
8 then we got a -- say a property tax rebate, I wouldn't
9 want to split it with you 50:50. I would argue that,
10 you know, I should get my share of that sort of
11 windfall revenue based on what I was contributing to
12 costs.
13 So -- so I -- I remember an argument
14 about, you know, different classes are bearing a
15 certain amount of the risk in the export market, and -
16 - and if that's the case should it be treated through
17 the allocation of revenue or treated through the
18 allocation of cost?
19 MR. MICHAEL O'SHEASY: M-hm.
20 BOARD MEMBER GRANT: So in other
21 words, if -- if I'm bearing some particular risk then
22 -- then that should be reflected on the cost side and
23 maybe on both. But I guess I'm -- sorry for the long
24 question.
25 Why aren't they equivalent? Why -- why

1 aren't the cost of service measure and the allocation
2 of revenue the same?
3 MR. MICHAEL O'SHEASY: Right. And we
4 tried to deal with this in our -- our reports that
5 came out early. In our first report where we gave
6 half a dozen different ways to allocate NER back, one
7 of them would be an attempt to look at the costs that
8 -- that functionally enables exports to be made, okay.
9 Another one was just -- strange enough
10 is just what you were talking about, is risk. Let's
11 pret -- and -- and if I can describe it in my own
12 words, let's imagine that export sales were to fall in
13 half, or go away. The cost don't go away. The
14 revenues do but the cost to Manitoba Hydro of all
15 those hydro units, they don't go away. So who's
16 bearing the risk for that?
17 Well, obviously all of your domestic
18 customers are bearing the risk of -- of that. Some
19 more than others though. It would impact the RCCs of
20 some classes more than other classes if those export
21 sales were to go away. It wouldn't be a pro rata risk
22 sharing, and that's kind of what you're getting at.
23 Could you allocate the NER on a risk
24 basis, and we put that into ours, but our conclusions
25 were because NER is -- it's -- it's beyond cost.

1 We've already taken all the cost out of it. It's the
2 super earnings that we got from this export market.
3 There's really not cost basis to it.
4 Now, you can logically conclude that
5 what's the -- what in my mind is the best way to do it
6 is based on the risk that the -- the cust -- rate
7 classes take on with export sales, and do it that way.
8 And there's nothing irrational about that. There's
9 nothing illogical about that.
10 But I don't think there's anything
11 illogical about the way they currently do it now,
12 which is -- I would term in a fairness type of
13 allocation of NER based on the total cost of the --
14 the system. That's kind of a fair way to do it, and
15 it achieves some factors that were problems back, I
16 think, in '04. So I think that's a good way to do it,
17 too.
18 But this -- this -- quite a few
19 different ways to do it, and I don't think there is
20 one (1) and only one (1) irrefutable way to allocate
21 NER back. And that's what we said in our report.
22 And unless there is clearly superior
23 and compelling reasons to change from the status quo,
24 we normally suggest you stay with the status quo --
25 the devil you know is better than the devil you don't

1 know -- unless it's a real compelling reason to change
2 it. And we just didn't see a compelling reason to
3 change it.
4 BOARD MEMBER GRANT: Sorry, I don't
5 understand why you would think about making an
6 accommodation on one (1) side of the equation and not
7 the other when, you know, they're going to -- they're
8 equivalent, right? They should be the same.
9 So -- so if you think some adjustment
10 for risk should be made, then it can be treated on --
11 on both the cost and the revenue side in terms of some
12 discount or premium that you might grant to different
13 classes --
14 MR. MICHAEL O'SHEASY: M-hm.
15 BOARD MEMBER GRANT: -- you know, to
16 adjust the sort of cost allocation.
17 So I guess I'm just curious why 'A' and
18 'B' aren't calculated the same way because they
19 should.
20 MR. MICHAEL O'SHEASY: M-hm.
21 BOARD MEMBER GRANT: In my a priori,
22 they should be the same.
23 MR. MICHAEL O'SHEASY: Yeah, yeah.
24 Well, it's complex and it's -- it's not simple. And
25 because it will nec -- each factor will impact the

1 various rate groups and the Intervenors here
2 differently, parties will have different opinions on
3 what is the -- the best way to do it.
4 And the current way has been working,
5 and it may not be any better than what you're talking
6 about, but I don't see any damage in continuing it.
7 THE CHAIRPERSON: But, Mr. O'Sheasy,
8 when you say that there's no cost foundation for net
9 export revenue --
10 MR. MICHAEL O'SHEASY: Right.
11 THE CHAIRPERSON: -- I mean, we're --
12 we're really trying to get to the heart of cost
13 causation here.
14 MR. MICHAEL O'SHEASY: Yes.
15 THE CHAIRPERSON: And so if -- if
16 we're looking at the export class as we have it now
17 and there's the two (2) different kinds of export
18 sales, and there is a cost causation with both of
19 those, it seems like then that would build up to some
20 kind of cost foundation for next -- and you said that
21 if exports were to disappear, the costs would still be
22 there. So from a cost causation point of view, I just
23 think, you know, what Dr. Grant is saying is that we
24 would want to see that handled not necessarily looking
25 at the impacts on all the different classes, but just

1 from a principles point of view --

2 MR. MICHAEL O'SHEASY: M-hm.

3 THE CHAIRPERSON: -- and a cost

4 causation point of view, would that change your

5 answer?

6 MR. MICHAEL O'SHEASY: I don't think

7 so, and let me try to demonstrate why. Let's just

8 imagine that in the export market, by selling off

9 these export sales, I can get a hundred dollars ($100)

10 worth of revenue. Now, that hundred dollars ($100) of

11 revenue, let's pretend that sixty dollars ($60) comes

12 from dependable sales, forty dollars ($40) comes from

13 opportunity sales, okay?

14 Now, when I sell the -- that sixty

15 dollars ($60) and that forty dollars ($40), I'm

16 selling electricity, and I'm selling it to some third

17 parties out there. And as I do that, it costs me

18 something to provide that electricity, okay?

19 Well, in PCOSS, I'm going to try to

20 figure out: What did it cost to provide that sixty

21 dollar ($60) dependable sale? What did it -- did it

22 cost to provide that forty dollar ($40) of opportunity

23 sale? And let's just say for the sake of discussion

24 that the dependable sales cost me fifty dollars ($50)

25 and the opportunity sales cost me twenty-five dollars

1 ($25).

2 So I've got a -- I've -- in PCOSS, I've

3 said, Of the hundred dollars ($100) worth of revenue,

4 seventy-five dollars ($75) it cost me. And I'm going

5 to subtract that from the hundred dollars ($100), so

6 I've got twenty-five dollars ($25) left over, okay?

7 And of the twenty-five (25), that --

8 much of that is driven by a competitive market that

9 bids the price up and down based on demand and cost

10 factors. So if the twenty-five dollars ($25) -- or

11 the hundred dollars ($100) were to go to two hundred

12 dollars ($200) because maybe there was a carbon tax

13 that was initiated in the United States, and all of a

14 sudden hydro became a lot more valuable in the United

15 States than it is right now.

16 So what I was selling at a hundred

17 dollars ($100) I'm now going to sell for two hundred

18 dollars ($200). And it didn't cost me a dime more to

19 produce those same kilowatt hours that I sold for

20 sixty dollars ($60) and forty dollars ($40) or

21 whatever my math was, but I'm getting two hundred

22 (200) extra dollars for it that -- excuse me, one

23 hundred (100) extra dollars.

24 That one hundred (100) extra dollars

25 has nothing to do with cost. It has to do with a

1 competitive market, and that's what NER is. So how do
2 I treat it?
3 Now, it's not irrational to say, Well,
4 I'll treat it just like the hundred dollars ($100).
5 I'll -- I'll look at the cost of doing it. You could
6 do it that way. But -- and that's the way Hydro used
7 to do it before '04, basically.
8 And there were some ramifications of
9 that, because it was allocating back so much revenue
10 to certain rate classes that the resultant price of
11 those rate classes got below marginal cost, and that's
12 not a good thing, not for the long run, anyway.
13 And so for that reason, I think they
14 changed it to a -- a non-pure cost-based allocation.
15 It's total cost. And by total, we mean generation,
16 transmission, and distribution. And it -- that solved
17 that problem, but it moved it away from what you're
18 suggesting is a -- a -- strictly a cost-based
19 philosophy and utilized a -- a fairness-based
20 philosophy. Good luck.
21 MR. ROBERT CAMFIELD: Thank you,
22 Michael.
23
24 (BRIEF PAUSE)
25

1 MR. ROBERT CAMFIELD: The topics that
2 I plan to address today relate to several identifies -
3 - identified topics by the -- by the Public Utilities
4 Board of Manitoba. This includes weighted energy, and
5 specifically, the inclusion of capacity class within
6 weighted energy.
7 I will talk about the allocation, cost
8 allocation, of Bipole III, and then, of course, the
9 converter stations or facility stat -- situated at
10 Dorsey and Riel stations, the US interface, and
11 finally conclude with some comments with respect to
12 the allocation of DSM.
13 Before I go there, I'm going to talk
14 about, or at least touch on, should I say, some basic
15 foundations that I think relate to the cost allocation
16 problem that we -- we have in front of us.
17 So to begin, and I know that this
18 common theme is familiar to all of us, as far as
19 overarching objectives for setting rates and
20 determining the prices paid for electricity services,
21 we first of all want to ensure that those prices cover
22 the financial cost. I refer to this as a financial
23 cost basis.
24 Secondly and -- and an important
25 objective, of course, is just simply the efficiency.

1 We want the prices to reflect the resource cost
2 associated with the provision of resources.
3 And then, third, of course, we want to
4 ensure that the cost allocation result, the COS
5 result, is fair and fair in a sustainable way, which
6 would suggest that once you settle on a cost
7 allocation approach, you want to ensure that that
8 result is something that is sustainable over the
9 longer term.
10 Turning to the reason. The fundamental
11 reason we need to do cost allocation, and it is a
12 necessity, is simply because the provision of
13 electricity services are provided by common use
14 resources. And then, secondly, services embodied in
15 electricity services to -- to domestic retail loads
16 involve multiple services all provided simultaneously.
17 And we can just think about this very
18 briefly. Like, right this moment, Manitoba Hydro is
19 providing electricity service to thousands of
20 customers throughout the province, all served in
21 common at the same time.
22 And the resources also provide joint
23 services all at the same time. In the case of
24 generation, for example, it's not just energy that's
25 being provided. But in order to ensure that that

1 energy is provided reliably, it's energy supply plus
2 regulation reserves, and spinning reserves, and
3 nonsynchronous reser -- reserves. All these things
4 come together and are provided simultaneously.
5 But, of course, we can't tell exactly
6 which share of the cost of these resources are
7 attributable to any one (1) customer load. We must
8 thus engage in cost allocation.
9 I want to touch upon the physical
10 properties of power systems. I mean, it's rather
11 unusual that you find as a matter of simply the
12 technology of power supply. We must balance load
13 demand, in other words, with supply in real time,
14 exactly. And then, secondly, non-storability,
15 electricity, just the power itself. Electricity
16 cannot be readily stored. So you can't arbitrage
17 across time frames. If we could, we would construct
18 inventories.
19 So we would produce supply during low
20 cost off-peak time frames, and then call upon that
21 inventory built up during those off-peak periods
22 during the high-load time frames. We -- we can't
23 readily do that.
24 And, of course, that's the unique
25 property of hydro systems, right? Well, you can't

1 sort of store the electricity itself. You can
2 certainly store the energy in the hydro facilities to
3 the net benefit of society as a whole.
4 But because of this set of properties,
5 real time balancing, non-storability, it means that
6 the real time operations of power systems must be
7 carried out in very strict exacting protocols. Now,
8 those protocols have been built up over decades of
9 electricity supply in North America and throughout the
10 developing world, but are codified also in the North
11 American electric reliability corporations standards.
12 So we have standards of reliability
13 that are very high -- highly structured, and highly
14 detailed. And it's, I think, actually instructive to
15 actually take a look at and review some of the NER
16 standards that Manitoba Hydro and other electricity
17 mark -- suppliers that operate with an eastern inner
18 connection are governed by.
19 As a consequence of these physical
20 properties, you find that the economic costs vary with
21 very high levels of granularity. Loads cost prices in
22 hourly frequency. And as a result of -- in particular
23 the store -- non-storability -- the limited
24 storability characteristic.
25 Not do we -- not only do we have high

1 granularity, but we have great variation. You don't
2 have to look too far to find within the unbundled
3 power markets of the eastern interconnection, the RTO
4 and ISO markets, including the markets of not just
5 MISO but also New York, New York ISO, New England ISO,
6 PJM, ERCOT, and Texas/California ISO.
7 All these markets will demonstrate very
8 clearly that where you are observed -- the unbundled
9 nature of -- of the markets revealed in those market
10 processes and the economic costs thereof that you just
11 have great variation. You can find prices easily that
12 vary with -- over the course of a day of twenty (20)
13 to one (1). And I can't think of any other market
14 where that's quite like that. All driven by these
15 physical properties.
16 So what does this mean in terms of cost
17 allocation? Well, on the one hand, the cost that we
18 want to allocate, the starting point, is just the
19 financial costs which are largely non-varying. And
20 then secondly, and this -- driven by the physical
21 properties raya -- relates directly to the -- the
22 efficiency that we want to obtain in addition to
23 covering costs, namely that the theory would suggest
24 that you ought to assign costs such that you reflect
25 the energy and capacity costs during the peak period,

1 and during off-peak periods, marginal energy costs.
2 Taken as a whole, we have what is
3 referred to, generally speaking, as the -- the common
4 -- commonly recognized utility pricing problem. As
5 they say, recovered financial costs reflect
6 simultaneously resource value. That's not easy to
7 obtain, and so there's some inherent compromises to
8 get there. But in the case of Manitoba Hydro,
9 actually, I think we have some very good solutions
10 here viewed globally.
11 As you know, Manitoba Hydro uses a
12 weighted energy approach. This methodology satisfies,
13 I think, quite well these cost recovery and economic
14 cost efficiency criteria. And because the financial
15 cost to Manitoba Hydro on average, and as a whole,
16 don't vary too far from the marginal cost as revealed
17 by the MISO prices.
18 I mean, it's not like the -- the
19 differences here between marginal cost and financial
20 cost, the -- the variation is -- or the difference is
21 greater than, say, two (2) or three (3) fold, as it
22 isn't often for -- for other areas of the country, and
23 North America generally speaking, but rather the
24 financial costs are fairly close to the average
25 marginal cost. So you're not too far from first best

1 pricing.

2 And that is -- that is a -- a close

3 realization in the case of -- of the use of the

4 weighted energy approach. I would suggest that we

5 need to touch things up a little bit. We need to

6 incorporate some cacid -- capacity costs into the peak

7 periods of Manitoba Hydro's weighted energy

8 methodology, and there's several ways to do that.

9 Because the MISO market -- at one time,

10 MISO really got rolling with its second-day markets

11 2002/2003 where we had locational prices and bid-based

12 markets for generation services. And it was an enge -

13 - energy-only approach which meant that the prices

14 were allowed to vary, and very substantially as a

15 result of the forces of supply and demand.

16 So during high-cost peak load periods,

17 yeah, you had some scarcity rent content in the

18 prices. And so implicitly then one might argue, well,

19 we have the scarcity rent in there, we are capturing

20 the capacity value and worth of economic resources on

21 the margin, so we're good.

22 But other time frames either where

23 you're faced with a unusually capacity tight situation

24 or supply is less than the equilibrium level of the

25 incremental internal cost of capacity, in scarcity

1 rent content the prices can go through the roof.
2 And, of course, there's some historical
3 evidence in this where for extended periods,
4 1998/1999, we saw some very high prices during high
5 load time frames because for those time frames the
6 North American macroeconomies were advancing very
7 rapidly and demand was rising more quickly than
8 expected.
9 As a consequence, capacity was a little
10 short and we saw some very high prices. On the other
11 hand, you can be capacity long. And beginning as a
12 result of the serious recession of North America and
13 other factors that I could go into but, because of
14 time constraints, I won't, we found ourselves
15 beginning in 2009/2010 with a capacity long situation
16 that continues to this day.
17 And as a consequence of that, the
18 scarcity rent content in market prices has pretty much
19 evaporated. That -- that may continue for some time
20 yet.
21 And then there's the issue of the
22 capacity option prices that MISO has put in place
23 beginning in 2013, and I need to say something about
24 that. As I mentioned, the scarcity rent con -- rent
25 content can be rather large or rather small depending

1 upon the conditions, the market conditions, just like
2 any other market.
3 In the case of the MISO capacity option
4 prices that have been put in place formally in it's
5 option beginning in 2013, the resulting prices are
6 highly sensitive to the market design. And like much
7 of the various features of wholesale unbundled power
8 markets these days, it's a continuing experiment.
9 Options for capacity originate in the
10 New York ISO and soon following, PJM. It wasn't clear
11 exactly how to organize those options. And because
12 of, again, the physical properties of electricity,
13 just the nature of supply, you find, and not
14 surprisingly, that the capacity option prices can vary
15 a lot, not just with respect to the conti -- the
16 conditions, but also with respect to how the market
17 design features and protocols are put in place.
18 And, as an industry whole, we didn't
19 know how to do that very well.
20 MR. KURT SIMONSEN: Excuse me --
21 MR. ROBERT CAMFIELD: So --
22 MR. KURT SIMONSEN: -- Mr. Camfield.
23 It's -- it's the Board secretary here. I'm playing
24 the -- the time clock --
25 MR. ROBERT CAMFIELD: Okay.

1 MR. KURT SIMONSEN: -- a little bit
2 here, but how much time do you think you need?
3 MR. ROBERT CAMFIELD: I would say I'll
4 need another five (5) to seven (7) minutes if it works
5 for you. Okay.
6 MR. KURT SIMONSEN: We're okay then.
7 MR. ROBERT CAMFIELD: Okay. So -- so
8 as a result of market design process ongoing across
9 the industry, there's a lot of design changes in the
10 works. What we can say is that the MISO option for
11 capacity these days is a work in progress. And you
12 cannot, in my view, rely upon the option prices that
13 come out of the MISO option as a basis to determine
14 what the capacity happens to be.
15 And so the -- the approach that we
16 would suggest you consider is to rely upon the
17 internal capacity cost of MIS -- of Manitoba Hydro as
18 captured in and as part of its curtailable rate
19 program. This is a little less than forty dollars
20 ($40) Canadian per kW year.
21 There's some rain -- remaining
22 questions here, as I mention, or at least allude to
23 here at the bottom of this page. And that is we don't
24 know how to exactly assign a capacity cost across
25 loads, and hours.

1 And there's some analytics that we'll
2 have to go through to finalize that, but the bottom
3 line is that we must, at least if we wish to adhere to
4 the efficiency principles defined in terms of how --
5 how peak and off-peak prices are to be defined for
6 efficiency purposes, we need to include some capacity
7 costs. That's a must.
8 The question is just how best to,
9 again, assign that capacity cost across hours,
10 providing that you accept our recommendation to use
11 the curtailable rate program basis of what the dollars
12 for kW value happens to be.
13 Bipole, as you perhaps know, and -- and
14 are aware, in our view, is appropriately assigned as a
15 generation service, that it be functionalized as
16 generation along with Bipoles I and II. And you've
17 heard -- the Board has heard considerable discussion
18 about the reliability benefits of -- of the Bipole
19 facilities.
20 We believe that is a key element and
21 because of the operational features of the Bipole
22 facilities, the Bipole is inherently part of the
23 northern generation fleet. It is an integrated
24 package taken as a whole and is very much generation.
25 So we would recommend that you

1 functionalize it as generation. And because it is
2 part of the generation services, integral to the
3 provision of generation services, we would suggest
4 that you classify and allocate it according to
5 weighted energy.
6 There's various details that we have
7 incorporated in our report on this issue, a report of
8 August 2015.
9 The inverter facilities, which reside
10 at the Dorsey and Riel station, are defined issue by -
11 - by the Board. And I'll touch on that at this point.
12 First of all, as we know, these are costly facilities
13 when implemented at the size and -- and flow
14 capabilities inherent to large scale HVDC lines.
15 So we shouldn't be too surprised
16 there's a lot of money here. And because it is
17 integral to the HVDC system, and thus part of the
18 generation fleet of the northern system of Manitoba
19 Hydro, thus integral to the provision of generation
20 services, the weighted energy approach is -- is, I
21 think, rather compelling for -- for these facilities.
22 I think there's something else to this,
23 however, and that is that while these inverter
24 facilities, the way they are equipped with what's
25 known as a special protection system by Manitoba

1 Hydro, allows for Manitoba Hydro given the long lines
2 inherent to covering the territory of the Province and
3 -- and also integration with the US eastern
4 interconnection, provide for fast responding controls
5 of the HVDC system.
6 And what -- what's going on here is
7 simply that with the special protection system in
8 place at the convertor facilities, Manitoba Hydro
9 avoids having to put in place other sorts of devices,
10 fax devices or other serious compensation devices in
11 order to maintain reliability and satisfy transient
12 stability requirement. Essentially, the stability
13 requirements as defined by the reliability standards
14 of -- of NERC.
15 So to some degree then one might argue
16 that some share of the HVDC special protection system,
17 and I mean to say here the special protection system,
18 including the conve -- the invertor facilities at
19 Dorsey and Riel, allow for the utilization, not just
20 of the -- the generation system up to its full
21 capability. You would be constrained otherwise -- but
22 also the transmission system. So Manitoba Hydro's
23 conducted some studies to assess this, transient
24 stability studies, to be specific.
25 And as expected, these studies

1 confirmed what was anticipated. The converter
2 facilities at Dorsey and Riel with special protection
3 provides for a sizable, indeed nearly a twofold,
4 increase in the full-flow capability on the AC network
5 while also satisfying the stability requirements.
6 You would not be able to do both absent
7 this equipment and absent additional and very costly
8 serious compentation -- compensation technologies.
9 So as a consequence, we would suggest
10 that approximately 50 percent -- and this is confirmed
11 by the study results -- approximately 50 percent of
12 the HVDC facilities, including special protection
13 equipment, be assigned to generation exclusively, and
14 that the remaining 50 percent be assigned jointly to
15 generation and transmission.
16 Because study results vary with respect
17 to, oh, the assumptions and parameters of all the
18 numerous studies that would together represent a kind
19 of a group or portfolio of -- of various studies of
20 transient stability and other flow capability results
21 facilitated by the equipment, you get -- you get
22 different results depending upon the assumptions, just
23 like any other model paradigm.
24 So we can't say for sure exactly what
25 share beyond 50 percent is attributable to generation

1 and transmission. We would suggest hence that you
2 consider assigning somewhere between 75 and 100
3 percent of the total costs of the inverter facilities
4 in total to generation, and the remainder to
5 transmission which would give you naturally a range of
6 between zero and 25 percent.
7 And just to clarify, Manitoba Hydro
8 suggests that we assign 100 percent of the converter
9 facilities to -- to generation.
10 US interface. The US interface is
11 necessary for reliability. It is integral to the
12 overall system. We would suggest that the US
13 interface, because it is predominantly AC, be
14 functionalized as transmission but allocated according
15 to weighted energy. And we suggest that the reasoning
16 for this is that weighted energy, viewed broadly,
17 captures the time-varying value of reliability to
18 consumers.
19 So because of the reliability benefits
20 of the US interface and how those benefits would be
21 distributed over time in -- in terms of foregone
22 outage costs incurred by consumers, domestic consumers
23 in Manitoba, recognizing, you know, the differences in
24 the way that outages occur and result from supply-side
25 events compared to demand-side high-load events, we

1 believe that the weighted energy approach of Manitoba
2 is the better way to allocate the costs of the US
3 interface.
4 Trying to stay on time here. DSM.
5 Well, for sure DSM is unrelated as a matter of
6 causality to exports, and so it makes in our view no
7 sense to assign DSM costs to the export sales of
8 Manitoba Hydro. If anything, there's a reverse
9 causality. The impacts on load and energy from the
10 DSM activities if anything gives rise to a larger
11 export sale, so making greater sales available.
12 And -- but as a matter of causality,
13 simply the export sales, the -- those loads
14 themselves, export loads, have -- have no relationship
15 to -- to the DSM programs which of course are applied
16 to the -- the various domestic loads and customers,
17 predominantly residential and small -- small
18 commercial customers.
19 So in lieu of that, if we're going to
20 now move DSM costs out of exports there are several
21 approach options available to you. We would suggest
22 two (2) options for serious consideration, namely that
23 we simply match the class specific DSM cost to class
24 participation. So DSM programs geared to residential
25 should be assigned to the residential class.

1 The other plausible way as suggested by
2 certain stakeholders to this immediate proceeding is
3 to take a system benefits approach, and assign a DSM
4 cost to system-wide generation resources.
5 That con -- concludes my -- my
6 discussion. Thank you.
7 THE CHAIRPERSON: Thank you, Mr.
8 Camfield. Just quickly on DSM. You've given two (2)
9 approaches but you didn't give any kind of
10 recommendation as you have on some of the other areas.
11 MR. ROBERT CAMFIELD: Madam Chair, if
12 I had to settle on one (1) approach, I would assign it
13 to the classes. I would match up class-specific DSM
14 cost to class level participation as a first cut
15 certainly.
16 THE CHAIRPERSON: Thank you.
17
18 (PANEL RETIRES)
19
20 THE CHAIRPERSON: Mr. Williams, are
21 you staying where you are, or are you relocating?
22 MR. BYRON WILLIAMS: We'd prefer to
23 relocate, if -- if that's okay?
24 THE CHAIRPERSON: Please, do.
25

1 (BRIEF PAUSE)

2

3 THE CHAIRPERSON: All right. Mr.

4 Williams, please.

5 MR. BYRON WILLIAMS: Yes, thank you,

6 and -- and good morning. My understanding is that Mr.

7 Harper continues to be under oath. Before we -- we

8 start off, I'd just like to mark the -- the blue cost

9 of service evolution PowerPoint as -- as -- I'd

10 suggest as Coalition Exhibit 29.

11

12 --- EXHIBIT NO. CAC-29: Cost of Service Evolution

13 PowerPoint

14

15 MR. BYRON WILLIAMS: And the

16 PowerPoint by Mr. Harper lacking the beautiful colours

17 Exhibit 30 for the Coalition.

18

19 --- EXHIBIT NO. CAC-30: Mr. Harper's PowerPoint

20

21 CONSUMER COALITION PANEL:

22 BRUCE HARPER, previously sworn

23

24 OPENING COMMENTS BY MR. BYRON WILLIAMS:

25 MR. BYRON WILLIAMS: And, Diana, I

1 appreciate your working with us in terms of -- of the
2 Power Point. If we could just flip to the -- the
3 second page, and usually I have really colourful
4 titles for my Power Point but I -- we chose not to
5 here. We -- we see this as an evolutionary process.
6 We think today you're going to hear
7 significant gaps -- significant differences in the
8 perspectives of -- of key witnesses. The areas
9 obviously are the export class or classes, DSM, the
10 treatment of important infrastructure, and net export
11 revenue.
12 And there would be a natural temptation
13 to dismiss these distinct perspectives as -- as simply
14 being results driven to sugg -- to consider that
15 there's an outcome that -- that these independent
16 experts are -- are seeking rather than a principled
17 approach.
18 Well that might be a natural
19 temptation, I think the -- and while there are some
20 parties who profess a significant degree of certitude,
21 I think the Board had wide - - wise guidance from its
22 order about a decade ago, highlighting the fact that
23 reasonable persons can disagree, that there's
24 considerable judgment, no industry standard, and --
25 and highlighting that there's a -- a balancing act

1 reflecting both cost causation and equitable sharing
2 of costs. And that's the dialogue that our client
3 wishes to -- to explore.
4 And reasonable persons can especially
5 disagree, go into the next slide, at times of material
6 change. Our client's submission is that we're --
7 dating back to the 1990s, we had a big change up to
8 2006. And as you heard from Christensen and
9 Associates today, the retail market is still changing
10 dynamically. And that's why some of the differences
11 in opinion you're -- you're seeing, in our client's
12 submission, are -- are appearing, struggling at times
13 with fundamental change.
14 And the Board in '06 flagged that
15 fundamental change, and especially as the implications
16 of -- of the opening up of the MISO marketplace. And
17 in our client's view, there were three (3) outcomes of
18 that decision that -- that were especially indicative
19 of its attempt to grapple with fundamental change.
20 One (1) was the creation of the export
21 class to make sure that generation and transmission
22 got their fair share of the export revenues, and then
23 after they got their fair share, to de-link that
24 relationship and -- and move to the -- the net export
25 revenue allocation of revenues.

1 So the imbedded class, the -- the
2 export class, was about cost causation. That de-
3 linking and moving to N-E-R and allocating across a
4 broader base was about fairness, was about equity. It
5 was about efficiency.
6 And the third element we see out of
7 that '06 order is the effort not to replace imbedded
8 costs, because I think everyone here's agreed that
9 should be the primary approach, but to look more
10 seriously at marginal costs, to undertake marginal
11 cost studies. And, as we learned yesterday, that's
12 still a bit of a work in progress.
13 I want to assure the Board we're
14 suggesting that there's a need for reform and ongoing
15 development of your cost-of-service approach in the
16 face of material change. Our clients wish to assure
17 the Board that you're not the only regulator facing
18 this issue. Leading regulators continue to face this
19 -- the need for evolutionary change in the face of
20 material change.
21 And you -- this is FERC, the federal
22 regulator for the United States, talking about how
23 challenging cost allocation reform is at this time in
24 the United States, this was back in 2010, the
25 challenge of building new transmission facilities

1 linking location-constrained generation.
2 We're not trying to draw an analogy
3 between this decision and what -- the issues that face
4 you. We're just saying that in the face of material
5 change there are issues for regulators. You're not
6 the only ones grappling with it.
7 And here you have FERC again telling us
8 we've still got the same responsibility, just and
9 reasonable rates, rates that are not discriminatory,
10 but the circumstances have changed, and so we have to
11 change. And that's an important message, from our
12 client's perspective.
13 And if you look to our evidence, our
14 clients presented Mr. Harper, an independent witness.
15 And, from our client's perspective, his evidence seeks
16 to respond to that material change in -- both in Hydro
17 operations and in the broader marketplace. He's
18 speaking about you incorporating marginal costs in
19 establishing cost responsibility and looking, in terms
20 of cost causality, at current requirements and system
21 operating -- operations as compared to historic
22 underpinnings.
23 In terms of the material change of
24 which our clients speak, we identify five (5). And
25 one (1) is the reality that Hydro is -- is heavily

1 invested in the MISO marketplace. That first quote is
2 simply from the '06 Board order. But the second quote
3 by Christensen and Associates, CA Energy, really flags
4 -- that that marketplace is continuing to evolve with
5 considerable price volatility.
6 And the third quote flags that even
7 between 2012 and 2015 there's still a lot going on.
8 It's a marketplace that, as you heard today, is
9 continuing -- a marketplace of continuing
10 experimentation.
11 A second material change is just the
12 increased interlinking of Manitoba Hydro's planning
13 and operating as part of an interconnected grid across
14 North America. And you've heard -- seen that well
15 characterized in Hydro's rebuttal evidence.
16 A third material change is the
17 increased focus on low probability high impact events.
18 We all remember the great cascading power failure in
19 the North East in 2003 or '04. That's -- our approach
20 to reliability has changed consi -- significantly, we
21 would suggest, since then. And that's part of the
22 dynamic behind Bipole III and the US interconnection.
23 Whether or not we agree with those
24 decisions, we have to understand that's part of the
25 dynamic that has materially changed.

1 A fourth material change we flag flows
2 from the Board's own advice in the NFAT. Here's the
3 Board talking about the need for integrated resource
4 planning and the need to realize more opportunities in
5 tar -- in terms of demand-side management, to treat it
6 not as an outlier in a system. To treat it as an
7 integral part of -- of the -- the load question.
8 And you see Manitoba Hydro accepting
9 the Board's advice. And this has important
10 implications for DSM and Mr. Harper's advice about
11 treating DSM from a system perspective rather than a
12 class perspective.
13 And the final material change relates
14 to these very significant expenditures that have been
15 committed to over the last few years. Our client did
16 not endorse Bipole III. Our client did not endorse
17 Keeyask. But collectively, as Manitobans, we are left
18 to deal with those consequences and there are real
19 practical implications from that.
20 In the NFAT consumers were told take
21 the long-term perspective. Take the patient capital
22 approach. You would be better off over time compared
23 to the other plans. Now, whether or not our client
24 agreed with that, that's the implications of the NFAT
25 decision.

1 There would be shared risks, but shared
2 opportunities over the long-term. Out of the NFAT it
3 was also realized that there would be very high cost
4 pressures coming out of those decisions. And that
5 NFAT decision was taken at a time when the cost
6 allocation, in terms of the net export revenue was
7 allocated more equitably across GT&D.
8 And so we think there are important
9 cost implications. How do we realize that NFAT
10 promise? And from our client's perspective, an
11 allocation of net export revenue that reflects that
12 the -- a more equitable sharing across a broader
13 spectrum is the appropriate one once the appropriate
14 costs have been assigned to generation and
15 transmission, and the appropriate revenues.
16 Just finally going to the last two (2)
17 slides, from our perspective the challenges are to
18 evolve in the face of material change, not to be
19 locked in the past. To acknowledge as you heard from
20 CA Energy just now, that insight and Cost of Service
21 can arise from both the embedded and efficiency
22 perspective and to fulfill the NFAT promise.
23 And I'll leave you with some good
24 advice from the Board from a decade ago that Mr.
25 Harper will speak to. If we could pull up the other

1 PowerPoint, Diana.

2

3 (BRIEF PAUSE)

4

5 PRESENTATION BY CONSUMER COALITION:

6 MR. WILLIAM HARPER: Thank you, Diana,

7 and good morning. The purpose of my presentation is

8 to speak to the evidence I prepared on behalf of the

9 Consumers Coalition, focussing on those aspects that

10 the PUB has directed to me subject to this oral

11 hearing.

12 Can you go to slide 2, please? For

13 purp -- purposes of today I plan to start by providing

14 some context for Cost of Service studies in terms of

15 their purpose and the associated principles that

16 should guide their development.

17 I then plan to go through each of the

18 key areas that the Board has designated for oral

19 review, namely, the treatment of exports in terms of

20 the number of export classes and the costs that should

21 be allocated to them; DSM costs, including both the

22 question of their general classification and

23 allocation, as well as specific issues related to the

24 CRP program; transmission costs in terms of the

25 functionalization and allocation of the various

1 transmission facilities; generation costs in terms of
2 their classification and the determine of the weight -
3 - determination of the weighted energy allocation
4 factor that Manitohybo -- Manitoba Hydro proposes to
5 use; and net export revenues in terms of both the
6 general approach to be used for their allocation as
7 well as the specific allocation base that Manitoba
8 Hydro has proposed.
9 In each case, I plan on outlining my
10 views as to the appropriate treatment and address some
11 of the issues that have arisen during the workshops
12 and rebuttal evidence.
13 In my June evidence, I also raised
14 several other issues related to the cost of service
15 treatment of generation and transmission which have
16 not attracted much content -- comment or -- to date.
17 In the interests of time, I do not plan
18 on speaking to the -- to these as part of this
19 presentation, but I encourage the Board to consider
20 them in its final deliberations.
21 Go to slide 3, please. As both
22 Manitoba Hydro and the Intervenor exports have all
23 noted, cost of service studies are part of the overall
24 rate-making process that takes place once a utility's
25 revenue requirement has been established, and which

1 ultimately produces the -- the rate schedules that
2 will be used to bill customers.
3 This rate-making process is guided by
4 what are a number of generally accepted principles or
5 goals including fairness and equity, encouraging
6 efficiency, rate stability, and public acceptability.
7 Cost of service studies are used to
8 support the objective that rates should be fair and
9 equitable. Rates effectively apportion the
10 responsibility for the approved revenue requirement
11 amongst the various customer classes. And one (1) of
12 the generally accepted measures of fairness is that
13 apportionate (sic) should reflect cost/causation.
14 What is generally meant by this is that
15 cus -- customers should pay for the facilities that
16 they use and benefit from -- i.e., pay for the costs
17 incurred to serve them. Therefore, the purpose of a
18 cost of service study is to apportion the revenue
19 requirement to customer classes based on cost
20 causality.
21 This was confirmed by the PUB in its
22 Order 117/06 where it stated that:
23 "This fairness objective is met in
24 part by the allocation of Manitoba
25 Hydro's respective revenues and

1 expenses by customer class in
2 accordance with cost causation,
3 legislation, policy, and public
4 interest."
5 As a result, cost of service studies
6 focus -- focus on distinguishing the different types
7 of services that customers are provided and benefit
8 from, and what customers characteristics drive the
9 costs incurred to provide those services.
10 At the end, a comparison of the ratio
11 of each customer class's revenues versus its allocated
12 costs provides a benchmark as to the degree that rates
13 are fair from this particular perspective.
14 Go to slide 4, please. However, there
15 are a number of complexity that -- that arise in
16 establishing cost causation. And I think Christensen
17 Associates went through some of those, but I'll just
18 highlight them again.
19 First, there's a question of whether
20 it's embedded costs or marginal costs that are being
21 allocated. For purposes of Manitoba Hydro's cost of
22 service study, the PUB has decided that the cost of
23 service study will rely on forecast embedded costs.
24 But it was also determined that marginal costs and the
25 value of emissions will be considered in the overall

1 rate-setting process.

2 Second, a significant portion of the

3 Utility's facilities are used by more than one (1)

4 customer class, provide more than one (1) service,

5 and/or may have more than one (1) cost driver such

6 that cost responsibility has -- cannot be readily

7 established. This is the joint cost responsibility

8 problem that was referred to earlier this morning.

9 Third, while it is fair to conclude

10 that customers not using a specific facility or cost -

11 - or -- or service should not be responsible for any

12 of the costs, all customers using a service do not

13 necessarily impose the same costs.

14 Service quality or benefits may -- may

15 vary in terms of the service received. And a good

16 example of that is curtailable rates versus firm load

17 in Manitoba Hydro. And to the extent that customers

18 do not -- customers are not equal in terms of the

19 service they provide, their -- their cost

20 responsibilities should not be the same.

21 Fourth, utility assets have long lives.

22 With -- and with changes in time in terms of

23 technology, economics, and government policy, their

24 original intent may differ from their current use and

25 role in the system.

1 While it is useful to understand both,
2 generally, in my view, more weight should be given to
3 the current role and use of assets in meeting
4 customers' requirements. Similarly, more weight
5 should be given to the current costs and cost
6 relationships than historic costs when seeking to
7 establish relative cost differences between different
8 services.
9 Also, while the revenue requirements
10 are usually established based on a specific forecast
11 of system conditions, the use and benefits of system
12 facilities will vary with those conditions. Given
13 that in Manitoba Hydro's case, the need for facilities
14 considers the full range of system conditions, it is
15 appropriate that consider -- considerations of cost
16 causality do -- do the same and not rely solely on
17 those used to determine the revenue requirement.
18 A related issue is that with utilities
19 such as Manitoba Hydro, which rely heavily on water
20 flows, the resulting use of the facilities,
21 particularly those related to generation and
22 transmission, can change from year to year. It's
23 important that cost of service studies track trends in
24 overall system use and conditions as opposed to overly
25 focussing on what's happening in one (1) year compared

1 to the next.

2 As well as cost causation, there are

3 other considerations that a cost of service study

4 must take into account. One is practicality which is

5 -- encompasses issues related to both feasibility as

6 to whether the information required to implement a

7 particular approach is available, and complexity in

8 terms of whether the cost of implementing and

9 maintaining a particular approach are warranted. This

10 -- this can be generally linked to what's -- what's

11 the materiality of -- of the costs we're dealing with.

12 This all -- also ties to another

13 consideration, which is transparency and

14 understandability. Regardless of how accurate or

15 correct a cost of service methodology may be in terms

16 of reflecting cost causation, if it is not

17 understandable and if parties cannot follow how the

18 costs are being allocated, then parties aren't even --

19 even able to judge whether it's fair or not.

20 Finally, it's important to recognize

21 that as a result of these complexities cost of service

22 studies involve judgment, and cannot be simply

23 regulated to a slide rule as noted here, or -- or with

24 more modern times a computer, which is one of the

25 reasons why we find them frequently being debated in

1 proceedings such as you're having here, and that's
2 also why there are legitimate agreements amongst
3 experts.
4 At the same time, it is important that
5 such judgments be based on facts and not -- and not
6 have -- not theories that then facts are twisted and
7 made to fit. Can we go to slide 5, please.
8
9 (BRIEF PAUSE)
10
11 MR. WILLIAM HARPER: As I noted on an
12 earlier slide, in Board Order 117/'06 the PUB noted
13 that as well as cost causation there were other
14 factors, including legislation, policy, and public
15 interest, that would -- that it would take into
16 account when considering fairness in Manitoba Hydro's
17 cost allocation.
18 These factors provided an important
19 context, and indeed can inform the application of the
20 principle of cost causation as it applies to a
21 particular utility's situation. In the terms of
22 Manitoba Hydro, relevant legislation would include the
23 Manitoba Hydro Act, the requirements for uniform
24 rates, requirements for the affordable energy fund,
25 the requirements of the Climate Change and Emissions

1 Reduction Act, and the requirements of the Sustainable
2 Development Act, as they relate to the planning and
3 operating of Manitoba Hydro.
4 In terms of policy, relative matters --
5 relevant matters include the Board's adoption
6 following the recent NFAT proceeding of an integrated
7 resource planning with DSM as an alternative resource.
8 It would also include the reinforcement through the
9 NFAT decision of the long-term perspective that is to
10 be taken in applying resource planning in the
11 consideration of cost and benefits, which I believe in
12 the NFAT proceeding Mr. Bowman coin -- coined as the
13 patient capital per -- perspective.
14 It would also include the emphasis that
15 Manitoba Hydro's planning puts on high consequence/low
16 probability events in determining the need for
17 additional facilities and resources. This perspective
18 has long been evident in Manitoba Hydro's use of the
19 worst drought conditions in terms of planning it's
20 dependable energy requirements, and has recently been
21 extended to the Bipole lines in the finding the need
22 for Bipole III at Riel.
23 And finally, Manitoba Hydro's active
24 participation in the MISO markets, and the influence
25 this has on the Utility's operations and planning, as

1 well as its active reliance on neighbouring
2 jurisdictions to address its capacity and energy
3 needs.
4 In this regard, Manitoba Hydro is
5 fundamentally different from say a utility like BC
6 Hydro which despite its interconnections plans and
7 operates more as an island, and does not rely on
8 interconnections for planning purposes.
9 In terms -- in terms of public
10 interest, one matter that the Board has long
11 considered in the allocation of cost is that related
12 to -- to diesel communities and the impact that the
13 allocate of cost has on those communities. In this
14 regard, the cost of service implications of the diesel
15 settlement agreement is still an outstanding matter
16 awaiting the submission of the final diesel agreement.
17 Can we go to the next slide, please?
18
19 (BRIEF PAUSE)
20
21 MR. WILLIAM HARPER: Given this
22 context, I'd like to turn now to the first key issue
23 area identified by the PUB, namely the treatment of
24 exports. As you've heard this morning, and I believe,
25 too, there is general agreement amongst parties that

1 there's a need to include an export class, or classes,
2 within the cost of service study.
3 Furthermore, I believe there is an
4 agreement that the creation of these export -- this
5 export class or classes is not for purposes of
6 determining export prices which are set by market
7 forces, but rather to provide for a reasonable
8 allocation of cost to exports such that net export
9 revenues can be calculated and allocated in an
10 appropriate manner, which is in itself another key
11 issue that the Board -- Board is subject to this oral
12 hearing process.
13 Key areas where there is disagreement
14 or what costs and how costs should be allocated to
15 exports, which has given rise to a related issue,
16 mainly, is there a difference between firm and
17 opportunity exports such that two (2) classes of
18 export are required.
19 Another issue related to the allocation
20 of exports is whether exports differ or are equal to
21 do -- domestic load from a cost causation perspective.
22 So is there a need to somehow distinguish between
23 exports or domestic load or can they be treated in the
24 cost allo -- cost of service process. Slide 7,
25 please.

1 As I outlined in the June workshops,
2 there are two (2) approaches or perspectives that can
3 be taken in trying to consider these questions. The
4 first is what I have called the economic perspective,
5 where the relative cost responsibility of domestic
6 load, firm exports and opportunity exports would be
7 assessed by looking at their roles in the economics
8 used to justify the types and timing of new -- new
9 generation facilities.
10 The second approach is what I would
11 call the cost-of-service perspective, where one would
12 apply standard cost-of-service principles to determine
13 if domestic load, firm exports, and opportunity
14 exports are equal and should, therefore, be treated as
15 such in the cost-of-service study.
16 I start first with economic
17 perspective. From looking at the role that exports
18 play in the business cases used to justify new
19 generation, I think it be -- it can be concluded that
20 in the recent generation decisions related to
21 Wuskwatim and Keeyask both firm and opportunity
22 exports played a role in those economic evaluations.
23 And this would -- this would suggest that both firm
24 and opportunity exports should, in principle, attract
25 some responsibility for fixed costs.

However, as I noted in my rebuttal evidence, in the cases of both Wuskwatim and Keeyask, the additional investment supported by a kilowatt hour of exports is less than the basic investment required just to support domestic load. This suggests that exports should bear less cost responsibility than firm domestic load.

Furthermore, it is evident from both the Wuskwatim and the Keeyask NFAT reviews and the Public Utility Board decisions that a kilowatt hour of firm exports has a greater impact on the business case than the kilowatt hour of opportunity exports in terms of both the associated risks and the associated prices.

Finally, as we've heard, Manitoba Hydro has noted in its rebuttal evidence that for earlier Hydro investments opportunity sales were not considered at all in the economic business cases used to support them. These facts all support the view that the cost responsibility for firm exports is greater than that for opportunity exports.

Can we have the next slide, please? If we turn to the cost-of-service perspective, the first question is whether the service provided to exports is the same as that provided to domestic load such that

1 they should be treated equally from a cost/causality
2 or cost/responsibility perspective.
3 In this regard, the answer is clearly,
4 no. As you've heard in this proceeding, Manitoba
5 Hydro does not carry plan -- planning reserve margins
6 for exports, even firm dependable exports. Also,
7 export contracts, again even firm exports have
8 provisions that can be activated when continuing to
9 serve exports would jeopardize Manitoba Hydro's firm
10 load.
11 These differences suggest that exports
12 do not receive the same level of service reliability
13 as firm domestic load and, therefore, should not carry
14 the same cost responsibility.
15 Furthermore, it is also clear that
16 there's a difference between firm and opportunity
17 exports in terms of the service provided. Manitoba
18 Hydro does include firm export commitments in its
19 planning process for generation and transmission; it
20 does not do so for opportunity exports.
21 Also, in terms of when it comes to who
22 gets cut first if curtailments are required in order
23 to support domestic load, opportunity exports are
24 curtailed before firm exports. This would indicate
25 that there's also a difference in the quality of

1 service provided to firm versus opportunity exports.
2 Overall, the per -- the results from
3 both the economic perspective and the cost-of-service
4 perspective are the same and suggest that both
5 opportunity and firm exports should attract some fixed
6 cost responsibility. However, the fixed cost
7 responsibility attributed to firm exports should be
8 less than that attributed to firm domestic loads on a
9 per kilowatt hour basis. And the fixed opportunity
10 attributed to opportunity exports should be less than
11 that attributed to firm exports.
12 The corollary is that there needs to be
13 two (2) export classes in order to make these
14 distinctions and appropriately -- appropriately
15 allocate cost to exports. May I have the next slide,
16 please.
17 However, there are practical issues
18 associated with establishing methodology for
19 establishing the appropriate cost responsibility for
20 both firm and opportunity exports. First, there are a
21 number of firm export contracts which vary in terms of
22 their precise terms and service commitments.
23 Similarly, there is a variety of
24 opportunity sales ranges from commitments that can be
25 up to a year all -- all the way down to ones that are

1 made only in realtime on an hour-by-hour basis. This
2 means that the specific or even relative cost
3 responsibility for each would be difficult if not
4 impossible to establish.
5 This fact was recognized by CA
6 Consulting in their second report to Manitoba Hydro
7 where they discussed an approach wherein a firmness
8 index would be attached to each type of export or
9 export contract, and the costs allocated on that
10 basis.
11 However, they similarly concluded that,
12 even if feasible, such an approach would be resource
13 intensive and would likely be subject to differences
14 of opinion in terms of how the export -- how -- how
15 that index of firmness should be developed.
16 This effectively leaves us with three
17 (3) options: allocate fixed costs to all exports on
18 the same basis of firm load, which would clearly
19 result in an over-assignment of costs to both firm and
20 opportunity exports; allocate no fixed costs to
21 exports, which in this case would clearly result in an
22 under-assignment of fixed costs to both firm and
23 opportunity exports; or, allocate fixed costs to firm
24 exports on the same basis as domestic load, but
25 allocate no fixed cost to opportunity exports.

1 In my view, the third option is the
2 best as while it overstates the cost responsibility of
3 firm exports, it understates the cost responsibility
4 of opportunity exports, and thus provides a more
5 reasonable and balanced result than either of the
6 other two (2) options. This is what Manitoba Hydro
7 has proposed, and this is why I support their
8 particular proposal.
9 Can we have the next slide, please?
10 There are two (2) other issues related to the
11 assignment of costs to exports, and those are the
12 treatment of the uniform rate adjustment and the
13 Affordable Energy Fund costs.
14 With respect to the uniform rate
15 adjustment, uniform rates are a statutory requirement.
16 At the time the legislation was introduced, the
17 government of the day indicated that the ability to
18 implement uniform rates was due to the benefits
19 generated by export sales, and that it was not asking
20 Manitobans to pay more.
21 Given this policy context, it is
22 appropriate that the costs of implementing the uniform
23 rate adjustment be assigned to exports as Manitoba
24 Hydro has proposed.
25 In the case of the Affordable Energy

1 Fund, this too is a statutory requirement which
2 legislation specifically states is to be funded from
3 export revenues which also funds non-electric
4 efficiency initiatives. As a result, in my view, it
5 is also entirely appropriate here that the
6 amortization of AEF costs be allocated directly to
7 exports.
8 Could we have the next slide, please?
9 The next key issue I would like to deal with is the
10 treatment of DSM. During the course of this
11 proceeding, there have been three (3) alternative
12 approaches that have been identified. The first is to
13 treat DSM as a resource. Under this approach, DSM
14 costs would be functionalized and allocated based on
15 the resource savings they provide.
16 The second approach is to view DSM as a
17 benefit to the participating classes and assign costs
18 directly to customer classes based on program costs
19 and participation.
20 The third option is somewhat of a
21 hybrid that would consider both system benefits and
22 benefits to participating customers.
23 Can I have the next slide, please? In
24 my evidence and June appearance, I supported the first
25 option, and still do, for a number of reasons. First,

1 treating DSM as a resource option in the cost of
2 service study is consistent with the Board's emphasis
3 in its recent NFAT decision on integrated resource
4 planning and the need to fully include and treat DSM
5 as a resource option.
6 Second, while DSM plans do benefit
7 participating customers, this is not their main
8 purpose. Rather, they target savings opportunities
9 that would not otherwise be undertaken and are
10 selected on the basis of their overall economics and
11 their ability to contribute to a least-cost plan for
12 Manitoba Hydro.
13 Third, customers participate, not as a
14 result of natural market forces, but because they are
15 encouraged to do so. This is a fundamentally
16 different circumstance from the more traditional
17 utility service offering where a customer seeks
18 service from Manitoba Hydro, and it's the Utility's
19 obligation to provide the service and incur the costs.
20 Manitoba Hydro has no similar
21 obligation to provide DSM programs, and it elects to
22 do so because it benefits the system overall.
23 Given this context, in my view DSM
24 should be treated and allocated in the cost of service
25 as a resource option.

1 If we could have slide 13, please.
2 During the course of the proceeding, parties have
3 raised various issues regarding the specific treatment
4 of DSM. And I would like to take this opportunity to
5 address a couple of them.
6 First, there's been a suggestion that
7 since the need for DS -- the need date for new
8 generation is currently years away, there's no
9 immediate need for DSM programs to offset generation
10 costs, and indeed DSM is simply increasing rates.
11 I have three (3) -- I have three (3)
12 specific responses to this perspective. The first is
13 that, without past DSM investments which are what is
14 what's currently being amortized in rates, there would
15 be shortages now.
16 This can readily be seen from the fact
17 that the most recent power resource plan shows a
18 surplus of dependable energy at 2,197 gigawatt hours
19 in 2015/'16, which is considerably less than the 2,961
20 gigawatt hours which represents the total historic DSM
21 savings reported through to 2014, plus the planned
22 savings for 2015/'2016.
23 Therefore, it is incorrect to say that
24 current customers are not benefiting from DSM costs
25 included in the revenue requirement. Indeed, without

1 the associated DSM savings other resources would have
2 been required.
3 Second, the projected need date to the
4 mid-'20/'30s assumes continued investment and spending
5 on additional DSM.
6 And third, taking such a perspective is
7 inconsistent with the long-term patient capital
8 perspective which underlines the approach Manitoba
9 Hydro and the PUB have adopted for purposes of
10 resource planning.
11 The second concern was with respect to
12 the possible cost impacts of DSM programs on non-
13 participating customer classes if DSM is treated as a
14 resource option in the Cost of Service. Again, I have
15 a couple of comments.
16 The first is that Manitoba Hydro's DSM
17 portfolio passes the RIM test, which means that
18 resource savings from DSM are equal to or exceed the
19 sum of the utilities loss revenues, plus any costs for
20 those DSM programs.
21 This means that rate levels will be low
22 -- lower over the long-term with the DSM programs.
23 Given this perspective and the impac -- the impact on
24 non-participants over the long-term should not be a
25 material issue. And this is the appropriate view I

1 think should be taken.

2 Second, not all customers within --

3 within even a customer class can actually participate

4 in a classes DSM programs. For example, residential

5 customers with natural gas space heating can no more

6 participate in programs that are aimed at electric

7 space heating than can commercial or industrial

8 customers.

9 As a result, the issue of non-

10 participant impacts is not only an interclass issue,

11 but also intraclass issue, which is not addressed and,

12 indeed, may be aggravated if costs are directly

13 assigned to those customer classes.

14 If we can go to the next slide, please.

15 I'd like to turn now to one (1) specific DSM related

16 issue and that is the treatment of the curtailable

17 rate program in the Cost of Service Study.

18 The curtailable rate program enters the

19 Cost of Service Study in two (2) ways. First, there

20 is the $8 1/2 million cost of -- cost of the program,

21 which under Manitoba Hydro's approach is directly

22 assigned to those classes with CRP customers, namely

23 the GSL 30:100 and the GSL greater than one hundred

24 (100) classes.

25 Second, the allocation of generation

1 costs uses the full load for these classes and it
2 gives no recognition to the fact that a portion of the
3 load is actually interruptible and should not be
4 allocated costs on the same basis as firm load.
5 In the initial Manitoba Hydro
6 submission, in order to recognize this, the cost
7 attributed to the classes with customers -- customer -
8 - with CRP load, excuse me, were reduced by $5.8
9 million in order to specifically to recognize this
10 fact where this $5.8 million represented the value of
11 the generation savings attributed to the CRP load and
12 is the basis for the discount paid to the CRP
13 customers.
14 The same 5 1/2 -- excuse me, $5.8
15 million was then added to -- to generation to be
16 allocated to all customers. The issue raised by Mr.
17 Bowman, and I think appropriately so, in his evidence,
18 was that the cost of the program exceeded the credit
19 due to the customer, such as the classes with CRP load
20 reflectively paying $2.7 million more overall.
21 In its rebuttal evidence Manitoba Hydro
22 noted that this was really a timing issue. A propose
23 to change the treatment of CRP and set the credit
24 given to the class at $8 1/2 million and then in order
25 to maintain the same revenue requirement, increase the

1 amount assigned to generation from 5.8 to $8.5
2 million.
3 In my view, these proposed changes are
4 inappropriate, as they do not solve the problem. They
5 merely create new and different problems. First, as a
6 result of these changes CRP customers are now
7 receiving a credit of $8 1/2 million, which exceeds
8 the benefit they bring to the system.
9 Second, the cost of generation which
10 used to be allocated to customer classes is increased
11 by $8 1/2 million, which exceeds the savings created
12 by the program.
13 And third, more fundamentally, the
14 problem that I noted in my June presentation still
15 exists. Namely, the overall allocation of costs to
16 classes with CRP is the same as for classes that have
17 just firm load and there will be no recognition given
18 to them to the fact that some of that load is less
19 reliable.
20 In contrast, the DSM approach that I
21 have pro -- propose effectively solves the problem by
22 not directly assigning the $8 1/2 million for the CRP
23 costs to classes, but rather treating it as
24 generation. However, there would still be a $5.8
25 million credit given to those classes with CRP in

1 recognition of the fact that a portion of their load
2 is interruptible.
3 Slide 15, please. I'd like to turn
4 down to another key issue and that is transmission,
5 and start with generation related transmission assets.
6 Manitoba Hydro first introduced this concept in its
7 2002 status update filings where it proposed that the
8 AC northern collector lines and HVDC facilities,
9 excluding the Dorsey convertor, be treated as
10 generation related based on FERC's criteria for
11 determining transmission assets.
12 In Board Order 7/03, the PUB accepted
13 Hydro's reasoning that the primary function of these
14 facilities is to move energy from remote generation
15 sites into the backbone transmission system. However,
16 in the same Order the PUB expressed concern about the
17 exclusion of Dorsey from these assets and expected
18 Hydro to re -- reevaluate that particular treatment.
19 I think in this proceeding there has
20 been general acceptance of the principle that certain
21 transmission assets can be considered as generation
22 related and should be functionalised as such. The
23 various issues have arisen as to the application of
24 that principle.
25 What I propose to do is go through and

1 address these issues as they apply to the various
2 types of transmission assets that are being considered
3 treatment -- it'll be considered for treatment as
4 generation related. If we could have the next slide,
5 please.
6 The first category of transmission
7 assets that I'd like to address are AC facilities used
8 to integrate generation. These facilities include
9 both the northern AC collector lines which bring power
10 from the northern gener -- generation facilities to
11 the northern converter stations and the AC lines that
12 serve to incorporate power from southern generation
13 into Manitoba Hydro's transmission network.
14 From reading the material to date, the
15 only real issue that appears to me is with -- appears
16 to me is where the -- where there's a problem with the
17 treatment is where we have lines that were initially
18 built to incorporate generation, but they're now being
19 used to serve load as well as incorporate the
20 generation.
21 In such instances, Manitoba Hydro
22 proposes to treat the lines as part of the
23 transmission network consistent with the FIRSO --
24 FERC/MISO criteria. Now, there have been suggestions
25 that such lines could be split between generation and

1 transmission.

2 I consider Manitoba Hydro's approach to

3 be reasonable and appropriate for a couple of reasons.

4 First, it recognizes the evolving and changing use of

5 transmission facilities. Second, it is consistent

6 with the PUB's own 7/03 determination that only those

7 facilities which would be recognized for inclusion in

8 the transmission tariff should be assigned to the

9 transmission function and, finally, it is practical to

10 apply.

11 I must admit I have some sympathy with

12 the view that Manitoba Hydro's approach could lead to

13 treating some transmission lines that serve only a

14 small amount of load and -- and function primarily to

15 incorporate generation as network.

16 However, I am concerned that the

17 suggestions which have been made as to how -- how the

18 split would be made for such lines is rather complex

19 and would likely require a significant amount of

20 judgment. Could we have the next slide, please?

21 The second issue regarding generation-

22 related transmission assets is the appropriate

23 treatment of the Dorsey converter station. There is

24 general agreement that the Dorsey converter is

25 integral to the overall integration of norther

1 generation into Hydro's transmission network.
2 However, there's also been evidence
3 that it serves to support the AC network and that its
4 costs are currently included in Manitoba Hydro's
5 transmission tariff, which would suggest the facility,
6 or at least a portion of it, should continue to be
7 treated as transmission for cost of service purposes.
8 As I noted earlier, the appropriate
9 treatment of Dorsey is not a new issue. Indeed, it's
10 been an issue since Manitoba Hydro first introduced
11 the concept of generation-related transmission assets
12 and has been an evolving issue during -- during the
13 development of Manitoba Hydro's current proposal.
14 Again, I agree with Manitoba Hydro's
15 proposal as it stands right now, which is to treat the
16 converter station as generation-relation transmission
17 asset. First, the role and -- the role and use of the
18 asset has not changed since it was constructed. And
19 while there's no business case available for Dorsey,
20 the business case through Riel, its sister station,
21 does not include any reference to transmission
22 benefits as one (1) of the justifications for the
23 construction.
24 Second, as evidenced by CA's Consulting
25 2015 report, the determination of transmission

1 benefits is complex as it relies on simulation studies
2 which require a number of assumptions that directly
3 impact the results.
4 As I noted in my June presentation, the
5 BCUC faced a similar situation regarding BC Hydro's
6 transmission assets which it uses to integrate remote
7 generation and ultimately concluded that the assess --
8 assessment of transmission benefits was highly
9 subjective and that a hundred percent of the assets in
10 question should be treated as generation related.
11 Finally, while there's some confusion
12 about its treatment in Manitoba Hydro's open access
13 tariff, there is no confusion in my mind about the
14 fact that the FERC criteria MISO uses as the basis for
15 its determina -- determination of assets to be
16 included in transmission tariffs in which MISO also
17 expects Manitoba Hydro to comply with would exclude
18 the Dorsey converter from the tariff.
19 Can we go to the next slide, please?
20 Given the references myself and other -- others have
21 made to BC Hydro, I thought it might be useful to
22 include a map setting out what BC Hydro's generation-
23 related transmission assets are.
24 BC Hydro's generation-related
25 transmission assets consist of about -- and I've got

1 three (3) circles on the -- I apologize for the
2 quality. It's difficult drawing on -- on PDF files.
3 BC Hydro's transmission -- generation-
4 related transmission assets consist of the lines
5 running from its GM Shrum and Peace Canyon generating
6 stations in northern BC to a 500 kV substation at
7 Prince George, along with the 500 kV lines running
8 from its Mica and Revelstoke generating stations to
9 substations on its transmission network at Nicola and
10 Ashton Creek. Those are the three (3) circles I've
11 drawn there.
12 In all three (3) cases, the line --
13 lines concerned bring power to a point of connection
14 with BC Hydro's transmission network similar to the
15 role fulfilled by Manitoba Hydro's HVDC facilities.
16 Slide 19, please.
17 The final issue regarding generated
18 related transmission assets is with respect to the
19 cost of service treatment of Bipole III and Riel when
20 they ultimately come into service. Issues have been
21 raised that the treatment of Bipole III as a
22 generation-related asset is not appropriate because
23 it's not directly linked to the construction of a
24 northern generation facility, and it's required to
25 maintain reliability for winter load.

1 While the construction of Bipole III is
2 not directly linked to past northern generation
3 development, or expressly justified on the faces of
4 future northern development, it is clear that the need
5 for Bipole III in order to support reliable delivery
6 of the existing northern generation to the
7 transmission network has evolved over time as
8 reliability standards have changed, and Manitoba
9 Hydro's own understanding of its -- of the
10 vulnerability of its transmission network to weather-
11 related events has improved.
12 It is also clear that the reliance on
13 northern generation is growing over time which is
14 contributing to the increasing supply deficit that
15 would occur in the absence of Bipoles I and II.
16 Indeed, the Clean Environment Commission in its report
17 on Bipole III noted that the current HVDC facilities
18 running from the north -- northern Mani -- Manitoba to
19 the Dorsey converter station do not have the capacity
20 to transmit all of the power from Keeyask.
21 So that while not directly linked to
22 Keeyask, Bipole III is needed to enable the full
23 delivery of northern generation in Manitoba Hydro's
24 current approved Development Plan.
25 Also as approved -- as confirmed by

1 Manitoba Hydro in its August rebuttal evidence, Bipole
2 III is needed to support domestic load in the event of
3 an outage at Dorsey, or the loss of the Bipoles I and
4 II in either the winter or the summer. It is an
5 integral part of the facilities required to deliver --
6 deliver northern generation. And finally, Bipole III
7 does not qualify for inclusion in Manitoba Hydro's
8 transmission tariff based on the MISO four (4)
9 criteria.
10 Based on these facts, I consider
11 Manitoba Hydro's proposed treatment of the Bipole III
12 and Riel converter as generation related assets to be
13 appropriate. Next slide, please.
14 Another transmission related issue is
15 Manitoba Hydro's proposal to allocate interconnections
16 with the US using a weighted energy allocator as
17 opposed to a demand-related allocator such as 2CP.
18 When considering this issue, it is
19 important to note that the winergyal -- weighted
20 energy allocator is meant to capture both energy and
21 capacity considerations. Use of this allocator
22 recognizes that investments in interconnections were
23 made to support both energy and capacity reliability
24 for domestic load with energy reliability actually
25 being more critical.

1 It also recognizes that exports are a
2 fundamental part of Manitoba Hydro's business model,
3 and that Manitoba Hydro's firm export commitments are
4 typically blocks of power over five (5) by sixteen
5 (16) or seven (7) by sixteen (16) periods.
6 The observation has been made that this
7 treatment differs from that used by BC Hydro, which
8 does not separate out interconnections in its cost of
9 service study. However, there are significant
10 differences between the utilities in terms of their
11 use of interconnections. In BC Hydro's case, the
12 utility does not rely on imports or interconnections
13 in its planning process to support domestic load.
14 Also BC Hydro does not enter into firm export
15 contracts.
16 Overall, I view Manitoba Hydro's
17 proposed treatment of the US interconnections to be
18 reasonable and appropriate. I'd like to turn now to
19 slide number 21 if we could, please.
20 I'd like to turn now to the key issues
21 identified by the PUB as being related to the
22 treatment of generation of -- the treatment of
23 generation in the cost of service study. The first
24 issue is the general approach adopt -- adopted by
25 Manitoba Hydro for classifying generation costs, and

1 the fact that it does -- does not specifically
2 classify costs as demand versus energy related before
3 allocating to customer classes.
4 As I noted in my evidence in the June
5 presentation, the classification and allocation of
6 generation cost is the one (1) area in cost of service
7 where experts tend to disagree the most, and where
8 there appears to exist the greatest number of
9 alternatives. Many of these alternatives are
10 different ways of attempting to classify generation
11 cost as demand or energy related and recognize -- in
12 recognition of the fact that generation provides both
13 capacity and energy.
14 The approach that Manitoba Hydro has
15 adopted takes advantage of the fact that it is inter -
16 - that it is interconnected with other electricity
17 markets where the hourly market prices reflect
18 capacity and energy cost considerations, and that
19 these markets actually impact the economics of
20 Manitoba Hydro, both in its day to day operations and
21 its long-term system plans.
22 Rather than attempting to classify
23 generation costs as demand-related and energy related
24 and then allocating each of them separating, Manitoba
25 Hydro uses the prices it charges under its surplus

1 energy program which largely reflect market prices to
2 establish the relative value of the kilowatt hour sold
3 in different periods, and then to weight each customer
4 class's energy in each of those periods for purposes
5 of allocating generation costs.
6 Conceptually I view this as being a
7 superior method as it addresses the classification and
8 allocation of generation costs in a holistic manner
9 that is reflective of costs. And furthermore, it uses
10 costs that are reflective of current conditions.
11 Can we have the next slide, please.
12 The weighted energy approach to classifying and
13 allocating generation costs was introduced by Manitoba
14 Hydro and accepted by the PUB in the 2006 review.
15 However, in this proceeding, issues
16 have been raised regarding the adequacy of the
17 approach. In its August 2015 report, CA Consulting
18 noted that the introduction of MISO's capacity
19 markets, the relative prices for market -- MISO's
20 energy markets may no longer be -- adequately reflect
21 capacity considerations.
22 As a result, Manitoba Hydro has
23 proposed to include a capacity adder in all peak and
24 shoulder periods based on the reference value from its
25 CRP program.

1 The concern I have with this proposal
2 is that Manitoba Hydro calculates the relative
3 weightings it uses in its PCOSS using eight (8) years
4 of historical data, and for purposes of the 2013/'14
5 cost of service study has included a capacity adder in
6 years prior to when the MISO market was actually --
7 for capacity was actually created.
8 Furthermore, the price of capacity as
9 established in these markets has been extremely low,
10 well below the CRP reference value that Manitoba Hydro
11 bases the adder on.
12 In addition, if we look at the relative
13 peak/off-peak energy weights for the post-2009 period
14 and relate it to relative values that are important,
15 in this period after the MISO market opened, and as
16 you'll see on the next slide, the values even without
17 the inclusion of the capacity adder have actually
18 increased such that the facts do not support the
19 theory put forward by CA Consulting.
20 Finally, with respect to the question
21 of what hours or periods the capacity adder, if one is
22 required, should be added, it's useful to note that
23 the use of a single peak hour to determine capacity
24 need is really a simplification of a more
25 comprehensive loss of load or loss of energy analysis

1 that a utility would generally do when it's doing its
2 resource planning, and that in my mind any assessment
3 of the hours which should attract a capacity adder
4 would have to consider at a minimum the results of
5 such analysis.
6 Also, it's interesting to note and
7 perhaps think of how one would align with the
8 inclusion of the capacity adder here with where
9 Manitoba Hydro includes a capacity adder in its
10 current marginal costs where it includes the capacity
11 adder in all peak hours for both the winter and the
12 summer.
13 The next slide, which is slide 23, is
14 the one I've just referenced which sets out the
15 relative energy weightings from the various -- for the
16 various peak periods as established in PCOSS06,
17 PCOSS08, and the current PCOSS14 which is being used
18 in this proceeding.
19 As one can see, the peak period weights
20 in PCOSS14 are higher in all four (4) periods than the
21 weights in the earlier cost of service studies that
22 there's been -- and that there's been no deterioration
23 since the introduction of the MISO capacity market in
24 2009.
25 MR. KURT SIMONSEN: Excuse me, Mr.

1 Harper.

2 MR. WILLIAM HARPER: Sure.

3 MR. KURT SIMONSEN: It's Kurt

4 Simonsen. About ten (10) minutes.

5 MR. WILLIAM HARPER: Okay. Thanks. I

6 -- I should -- hopefully we'll be there. Okay. Now

7 slide 24, please.

8 Based on the preceding, I have

9 concluded that, first, the need for a capacity adder

10 has not been substantiated. However, the need for one

11 may evolve if the MISO mar -- MISO capacity markets

12 mature and the prices established become more

13 material. This is a matter that warrants monitoring

14 and more investigation by Manitoba Hydro going

15 forward.

16 And lastly, if a capacity adder is

17 needed, more work is required to determine the hours

18 in which it should be included which in turn may

19 result in a need for more weighting periods than the

20 twelve (12) currently used.

21 The last key issues I would like to

22 deal with are those related to the treatment of net

23 export revenues. From my perspective, several issues

24 regarding the treatment of net export revenues have

25 developed during the proceeding.

1 First, suggestions have been raised as
2 to whether the RCC ratios prior to the allocation of
3 net export revenues should be used.
4 Second, if net export revenues are to
5 be allocated to customer classes, should it be based
6 on costs to -- of each customer class or some other
7 basis?
8 And finally, if costs are to be the
9 allocation base, is Manitoba Hydro's proposed
10 approach, which excludes certainly dir -- certain
11 directly assigned costs, the most appropriate way to
12 proceed?
13 Turning to the first issue, if we
14 exclude net export revenue from the determination of
15 the revenue-to-cost ratios, then the overall revenue-
16 to-cost ratio for all domestic customers will either
17 be greater or less than 100 percent depending upon
18 whether net export revenue is positive or negative.
19 The question then arises as to how
20 these results should or would be applied for rate
21 setting. One (1) suggestion we've seen is that the
22 ratio should be indexed to 100 percent. However, in
23 its rebuttal evidence, Manitoba Hydro has demonstrated
24 that this approach yields results that are very
25 similar to those -- simply to include net export

1 revenues, but allocated on the basis of each class's
2 revenue.
3 In my view, it is preferable in terms
4 of both transparency and objectivity if one makes a
5 conscious decision as to how net export revenues
6 should be allocated and explicitly incorporates that
7 decision in the Cost of Service Study as opposed to
8 ignoring the issue, and by default having an export
9 revenues allocated and perhaps what may be in some
10 unknown fashion.
11 Another suggestion has been to focus
12 first on the pre-net -- net expo -- net revenue export
13 -- the pre-net export revenue -- revenue cost ratios,
14 that's a mouthful, that are below 95 percent, and
15 ultimately adjust all ratios to 100 percent prior to
16 worrying about net export revenue allocation.
17 Although there are problems with this
18 suggestion. First, depending upon the Cost of Service
19 Study results, net export revenue can be positive or
20 negative. And if negative, it's conceivable that none
21 of the RCC ratios would be -- be below 95 percent or
22 even 100 percent.
23 Second, it's mathematically impossible
24 to move all RCC ratios to 100 percent without either
25 concluding net export revenues or increasing rates.

1 And finally, in my mind and more
2 fundamentally, such an approach ignores that fact that
3 the inclusion of an export class and the calculation
4 of net export revenues was undertaken in the first
5 place so that net export revenues could be calculated
6 and appropriated allocated to customer classes.
7 If we turn to how net -- how net export
8 revenues should be allocated, I consider Manitoba
9 Hydro's proposed approach of allocating them based
10 generally on overall cost attributed to each customer
11 class as being reasonable.
12 Such an approach helps mitigate the
13 problem that arises from using a narrow allocation
14 base, such as strictly generation and transmission,
15 where rates for a particular class is less than export
16 prices, increases in the class' load will increase
17 system cost overall, but the allocation of those costs
18 will fall disproportionately on all cus -- all other
19 classes, which is really inconsistent with the
20 principle of cost/causation.
21 In my mind, Manitoba Hydro's approach
22 is also consistent with what I call the NFAT promise,
23 which Mr. Bow -- Mr. Williams stole from me, which was
24 made in both the Wuskwatim and the Keeyask reviews,
25 which was investments in -- to increase exports would

1 lead to lower costs and rates for all customers over
2 the long-term, which -- which suggested all customers
3 should share equa -- equally in -- in whatever low --
4 lower rates arise over the long-term.
5 THE CHAIRPERSON: Mr. Harper, can I
6 just ask you to clarify?
7 MR. WILLIAM HARPER: Sure.
8 THE CHAIRPERSON: You had mentioned a
9 couple times that net export revenue could be positive
10 or negative. And so your view that the Manitoba Hydro
11 approach is reasonable would not change regardless of
12 that, which circumstance we were looking at?
13 MR. WILLIAM HARPER: No, you're
14 correct. And I guess I'm -- I'm -- given the nuances
15 of where export prices could go in the futures and how
16 Cost of Service studies work, I'm not as convinced as
17 Manitoba Hydro was yesterday that the situation might
18 arise where for a -- for a particular short period of
19 time you might actually see in the Cost of -- Cost of
20 Service Study a negative net export revenue.
21 You should not expect to see it over
22 the long-term, because -- because net export revenues
23 are over the long -- long-term are expected to be
24 positive. That was part of why we -- why we're
25 engaged in the -- in the export markets. But for a

1 particular year, I -- I'm not convinced you -- that --
2 that result could -- could actually come to pass.
3 THE CHAIRPERSON: But regardless, you
4 agree --
5 MR. WILLIAM HARPER: Yes, regard --
6 regardless, I guess -- I mean, what's good for the
7 goose is good for the gander, if I can put it that
8 way.
9 THE CHAIRPERSON: Thank you.
10
11 CONTINUED BY THE COALITION:
12 MR. WILLIAM HARPER: The final issue
13 regarding the treatment of net export revenue is a
14 specific allocation base that Manitoba Hydro uses in
15 the extent to which it excludes directly assigned
16 costs.
17 I agree with the general approach,
18 which is to include costs that are viewed as being
19 part of Manitoba Hydro's obligation to serve, but
20 exclude those costs that Manitoba Hydro incurs on
21 behalf of customers for reasons that go beyond this
22 obligation, i.e., costs associated with assets
23 considered to be customer equipment behind the meter.
24 Manitoba Hydro's application -- could I
25 have slide 26, please? Manitoba Hydro's application

1 of this principle results in both DSM costs and those
2 assets that are directly assigned to street lighting
3 and sentinel lighting bring excluded from the
4 allocation base for net export revenues.
5 And issues have been -- have arose with
6 both of these cost categories in this proceedings. In
7 the case of street and sentinel lighting assets, the
8 issue is that the cost -- the issue is that the cost
9 being excluded consist of both distribution assets
10 linked to the obligation to serve, as well as light
11 fixtures and lightbulbs, which would more typically
12 fall under the category of the behind the meter
13 customer equipment costs.
14 Complicating the matter is the fact
15 that Manitoba Hydro's accounting records do not allow
16 these two (2) types of costs to be separated.
17 However, in my view there are other approaches that
18 exist for making a reasonable separation of these
19 costs.
20 For instance, Manitoba Hydro and the
21 lighting owners could agree on what are more typical -
22 - what are the more typical installation
23 configurations, a cost split established for the --
24 would be identified for these and those cost splits
25 would be applied to the pool of costs overall.

1 Alternatively, those familiar with the
2 installations could be asked to provide their
3 professional judgment. And I must add that in many
4 utilities and many instances the allocation factors
5 are based on -- on professional judgment for the
6 people who are actually involved in the utility.
7 With respect to DSM, it has been
8 suggested that if these costs provide a system
9 benefit, they are incurred as part of Manitoba Hydro's
10 obligation to serve. This -- this is consistent with
11 the approach that I recommend for the treatment of DSM
12 under which DSM cost would be all -- would be included
13 in the allocation base for net export revenues.
14 Finally, we can go to the last slide,
15 as well as the recommendations I have made on various
16 aspects of Manitoba Hydro's cost of service study I
17 have a few more general conclusions and observations
18 I'd like to finish with, and ask the Board to
19 consider.
20 The first is the cost of service
21 studies will reflect the unique attributes of the
22 utility concerned in terms of system configuration,
23 generation mix, its relationship with neighbouring
24 markets, and the legislative and policy context they
25 operate in. As a result, cost of service

1 methodologies and results will vary by utility.
2 The second is that cost of service
3 studies are not static. They should evolve with the
4 utility's environment as the system configuration and
5 operation changes, as legislative and policy context
6 within which the utility work changes, and as
7 information and analytical capability improve.
8 Finally, I -- I believe it is
9 reasonable to say that Manitoba Hydro's cost of
10 service study is a work in progress, and if there are
11 areas where the PUB believes there are insufficient
12 facts to make a definitive decision at this time, it
13 should direct Manitoba Hydro to work with its
14 stakeholders to -- to flush out the missing pieces.
15 In the meantime, imperfections in cost
16 of service were one of the reasons why regulators use
17 zones of reasonableness when considering the
18 application of the results. Indeed the bands
19 established for utility zones are reasonable, and
20 frequently reflect the confidence parties have in the
21 cost of service study.
22 And with that -- and with that, that
23 concludes my comments. Thank you.
24
25 (BRIEF PAUSE)

1 THE CHAIRPERSON: Thank you, Mr.
2 Harper. So if we can take a break, and come back at
3 11:17.
4
5 (PANEL RETIRES)
6
7 --- Upon recessing at 11:06 a.m.
8 ---- Upon resuming at 11:20 a.m.
9
10 THE CHAIRPERSON: All right. Ms.
11 Pambrun, please.
12 MS. DENISE PAMBRUN: Thank you very
13 much, Madam Chair.
14
15 OPENING COMMENTS BY MS. DENISE PAMBRUN:
16 MS. DENISE PAMBRUN: City of Winnipeg
17 is prepared to make its presentation. I have with me
18 a representative of my client, the City of Winnipeg,
19 Mr. Bruce Chin, and you will hear the evidence this
20 morning of Mr. John Todd, president of Elenchus. You
21 have his CV obviously marked as an exhibit. I
22 understand he's already been sworn as a witness in
23 these proceedings, and his presentation is before you.
24 If anyone requires hard copies, I believe the Board
25 secretary has a few spare copies.

1 MR. KURT SIMONSEN: Not any more.
2 MS. DENISE PAMBRUN: They're going --
3 they're --
4 MR. KURT SIMONSEN: They're going
5 fast.
6 MS. DENISE PAMBRUN: -- they're going
7 like pancakes. All right. They're flying off the
8 shelf. So we will have Mr. Todd proceed with his
9 evidence.
10 MR. KURT SIMONSEN: For the record,
11 Ms. Pambrun, this will be City of Winnipeg Exhibit --
12 MS. DENISE PAMBRUN: Oh, I'm sorry --
13 MR. KURT SIMONSEN: -- number --
14 MS. DENISE PAMBRUN: -- sixteen (16).
15 MR. KURT SIMONSEN: -- 16.
16
17 --- EXHIBIT NO. COW-16: City of Winnipeg
18 presentation
19
20 MS. DENISE PAMBRUN: That's correct.
21
22 CITY OF WINNIPEG PANEL:
23 JOHN TODD, Previously Sworn
24
25 PRESENTATION BY CITY OF WINNIPEG:

1 MR. JOHN TODD: Good morning, Madam
2 Chair, and panel. Pleasure to be back here in front
3 of you. As you see form the first slide which has a
4 title 'The Treatment of next -- Net Export Revenue and
5 the Allocation Thereof' my comments are limited to
6 issue B as identified in the August 25th letter. That
7 limitation reflects the scope of my evidence, and the
8 scope of the -- my client's intervention, the City of
9 Winnipeg. Slide, please.
10
11 (BRIEF PAUSE)
12
13 MR. JOHN TODD: This is a slide you
14 saw yesterday. Allocation of NER to GT&D is
15 reasonable. It was flagged as generally supportive.
16 Todd was included in that list. Click, please.
17 Generally supportive, yes and no.
18 Supportive of the general concept, not supportive of
19 what I could refer to as simplistic detail around the
20 prob -- there's a problem in definition of 'D'. 'D'
21 of course is the distribution part of generation,
22 transmission, and distribution. Hydro excludes
23 directly allocated assigned costs in its cost
24 allocation model as filed. Next, please.
25 So where do we agree and where do we

1 disagree. Well, firstly as Hydro mentioned in its
2 presentation yesterday it is seeking in the cost
3 allocation model reasonability. I like that term. I
4 suppose you could say "reasonable," but reasonability,
5 yeah, I'll take that. We agree.
6 That's a goal of the cost allocation
7 model. It is seeking fairness. And, in particular,
8 we're talking about the allocation of net export
9 revenue. As you've heard already this morning, the
10 driver there to the methodology is fairness, not the
11 pure cost -- cost causality principles that drive most
12 of the model. Fairness is -- is a stronger play when
13 it comes to the allocation of net export revenue.
14 Where we disagree, and I'm not even
15 sure we disagree that much, Hydro treats directly
16 assigned costs as second class costs. They -- these
17 costs, these directly assigned costs, do not merit a
18 share of net export revenue. That is where we
19 disagree, whether they should be treated as second
20 class costs. The next slide, please.
21 So again, going back to the Manihybro -
22 - Manitoba Hydro cost of service overview, so you can
23 see to slide 4 from yesterday, they said several
24 things that I think are important in the context of
25 this issue that I agree with. There's no one (1)

1 right answer. Good judgment must prevail. As such,
2 reasonable -- reasonability is sought, not perfect.
3 Click, please. I agree entirely with that. Next
4 slide, please.
5 On slide 25, why does Manitoba Hydro
6 have an export class at all, it's to more fairly share
7 export revenue among Manitoba customer classes. No
8 export class in the past led to an unfair sharing of
9 export revenue. Changes were made to try to achieve
10 greater fairness. Click, please. Again, I agree
11 entirely.
12 The use of the export class is
13 reasonable, a reasonable and transparent mechanism to
14 accomplish appropriate sharing of export revenue
15 between cla -- customer classes is required. Once
16 reasonable costs are allocated to the export class,
17 residual NER is allocated to GT&D that can reduce
18 absolute and relative distortions of cost
19 responsibility by class for Manitobans. Again, I
20 agree. The next slide.
21 Now I want to go back to Manitoba
22 Hydro's May 2016 slides, slide 47, as you can see, the
23 one (1) slide in the workshop number 1 which dealt
24 with the treatment of NER in the cost of service.
25 NER is viewed as a system dividend to

1 be shared in a fair and equitable manner and is
2 allocated based on total allocated costs. Those exact
3 words are very important here, "total allocated
4 costs."
5 The majority of export revenue is
6 continued to be used to offset generation transmission
7 costs which represent 71 percent of allocated costs.
8 CA is supportive of cur -- current NER treatment.
9 Agree, but...
10 So the wording on that slide was:
11 "NER is viewed as a system dividend
12 to be shared in a fair and equitable
13 manner and is allocated based on a
14 to -- on total allocated costs."
15 Now, if we actually go back to Manitoba
16 Hydro's evidence of December 4th, 2015, page 17 to 19,
17 they said:
18 "Manitoba Hydro agrees with CA that
19 the allocation of net export revenue
20 on the basis of each class total
21 cost of service is a reasonable
22 perspective of fairness and will
23 continue with this allocation
24 approach for the following reasons."
25 I've -- the emphasis underlying is my

1 addition. The wording has changed from the original
2 filing to workshop number 1. The reasons given, the
3 rationale behind that treatment, number 1, are two
4 reasons:
5 "Weight is also given to fairness
6 and efficiency objectives, the
7 allocation of NER on the basis of
8 total cost to serve --"
9 -- again, the phrasing is, "total cost
10 to serve," not total allocated costs:
11 "-- results in an improvement in the
12 equitable sharing of export revenue
13 between customer classes."
14 The export benefit provided to
15 residential customers increases to 70 percent of that
16 received by the GSL greater than one hundred (100)
17 class compared with 62 percent of that received by the
18 GSL greater than one hundred (100) under the past
19 approach.
20 And the second -- next slide, please --
21 the allocation of net export revenue on total cost --
22 again total cost -- is consistent with cost of service
23 treatment of net income. You can read the rest at
24 your leisure.
25 Next slide, please. So firstly, let's

1 be clear on definitions here. The evidence uses the
2 word "total cost to serve." And when you actually
3 look at the model, the model is not consistent with
4 what it says in the original evidence.
5 I won't go to worksheets in the model,
6 but I'll point out to you that there is a total cost
7 worksheet. And in that worksheet, total cost is
8 calculated as total allocated cost plus direct cost.
9 So using the words and the definitions in the model
10 itself, total cost to serve would seem to be total
11 allocated costs plus direct costs.
12 It would appear to me that Manitoba
13 Hydro thought when it filed its evidence that it was
14 allocating costs on the basis of total cost to serve,
15 as it said. And that is quite reasonable.
16 We have heard from Ms. Derksen that --
17 if we can go to transcript page 71 from yesterday and
18 go down to lines 22 to 25:
19 And so I -- when we decided on the
20 GT&D allocator way back when, it
21 wasn't explicitly with the intention
22 of excluding directly-assigned
23 costs."
24 You actually have to go to one
25 worksheet in the model, and there are four (4) or five

1 (5) cells where you see the direct cost deducted from
2 the allocated -- sorry, deducted from the total costs
3 to get back to the allocated cost to use as an
4 allocator.
5 It is very easy to miss. Nobody cared
6 about it because it's a minor matter. The City cared
7 because it was significant to them, so I looked at it
8 closely. Nobody else did. So this issue to me was
9 actually not really thought through very carefully.
10 Now, since we got the transcript up, if
11 you can slide up to page 70, lines 6 to 12, Mr. Peters
12 was asking a question:
13 "So if Manitoba Hydro believes it's
14 fair to return to the net export
15 revenue based on generation,
16 transmission, and distribution as
17 allocated, why is it not fair to
18 return the net export revenue based
19 instead on the total costs which
20 include generation, transmission,
21 distribution, and directly assigned
22 costs?"
23 And if you go down to the bottom of
24 that page, the beginning of that answer at lines 22 to
25 25 is:

1 "It is not unreasonable to take the
2 perspective that the treatment of
3 net export revenue be made available
4 to those customer classes, including
5 direct assigned costs."
6 And you go to the top of the next page:
7 "We think what we're doing is
8 reasonable. It doesn't mean other
9 things are unreasonable. As we sit
10 here, we're listening to
11 perspectives. We're listening to
12 the perspectives of the City of
13 Winnipeg in particular, to Mr.
14 Borman -- Mr. Bowman, Mr. Harper."
15 And lower on that page, at the bottom
16 of the page, she says -- Ms. Derksen says:
17 "This one in particular is a more
18 subjective. It's quantum money
19 sitting there available to be used
20 to offset cost to Manitobans, and so
21 we decided on the GT&D allocator way
22 back then, which is what we started
23 with."
24 Okay. So using the definitions that
25 Hydro has been using, if we go back to the -- to this

1 slides, it sounds to me that there isn't disagreement
2 and that if I were to take my proposals that Manitoba
3 Hydro would be in the category of, I'm not sure
4 whether supportive or generally supportive, but we may
5 hear about that in final argument.
6 I may inter -- interpret as being
7 supportive of the approach being proposed by myself as
8 being a -- another reasonable approach. Okay.
9 So I would point out that it appears
10 the issue is not thought through explicitly, because
11 Manitoba Hydro, as they've said throughout this
12 proceeding, were focussed on the big issues. This is
13 a small issue. There's nothing in the CA evidence,
14 nothing in the Hydro original evidence that explicitly
15 addressed the issue of whether directly allocated
16 costs -- sorry, directly assigned costs should be
17 included or not.
18 That's the last bullet here. There's
19 no evidence that either Manitoba or CA thought about
20 this allocation method in preparing the Cost of
21 Service methodology redo -- review. They can
22 disagree, but there's no evidence on the record of it.
23 So let's think about the issue
24 carefully. Now, first of all, what costs are directly
25 assigned? To be directly assigned costs that are --

1 costs that are caused exclusively by a single customer
2 class must be separately tracked in the Manitoba Hydro
3 accounts. Otherwise, they have to be allocated.
4 Some -- this creates some arb --
5 arbitrary distinctions. And I think we heard about
6 that yesterday when Ms. Pambrun was -- was questions
7 Ms. Derksen. That discussion back and forth, the
8 transcript is lengthy on it, so I'll just summarize.
9 Needers and line drops, as Ms. Derksen
10 said, are conceptually exactly the same. There --
11 there are charge -- are directly charged to
12 residential customers. It's not a direct allocation.
13 It doesn't appear on the page that is called 'direct
14 costs'.
15 That's because the accounting system
16 keeps track of meters and line drops for more than one
17 (1) class together. And so the costs that are
18 equivalent to the poles and wires of street lighting,
19 are allocated to classes based on a weighted customer
20 count.
21 Now, as it happens, Manitoba Hydro
22 knows exactly what the cost is of dedicated poles and
23 wires. So although they are equivalent costs, they
24 get directly allocated. And as a consequence, we end
25 up with them being treated differently than the meters

1 and line drops of residential customers.
2 And this is an artifact of the
3 accounting system. It's not because they're
4 different. So they're conceptually the same. They
5 are treated differently in terms of who get allocated
6 net export revenue. That would appear inequitable.
7 It would seem to be a no-brainer to treat it
8 differently, but there's always a 'but', because this
9 is a complicated world, a complicated process.
10 Next slide, please. So why is there
11 disagreement? Well, ARL costs, direct costs also
12 include luminaires. Luminaires are more like
13 residential appliances rather than being like meters
14 and line drops. So that makes it -- you sit back and
15 say, Well, if the street lighting direct costs are
16 equivalent to fridges and stoves, as you heard in
17 workshop number one, they should not be something that
18 attracts the net export revenue, which is a flow back
19 of the benefit of the exports to all customers.
20 Why should street lighting get
21 something based on luminaires when residential
22 customers can't get it based on their stoves and
23 fridges and their own lights?
24 So that creates a dilemma. If you
25 include directly assigned costs in allocating NER,

1 that creates an unequal treatment. Luminaires would
2 be included when you -- if you include all of the
3 directly assigned costs because it happens that the
4 luminaires are supplied by Manitoba Hydro, and
5 customers supply their own lights inside their houses.
6 So the only way -- and the flip side,
7 of course, to that dilemma is if you exclude --
8 exclude directly allocated costs then you're excluding
9 the costs associated with the poles and wires that are
10 used for street lighting which are equivalent to the
11 drops and metres of residential customers.
12 What we end up with is whatever you do
13 is not perfect. Whatever you new -- do has a little
14 bit of unfairness in it. So the bottom line here, the
15 resolution requires reasonability, not perfection.
16 Going back to Hydro's slide, as such reasonability is
17 sought, not perfection. I agreed with that. Okay.
18 So in this case what's the tradeoff between perfection
19 and reasonability? Next slide, please.
20 Perfection for ARL would mean let's
21 separate out the cost associated with poles and wires
22 from the luminaire costs. I think that's what Mr.
23 Harper was suggesting just moments ago, just before
24 the break. Then we could include the directly
25 allocated -- directly assigned costs associated with

1 poles and wires, and exclude those costs associated
2 with luminaires.
3 Now, as Mr. Harper pointed out, Hydro
4 doesn't track those costs. So we have three (3)
5 reasonable approaches that are feasible and simple.
6 One (1) reasonable approach is to say: Leave all the
7 costs in. Just use -- just use all the direct costs
8 and, yes, there's a slight over allocation but we
9 won't worry about it. We could leave all the direct
10 costs out, which is what's currently being done, or we
11 could try to divvy it up.
12 MR. KURT SIMONSEN: Ten (10) minutes,
13 please, Mr. Todd.
14 MR. JOHN TODD: Which approach best
15 achieves the intended results? Well, the intended
16 result is: Why does Manitoba Hydro use an export
17 class? It's all about being fair. Let's think about
18 -- for a moment about the direct costs.
19 Every class has some direct costs.
20 This -- these numbers come from workshop number 2, one
21 of my slides in that presentation. Here are the costs
22 that each class has that are direct -- direct costs.
23 Diesel is a significant share. Notably diesel costs
24 are included for purposes of allocation of net export
25 revenue. Essentially all their costs are directly

1 allocated because they're a stand-alone system, so
2 they would get none of the benefit of net export
3 revenue if you excluded direct costs for that class.
4 So you have one (1) class with that different
5 treatment. ARL has significant costs. They are
6 included.
7 If we go to the next slide, which is
8 reproduced from Exhibit COW-7 from workshop number 1,
9 it shows you how significant the direct costs are for
10 different classes, which illustrates why area and
11 roadway lighting cares about this issue.
12 If you go down that yellow highlighted
13 list to the right you'll see diesel, 100 percent of
14 their cost are direct, 70 percent of area and road
15 lighting costs are direct. Big difference to them.
16 With the exception of the SEP classes, everybody else
17 is 1, 3, 4 percent of their costs.
18 So it brings me to my conclusions.
19 Hydro has acknowledged throughout the review that --
20 that it has focussed its efforts on the more
21 significant cost allocation issues. The inclusion or
22 exclusion of directly assigned costs for allocating
23 NER is not a big dollar issue for Hydro. The evidence
24 that's been filed does not refer directly to this
25 issue.

1 I observe that it appears that neither
2 CA nor Manitoba Hydro really was concerned about this
3 and thought about it carefully, it just what -- is
4 what was -- existed previously.
5 Neither exclusion or inclusion is
6 perfect. In my view, inclusion is more fair and more
7 reasonable than exclusion for all cas -- classes. We
8 can't be sure of that without actually determining how
9 many of the costs are the poles and wires versus the
10 luminaires themselves, but the luminaires would appear
11 to be less of a cost than a pole and wires.
12 It matters for diesel; it's included
13 for them. It matters for ARL; it should be included
14 for them. The Bill Harper alternative of using some
15 sort of judgment would be an alternative. A further
16 option would be, in 1989 Manitoba did its last cost-
17 of-service study for street lighting. That study was
18 filed in response to a City of Winnipeg Information
19 Request in the '15/'16 GRA.
20 The City has hoped that Manitoba Hydro
21 would update that study at some point. When it does,
22 it could address this issue. That would be the right
23 time to divvy it up. In the meantime, it would seem
24 that it would be simpler to simply include direct
25 costs in the costs being used to allocate net export

1 revenue. Thank you.

2 BOARD MEMBER GRANT: Can I just --

3 just so I've got the order of magnitude? On the

4 slide, are these -- are these thousands of dollars?

5 That's --

6 MR. JOHN TODD: Yeah, those -- those

7 would be thousands of dollars. Sorry, yes. Sorry.

8 Manitoba Hydro's filings --

9 BOARD MEMBER GRANT: Yeah, no.

10 MR. JOHN TODD: -- yes.

11 BOARD MEMBER GRANT: I just wanted to

12 make sure I was following the --

13 MR. JOHN TODD: Yes, you're right.

14 BOARD MEMBER GRANT: And just quickly,

15 why 01? Like, in the interim, why all in, all out?

16 Why not take somebody's informed guess?

17 MR. JOHN TODD: That would be

18 reasonable. Manitoba Hydro's approach -- and,

19 frankly, the slides are written before Mr. Harper made

20 his comments this morning. And I think I have

21 suggested the same thing in workshop number 2, that we

22 divvy it up through some sort of judgment.

23 Judgment is best when it's informed by

24 some facts. I suppose there's design consideration

25 could do it; that would certainly be feasible.

1 Manitoba Hydro has consistently through this process
2 said, Let's try to go with simple approaches.
3 I work with other utilities and their
4 cost allocation. Every time management's involved
5 there's two (2) implications. One (1) is you've got
6 to spend time thinking about it. In fact, some of
7 these things are hard. It sounds like simple, just
8 pull it out of the air. But companies are trying to
9 be conscientious, and so they're going to try to find
10 some information and come up with a way of doing it,
11 so it's -- it's not trivial.
12 And, number 2, whenever management
13 judgment's involved for clients that I do cost
14 allocation studies for, those are always the issues
15 that are controversial, so it's -- it's a simplicity
16 issue.
17 THE CHAIRPERSON: Thanks, Mr. Todd.
18 Mr. Monnin, are you going to relocate? Okay.
19
20 (PANEL RETIRES)
21
22 THE CHAIRPERSON: Me. Monnin, s'il
23 vous plait.
24 MR. CHRISTIAN MONNIN: Merci, Madam
25 President.

1 GSS/GSM GROUP PANEL:

2 A.J. GOULDING, Previously Sworn

3

4 OPENING COMMENTS BY MR. CHRISTIAN MONNIN:

5 MR. CHRISTIAN MONNIN: Just a couple

6 of clean up issues. As you know, we -- we jumped the

7 queue today. We made place for -- we're taking Green

8 Action Centre's slot, which was thirty (30) minutes,

9 or I believe more than that, but our -- our slot is

10 thirty-five (35) minutes, just to -- to make sure that

11 everyone's on the same -- on the same song book.

12 I have a few questions for Mr.

13 Goulding, and a couple comments with regards to

14 evidence, and -- and then we'll proceed.

15 Mr. Goulding, you're here on behalf of

16 the general service small and general service medium

17 customer classes to assist the Public Utilities Board

18 in understanding the views and position of the GSS and

19 GSM customer classes in respect of Manitoba Hydro's

20 cost of service study methodology review application.

21 Is that correct?

22 MR. A.J. GOULDING: Yes, that is

23 correct.

24 MR. CHRISTIAN MONNIN: Your firm,

25 London Economics International, prepared a review of

1 Manitoba Hydro's cost of service methodology on behalf
2 of the GSS and GSM customer classes. Is that correct?
3 MR. A.J. GOULDING: Yes, that is
4 correct.
5 MR. CHRISTIAN MONNIN: And your firm,
6 London Economics International, also prepared rebuttal
7 evidence on behalf of the GSS/GSM customer classes.
8 Is that correct?
9 MR. A.J. GOULDING: Yes, that is
10 correct.
11 MR. CHRISTIAN MONNIN: Were the review
12 report and the rebuttal report prepared by you, or
13 under your supervision?
14 MR. A.J. GOULDING: Yes.
15 MR. CHRISTIAN MONNIN: There were also
16 slide presentations prepare -- prepared for the
17 present -- for presentation of the review and the for
18 the purposes of today's concurrent evidence. Is that
19 correct?
20 MR. A.J. GOULDING: Yes.
21 MR. CHRISTIAN MONNIN: Were these
22 prepared by you, or under your supervision and
23 control?
24 MR. A.J. GOULDING: Yes.
25 MR. CHRISTIAN MONNIN: And do you

1 adopt the evidence that's been provided by London
2 Economics International in these proceedings?
3 MR. A.J. GOULDING: I do.
4 MR. CHRISTIAN MONNIN: Mr. Secretary,
5 the CV of Mr. A. J. Goulding is Exhibit 10-1. He was
6 sworn in earlier this year. We also have Mr. Jarome
7 Leslie, who was sworn in. He'll be here just to give
8 support to -- to the expert witness. His CV was
9 Exhibit 10-3. And I believe this -- the presentation
10 slide deck will be Exhibit 15.
11 MR. KURT SIMONSEN: Thank you very
12 much.
13
14 --- EXHIBIT NO. GSS/GSM-15: Presentation Slide
15 deck
16
17 PRESENTATION BY GSS/GSM CLASS:
18 MR. A.J. GOULDING: Thank you. It's a
19 pleasure to be here today once again in -- in
20 Winnipeg. As -- as Christian mentioned, we were -- if
21 we go to slide 3, LEI was retained to represent the
22 interests of the general service small and medium non-
23 residential customers. And as -- as you can see on --
24 on slide 3, if we go back a slide.
25 I apologize that it doesn't show up as

1 elegantly as we would have liked in this -- in this
2 format, but as -- as you can see our -- the -- the
3 customer classes that LEI represents account for a
4 little bit less than 30 percent of the revenue
5 requirement. And so while our discussion today
6 focusses on the key issues that have been identified
7 for this hearing, we do want to continue to emphasize
8 that the concerns for our customer class also include
9 the revenue to cost ratios which we hope will be a
10 focus of in future proceedings.
11 Now, in our discussions today we cover
12 the treatment of export costs of the net export
13 revenue of generation and transmission assets, and of
14 demand-side management. And we want to echo the
15 comments of other speakers today that there are a
16 variety of reasonable approaches that can be
17 considered, and often on some of these your
18 perspective depends upon where you sit.
19 Cost allocation is more of an art than
20 a science, and there are many aspects of Manitoba
21 Hydro's approach that -- that we agree with. And so
22 while we have drawn out some key issues, we do want to
23 keep the -- the big picture also in mind. And if we
24 can go to slide 5? Thank you.
25 So with regards to the four (4) key

1 issues, we wanted to summarize our positions on these
2 before we proceeding to providing more detail.
3 First, on the issue of the allocation
4 of fixed costs to export sales, the proposed approach
5 is to assign these only to dependable export sales, 50
6 percent of total exports. Our recommendation, as we
7 will discuss shortly, is that the fixed costs be
8 allocated to 63.8 percent of export sales.
9 If we turn to the allocation of the net
10 export revenues, the proposal is that they be based on
11 a share of allocated costs. We believe that they
12 should be based on a share of total costs, both
13 allocated and direct.
14 On treatment of generation and
15 transmission assets, while LEI generally supports the
16 use of the weighted energy allocator, we do have
17 concerns about the capacity adder. And we think that
18 some further study may be warranted in that regard.
19 Turning to the treatment of DSM costs
20 which are proposed to be directly allocated to
21 participating classes, we propose that these be
22 classified as demand and allocated using the winter
23 and summer peak allocator adjusted for losses.
24 Overall, as we'll discuss, we view these as a resource
25 that should be attributed to peak energy.

1 If we turn to slide 7, so as we've
2 said, currently fixed costs are assigned only to what
3 are referred to as "dependable" exports, and those are
4 viewed as 50 percent of total export sales.
5 And this methodology we believe is --
6 is a bit at odds with the way in which the various
7 assets have been selected both in terms of the types
8 of technology and the timing. We believe that
9 sustained export sales, both opportunity and firm,
10 have played a role in advancing generation
11 investments, and potentially in the type of technology
12 and sizing.
13 And we've noted that there are -- there
14 is support for this position both in the Needs For and
15 Alternatives To that was put forth in 2014 where the
16 assumption is that all surplus energy can be sold in a
17 variety of ways. And indeed, over time, the trading
18 strategies may change with regards to exports.
19 So we've seen support that investments
20 have been made a bit earlier, and that that in turn is
21 attracting additional revenues also from the
22 opportunity market. And we've seen discussion that
23 all surplus energy plays into the decision-making
24 process.
25 Now, if we go to slide 8, in

1 Undertaking 34, we identified two (2) facilities that
2 were advanced partially on the basis of opportunity
3 exports. So we'll look at Limestone, and we'll note
4 that the
5 "...extra year of advancement will
6 allow for the profitable sale of
7 additional interruptible energy."
8 And more generally at Wuskwatim. The
9 advancement was to obtain additional export revenues
10 and -- and profits.
11 Now, if -- if we turn to slide 9, we
12 have augmented our previous analysis of what we
13 believe should be a reasonable lower bound of expected
14 exports and with the additional data, we have examined
15 what the -- relative to the average over the period
16 for which data was provided to us, what two and a half
17 (2 1/2) standard deviations would be above and below.
18 And we've conservatively chosen as the
19 lower bound a point that is two and a half (2 1/2)
20 standard deviations below the average as something
21 that would be reasonably representative of expected
22 export volumes. And you'll note that this lower bound
23 remains below the volumes of actual exports within
24 this particular time horizon.
25 So what we have suggested is that the

1 view of reasonably expected exports should be expanded
2 by moving approximately 13.8 percent from opportunity
3 exports into what we would call reasonably expected.
4 So whether you want to say that we're adding that to
5 dependable or we're changing slighting the description
6 of the classes, either way, we're essentially looking
7 at this the way a financing party would be.
8 If you were going to a bank and you
9 were presenting your reasonable worst-case scenario,
10 this would be the way that a -- a financing party
11 would -- would think about it. So we've examined that
12 data from a variety of perspectives within the
13 constraints of the data that was provided to us.
14 So on slide 10 you'll see that we
15 performed further analysis looking at the ten (10)
16 year slices that existed within the data that was
17 provided and we note that when we look at each of
18 those ten (10) year slices, the range of 57 to 87.5
19 percent encompasses our recommended approach.
20 And that recommended approach, obviously, is taking
21 into account these sixteen (16) periods.
22 Now, if we move to the next slide,
23 slide 11, we want to emphasize that we worked with the
24 data that we were provided. And what we would also
25 point out is that while we have high regard for

1 Manitoba Hydro's analytic cap -- capabilities, and the
2 work that they've done, and the data that they have,
3 we're not convinced that in all cases more data is
4 better data.
5 And so we believe that there are
6 several instances in which it may not, in fact, be
7 appropriate to use the one hundred (100) year
8 hydraulic flow and we also believe that given the way
9 that circumstances have changed over the past twenty
10 (20) years, in particular, that using a shorter time
11 period may well be appropriate.
12 So we've seen, since 1970, seven (7)
13 major inner connections. Since 1974 we have seen
14 nearly 4,000 megawatts of additional hydro. And that
15 suggests that export patterns will have been
16 significantly different in more recent periods than --
17 than in the past. And that's why we do believe it's
18 appropriate to weight the analysis to -- to more
19 recent periods.
20 And we would note that it would be
21 worthwhile to be able to have a more fulsome
22 discussion of the dependable opportunity split.
23 Manitoba Hydro has noted that it's based on an
24 integrated financial forecast incorporating dependable
25 and average water flows, but it would be helpful for

1 other Intervenors to be able to replicate test that
2 analysis with further data. We move to the next
3 slide.
4 We would also emphasize that it's
5 important to think about the difference in the
6 approach with regards to the question of reliability.
7 What -- what we're focussing on is simply the
8 probability that a lower bound of exports will exist
9 because, as we've said, when you think about building
10 this new facility you are taking into account not just
11 the firm sales, but also you're assuming that some
12 degree of opportunity sales will exist.
13 And so this question of reliability,
14 from an engineering perspective, is different from the
15 question of what can reasonably be expected from a
16 financial perspective. Our focus is on the
17 probability of realization, it is not on whether a
18 particular sale embodies within it a one (1) in ten
19 thousand (10,000) hours loss of load probability or is
20 backed by firm capacity.
21 So if we move then from this issue of
22 the treatment of net export cost to the treatment of
23 net export revenue and go to slide 14. We share the
24 concern with regards to the exclusion of direct costs.
25 And we believe that it is more appropriate to allocate

1 based on total costs rather than allocated costs and
2 that there are principles of -- of fairness that --
3 that are involved.
4 Now, for our customer class there's
5 less of an issue with distinguishing between the
6 luminaires and the infrastructure that supports the
7 luminaires. But, nonetheless, from the perspective of
8 our customer class, we believe that the direct
9 assignment is -- is more appropriate.
10 Now, in addition, there's been
11 discussion of the treatment of the uniform rate
12 adjustment and the affordable energy funds. And,
13 obviously, as witnesses, we -- we have the luxury of -
14 - of perhaps thinking about the world in a theoretical
15 way that's less burdened by the statutes. And we
16 understand that in some ways you may be constrained by
17 the -- the language within them.
18 Nonetheless, neither the uniform rate
19 adjustment nor the affordable energy fund currently
20 are incorporated into rates in a way that reflects
21 cost/causation.
22 And there are some additional concerns
23 about the way in which these costs are allocated.
24 Both of these measures are redistributive in nature,
25 and in -- in that sense the way in which they are

1 implemented bears some similarities to the way in
2 which you would try to implement a tax.
3 And it's potentially problematic to the
4 customers in our customer class, in particular the
5 Affordable Energy Fund. If I'm a small dry cleaner,
6 for example, I don't have the ability necessarily to
7 draw on something like the Affordable Energy Fund, but
8 I have to pay for it. And if ultimately that pushes
9 my costs up to the point where I'm no longer
10 competitive, I go out of business.
11 If I'm a small residential consumer and
12 I fall into financial distress, I do have access to
13 this Affordable Energy Fund. So the Affordable Energy
14 Fund serves as a form of social insurance for a
15 particular customer class, and not all customer
16 classes can benefit from that. So there are concerns
17 about the way in which that is allocated.
18 Now, if we turn to the uniform rate
19 adjustment, arguably some members of the customer
20 class that -- that we represent in different areas of
21 the province may well benefit from that. And some
22 thought may need to go into how the costs and benefits
23 are attributed.
24 Again, we note that all of this is in a
25 perfect world where the Board has complete flexibility

1 to do things based on economic principles, and that
2 flexibility may not exist within the -- within the
3 statutes. Nonetheless, we -- we do believe that this
4 -- both of these public policies are outside of the
5 realm of cost causation.
6 Moving to the treatment of generation
7 and transmission assets, if we go to slide 16, so
8 there are a number of interesting aspects with regards
9 to this topic. And we generally agree with the use of
10 the weighted energy allocator.
11 However, it's striking how often people
12 like to use market-based solutions when they produce
13 the results that they like, and then assume market
14 failure when the market produces results that they do
15 not like.
16 And so there is a concern about a mix-
17 and-match approach in which we say, Well, we don't
18 think that the energy market in the Mid-Continent ISO
19 adequately reflects scarcity rents.
20 We don't believe that the Mid-Continent
21 ISO knows what it's doing with regards to establishing
22 a capacity market to correct that problem. And so
23 we're going to accept Mid-Continent ISO energy prices,
24 but we're going to throw out their capacity prices and
25 we're going to add our own.

1 And so when we look at the comparison
2 between the current capacity market clearing prices in
3 -- in the Mid-Continent ISO, and we compare that to
4 the proposed capacity adder here in Manitoba, we -- we
5 do have some concerns. And we note that this design
6 essentially would set the cost for capacity that's
7 used in the energy allocator at the upper bound of
8 what -- what the value of capacity would be.
9 Now, as we're all aware the capacity
10 market design in the Mid-Continent ISO is evolving,
11 and may well result in differing prices in the future
12 but given the dynamic nature of the issue we do
13 believe that -- that this is something that should not
14 -- that the capacity -- the incorporation of capa --
15 of a capacity adder should not be incorporated at this
16 time, and should be subject to further study.
17 MR. KURT SIMONSEN: Ten (10) minutes,
18 please, approximately.
19 MR. A.J. GOULDING: Thank you. So if
20 we move to our final slide here on slide 18, turning
21 to the classification and allocation of DSM, as we've
22 heard the cost of DSM programs are directly attributed
23 to the individual participating customer classes. And
24 we have seen that it is accepted that there are system
25 wide benefits from DSM.

1 We have a quote from Manitoba Hydro's
2 web site stating that reductions in domestic demand
3 have contributed to electricity surpluses, and in turn
4 that the benefits of those surpluses included lower
5 domestic rates, lower greenhouse gas emissions, and
6 deferred need for new Manitoba resources.
7 Consequently, we believe that it is
8 inappropriate for the cost of DSM programs to be
9 attributed to the participating customer classes, and
10 indeed we believe that this leads to a potentially
11 pernicious outcome in that a customer class could be a
12 net provider of system benefits to other customer
13 classes but be required to pay for all the costs of
14 those system benefits entirely itself.
15 So if we imagine that there was a
16 single customer class that was providing all of the
17 DSM, and the cost of the DSM programs are allocated
18 only to that customer class, we can see that there
19 would clearly be an inequity if there are significant
20 system benefits.
21 As such, we -- we do believe that it is
22 more appropriate to use an allocator that reflects
23 peak demand rather than one in which the costs are
24 directly attributed to the individual participating
25 customer classes. And with that, I'll conclude my

1 presentation.

2

3 (BRIEF PAUSE)

4

5 BOARD MEMBER GRANT: I may have asked

6 this at the workshop but can -- can I go back to your

7 sixty-eight point three (68.3) or is it -- what was

8 that number?

9 MR. A.J. GOULDING: It's -- I think

10 it's sixty-three point eight (63.8).

11 BOARD MEMBER GRANT: Sixty-three point

12 eight (63.8), just on the face of it, it's -- it's an

13 interesting approach but if -- if I was separating --

14 doing this allocation between dependable and

15 opportunity, why wouldn't I use a value rather than a

16 volume measure?

17 MR. A.J. GOULDING: I think that's a -

18 - that's an excellent question. And I think that what

19 we've been doing is essentially trying to extend the

20 analysis as its been done previously, right. And so

21 we see that this was an average share of exports.

22 I don't actually disagree with you that

23 there should be a consideration of potential revenues,

24 and revenues from both types. And I would also argue

25 we've -- we've heard that fixed are -- have the

1 potential for more revenues than opportunity. That's
2 not always the case. In fact, there will be cases in
3 which you will have entered into a long-term contract
4 at a particular price and then you have the
5 opportunity to do opportunity sales at a -- at a
6 higher price. And so the revenues may, in fact, be
7 quite different.
8 But I -- I agree with you that some
9 consideration of future revenues would be a reasonable
10 topic to explore.
11 THE CHAIRPERSON: Okay. Thank you
12 very much. We've got a very long afternoon ahead of
13 us, so the panel suggests that we shorten our lunch
14 hour just very slightly and come back at 1:15.
15
16 (PANEL RETIRES)
17
18 --- Upon recessing at 12:18 p.m.
19 --- Upon resuming at 1:15 pm.
20
21 THE CHAIRPERSON: All right. Since it
22 is the appointed hour, Me. Hacault, s'il vous plait.
23
24 OPENING COMMENTS BY MR. ANTOINE HACAULT:
25 MR. ANTOINE HACAULT: Merci, Madame le

1 President. Patrick Bowman, who was previously sworn
2 in, will be testifying. His presentation, which has
3 been distributed, will be marked MIPUG-25, I believe.
4
5 --- EXHIBIT NO. MIPUG-25: Presentation by Patrick
6 Bowman
7
8 MR. ANTOINE HACAULT: And the second
9 document, which is a presentation outline, will be
10 marked as MIPUG-26.
11
12 --- EXHIBIT NO. MIPUG-26: Presentation outline
13
14 MIPUG PANEL:
15 PATRICK BOWMAN, Previously Sworn
16
17 PRESENTATION BY MIPUG:
18 MR. PATRICK BOWMAN: Thank you. Good
19 -- good afternoon, Madam Chair, members of the Board.
20 Today I hope to go through focussing on Exhibit MIPUG-
21 25, which is the presentation document.
22 To keep things simple, we prepared
23 MIPUG-26 to outline the major positions that we're
24 taking in the -- in the various materials filed for --
25 from my pre-filed testimony and the undertakings so

1 that there's a bit of a guide organized by the four
2 (4) main topic areas that the Board had asked that we
3 address.
4 Starting with the presentation going to
5 -- it will come on the screen, I'm told. But moving
6 to -- I believe people probably have a paper copy, and
7 perhaps we can keep moving.
8 Focusing on the second slide, second
9 page, as we highlighted in the workshop, the focus of
10 the evidence was on cost causation principles.
11 There's a fair bit of discussion in the pre-filed
12 testimony about those principles, particularly as
13 relates to large industrials, which is the issues I
14 was focussed on.
15 I note that Hydro's cost of service
16 methods are -- largely reflect industry standard, and
17 some areas are -- are outside the norm. I take some
18 specific guidance in wording in saying that -- that
19 there is an industry standard.
20 There were some comments earlier about
21 there being no standard or no -- no universal
22 approach. And I think that's not fair. The -- I
23 think it's much like someone would describe accounting
24 standards of generally accepted accounting principles.
25 They're not universally accepted accounting

1 principles, but people still generally have an idea
2 about what they're trying to do with these things.
3 And there is a useful industry norm.
4 It's -- I think Mr. Todd gave a good example of the --
5 the hockey analogy in the first workshop that cost
6 causation as -- as just a word could lead you to
7 conclude any number of people caused the goal.
8 But if you really get into the way that
9 an industry looks at -- at data, there -- there is --
10 there is some pretty standard ways of looking at -- at
11 contribution of various factors. And -- and I will
12 make reference to that as we go through the -- through
13 the document.
14 There -- at the end of the day, there's
15 going to be about ten (10) different issues that we
16 deal with, including the sub-issues on transmission.
17 The first major issue is the net export
18 revenue. I will spend a little bit less time on this
19 than some of the others because I think the -- the
20 record is -- is fairly clear. It's been described as
21 a revenue that bears limited linkage to the imbedded
22 costs. I don't accept it bears no linkage, but there
23 is a limited linkage to the imbedded costs compared to
24 the -- the portions of -- of the export revenue that
25 are considered to be required to pay the imbedded

1 costs.

2 This is an overall essential component

3 of paying for the generation and transmission

4 investments. It's not like Hydro has a slush fund or

5 some kind of gravy. Those are terms that were thrown

6 around in the 2006 hearing to roughly describe some of

7 the methods that -- that sort of look at this as, oh,

8 we have all this money, what can we do with it.

9 We all know that Hydro's dealing with a

10 major investment. We know that it's dealing with

11 major borrowings. We know that it's dealing with

12 ongoing rate pressures. We're not talking about

13 windfalls here. We're talking about -- about revenues

14 that are needed to pay for the assets.

15 As I noted, Hydro proposes to assign

16 the co -- against all -- I say all assets and costs.

17 I take Mr. Todd's comment about all allocated, but, in

18 general, it's against all as opposed to just those

19 related to the generation and transmission system.

20 And at this point I'll note revenues

21 received from non-regulated sales would typically be

22 assigned against the assets that give rise to those

23 sev -- sales in -- in a full way, a hundred percent.

24 So that would be an industry standard.

25 We depart a bit here because of the

1 scale and because of some of the previous debates that
2 have gone on, but the -- putting the revenues against
3 the assets that give rise to those is -- is used in
4 other parts of the hydro system, and it's pretty --
5 pretty commonly used in -- in other types of -- in
6 other jurisdictions.
7 And there was a NERA survey from many
8 years ago that -- that was looked at in the 2006
9 hearing which -- which went through some of those
10 examples and came up with that same conclusion.
11 I say the best way to treat the net
12 export revenue is to leave out of the cost of service
13 study. I gave -- the Chair and I at the workshops had
14 some further discussion about what this means. I gave
15 some meat to the bones, if you like, in MIPUG
16 Undertaking 32 that I don't intend to go through here.
17 Primarily, it's a -- it's -- it's an
18 issue for -- for a different hearing, if you like.
19 But just in terms of measuring the cost and the
20 purpose of the cost of service study, if the assertion
21 is these are not linked to the assets anymore or
22 they're not -- don't -- don't bear the same linkage,
23 then they -- they don't belong in the cost of service
24 study.
25 The next slide shows -- this is from

1 that Undertaking 32 which shows that, if you do take
2 the type of methods that -- that I've been
3 recommending and do not credit the net export revenue
4 back, one (1) of the first things you'll note is the
5 net export revenue number is lower than Hydro would
6 have a calculated; it ends up being somewhere around
7 37 million.
8 The second thing you'll note is that
9 the cost of service study is not balanced, to use
10 Hydro's language. The total costs are higher than the
11 class revenues. And it's basically saying that
12 general consumers are paying 97.4 percent of their
13 costs. That's not necessarily a bad thing, but it's
14 an -- it's an informative measure. It shows the
15 revenue cost coverage by class there once you do those
16 adjustments and the other things we're recommending.
17 And, interestingly, these results are
18 pretty close to 2 1/2 percent lower than those shown
19 in MIPUG IR 1C where we asked Hydro to run the cost of
20 service study using the methods last approved by the
21 Board, and it gave RCC ratios of, like, the same level
22 but about 2 1/2 percent higher because it included the
23 N-E-R in full and this takes them out.
24 So, in practice, there's a statement
25 that's often made. This N-E-R is just a subsidy to

1 ratepayers and subsidizing everyone and everyone's
2 getting a share of them. But, actually, if you look
3 down the surplus shortfall at the end column, at the
4 end of that, you'll see that that is not in fact the
5 case. Even without an allocation of N-E-R using this
6 type of method, many classes are overpaying, some are
7 underpaying.
8 Because of the size of this difference
9 in the classes, those that are underpaying are lower
10 than the others. Now, this doesn't mean the 37 method
11 -- seven -- $37 million deficit doesn't undermine the
12 ability to use these RCCs to set rates.
13 If we were to go into a next -- a next
14 GRA and dis -- discover that Hydro needs rate
15 increases, those revenue cost coverage ratios could
16 very much help guide the Board as to which classes to
17 give the rate increases to.
18 The last slide on this matter is -- is
19 slide 6, which is just about the extra policy
20 adjustments against the -- against the -- the net
21 export revenue. And I note that -- I -- I quote
22 Christensen, who says:
23 "These are not necessarily a
24 directly cost/causative factor."
25 I agree. Uniform rates, in fact, is

1 not even a cost factor. It's a revenue factor that --
2 that we make an adjustment on, and as a useful tool to
3 inform -- inform us all about the -- Hydro's cost.
4 These are best not addressed within the cost of
5 service study. There's plenty of ways we can have
6 them incorporated if they -- it merits it in the
7 process of setting rates.
8 That's the end of that topic. Sorry,
9 we have a fair bit of ground to cover so I hope I'm
10 not moving too quickly. If I am, please, feel free to
11 ask questions.
12 On the matter of export classes, I
13 think it was important to address that the purpose of
14 the export class that we're dealing with here has been
15 stated a couple of times by different parties
16 involved. I don't think there's that much
17 disagreement, but I think those words about the
18 purpose are not necessarily always getting translated
19 into the logic that is then being used.
20 I quoted the purposes as saying:
21 "To ensure export revenues are
22 making an appropriate contribution
23 towards the assets that their
24 existence served to underpin."
25 Hydro -- Hydro has a similar type of

1 statement in their rebuttal evidence that I didn't
2 write down, but it effectively says it's not for the
3 purpose of setting rates, it's not for the purpose of
4 necessarily measuring their cost. It's for the
5 purpose of calculating a contribution.
6 And I -- I guess a good example is if
7 you -- if we don't under -- if we don't understand
8 that purpose, then we get down a bit of a rabbit hole
9 of what is the quality of these services, and how do
10 they differ in terms of the -- the nature of the
11 service and it's value?
12 And I -- I scribbled down the example
13 that, you know, if -- if there was an opportunity for
14 someone to come to Hydro and say, I will buy some
15 power off you for twenty (20) cents a kilowatt hour,
16 or some high price, even if it's a low quality service
17 but they're willing to pay that and Hydro can incur
18 nineteen (19) cents to serve that power, they should
19 make the sale.
20 And -- and they would, and Mr. Cormie
21 has testified as much before when he described his
22 department has having very sharp pencils. And you
23 could then have a debate about how to deal with the
24 one (1) cent. But the -- the distracting debate is
25 whether that low quality service is a -- maybe a three

1 (3) cent or a four (4) cent value. It's irrelevant.
2 The point is you're going to incur
3 nineteen (19) cents in order to make twenty (20), and
4 you can talk about the margin. It doesn't matter what
5 that -- that value is, or is it -- is it opportunity,
6 or could it be interrupted. It's irrelevant to the
7 fact of the decision that you made where you were
8 counting on the twenty (20) cent revenue to make the
9 nineteen (19) cent cost. And those are just numbers
10 to illustrate.
11 So moving into this -- these slides for
12 the next few spend a bit of time quoting Board orders.
13 I'm -- I don't intend to read them into the record but
14 this issue of the export classes and whether
15 opportunity and dependable exports are of a
16 fundamentally different nature that requires two (2)
17 classes, or whether they are one (1) class that's all
18 allocated a fixed cost.
19 Has been dealt with not just in order
20 117/'06 that Mr. Hacault was -- was discussing with
21 Mr. Cormie. Hydro came back with their case again in
22 116/'08, and the Board made a decision and again it
23 was addressed in Order 5/'12 in 2012, and each time
24 the decision has been -- been made, and I encourage
25 you to read the orders and see the logic that was --

1 that was used to make those decisions. It's -- it's
2 effectively identical to the logic that's being
3 relayed today, and the -- the Board rejected it
4 outright.
5 I'm trying to keep moving. The --
6 there was a reference yesterday to the quilt from the
7 NFAT hearing that people in the room who were at the
8 NFAT might be familiar with. We've pulled it up. I -
9 - I don't have a lot of time to dwell on it.
10 But for the discussion about whether
11 one would advance a plant or one would invest in a
12 plant due to opportunity revenues, this was a very
13 instructive document to say that if your best estimate
14 of the opportunity market was represented by the
15 section called 'energy prices low' you would never
16 have advanced nor built the hydro -- Keeyask gets a
17 hydro plant.
18 You would have built gas turbines to
19 get you through some period of time when you would
20 have reconsidered the -- the investment and the -- the
21 low ref -- ref row that Mr. Peters was -- was
22 discussing emphasizes that. That the all -- all gas
23 is -- is the best case if -- in their -- under those -
24 - if those were your baseline assumptions, and none of
25 the development plans stack up against it.

1 So -- and the only thing that's varied
2 there is opportunity. The dependable prices are
3 already -- are already fixed in this because they're
4 under negotiated contracts. So -- opportunity and
5 related prices for fuel. So I -- I think it's -- it's
6 fair to say that -- that some -- some thought has gone
7 into this. I think an example is Christensen's
8 evidence this morning, which was thoughtful, but I
9 think some of the data -- some of the impressions they
10 used in reaching their conclusions I don't think bears
11 out on the facts.
12 One is that where they say 'opportunity
13 affects technology, but not the decision to advance'.
14 I think the quilt clearly shows that tech -- that --
15 that opportunity revenues and the level of opportunity
16 revenues affects the decision to advance.
17 And the other is their example of the
18 technology choice, which if you looked at that
19 example, it would say your choice was between Keeyask
20 and all gas, and their reference was Keeyask gets high
21 capital cost, low operating cost.
22 Gas is low capital cost, high operating
23 cost. But what they missed is that by 2030 that would
24 not in fact be the case, because if you had built the
25 gas you still wouldn't generally be running it. It

1 would only run in very, very rare circumstances. We
2 were building it because we had energy shortfalls in
3 extreme droughts, not on average.
4 And so if you look at -- and I
5 encourage people who love that sort of thing to go
6 into the NFAT economic tables and look at the -- the
7 difference between the amount of fuel used in an all
8 gas scenario versus the amount of fuel used in the
9 Keeyask scenario.
10 And up to 2030 and beyond there's not
11 much gas difference, because those resources were not
12 about operating them, they're just about a way to
13 backup the system. So it's not just a question of
14 does it affect the technology choice and does it drive
15 you to have to burn gas fuel, it affects your
16 decisions throughout, in to the opportunity sales do.
17 Moving to slide 9, this is where I -- I
18 quote the Board's order. The only point of this I
19 will highlight is if you go to the bottom, and again,
20 this is 116/08. This is not the first time this came
21 up. This is the second time this same issue was
22 debated.
23 And it -- the Board did reject Hydro's
24 position and said:
25 "The Board understands that this

1 will result in more costs being
2 allocated to the export class and
3 that as a result, unit export costs
4 will rise above five (5) cents per
5 kilowatt hour."
6 Which Hydro had said was -- was not
7 sensible, not -- not a reasonable outcome. And -- and
8 I don't think the Board did it with their eyes closed.
9 They were fully aware of what -- what the outcome
10 would be and they thought that was reasonable.
11 To -- to slide 10. If you look at the
12 results of what Hydro's proposing, in PCOSS08 exports
13 would have been -- would have had a cost of five point
14 five four (5.54) cents, exactly as the Board said.
15 Their methods led to the result that they said it
16 would.
17 When you compare that to PCOSS-14,
18 Hydro's model comes up with an export cost of two
19 point eight two (2.82) cents. So exports cost --
20 cost, according to Hydro, basically cut in half during
21 the time when Wuskwatim was added, which was a higher
22 than average resource.
23 And the two point eight two (2.82)
24 cents, by the way, include some policy allocations.
25 The real cost of assets going towards that is about

1 two point four (2.4). And those numbers are MIPUG/MH-
2 1(6a) if anyone want to go look.
3 The -- I say it's not a sensible
4 outcome. At the same period the calculation for the
5 industrial rates went from two point three two (2.32)
6 cents to three point six nine (3.69) cents. So they
7 went up by about 60 percent. Hydro's overall costs
8 only grew by about eight (8).
9 So the rest of it's all just about cost
10 shifting. And those aren't the type of cost changes
11 you should see on a hydraulic system when you're --
12 you're dealing with cost of service stability and
13 methods is one (1) of your objectives for a Cost of
14 Service Study.
15 And just to -- to put -- underline it,
16 when I see that -- that number of two point eight
17 (2.8), which is about two point four (2.4) in costs
18 and about point four (.4) in policy, what that's
19 really doing is it's mixing opportunity and -- and
20 firm in Hydro's model. And they're effect within
21 opportunity costs are half a cent and firm is four (4)
22 cents -- or dependable is four (4) cents.
23 So when Mr. Williams is defining that
24 once -- once the experts have paid for these experts
25 the rest -- we can go ahead and talk about how to

1 carve up the fair share, what he's basically saying is
2 as long as opportunity have paid their half a cent,
3 the rest of that opportunity revenue we can go ahead
4 and just decide how we want to carve up as some kind
5 of system dividend or benefit.
6 And -- and my understanding of the
7 system is opportunity is going to have to pay a lot
8 more than that towards the assets before it's covered,
9 the -- the amount of cost it had driven by the
10 assumption you're going to invest to -- and -- and
11 operate the systems to -- to chase those -- those
12 sales.
13 Onto slide 11. Again, from 116/08,
14 there's a -- a quote. 512 also emphasized some of
15 this quote and I -- I also highlighted one (1) of the
16 -- the quirks of Hydro only assigning opportunity
17 costs variable costs is that you end up with things
18 like opportunity, therefore, paying nothing towards
19 Bipole III. And in fact, paying nothing towards the
20 US interconnections either, which are the lines that
21 let's you get to the US to make the opportunity sale.
22 And just to summarize the -- the
23 difficulties of this for dealing with our clients who
24 had to swallow hard during an NFAT hearing when they
25 were trying to come up with their recommendation.

1 These are the types of -- of proposals that make them
2 -- that swallow turn into a choke.
3 The -- the message to the customers
4 when we had to brief them was Hydro can go ahead and
5 not build anything other than maybe some combustion
6 turbines that won't really run, minimize its costs, do
7 a bunch of DSM, wait for some things to settle out in
8 the markets, spend maybe a billion dollars over -- you
9 know, over the ten (10) or fifteen (15) years, and
10 maybe a billion and a half, but a relatively small
11 amount comparatively, and keep itself out of
12 situations like they were aware of in BC for site 'C'
13 and in Newfoundland with Muskrat Falls that were --
14 were hydro projects that turned very challenging and,
15 in the process, they'd -- they'd expose themselves to
16 some gas costs, but maybe $10 million a year or
17 something in that order.
18 But, instead, Hydro's proposing to
19 spend 6 billion on Keeyask and -- and follow it up
20 with 10 on -- on Conawapa. And there'll be more risks
21 as a result of that; we all recognize that. It's in
22 the Board's NFAT order. And there was going to be
23 more costs.
24 But as long as you can -- we had to
25 explain to them, as long as you can get the exports to

1 pay for it, eventually this will turn around and it's
2 a worthwhile investment and -- but our -- our data
3 showed it would be many years, even decades, until --
4 until it turned around, but that it would.
5 We had to explain to them, and I'm
6 using updated numbers here, but that in the first year
7 that Keeyask comes into service it's going to be $550
8 million or so a year in costs that go into the books;
9 that's depreciation, interest, and the like. And the
10 new revenue that comes with it is only $350 million a
11 year for that advanced plant. And those numbers, I
12 can point you to where they are in the latest GRA
13 filings. But, again, these numbers can turn around
14 and you can get some advantages, like -- like, the US
15 transmission line.
16 So the members had to decide what they
17 wanted to do and ended up getting pushed over -- over
18 to the positive decision largely because there was a
19 billion dollars in sub-costs and somebody was going to
20 have to deal with those if you didn't build the plant.
21 But then we get here and we effectively
22 say, oh, no, wait, we're -- we're not going to --
23 we're going to allocate all of those costs to you.
24 That 550 million, we're going to allocate all of that
25 to people who use the power, the dependables, but

1 we're going to take this export revenue and we're
2 going to take a bunch of it and say, no, no, this is
3 surplus, this isn't -- it's N-E-R. We can do whatever
4 we want with it. We can -- we can put it against
5 distribution system. We can pay for other assets that
6 don't give rise to that revenue.
7 And the -- the end result, you sprinkle
8 it in different places. And the end result is this
9 disconnect that I think if -- if somebody had been
10 fully aware of -- of that type of proposed treatment,
11 I'm not sure that they could have supported Keeyask
12 because you've just really de-linked the -- the
13 investment from the -- the revenues needed to pay for
14 it.
15 I haven't got the hook yet, so I think
16 I'm keeping on time. The next topic -- I will make
17 one (1) final comment. I -- I think it's been
18 characterized that I'm saying a full share of fixed
19 cost should go against opportunity, and -- and that's
20 not quite what I've said. What I've said is the Board
21 has previously said a full share of fixed cost should
22 go against opportunity. And I don't see any
23 compelling information today that would change that
24 conclusion. If anything, the information today would
25 reinforce that conclusion.

1 So I -- I'm open to people suggesting
2 it should be 80 percent of fixed costs. I've also
3 recognize the Board at times says it should have been
4 more than the average because exports are being chased
5 by higher than average cost resources. Keeyask is
6 higher than average costs.
7 But -- but just as a proposal, I think
8 Hydro's proposal doesn't -- doesn't cut the mustard
9 and -- and should be rejected. And in the absence of
10 that, the -- the Board's last decision -- the last
11 method would be the -- the -- a reasonable place to
12 go.
13 Generation and transmission. I --
14 we'll deal -- we can deal with these separately. I'm
15 up to slide 13 now. There are two (2) core issues.
16 One is I'd say Hydro is under classifying generation
17 costs to peak demand. And I think I'm going to do --
18 spend some time on clarifying some terminology in
19 terms of capacity versus demand versus peak. They're
20 all being used interchangeably in this hearing and --
21 and they're often used interchangeably in the
22 industry, but I think if -- in common parlance, but I
23 think they -- we need to understand they have a
24 specific meaning.
25 And then the others on the transmission

1 side where there is a fairly common industry standard
2 that transmission lines are a demand driven resource
3 and that would be allocated on some type of coincident
4 peak measure depending on the load shape.
5 There is a -- what I will call a narrow
6 exemption for -- for transmission that's generation-
7 related. And I think Hydro's taken a narrow exemption
8 and -- and tried to drive a truck through it in terms
9 of the methods that put them way outside the range by
10 the time -- by the time Bipole comes online.
11 I do note that this is important as an
12 example because of the different load shapes.
13 Industrials have a very efficient load profile. They
14 use about 15.2 percent of system energy but only about
15 12.6 percent of system peak. So if a cost is
16 classified to energy the industrials would pay about 3
17 percent more of that cost, and if it's peak they'll
18 pay about 3 percent less.
19 The opposite example is the
20 residentials, which is the peakiest class, which are
21 24.5 percent of energy and 29 percent of peak. So for
22 -- for the residentials or -- or people dealing with
23 residential classes the -- the impacts of -- of moving
24 to ener -- peak is -- is adverse to the class. And as
25 I say, Hydro is out -- outside the range of practice.

1 So on slide 14, generation cost
2 classification. It's -- it's almost universal in any
3 utility I've dealt with, any utility I've looked at,
4 that generation costs will have a demand-related
5 component. And it captures costs for investments
6 being able to supply load at peak times, including
7 reserves, reliability, a provision for -- for outages,
8 and the like. It's highly tied to that -- that type
9 of resiliency. It's highly tied to high load periods.
10 And I think Mr. Cormie said it well
11 yesterday in regards to discussion of Conawapa, why
12 you'd never build a five (5) unit Conawapa even if the
13 ten (10) unit version gave you no further dependable
14 energy. It gives you some opportunity energy. It
15 gives you an ability to cycle. And it gives capacity
16 which is a very important part of running a system.
17 That idea of capacity is what we're talking about
18 here. It is a part of the system you -- an aspect of
19 the system you invest in because it's an important
20 resource.
21 Hydro uses 100 percent energy related,
22 as we've discussed, and northern utility we could
23 identify uses 100 percent energy for all generation
24 which ignores key peak hours. The big question is do
25 -- I think Hydro had confusion as to whether I

1 supported a weighted energy allocation.
2 Yes, I think a weighted energy
3 allocation is a very sensible way to deal with the
4 allocation step of costs that have been identified as
5 an energy related cost. And I'll speak to that in a
6 moment. But I don't see that it includes a capacity
7 component, and all of the evidence we've seen in this
8 proceeding I think points to that same direction.
9 For wind, 100 percent energy is
10 reasonable. Weighting that energy is reasonable. It
11 has no capacity. But the rest of the resources have a
12 capacity component. There was a question about
13 whether doing this is -- actually I'll move on from
14 there. I'm sorry. The -- about capacity of market,
15 but I'll move on to keep on schedule.
16 Slide 15. As we know, Hydro uses 100
17 percent energy but marginally cost weights it, which
18 as I said is -- is sensible but the -- the idea of
19 weighting periods is that Hydro carves up the year
20 into twelve (12) periods. Each of them captures about
21 seven hundred (700) hours, somewhere in that order of
22 the -- of the year.
23 And seven hundred (700) hours is way
24 too coarse an average to pick up peak load drivers,
25 and I'll show you some -- some numbers that underline

1 that. But the idea of a on-peak energy is different
2 than the idea of a peak that drives capacity
3 requirements, which is very narrow. It's that -- that
4 day that's minus forty (40) when it's 7:00 a.m. and
5 everybody is running their toasters and their cars are
6 all plugged in. That's the peak you have to design
7 that -- a lot of the system around.
8 That's very different than the average
9 of the top seven hundred (700) hours across the
10 winter. And when Hydro says "peak" in its weighting
11 for marginal cost, they mean that they're going to
12 allocate based on the -- the loads in those seven
13 hundred (700) hours.
14 And -- and Mr. Hacault has encouraged
15 me to give a simp -- the simplified example that I --
16 I sometimes do when I have to explain some of these
17 concepts to -- to lawyers.
18 The classic cost of service example of
19 -- of peak versus energy is something like a diesel
20 community. You have to install a certain number of
21 diesel engines. How many diesel engines you need is
22 driven by that peak hour. You need all of the diesel
23 engine capacity to supply that peak hour, plus some
24 reserves above it. By the time you're done you
25 probably have three (3) or four (4) engines, and they

1 probably add up to about twice the size of the peak
2 because of the reserve requirements.
3 That -- that is a peak demand allocated
4 cost, and just about universally you'll look at -- at
5 utilities that have a thermal or a diesel engine
6 component and -- and they -- they will be allocated at
7 peak.
8 Energy is a classic allocator for the
9 fuel component of those costs. It doesn't matter
10 whether I use a kilowatt hour on Christmas Day or when
11 it's minus forty (40), or whether it I use it in the
12 middle of summer in the evening when it's -- it's warm
13 out and the load is low. I probably need about a
14 quarter of a litre of fuel for every kilowatt hour I
15 use during any of those hours. It doesn't matter
16 whether it's peak or not. That is a classic perfect
17 energy type of allocation, is that -- that fuel
18 component.
19 So those are the two (2) extremes. One
20 (1) type of cost related to the peak, that's what
21 drives my cost and once I build a big enough plant I
22 can use it all year round. The other is a cost
23 related to the energy which means when I use a
24 kilowatt hour I drive that cost. It doesn't matter
25 when I use it.

1 Now, to make -- let's make that just
2 one (1) step more complicated where if you think about
3 this diesel community like some of the ones that I
4 deal with up north, it has a winter road service to
5 deliver their diesel. But in this case let's say they
6 don't have a whole bunch of storage.
7 And so in the winter they can drive
8 their diesel in at a buck a litre, but in summer they
9 have to fly it in in drums on a plane, and it costs
10 five (5) bucks a litre. You might then say, I've got
11 different marginal costs of energy. My summer energy
12 costs more than my winter energy, because in the
13 summer I have to burn this expensive fuel. In the
14 winter I got to burn the cheap -- I can burn the cheap
15 fuel.
16 And so if I was going to do
17 allocations, if I had a lodge, let's say that was a
18 summer type of load, because they have visitors and a
19 -- and a house that's a winter type of load, that
20 lodge should be more, because they tend to use
21 expensive energy in -- for their energy component and
22 the -- the house should pay less.
23 I might talk myself into a weighted
24 marginal cost of energy allocation and that would be a
25 reasonable type of approach for that. You might as

well talk yourself into seasonal rates to send some of those price signals to people. But you still have -- it's a different concept than the peak, which was the engines I installed in the first place.

That is a capacity concept. So I just wanted to get the ideas of why I'm saying there is a difference between the time you use the energy and how it's weighted in different period versus the -- the costs and the -- the effort and the energy incurred in meeting those absolute peaks.

The next couple slides will be pretty quick, because it's the microfiche numbers. But these are an example -- this data sets out an example of why the -- the seven hundredish (700ish) hour average does not capture the same thing as a key peak hour and by even key peak hour we mean a fifty (50) hour value. We don't go to the highest hour of the year.

And you'll see, for example, on the winter part at the top the residential peak in the winter is about 1775 megawatts, which is about 42 percent of the load. But if you -- and that's over fifty (50) hours.

But if you just look at their load over six hundred and sixty-one (661) hours, which is what the marginal cost approach is doing, we really think

1 they only have fourteen eighty-four (1484) average as
2 their peak during those on-peak hours.
3 And they end up going from 42 percent
4 of the contribution to that peak to thirty-nine (39).
5 And other classes, some go up, some go down. At the
6 end of the day though, because you're doing it as a
7 relative proportion, you can move to the far right
8 side and you see that by using this -- this highly
9 aggregated average, the residential -- the highest --
10 the -- the worst usage tracked in the Cost of Service
11 Study would -- would lead to a 39.4 percent
12 allocation, which is below what they would get under a
13 two (2) coincidence peak allocation.
14 They -- or they benefit from this
15 approach. The other classes largely -- largely are
16 the same off or worse off. The summer numbers are
17 down below. And in terms of the overall system what
18 this emphasizes is that about 400 megawatts of -- of
19 true peak load is missed, focussing on the three-seven
20 (37) as the sum under the marginal cost approach, the
21 three (3) -- three thousand seven hundred and sixty-
22 seven (3,767) versus the -- the peak over the fifty
23 (50) hours, which is more like four thousand one
24 hundred and ninety-one (4,191).
25 Summer has the same effect, not quite

as -- as exaggerated. And for the visual types, the next slide shows it in a bar graph and emphasizes that for most of the classes at the bottom, the -- the dark blues, and the greens, and the yellows, the -- the peaks don't vary that much between the fifty (50) hour and the six hundred seventy-one (671) hour averages. But for the residentials, the light blue, it makes a big difference.

And that's what we're missing by not having a -- a coincidence peak allocator. We're missing the cost being driven by that type of load profile.

On slide 18 I discuss the -- the Christensen conclusion that Hydro's marginal cost values that they use from the export market don't include enough of a capacity signal and Hydro's solution to try to use the -- the adder, as it's called, in the marginal cost weighting.

And in effect, having looked at the previous graphs, all that the adder does is say, I'm going to pay even more attention to those seven hundred (700) hours of winter peak and pay a little bit less attention to the other hours, the -- the seven hundred (700) hours of shoulder, the seven hundred (700) hours of off-peak.

They're not all quite seven hundred (700), but in that range. I'm going to pay more attention to this -- the -- the particular bar graph shown, if we go back one (1), showed on -- on the -- the right-hand side of each graph, that six seventy-one (671). It -- it never picks up the ones here on the left, the -- the real peak.

It puts more weighting on these -- on these hours. But not only does it do the weighting on the two (2) winter and summer peak period hours, these two (2) seven hundred (700) periods, it also puts some weighting on fall and spring hours which are not really a system peak period at all to the same extent.

And -- and as a result --

THE CHAIRPERSON: Mr. Bowman?

MR. PATRICK BOWMAN: Yes?

THE CHAIRPERSON: Can you just go through that one (1) more time?

MR. PATRICK BOWMAN: Sure.

THE CHAIRPERSON: Thank you.

MR. PATRICK BOWMAN: So the marginal cost weighting, what it does is it takes every kilowatt hour used by a customer and it carves them into twelve (12) periods based on the customer's type of load profile, okay?

1 So it -- we have load data. If you use
2 a -- if -- if you flick your switch at home on in the
3 winter you'll add a kilowatt hour to whatever period
4 you flicked on that switch. If it's an on-peak hour
5 in winter, it'll fall in that group of -- of the
6 twelve (12) -- twelve (12) period weightings, right?
7 You'll -- you'll add a kilowatt hour to the
8 residential total. And if you do it at night, you'll
9 add a kilowatt hour to the off-peak total.
10 What Hydro then does is it says all of
11 those kilowatt hours matter but they matter different
12 amounts, and so it weights those, all right? And --
13 and remember there's this little grid. It's in the --
14 actually, I might even be able to show you in the
15 Board counsel's book of documents. But there's a
16 little grid that shows the weightings for each of
17 those periods and how important they are.
18 By definition, they call the summer
19 off-peak a weighting of one (1). That's your index
20 value, and everything else is -- is averaged off of
21 that. When the -- this extra comment came from
22 Christensen saying you need to pay attention to
23 capacity, what Hydro did is it weighted those -- added
24 to the weightings for each of those on-peak periods.
25 So where summer off-peak would have

been a weighting of 1 and winter on-peak would have been a weighting of five (5) we keep the summer off-peak at 1 but we move the winter on-peak to six (6), okay? And we did the same thing -- that -- that -- it actually went from five (5) to six point three (6.3), I think. We did the same thing to the fall on-peak hours, the same thing to the -- most I like the microfiche version, the same thing to the spring and the same thing to the summer.

So if you look at this -- this lovely table, about halfway down the page is something called weighting factor. This is the kilowatt hours used by each class. So you start at residential on the side, forecast load of eight five four one (8,541). How is that eight five four one (8,541) broken down into each of the twelve (12) periods? You've got all these twelve (12), with spring, summer, fall, winter. It comes up those are actual kilowatt hours use -- or used or forecast to be used.

Then at the bottom is these weighting factors. And in the previous version of this you would still see summer off-peak about the middle of the page where it's one point zero zero zero (1.000). That would still be one point zero zero (1.00).

And then you go to the left, and it

1 says, "Summer shoulder three point zero one one
2 (3.011)." That would still be three point zero one
3 one (3.011). But the next number over, where it says
4 five eight seven-o (5,870), in the previous version of
5 that study that number would have been four five
6 seven-o (4,570) or so, okay.
7 So -- and -- and then they multiply it
8 out and -- and work out your relative profile from
9 that. But -- so when Hydro adjusted, it said, I'm
10 going to place extra weight on all of these kilowatt
11 hours, every one of those numbers you see under the
12 column called peak, for the spring peak, the summer
13 peak, the fall peak, I'm going to up the importance of
14 those kilowatt hours.
15 And so, at the end of the day, of the
16 8.5 billion kilowatt hours used by residentials, all
17 two hundred and seventy-two (572) in spring peak, all
18 five thirty-two (532) in summer peak, all three fifty-
19 six (356) in fall peak, and all nine seventy-two (972)
20 used in winter peak hours were upped a bit. That's,
21 like, twenty-five hundred (2,500) hours of the year.
22 So if you're really trying to capture
23 how bad is it when it's minus forty (40), saying I'm
24 going to pay attention, I'm going to put a bit more
25 weight on twenty-five hundred (2,500) hours spread

1 throughout the year, it doesn't capture the fact that,
2 no, that minus forty (40) event is still important and
3 drives costs. That's why that -- that allocator is --
4 as it's been done, I think Christensen raised a valid
5 concern. I think it's -- it's been implemented
6 poorly.
7 At a minimum, you'd probably at least
8 drop -- if you were to do it through this route, which
9 I don't recommend because it's still too coarse, it's
10 still seven hundred (700) hour averages rather than
11 fifty (50) hour averages, but if you were going to do
12 it at minimum, you wouldn't weight the following
13 spring, you'd only weight the summer and the winter,
14 the same way we do for transmission, but even then
15 you're only doing it on the seven hundred (700). You
16 really should be doing it -- putting in a proper CP
17 allocator like basically every other utility does for
18 their -- for their generation.
19 At -- at the end of the day, there's a
20 lot of work that can be done on the right way to come
21 up with a demand allocator. I say it's not reasonable
22 that Hydro has no demand allocator. And I'm going to
23 move on to slide 19 here.
24 Oh, let me take one (1) moment on slide
25 18. Because the other thing that happens out of that

1 approach that we put it is, not only do you add
2 weighting to way too many hours, you also end up
3 getting some -- some odd results. And I'm not trying
4 to suggest a results-driven analysis. But if you're
5 trying to pick up the -- the drivers caused by a peak
6 usage, the thing you'd expect to see is that
7 residentials get allocated somewhat more costs.
8 And the way Hydro implemented that
9 residentials can end up with somewhat less costs. So
10 it's sort of just an indication that -- that somehow
11 this is missing the mark. And I've already gone
12 through why it misses the mark.
13 Slide 19. What I noted is that for a
14 lot of utilities who have a -- a peak allocator that -
15 - that we deal with that are similar to Manitoba
16 Hydro, you might something in the, say, 40 percent
17 range of their costs being classified to -- to demand.
18 Hydro ran some other numbers and -- about different
19 methods you could use, and came up with somewhere
20 around 20 percent.
21 I think it's reasonable to adopt a -- a
22 twenty (20) for now, somewhere in that range, while
23 they are sent off to investigate methods. Equivalent
24 peak is a method that Christensen referenced. I'm
25 told there's an average and excess method used at

1 Minnesota Power. But these different utilities --
2 it's just the load factor is -- is used with the --
3 the Newfoundland example, and I believe the BC as
4 well.
5 But there are some pretty well-accepted
6 methods Hydro could test the logic behind, and -- and
7 bring back a proposal. But for now, I think not
8 having at least a -- a -- about a 20 percent of -- of
9 cost considered demand -- demand-related is -- is
10 missing out on a -- a -- the key factor. And I think
11 Mr. Cormie, like I say, underlined that when he talked
12 about capacity being important when you look at the
13 investment in Conawapa.
14 There was also another example
15 discussed at the previous cost-of-service hearing of a
16 project called Kelsey Rerunnering, which involved
17 putting new runners in -- in Kelsey. It was a -- it
18 was a 1960s era plant put in new -- new runners. It
19 increased the capacity of the plant. It increased its
20 ability to produce opportunity energy. It didn't
21 increase its ability to produce dependable energy at
22 all. It's an expensive project. I think it's up to
23 about $300 million.
24 Had some investment in transmission to
25 be able to get all that capacity out. That's just an

1 example of -- and -- and this is huge. The capacity
2 they got was about 77 megawatts, I think. Like, the
3 third of Wuskwatim just by doing an upgrade to the bri
4 -- to the plant on the -- the capacity side.
5 That's a big investment. It's driven
6 by capacity. It's driven by -- well, it's driven by
7 aging infrastructure, but -- but the -- the -- from
8 the transmission components and -- and the -- the
9 sizes of the units installed gave an opportunity --
10 gave a -- a capacity bump, and -- and incurred a cost.
11 And it's -- it's just an example of why capacity
12 investment is a -- is a factor. It's not just about
13 energy.
14 Moving now to transmission.
15
16 (BRIEF PAUSE)
17
18 MR. PATRICK BOWMAN: I think I'll have
19 to talk faster. On the transmission issue, unlike
20 generation, which has -- which is a blended product,
21 all genera -- the generation we're dealing with
22 produces both capacity and energy. Transmission is
23 almost universally a -- a peak capacity/peak demand
24 type of resource. And Hydro does that for its good
25 transmission.

1 And the web is a -- like they call it.
2 There -- there are some exceptions, like I said, and
3 the biggest example being generation-related
4 transmission, what some people say, suits -- it's
5 better to think about that wire coming out of the
6 generator -- between the generator and the first
7 substation, and the first major station as part of the
8 generation unit. It's assessed on that basis. It's
9 considered an economic decision to proceed with the
10 project. Its -- its economic profile, its economic
11 identity, is far more linked to the generator than it
12 is to -- to moving power.
13 I said not every utility uses these
14 exceptions, and -- and an example -- an example of who
15 does is -- is BC Hydro, but they use it on a fairly
16 limited basis. Mr. Harper had a -- a map. I think if
17 you look at the map, it's important to look at the --
18 the scale of things that are -- are considered. GRTAs
19 verses not, both on dollars and on -- and on the --
20 the thresholds for making those decisions.
21 And you'll notice that it's only things
22 like lines that run to Prince George. From Prince
23 George south, massive lines that are designed to move
24 large amounts of power are not considered GRTAs.
25 To show it in the numbers on this page,

1 this is from the MIPUG rebuttal evidence. I noted
2 Hydro has two (2) exceptions. GRTAs, they also
3 considered US transmission to be something that should
4 be on energy.
5 But the end result is that, looking to
6 these other utilities, you can see on this table the
7 tra -- total transmission cost in their respective
8 cost-of-service studies is shown for BC Hydro,
9 Newfoundland Hydro, and Hydro-Quebec distribution
10 utility, which is the regulated component which
11 purchases these transmission services.
12 You can see the ratios that they
13 consider demand classified and the ratios they
14 consider energy classified, and how those break out.
15 You can see that by PCOSS10, Manitoba Hydro was
16 already pretty close to being an outlier, if not
17 entirely an outlier.
18 And then the impact of just throwing
19 massive dollars at -- at Bipole, at Riel, at the
20 Minnesota -- Manitoba/Minnesota transmission project
21 would put Hydro at a -- so far out there -- outside
22 the realm that less -- less than a quarter of their
23 costs would be considered for -- for assets that are
24 wires and substations.
25 And it's -- it's really -- you know,

1 it's -- it's -- the same time as they all have a
2 transmission system of about the same value as BC
3 Hydro, they'll consider about three thousand (3,000) -
4 - or thir -- thirty (30) times as much of their -- of
5 their ener -- costs to be energy-related as -- as the
6 BC example.
7 The BC example Mr. Harper drew in a
8 graph, in numbers, it's $18.2 million that ultimately
9 ends up as an energy share.
10 To slide 22. It's -- it's very nice
11 that those are the numbers and the results, and it
12 shows they're outside the realm, but why is Hydro
13 wrong in its logic? It -- the main reason is that
14 they overuse the classification for anything that they
15 consider to be not linked into the web, Bipole I and
16 II, now III, Dorsey, Riel, and I -- I don't think it's
17 a -- a valid rationale for -- for considering them to
18 be GRTAs.
19 To -- to me, the rationale is linked to
20 the -- the original investment and whether the --
21 linked to the original investment also -- and also, I
22 think, how the assets are used. I think it's fair.
23 But it's -- it's not necessarily driven by this issue
24 of the -- the web being an instantaneous response,
25 where the DC lines are not an instantaneous response.

1 You have wait up to five (5) minutes before someone
2 will make an adjustment for them to respond, which is
3 eff -- effectively a -- a key component of Hydro's
4 rationale.
5 Their -- their definition of the web is
6 those assets that are online and -- and all the flows
7 are -- are adjusted and affected by all of the events
8 that happened on the -- the grid and the -- the
9 Bipoles are different, because the flows are not
10 affected, they say, by what happens on the grid.
11 They're affected by somebody in Hydro's building
12 turning the dial about how much power is going to come
13 down from the north.
14 And what we clarified in the workshop
15 with Mr. Cormie is that dial is changing every five
16 (5) minutes, so -- or has the ability to be changed
17 about every five (5) minutes. So the -- the
18 difference between instantaneous and five (5) minutes
19 in terms of the -- whether these are -- are all of a
20 sudden not treated as a -- a series of wires and --
21 and substations, I think, is a -- is -- is not a -- a
22 useful distinction.
23 On slide 23, I think I may have made up
24 some time. The -- the question of Bipole III and
25 Riel, for the same reasons, I don't conclude that it

1 meets the test of a generation-related transmission,
2 as it was not developed as part of the existing
3 generation. It wasn't pursued for about thirty-five
4 (35) years after Bipole I and II, and it -- in -- in
5 all the evidence we have, it wouldn't be a justifiable
6 project just on the basis of the existing transmission
7 anyway.
8 It wasn't part of the business case to
9 the new generation. It wasn't part of the required
10 assets for the old generation. It was just a way of
11 getting some capacity -- or getting some reliability
12 from the north. Reliability is a classic component of
13 -- of investing in transmission assets.
14 So it -- it seems to meet those tests
15 that -- that are throughout this process and the way
16 that the discussion was set up, we had a considerable
17 number of -- of exchanges, including the workshops and
18 the rebuttal evidence, so I accept that the position
19 on Bipole has -- my position has been open to hearing
20 different facts throughout.
21 And I think at the end, if MIPUG says -
22 - if Manitoba Hydro says the position is unclear, I
23 would clarify that. It appears it would well suit a
24 two (2) CP allocation, which is a transmission
25 allocation, that you don't need to treat it any way

1 special, it -- it becomes a transmission asset.

2 There was a comment that Bipole III

3 should be a GRTA, because it serves the generation. I

4 don't know what that means. All of the assets serve

5 customers. All the assets -- the transmission is

6 designed to move -- get generation to the load. Does

7 it relocate the generator to a different spot?

8 All transmission effectively relocates

9 generators. I might as well have a generator where my

10 meter is on my house. I don't -- the -- these are

11 maybe fascinating concepts in an -- in -- in a -- a

12 transmission planner or operating mind. Does it

13 operate eight thousand seven hundred and sixty (8,760)

14 hours a year? Yes, just like every other transmission

15 that is almost cla -- classically allocated demand,

16 just like the diesel engines up north.

17 And -- and the question was: Does it -

18 - does the fact that it fails to operate like part of

19 the spiderweb matter? Not -- not particularly, given

20 that -- that the adjustments that are -- are frequent

21 anyway, and -- and I -- I had a -- a further example I

22 could give there, but I think we're -- we need to move

23 on to stay on schedule.

24 But further I'd note that the fact that

25 it's a DC is not in any way determinative either. All

1 of those BC Hydro examples we gave were AC lines at --
2 at GRTAs, and I don't think being DC somehow magically
3 makes it into a -- not a transmission asset either.
4 The -- slide 24. There's a question of
5 the special case is the Dorsey converter and this is a
6 bit of a complicated history. This is a southern
7 term, this is Bipoles I and II. So it's a unit that
8 converts the DC power back into AC for use on the
9 system and in -- I think it's fair to say that in a
10 very simplistic analysis Dorsey's converters would be
11 considered to be part of the Bipole I and II assets.
12 And so the Board back in 2003 asked the
13 same question we did: Why is this not part of the
14 Bipole I and II? Why are you treating it differently?
15 And Hydro came up with a very
16 thoughtful response in 2003-2002 in that hearing where
17 they said, we're treating it differently so we can
18 include it in the open access transmission tariff and
19 we think it should be included in the open access
20 transmission tariff because that is a rate that people
21 who use our transmission lines will pay. Third
22 parties who use our transmission lines and if we only
23 include ACS, it will be undercharging them because
24 they won't be paying anything towards this converter
25 which gives a huge benefit to the AC system and but

1 for this converter, you'd have to make major other
2 investments in a different type of equipment and so we
3 think it should be included in the transmission
4 tariff.
5 My understanding is it was included and
6 it has been for the last 15 years. So I was surprised
7 when we saw the filing saying that one of the reasons
8 Hydro wanted to change Dorsey to a generation is to be
9 consistent with the tariff because my understanding is
10 that it had always -- that -- that the tariff was
11 always considered a transmission,
12 same as the PCOSS.
13 And -- and we've now learned that, in
14 fact, the transmission tariff does in fact include it.
15 They only want to change it in the future to be a
16 generation asset so that it's no longer charged in any
17 way to -- through the transmission tariff. People
18 using Hydro system, third parties, wouldn't pay
19 anything towards it and so that it gets allocated as
20 part of lead generation.
21 At a basic level I accepted that it
22 plays a dual role. I think in the case of something
23 that plays a dual role like that you would go with the
24 normal type of allocation, like, -- consider
25 transmission allocated on the basis of -- and peak

1 demand. I think some of the -- considering a GRTA is
2 a -- GRT is a narrow exception and it should be for
3 assets that are quite strongly, if not overwhelmingly,
4 meet that test, not something that is a -- a jump
5 ball.
6 And further, the -- the detail side of
7 this issue, which I'm hesitant to get into, was raised
8 by Christensen as saying perhaps we should go down the
9 road of carving it up and they had some analysis done.
10 I don't want to get into the details of the analysis.
11 They are complicated studies. I didn't actually spend
12 that much time on them except to see the approach that
13 they took and at the end of the day, I found that they
14 took an approach that was different than the previous
15 logic. The previous logic was based on the idea of a
16 replacement concept; that if you didn't have the
17 Dorsey converters you would have to have something
18 else. So how much would that something-else cost?
19 And if it's -- if you needed something else we can
20 include it in the transmission tariff.
21 Maybe you'd say that something else
22 isn't very expensive and you don't include, you know -
23 - or deal with how to deal with that situation then.
24 But it was always based on the what -- what's the
25 something else I would need. That CA went -- that

1 Christensen and Associates and Hydro went down a
2 different path which said, If it didn't exist, how
3 much would it hamstring your ability to get the
4 northern generation out? So they went to sort of
5 percentages of functionality rather than just
6 replacement.
7 I -- I don't know that it needs a whole
8 bunch of time on it but I think at the end of the day,
9 I would say based on the evidence here, I don't see
10 the rationale to change what the Board had included
11 before and which Hydro proposed for the last 14 or 15
12 years. I don't see the rationale for not including it
13 in the transmission tariff, including a tariff that
14 gets allocated against Hydro's exports at times.
15 MR. KURT SIMONSEN: About ten (10)
16 minutes, Mr. Bowman.
17 MR. PATRICK BOWMAN: I think we're
18 just about on track for that. Slide 25 was on the US
19 interconnections. We don't have to take a bunch of
20 time on this because it is a tiny tiny component of
21 Hydro's cost allocation.
22 The -- it is -- it is almost a rounding
23 error in any of the numbers we talk about. It
24 allocates a total of less than $5 million. So, I
25 raise in part because it shows this strange underlying

1 incentive bias that Hydro tends towards everything
2 being related to energy, but also, because it -- it
3 seems to be inconsistent with their case on other
4 things I've raised like coal and wind where we say
5 it's too small to worry about.
6 The US interconnections are
7 transmission. They are wires and substations. They
8 are not different than transmission in that regard.
9 They move power over distance. They deliver it over
10 8000 AC hours. In that regard they are no different
11 than any other transmission in any notable way.
12 The -- I thought the logic was oddly
13 inconsistent with their argument in Dorsey where
14 Dorsey must match the tariff. In this case, Hydro
15 wants to take the US interconnections and charge them
16 to customers based on energy rather than demand.
17 Transmission tariffs would be charged on the basis of
18 demand.
19 So this one, they want to move to a
20 version where it doesn't match the transmission
21 tariff. As a result of doing that -- and the -- the
22 remainder of Hydro's proposals, opportunity exports
23 would not pay anything towards these.
24 It's important to industrials because
25 of this underlying sort of energy cost incentive bias.

1 And if you follow the logic used on the US
2 transmission I think you'd pretty quickly get yourself
3 into a situation where you'd say all transmission is
4 energy.
5 The last few minutes on the DSM topics.
6 There were two (2) DSM topics that were included in
7 the scope for this. One (1) is this curtailable rate
8 program. I think Hydro understood the -- and
9 explained the issue well and is -- is now in
10 agreement.
11 I would say that, if -- if Hydro's
12 original approach is kept, what you end up doing is
13 taking a group of customers and paying them about $5
14 million a year for the privilege of them having lower
15 reliability, and then in the cost of service study
16 charging them $3 million because they happen to be in
17 that program, which completely nets out the basis for
18 them participating in the program, so I think it was a
19 math quirk.
20 I think Hydro's -- we -- we proposed a
21 solution that Hydro accepted. And I don't know that a
22 whole lot more has to be said on that, except when you
23 flip to page 28 there had been a table -- or a comment
24 made a few times. Slide 28.
25

1 (BRIEF PAUSE)

2

3 MR. PATRICK BOWMAN: Oh, sorry. It
4 seems the computer's frozen. But on slide 28 there
5 was a table, here we go, which, at one point, someone
6 said that the reason this is in a deficit charge to
7 the customer is because they got a benefit before, but
8 it's just timing issue and it'll work itself over
9 time.
10 If you look at the bottom row you can
11 see that this has nothing to do with timing issues.
12 If there was a bit of timing and there was some --
13 some mismatches in the early years, they more than
14 worked themselves out long before this PCOSS. And
15 remember there are years -- intervening years in the
16 middle of this, and it's no basis to keep doing it.
17 The reason it's -- it's there is -- is -- the reason
18 there's a higher cost to the program than the annual
19 benefit to the program is because Hydro has chosen to
20 amortize the -- the cost, not charge ratepayers
21 collectively in the -- one (1) year for the program
22 but to charge them over time.
23 As a result, there's a financing cost.
24 There's a capital tax cost component added. And the -
25 - the people who benefit from Hydro's decision to

1 defer and amortize is all ratepayers because they have
2 the opportunity to have had this program in place in
3 those early years when -- when Hydro -- the -- the
4 value that they were receiving in one (1) year was
5 less than they were paying in their rates.
6 So that is not a benefit to the
7 participating customers. That's a benefit to all of
8 the ratepayers in the early years, and it's offset by
9 the higher cost today. That's the same way that all
10 DSM is done.
11 The last issue is slide 29, which is
12 the assignment in -- of DSM costs. And this one I
13 think you have heard thoughtful positions from a
14 number of different parties who -- who disagree on
15 this. That I would say it's probably the most grey,
16 if I can call it that, topic in -- that I -- I see
17 being dealt with.
18 In most utilities, you'll find DSM
19 provides -- provides very immediate benefits, things
20 like fuel. In Hydro's case, where we have these
21 amazingly long lived assets, DSM's benefits is very
22 long-term. DSM -- people will talk about Hydro's
23 marginal cost or marginal values. Those marginal
24 values are driven by export markets. Primarily,
25 export markets today are very low. Hydro's forecast

1 for twenty (20) years from now they will be very high.
2 So when Hydro runs a DSM program it
3 banks on that -- that -- a long life. It banks on
4 this huge payoff ten (10) or fifteen (15) years from
5 now, twenty (20) years from now. And I do know from
6 being involved with other DSM negotiations with Hydro
7 that, if you can justify a program that's giving
8 twenty-five (25) years of benefit versus twenty (20),
9 the value goes way up, and up even more because that -
10 - that far end is where all the value is.
11 So if you look at the investment being
12 made in DSM and the actual operating current
13 situations on it today, it is not paying for itself.
14 We hear that in GRAs when Hydro says, I'm spending
15 more in DSM and -- and it's causing my rates to be
16 higher, it's the one (1) of the reasons I need weight
17 -- rate increases.
18 For -- for pra -- practical reasons, we
19 would say allocating to the classes makes more sense
20 simply it -- it isolates a certain ability for classes
21 to be -- to be questioning or -- or challenging the
22 economics of program by program that they have to pay
23 for. As long as it's isolated in the class, I think
24 there's less -- less concern for that pragmatically,
25 and it -- it -- I think it leads to a reasonable

1 result.

2 So that's where we end on -- on that

3 point. I think -- I -- I think Christensen summarized

4 it well in slide -- I put it on slide 30, the quote

5 that DSM does free up load to be sold to exports, but

6 it's -- it's not the purpose for DSM pro -- DSM

7 programs that are instituted today.

8 And that's the end of the -- the slide

9 presentation. I -- I thought it might merit -- well,

10 I think we're on time.

11 MR. ANTOINE HACAULT: Down to the last

12 minute.

13 MR. PATRICK BOWMAN: Time for

14 questions.

15

16 (BRIEF PAUSE)

17

18 THE CHAIRPERSON: Okay. I think

19 we're good. Thank you.

20 Mr. Gange, are you relo -- relocating?

21 MR. BILL GANGE: Yes, we will

22 relocate. Why don't we take five (5) minutes for --

23 to -- to stretch legs and...

24

25 (PANEL RETIRES)

1 --- Upon recessing at 2:14 p.m.
2 --- Upon resuming at 2:20 p.m.
3
4 THE CHAIRPERSON: Okay. So are we
5 ready to resume? Mr. Gange...?
6
7 GREEN ACTION CENTRE PANEL:
8 PAUL CHERNICK, Previously Sworn
9
10 OPENING COMMENTS BY MR. BILL GANGE:
11 MR. BILL GANGE: Madam Chair, thank
12 you. Members of the panel. A couple of housekeeping
13 items. This morning I sub -- circulated a budget
14 increase letter with respect to Green Action Centre.
15 I think all the parties received that, and Mr.
16 Simonsen advises me that that will be Green Action
17 Centre number 21.
18
19 --- EXHIBIT NO. GAC-21: Budget increase letter
20 from Green Action Centre
21
22 MR. BILL GANGE: We have a
23 presentation that was prepared by Mr. Chernick, and
24 that will be Green Action Centre number 22.
25

1 --- EXHIBIT NO. GAC-22: Green Action Centre
2 presentation
3
4 MR. BILL GANGE: And as well, Mr.
5 Chernick sent out an email this morning with respect
6 to the correction of some -- some information that he
7 provided in his direct testimony, and that will be
8 marked as Green Action Centre number 23.
9
10 --- EXHIBIT NO. GAC-23: Green Action Centre's
11 email with some
12 corrections of some
13 information that was
14 provided in Paul
15 Chernick's direct
16 testimony
17
18 MR. BILL GANGE: With respect to the
19 presentation, Madam Chair, Mr. Chernick, on behalf of
20 Green Action Centre, the -- the material that's being
21 presented is through the lens of Green Action Centre
22 based on social justice and equity. We don't
23 represent a single class, and as a result, what we've
24 attempted to do is to -- to come here in -- in the
25 discussions that Green Action Centre has had with Mr.

1 Chernick to present as fairly as -- as we are able to,
2 a dispassionate review of the cost of service issues,
3 hopefully free of bias, and free of -- of customer
4 class prejudices or biases.
5 And with that, I will turn the
6 presentation over to Mr. Chernick.
7 THE CHAIRPERSON: Mr. Gange, just
8 before you do that, you mentioned a -- an exhibit that
9 corrected some previous information?
10 MR. BILL GANGE: That's correct.
11 THE CHAIRPERSON: And I'm not sure
12 that we've seen that.
13 MR. KURT SIMONSEN: I don't have hard
14 copies yet, Madam Chair. We'll get those to the
15 parties as soon as we make a copy.
16 THE CHAIRPERSON: Okay. And is it
17 relevant to the presentation today?
18 MR. BILL GANGE: I think that Mr.
19 Chernick may -- may touch upon it briefly during his
20 presentation, but he wanted to make certain that --
21 when -- as he was reviewing it, he came across an
22 error in one (1) of his tables, and wanted to make
23 certain that -- that the evidence that he presented
24 was -- was accurate, and so he corrected the -- the
25 error that he had discovered.

1 THE CHAIRPERSON: Okay, thank you.
2 And -- and so, Mr. Chernick, you'll point that out to
3 us, then, when you get to that point in your
4 presentation?
5 MR. PAUL CHERNICK: Yes, I will.
6 THE CHAIRPERSON: Thank you.
7
8 PRESENTATION BY GREEN ACTION CENTRE:
9 MR. PAUL CHERNICK: Thank you. My
10 first slide, it just says who I am and -- and where we
11 are, and the second slide is a table of contents, so I
12 think we can start on the third slide, which is the
13 purpose of the PCOSS, which is to divide up cost of
14 service among classes in an equitable way relying on
15 cost/causation where that's possible. Why was the
16 cost incurred, and what factors drove it, and what
17 classes are using those factors today?
18 Now, sometimes, as we've talked about
19 earlier, the time scales get a little more
20 complicated. But that's our basic -- or at least my
21 basic perspective, that you want to start with cost
22 causation.
23 It's important to remember as we're
24 working on the cost-of-service study that it does not
25 determine the revenues to be collected from each

1 class. That's a separate decision of the Board. The
2 Board may say, We want to have the cost-of-service
3 study done in a particular way.
4 And then they can say, Okay, well, that
5 would -- say if we wanted to bring everybody to unity,
6 we would have a 15 percent increase for this class and
7 a 5 percent decrease for that class. Doesn't mean you
8 have to do it, doesn't mean you have to do it right
9 now, and you may not do it ever depending upon a whole
10 range of considerations.
11 And it's also important to remember
12 that the cost-of-service results are not critical in
13 rate design considerations. So we're talking here
14 about one (1) portion of the rate-setting process, but
15 not the whole process.
16 In the next slide, I sort of expand on
17 -- on the idea of -- of the cost/causation and the
18 importance of not worrying about where the cost
19 causation's going to lead you. Manitoba Hydro has
20 indicated that some changes are -- are just too small
21 to bother with. At least I think that's what they
22 were saying. And they've said that other changes
23 would be perhaps too burdensome to make.
24 And I think yesterday we heard Ms.
25 Derksen say that, in looking at a methodology, she

1 thinks about the outcome. I don't think the Board
2 should think about it that way. I would hope that the
3 Board would say, What do we believe about cost
4 causation? And we'll worry later about the impact on
5 classes and -- and other considerations.
6 I think it's also important, where
7 data's available, where analyses are easy to do, that
8 we use the best available allocation methodology
9 rather than saying, Well, we've done it this way for a
10 long time and we don't want to change, or, A lot of
11 other jurisdictions do it this way, so therefore it
12 must be okay.
13 If you've got a good reason for doing
14 something, then do it. Now, if you have to spend a
15 lot of money gathering data and you don't expect it to
16 have a big effect, then maybe you don't do it. But in
17 many cases, we're talking about data that the company
18 already has in its engineering records, already has in
19 its accounting records. And it's just a matter of
20 crunching some numbers.
21 And if you get to the point of saying,
22 We're not -- we've decided on what a -- an equitable
23 allocation of costs is, but we're not going to impose
24 that on certain classes, you -- I would hope that the
25 Board would be explicit in saying that that's what

1 it's doing. And that's a -- an issue for the rate
2 case, not for this proceeding.
3 And at that last point on the -- the
4 slide about don't fudge the analysis to get the
5 result, get the result, and then you decide what you
6 want to do with it.
7 Next slide. All right. Now we're
8 getting into the actual topics for the -- the hearing.
9 The allocation to -- to exports, I think people have
10 talked about that enough over the last couple of days
11 so that I don't need to do the introduction.
12 But from the evidence I've seen, no
13 fixed costs are incurred due to the opportunity
14 exports. And to the extent that some past plant --
15 Wuskwatim or Limestone -- were accelerated due to
16 opportunity exports, it would actually be less
17 expensive today.
18 The costs in the cost-of-service study
19 would be lower because they would have been built
20 sooner with less inflation, and they'd be more
21 depreciated today than if they'd been built later
22 because of a lack of opportunity sales.
23 So there's no burden on current
24 ratepayers from the opportunity exports. And I don't
25 see any reason to -- to allocate any of the fixed

1 costs to opportunity sales.

2 Next page. In terms of how the -- the

3 next export revenues are used, the fact that Manitoba

4 Hydro has the NER means that there's a convenient

5 source for funding costs that really aren't caused by

6 any class. The uniform rates adjustment, the

7 affordable energy funder are two (2) obvious examples.

8 They're just costs that are required

9 for -- for social purposes. They're not being caused

10 by the number of customers or the demand, or the --

11 the energy use in any class.

12 And then whatever is left over after

13 those purposes are fulfilled can be used to reduce

14 current revenue requirements. And I agree with the

15 logic that all utility service costs including costs

16 that are directly assigned to classes should be

17 included in the allocator for the NER, but I wouldn't

18 include the rental of street lighting equipment, which

19 in my line includes luminaire in the poles on -- on

20 which they stand, because that's part of the -- a -- a

21 non-utility function.

22 You can put up your own pole luminaire

23 and -- and just have Manitoba Hydro connect a line to

24 it. Manitoba Hydro does not provide residential

25 customers with foundations for their houses. There's

1 no reason why that should be con -- providing a
2 foundation for a -- a streetlight should be considered
3 part of the utility service. And it's certainly not
4 part of the natural monopoly.
5 And I don't see any basis for diverting
6 the forecast next exp -- net export revenues to a
7 reserve fund.
8 The next page. On DSM costs we have
9 two (2) duelling perspectives, each of which has some
10 merit. On the one (1) hand DSM benefits the
11 participants and their class. Also -- it also
12 benefits the system by reducing costs. It reduces
13 total costs. And it's caused by the system
14 requirements, by the need to reduce system costs.
15 It's made available by the
16 participants. The participants are like the vendors
17 of the DSM. And the allocating costs to the
18 participants is not really cause based, but they do
19 benefit disproportionately compared to other classes.
20 Next slide. In selecting a -- a DSM
21 cost allocation methodology, the Board should try to
22 ensure, or at least maximize the probability that DSM
23 that's benefiting the system is not harming one (1)
24 particular class, or some set of classes.
25 And direct assignment can do that

1 because the DSM is generating benefits to go to
2 everybody. Only some of the benefits go to the
3 participating class. If you put all the costs on the
4 participating class, they may be worse off. And as
5 representatives of the class figure that out they may
6 say, No, I -- we don't want you to do a lot of DSM for
7 us, because we wind up paying more than we save.
8 We want you to do a lot for other
9 classes so that we'll get the benefits and not have to
10 pay for them. On the other hand, when you reduce the
11 usage by say the residential customers, then there's
12 some fixed costs, at least in the short-term, that are
13 going to get picked up by other classes, like all the
14 overheads for the -- the system, the -- the co -- a
15 lot of the cost of the distribution system, the
16 transmission system that are fixed in the short-term.
17 Residentials will be using less than
18 that -- less of those things. You'll be getting less
19 revenue from them. You'll be allocating them less
20 cost. And so therefore, other classes will pay more.
21 So you could have a situation where total costs for
22 the system go down. The participating class does
23 very, very well and other classes are worse off. So
24 either way you go, you could wind up with a problem.
25 So given these two (2) possibilities,

1 my preference is -- would be to look at the effects of
2 doing it each way, as a system benefit or a direct
3 assignment, and seeing whether both of them work,
4 whether neither of them works, or whether one (1)
5 works just fine, has no adverse effects, and the other
6 one is problematic. And then you have a basis for
7 making a decision going forward.
8 And if both of those methods are -- are
9 equitable you can choose something in-between, as Nova
10 Scotia did, and do it using 75 percent direct
11 assignment and 20 -- 25 percent assign -- allocation
12 on benefits.
13 The next slide. The Manitoba portrayal
14 of the DSM positions yesterday I think maybe sort of
15 misrepresented things a little bit. It put my
16 position on the -- on the far right. I think I'm in
17 the middle saying you want to do it fairly. And you
18 can take from column A or column B, whichever one
19 works, or some combination, but you have to test it.
20 And, also, their -- their diagram
21 really should have included Christensen saying maybe
22 the direct assignment, but maybe not, so maybe they're
23 sort of in the middle, closer to -- to my position.
24 And London economics really doesn't endorse system
25 resources, they want to use a 2 CP allocator, which

1 really doesn't reflect the system benefits. The next
2 slide.
3 So here I lay out the steps of looking
4 at -- at the effects of DSM on the participating and
5 nonparticipating classes. I won't go through them
6 all. It's not a very complicated analysis. We're
7 talking about basically something done in a page or
8 two (2) spreadsheet just to get a sense of whether it
9 looks like you're going to be helping or hurting the
10 various classes. The next slide.
11 On generation classification I think
12 the evidence is really very clear that energy drives
13 Manitoba's fixed generation costs, energy needs.
14 Manitoba Hydro, I believe, is -- is correct on this
15 point. And that generation that's built to serve
16 energy requirements also provides peak demand, will
17 meet load in all hours, but that's sort of a byproduct
18 of having the energy available economically.
19 Now, this is specific to Manitoba, and
20 it's not true very many places. It's not true for the
21 diesel system, but it's true for the -- the basic
22 Manitoba Hydro system. The next slide.
23 The use of some kind of weighting of
24 energy by market value by time period makes sense, but
25 including a capacity value in that weighted energy

1 calculation is -- is not reasonable. As I just said,
2 as Manitoba Hydro says, capacity doesn't drive
3 generation investment, nor does -- is there any value
4 in the short-term to go along with the short-term
5 energy valuation that -- that Hydro uses for weighting
6 the energy value between time periods.
7 There's no con -- capacity value on
8 that time scale. The MISO capacity contract is an
9 annual product. It's not some kind of hourly
10 opportunity product where you can sell a little bit of
11 -- of capacity here and there.
12 And this morning -- no, it was yest --
13 excuse me, yesterday we heard Manitoba Hydro say that
14 if loads were lower -- domestic loads were lower they
15 wouldn't have been able to sell any additional
16 capacity to -- to MISO. That the amount of capacity
17 they could sell to MISO over the last few years when
18 there was a real market was constrained by other
19 factors. It's not constrained by the amount of
20 generation capacity that's free and -- and not con --
21 not held up by, or not devoted to meeting domestic
22 load. Next page.
23
24 (BRIEF PAUSE)
25

1 MR. PAUL CHERNICK: There may be a
2 better way of doing the -- the shaping of prices
3 within the year, the energy prices. Yesterday
4 Manitoba Hydro said that their SEP weights, S-E-P
5 weights, are not really the SEP prices which are set
6 on a weekly basis but they're after-the-fact MISO
7 prices of some sort.
8 They don't match the MISO prices that -
9 - that I looked up on the MISO web site but they may
10 be defining things differently. I'm not sure exactly
11 what's going on here. But that improvement in the
12 weighting might be a suitable subject for the next GRA
13 within the -- the general approach that the Company
14 has taken. Next slide.
15 Now, just in case people are still
16 thinking about it this way, even though you -- there's
17 no way that Hydro could have sold any more capacity if
18 loads had been lower, the -- this graph just shows you
19 that the capacity prices in MISO have been much, much
20 lower than the capacity prices that Hydro proposes to
21 use in this weighting factor based on its CRP credit.
22 And in -- in many years they're zero, or so close to
23 zero it's -- it doesn't really matter. Next slide.
24 And here I -- I take the numbers, and -
25 - and average them out over the eight (8) year period

1 that Hydro used in PCOSS14, and then I moved the time
2 period forward three (3) years assuming that in GRA --
3 the GRA that would be filed later this year that we'll
4 be looking at a PCOSS-17. And we're only talking
5 about the -- the MISO prices being rough -- roughly 4
6 percent of what Hydro used. Really irrelevant even if
7 there were a marginal capacity price that's available.
8 Christensen finds the use of the CRP
9 prices to be plausible. I don't know where they get
10 that from. It's not tied to anything in the real
11 market. They say it captures current market
12 conditions. It's on page -- on page 23 of their
13 presentation today. But they're -- it's not tied to
14 the market conditions at all. And it's not even a
15 real cost to Manitoba Hydro. It's a value selected to
16 reward interruptability of customers on the
17 transmission system who may be valuable for a number
18 of reasons but they're not justified by market price
19 of capacity. Next slide.
20
21 (BRIEF PAUSE)
22
23 MR. PAUL CHERNICK: Oh, yes. And --
24 can we move back one (1) slide? Mr. Gange reminds me
25 that as I note in -- underneath this table that these

are the data that I corrected in my errata. I just had a mathematical error in formula for converting from dollars per kilowatt month to dollars per megawatt day to dollars per kilowatt year. Somewhere in that process I -- I got something mixed up. Okay. Next slide.

(BRIEF PAUSE)

MR. PAUL CHERNICK: Transmission is built both to reach load and to get generation out of -- away from the power plant and to the load area. Hydro treats some of that generation related transmission as load driven and I went through and -- and identified in my initial evidence the generation driven transmission and substations.

Next slide. A -- a lot of transmission is required by where the generation is. And where the generation is, is determined by the fact that you want the hydro, which gives you lots of low cost energy.

Next slide. PCOSS-14 treats -- treats most of the generation drive AC transmission as being driven by load. Using a philosophy that I called the one (1) electron approach, where if electricity could flow across the line without the generator operating,

1 then Hydro treated it as being load serving
2 transmission. Even if the only reason the line was
3 built, the only reason it's really needed today is to
4 serve the -- the generation.
5 And that really ignores cost causation.
6 That's kind of an accident.
7 Next slide. Here I've -- I've taken
8 the liberty of -- of amending the -- the web diagram
9 by adding some lines in red from the top right most
10 generator, representing transmission lines. It has --
11 in -- in my example, instead of having one (1) line
12 coming out of it, it has three (3) lines coming out of
13 it.
14 One (1) of which goes to another
15 generator, two (2) of which connect to the web, and
16 one (1) of those then connects at a substation where
17 another new line is required to get the power out of
18 that part of the web and down to meet load.
19 And these are the kinds of examples
20 that you see in Hydro's actual transmission system.
21 Generators connect to other generators. They connect
22 to the web in multiple places so that their power can
23 flow to different destinations and potentially get
24 around bottlenecks.
25 But all these lines are being added for

1 the generator. Now, in principle, if that generator
2 in the top right-hand corner were not running, and
3 depending upon what's happening on the transmission
4 system and the -- the magic of the way that -- that AC
5 transmission works, which is not easily understood by
6 anyone but transmission engineers, I believe, it's
7 possible that power would flow from the web up to that
8 -- the generator that's connected -- the -- the little
9 -- the one that's close to the web there and then flow
10 through the red line to our generator and down to meet
11 -- to a substation to meet load someplace else.
12 And Hydro would look at that and say,
13 Well, that serves load. And under some circumstances
14 some power would flow over it, but that's not why you
15 built it.
16 Okay. Next slide. In PCOSS-14 there
17 were a few categories of transmission that the company
18 recognized were generation related, the DC lines, the
19 convertor stations, the northern collectors, and the
20 switch yards and stations up in the north that tie
21 into the DC system.
22 Next slide. In the workshop I think we
23 reached agreement with Hydro that a number of other
24 lines really were genera -- generation related. From
25 the Winnipeg River, for example. The lines connecting

1 the wind plants to the system.
2 And I raised a number of other
3 examples, most importantly, Wuskwatim and its
4 relatively expensive 230 kV lines and Hydro did not
5 argue with -- with any of those.
6 The next slide has a table of the --
7 the costs just summarizing what's in my evidence for
8 the -- the generation-related transmission lines. And
9 about 25 percent of the -- of the generation that's --
10 excuse me, of the -- 25 percent of the transmission
11 that the Company treats as -- as transmission rather
12 than generation is really also generation and should
13 be moved over. The next slide.
14 This does the same thing for the
15 transmission substations. And then I -- I note that,
16 all together, this amounts to about $20 million
17 annually. And while that's not the biggest issue in
18 this case, it's about 2 percent of the generation
19 cost. It's four (4) times the cost of the US
20 interties, which a number of -- of parties have
21 thought were important enough to -- to deal with.
22 It's a third of the sub-transmission function which
23 Hydro also thought was important enough to argue
24 about.
25 So while I've -- I've -- I believe that

1 Manitoba Hydro has -- has taken a position that some
2 of the things I've pointed out are really too small to
3 even worry about, I think the -- the correction in
4 general in -- for an aggregate is substantial. And
5 the next slide, I guess.
6 On the allocation of transmission, the
7 2 CP allocator, which is really a hundred CP, seems
8 reasonable overall for allocating transmission costs.
9 The allocation of the US interconnections on energy
10 because they're there basically to sell energy to the
11 states and to buy energy from the US in -- either in
12 times of drought or to be stored for resale back to
13 other customers, that it makes sense to -- to allocate
14 on energy.
15 And the same argument really applies to
16 the -- the lines running to Ontario and Saskatchewan
17 and may become a bigger issue depending upon the cost
18 of the new line to serve Saskatchewan.
19 And that concludes -- I have a last
20 slide which is just sort of an appendix showing how I
21 calculated the -- the MISO prices for comparison with
22 CRP. I'm available for questions or you can move on
23 to the next witness.
24 BOARD MEMBER GRANT: Just on -- on
25 DSM. And if you were to direct assign the cost to

1 customer classes, I know this is going to apply
2 generally, but it would seem to me that there's so
3 much heterogeneity within that customer class, a
4 problem all the time, but...
5 So you would have -- if I'm a
6 nonparticipant in a DSM program, then arguably I'd pay
7 twice, right? I'd pay because I see higher overall
8 rates. And then I'm going to pay again because I'm
9 getting direct assigned these particular costs, right?
10 So maybe that's what -- the Green
11 Action Centre wants to punish recalcitrant people like
12 me. But if I could just -- let me get the rest in.
13 Also, I think of the heterogeneity in geographical
14 terms, where suppose Hydro spends a lot of money
15 advertising fuel switching or something, and -- and a
16 good chunk of the Province, that's not available to
17 them.
18 Or, you know, you think of some
19 northern communities that access the DSM programs
20 we've heard at times or they're less accessible. So
21 I'm just wondering how, if you direct assign to this
22 customer class, that that class itself is so
23 heterogeneous that -- that had -- right, that -- that
24 there may be issues about that or -- or extra
25 problems?

1 MR. PAUL CHERNICK: Well, you do have
2 issues with in classes of particular groups if they
3 can get organized enough to deal with it, say we --
4 we're paying for this, but we don't feel like we're
5 getting our share of the benefits.
6 Now, the thing is, with residential
7 programs, if Hydro is running a residential lighting
8 program, almost every residential customer can
9 participate in that program.
10 There are other kinds of programs where
11 you -- you don't own your house or its -- you live in
12 an apartment and -- and there's no way to add
13 insulation to the walls, and so on, where you can't
14 participate. And if there are groups within a class
15 that are getting left out who do have DSM potential,
16 then it's -- it's important to recognize that, and try
17 and find ways of reaching them.
18 Whether that's a matter of kind of
19 overcoming a cultural problem, or a geographic problem
20 of they're just in the wrong place and there aren't
21 many contractors in that part of the Province and
22 you're not doing enough outreach to them, or whether
23 it's a matter of a technological niche that they're in
24 some kind of housing that needs a different solution
25 that you haven't worked out a program for yet, or

1 haven't added measures to your program.
2 And it's very valuable to have
3 subgroups of classes represented in the DSM
4 development process to say, what about the apartments,
5 what about the rural people, if you can arrange that.
6 BOARD MEMBER GRANT: And can I just --
7 a couple other things quickly that have been quickly
8 with respect to DSM. One in terms of the sort of
9 system-wide benefits but is -- is it different in the
10 sense that the -- it -- it's Hydro that decides which
11 class -- customer class is going to get a DSM program,
12 or how much they're going to get. And so in a sense
13 it's a little bit different in terms of who
14 participates and who doesn't because part of that
15 decision is being made by the Utility.
16 And the second point -- so in the -- I
17 remember one time in the winter turning on the hockey
18 game and seeing a Manitoba Hydro Power Smart
19 commercial, and I got a warm fuzzy feeling, and then I
20 went and, you know, left all the lights on and the
21 fridge door open so it didn't affect my behaviour at
22 all but I -- I went -- you know, I went to bed that
23 night thinking, good -- what a wonderful Utility we've
24 got and they're so cor -- there's corporate
25 responsibility. I'm so proud to be part of this

1 Province.

2 So in your experience, do DSM programs

3 have a large, you know, public relations aspect to

4 them, and -- and in the sense there's -- of a system-

5 wide benefit in that context as opposed to necessarily

6 targeting particular -- you know, programs targeting

7 particular participants?

8 MR. PAUL CHERNICK: There's certainly

9 some awareness that's generated by DSM outreach. I

10 think that's most valuable when it's bringing people

11 into actual DSM programs. And if that commercial had

12 said, you know, before the game starts up again you

13 could call and schedule a home energy audit some

14 people might actually do that.

15 It -- the general jawboning about

16 'remember to turn out your lights' or 'let's all be

17 efficient', I -- I don't know that that really has

18 much effect. I think some people have actually tried

19 to study how much those behavioural programs work, and

20 with high motivation they can work very well. They

21 did in California after the -- or during the -- the

22 period when -- when the energy crisis when the -- when

23 Enron was driving prices through the -- the roof and -

24 - and draining supply.

25 They worked very well in Alaska and

1 Juno, I think it was, when transmission lines serving
2 the city went down and they were limited to their
3 local resources, and everybody had to cooperate or
4 else the lights were going to go out.
5 But just telling people in -- in a
6 situation of abundance that they really ought to be
7 more -- more careful in their energy use probably
8 isn't very useful. If you tell them, you know, you
9 probably aren't aware of it b ut you've probably got a
10 dozen things in your house that are sucking energy
11 right now, and doing you no good. You've got all
12 these chargers and converters, and stuff. Put them on
13 power strips and turn them off when you're not using
14 them, and here's where you can get a power strip
15 cheap: 1-800-HYDRO.
16 That might be pretty effective. Might
17 be effective enough to justify the cost of the ad
18 anyway, just telling people -- well, Boston-Edison, at
19 one point, had a -- a big billboard up that said,
20 "Trip the light. Fantastic," which was funny the
21 first time, and I doubt that it saved a kilowatt hour,
22 but that...
23 THE CHAIRPERSON: Okay. Thank you.
24 So we are going to move on to our concurrent evidence
25 panel, and so we'll take a ten (10) minute break. If

1 we could come back at 3:10 with the concurrent
2 evidence panel ready to go, that would be great.
3
4 (PANEL RETIRES)
5
6 --- Upon recessing at 2:59 p.m.
7 --- Upon resuming at 3:13 p.m.
8
9 CONCURRENT EVIDENCE PANEL RE THE TREATMENT OF NET
10 EXPORT REVENUE AND ALLOCATION THEREOF:
11 MICHAEL O'SHEASY, Previously Sworn
12 ROBERT CAMFIELD, Previously Sworn
13 WILLIAM HARPER, Previously Sworn
14 JOHN TODD, Previously Sworn
15 A.J. GOULDING, Previously Sworn
16 PATRICK BOWMAN, Previously Sworn
17 PAUL CHERNICK, Previously Sworn
18
19 THE CHAIRPERSON: All right. I think
20 we're ready to go again, and this is somewhat of a --
21 an historic moment because this is the first time that
22 we're embarking on a concurrent evidence panel in a
23 hearing setting.
24 And so just to remind us of the rules
25 of engagement, the panel has asked Ms. Steinfeld to

1 just go through those rules as per our order and --
2 just so that we set the right tone here.
3 Ms. Steinfeld...?
4
5 (BRIEF PAUSE)
6
7 MS. DAYNA STEINFELD: All right. I'm
8 on now. So as the Chairwoman indicated, we're moving
9 to the concurrent evidence panel. This is the cross-
10 examination portion of our hearing. It is intended
11 for the asking of questions on an issue to a party to
12 whom your client is adverse.
13 To that end, Order 84/'16 identifies
14 the following procedure on page 16 to 17, if anyone's
15 following along:
16 "All experts that are providing
17 testimony on key issues identified
18 by the Board are to participate in
19 the concurrent evidence session.
20 Manitoba Hydro staff will not
21 participate in this session, but any
22 independent expert retained by
23 Manitoba Hydro may participate.
24 Only legal counsel is permitted to
25 cross-examine, and experts are not

1 to ask questions of each other.
2 Legal counsel decides to whom a
3 question is asked. Only the person
4 to whom the question is asked is to
5 provide a response unless legal
6 counsel requests the perspective of
7 another expert on the panel.
8 Cross-examination proceeds
9 sequentially by issue rather than by
10 party, with time limits as set by
11 the Board on the agendas that
12 everyone has received to ensure that
13 the process can be completed."
14 And with that, I'll turn it back over.
15 THE CHAIRPERSON: Thank you, Ms.
16 Steinfeld. And so, Mr. Williams, please lead off.
17 MR. BYRON WILLIAMS: Yes. And thank
18 you. And if I -- if I might respectfully correct the
19 Board, this is our second concurrent evidence panel.
20 We attempted one (1) with MPI, but with a much smaller
21 crowd. This looks like the Reach for the Top team
22 from Toronto in 1972 or so.
23 THE CHAIRPERSON: I stand corrected,
24 Mr. Williams.
25

1 CROSS-EXAMINATION BY MR. BYRON WILLIAMS:
2 MR. BYRON WILLIAMS: And I'll indicate
3 -- and this is not with any disrespect to the other
4 witnesses -- the bulk of my questions will be going to
5 Mr. Bowman, just given the nature of this hearing.
6 There are some issues where, as you
7 heard yesterday, we disagree with Manitoba Hydro in
8 terms of the pace of marginal cost implementational
9 (sic). So there may be a few questions that go to --
10 to Christensen Associates. So I don't mean any
11 disrespect to the -- the folks on the -- the crew.
12 Mr. Bowman, can you see me, sir?
13 MR. PATRICK BOWMAN: Yes.
14 MR. BYRON WILLIAMS: Okay. With --
15 recognizing the time limitations, just in -- in terms
16 of the scope of your review, and in -- in examining
17 matters related to the proposed cost-of-service model
18 of Hydro, my understanding is that you -- you examined
19 it taking into account what you consider to be normal
20 regulatory review procedures and principles
21 appropriate for Canadian Crown-owned electric
22 utilities, agreed?
23 MR. PATRICK BOWMAN: Yes.
24 MR. BYRON WILLIAMS: And again,
25 without asking you to elaborate, in the course of that

1 review, you examined whether Hydro's cost-of-service
2 methods reflect standard practice for regulated
3 utilities in North America. That was one (1) aspect
4 of what -- one (1) of the questions that you
5 considered, agreed?
6 MR. PATRICK BOWMAN: Yes.
7 MR. BYRON WILLIAMS: And in
8 considering normal regulatory standards, principles,
9 and practices, one (1) of your sources was the
10 National Association of Regulatory Utility Commission,
11 or the acronym being NARUC, their electric utility
12 cost allocation manual from 1992, agreed?
13 MR. PATRICK BOWMAN: Yes.
14 MR. BYRON WILLIAMS: And you'll agree
15 that you cited it on a number of occasions in your
16 direct -- in your written evidence during the
17 workshops and in your rebuttal evidence, correct?
18 MR. PATRICK BOWMAN: Yes.
19 MR. BYRON WILLIAMS: While I'm
20 assuming you have not memorized the manual, Mr.
21 Bowman, it is a document you have some familiarity
22 with, and it is a regular source of reference for you,
23 correct?
24 MR. PATRICK BOWMAN: Yes.
25 MR. BYRON WILLIAMS: Now, Mr. Bowman,

1 in terms of what you consider to be within the scope
2 of cost-of-service review, the appropriate scope of
3 cost-of-service review -- and I'm not inviting a
4 speech -- I would ask you to confirm that from your
5 perspective, appropriate issues would include recovery
6 of the revenue -- revenue requirement, fairness and
7 equity, and simplicity, agreed?
8 MR. PATRICK BOWMAN: In terms of the
9 scope, was your question?
10 MR. BYRON WILLIAMS: Yes, sir. Let --
11 let me -- let me say that, if I -- my question may
12 have been imprecise. In terms of what you consider to
13 be appropriate cost-of-service objectives, sir --
14 MR. PATRICK BOWMAN: Yeah --
15 MR. BYRON WILLIAMS: -- you restrict
16 that to recovery of the revenue requirement, fairness
17 and equity, and simplicity.
18 MR. PATRICK BOWMAN: Yes. Those are
19 things that the cost-of-service study should help you
20 move towards. It doesn't solve, but it helps you move
21 towards.
22 MR. BYRON WILLIAMS: And, sir, from
23 your perspective, efficiency is not an appropriate
24 cost-of-service objective. You've said that in your
25 evidence?

1 MR. PATRICK BOWMAN: Yes, in a -- in a
2 classic sense of -- of, you know, marginal revenues,
3 marginal costs, those type of concepts of efficiency,
4 yes. That is not -- not a cost-of-service objective.
5 MR. BYRON WILLIAMS: Going back to the
6 NARUC manual, would it be fair to suggest that NARUC
7 devotes three (3) chapters of its manual to the
8 subject of marginal cost studies?
9 MR. PATRICK BOWMAN: Yeah, they --
10 they absolutely do. And that 1992 book has -- has a
11 whole section on -- on marginal cost cost of service,
12 yes. There's a whole -- I think it's the second half,
13 if I remember correctly.
14 MR. BYRON WILLIAMS: And indeed, sir,
15 that's focussed on -- on efficiency concepts?
16 MR. PATRICK BOWMAN: Right. The era
17 that that was written, there was a considerable focus
18 on whether marginal costs could play a -- a broader
19 role in helping people deal with -- with certain
20 issues.
21 And at the time that was written in a -
22 - for -- for cost-of-service studies, there was a lot
23 of discussion going on about whether marginal costs
24 could become the basis on which one did cost-of-
25 service studies, and we could move away from these

1 accounting costs to help us achieve efficiency.
2 In practice, though, that's almost
3 never happened. I -- I think I've heard citation
4 about three (3) or four (4) utilities in North America
5 who actually do a marginal cost cost-of-service study.
6 It's a -- it's a very rare type of thing.
7 MR. BYRON WILLIAMS: Now, just turning
8 to the folks from Christensen Associates, or CA Energy
9 Consulting, in your preparation for this proceeding
10 and in your work for Manitoba Hydro as consultants,
11 you also reviewed Manitoba Hydro's methods in light of
12 accepted costs of costing theory, North American
13 utility industry practice, and regulatory
14 requirements, agreed?
15 MR. MICHAEL O'SHEASY: Yes, we did,
16 agreed.
17 MR. BYRON WILLIAMS: And you're
18 familiar with NARUC, as well?
19 MR. MICHAEL O'SHEASY: Correct. I
20 haven't memorized it, but I'm familiar with it.
21 MR. BYRON WILLIAMS: And I -- we're --
22 we're going to come to efficiency in just a second,
23 but if I suggested to you that one (1) of the messages
24 from NARUC is that while there are common approaches
25 that each utili -- tility is a unique entity and that

1 unique nature of each utility needs to be taken into
2 account in cost-of-service analysis, you'd agree with
3 that suggestion?
4 MR. MICHAEL O'SHEASY: I would agree
5 with that.
6 MR. BYRON WILLIAMS: And so while it's
7 important to be mindful of accepted theory and
8 practices from the industry perspective, it's critical
9 to keep a -- an eye on the unique aspect of the
10 industry --
11 MR. MICHAEL O'SHEASY: Correct.
12 MR. BYRON WILLIAMS: -- of a particular
13 utility. And if we were to look at unique aspects for
14 Manitoba Hydro, or other large hydroelectric
15 facilities -- utilities in Canada, leaving them aside
16 for just a moment -- leaving aside hydroelectric
17 suppliers, it's generally accepted that electricity
18 cannot be readily stored?
19 MR. MICHAEL O'SHEASY: Correct.
20 MR. BYRON WILLIAMS: And so one (1) of
21 the factors that sets hydro -- BC Hydro, Manitoba
22 Hydro, Hydro-Quebec, apart from the industry is that
23 energy storage.
24 MR. MICHAEL O'SHEASY: Correct, with
25 the hydro capability of choosing when to create the

electricity.

MR. BYRON WILLIAMS: And -- and it's fair to say that another circumstances in which Manitoba Hydro is quite special is the relatively large proportion of its sales revenue that are -- are -- is derived from export or wholesale sales.

MR. MICHAEL O'SHEASY: Correct. We would agree.

MR. BYRON WILLIAMS: And that market that it sells into is characterized by considerable price volatility. Agreed, sir?

MR. MICHAEL O'SHEASY: I would agree. I think the volatility has dampened recently, but over the course of time you will, indeed, see a fair amount of volatility in wholesale prices.

MR. BYRON WILLIAMS: And you would agree that the treatment of embedded utility costs in light of sales where marginal coat is a dominate feature presents special challenges for cost allocation.

MR. MICHAEL O'SHEASY: All right. Repeat that, please?

MR. BYRON WILLIAMS: I can't repeat it but I'll try it again. The treatment of embedded utility costs in a -- in a -- in light of sales where

1 marginal cost is a dominant feature can -- can raise
2 special challenges when it comes to cost allocation.
3 MR. MICHAEL O'SHEASY: Yeah. And I
4 think where -- what you're talking about, in a
5 wholesale market where marginal cost play a role but
6 also prices indeed will -- will depart from marginal
7 cost, then how you translate those back into an
8 embedded cost of service will have complexities and
9 challenges to them.
10 MR. BYRON WILLIAMS: Just before we go
11 back to Mr. Bowman, it's my understanding that your --
12 your team considers that marginal cost as a basis for
13 prices fully satisfies the efficiency principle, which
14 is a main criteria in -- both for cost of service and
15 the design of retail utility tariffs.
16 Would that be fair?
17 MR. ROBERT CAMFIELD: Well, we can
18 say, I think, rather affirmatively that if we were to
19 set prices at marginal cost in view of the pres -- the
20 presence of -- of substitute energy sources, number 1,
21 and then secondly the conditions of wholesale markets
22 that -- yeah, if we were to set mar -- our prices at
23 marginal cost, those would satisfy first -- first best
24 pricing results -- efficiency results.
25 MR. BYRON WILLIAMS: And just to probe

1 a little bit deeper, in terms of cost-of-service
2 analysis is consideration of efficiency principles
3 relevant?
4 MR. ROBERT CAMFIELD: Absolutely.
5 MR. MICHAEL O'SHEASY: If I could add
6 just one (1) thing quickly on that. Many times, a --
7 a cost-of-service analyst defines efficiency, in a
8 cost-of-service world, where embedded costs play a
9 role to be prices that - that reflect cost. And it's
10 not necessarily a qualifier as to whether they exactly
11 match marginal costs.
12 Just in general, if you have a rate
13 that matches the embedded costs of providing it, many
14 times we, in -- in my world, we'll say that's
15 sufficient.
16 MR. BYRON WILLIAMS: And within a
17 cost-of -serv -- service methodology, that's -- that's
18 an appropriate consideration? You're nodding your
19 head. Is that a yes?
20 MR. MICHAEL O'SHEASY: Yes. Yes. In
21 many times, what we will do in -- in our world, when
22 we translate it into rate design, is we may have
23 prices that -- overall, the rate recovers embedded
24 revenue requirements, but some of the prices,
25 depending on where they are, like a time of use right

1 on peak will be quite close to marginal cost.
2 MR. BYRON WILLIAMS: I thank you for
3 that insight. And it's something I'd not really
4 considered.
5 Mr. Bowman, we're going to start aiming
6 a little more directly at issues related to net export
7 revenue. And -- and if you need a reference from your
8 NFAT evidence, Mr. Bowman, it would be at page 2 -- 2-
9 6. But you'll recall in that proceeding that you
10 spoke of the potential in jurisdictions with good
11 hydro potential to adopt a patient capital approach.
12 Is that fair, sir?
13 MR. PATRICK BOWMAN: Yes.
14 MR. BYRON WILLIAMS: And I don't think
15 we need to, but you can scroll down to the bottom if
16 you -- if you wish. And you noted for the purposes of
17 -- of taking advantage of Hydro opportunities, a -- a
18 number of Canadian jurisdictions have employed, what
19 you term the patient capital approach, generally being
20 provincial governments and/or Aboriginal governments.
21 Would that be fair?
22 MR. PATRICK BOWMAN: Yes, absolutely.
23 MR. BYRON WILLIAMS: And in essence,
24 at least as I understand that approach, that involved
25 low cost borrowings backed by the province and also

1 backed by the full faith and credit of the citizenry.
2 Is that right, sir?
3 MR. PATRICK BOWMAN: Yes.
4 MR. BYRON WILLIAMS: And the theory
5 being that that would, over the long run, allow for
6 the development of a -- of a valuable resource and
7 also provide rate advantages to consumers?
8 MR. PATRICK BOWMAN: Yes.
9 MR. BYRON WILLIAMS: And you talked
10 about this a little bit this morning in terms of your
11 -- the NFAT. In terms of the NFAT, it was ultimately
12 your opinion that an opportunity-based vision, such as
13 advancing Keeyask, taking up the Minnesota Power sale,
14 and building new transition was likely better than a
15 need-based vision.
16 Is that correct, sir?
17 MR. PATRICK BOWMAN: Yes.
18 MR. BYRON WILLIAMS: And you concluded
19 and recommended that Hydro should take up Minnesota
20 Power and that export agreement?
21 MR. PATRICK BOWMAN: Yes.
22 MR. BYRON WILLIAMS: And one (1) part
23 of that agreement was the -- the requirement for
24 Keeyask in 2019?
25 MR. PATRICK BOWMAN: Yes.

1 MR. BYRON WILLIAMS: We'll come back
2 to the NFAT in a moment. But it's your view that
3 exports play a fundamental role in the planning and
4 operation of the Hydro system?
5 MR. PATRICK BOWMAN: Yes.
6 MR. BYRON WILLIAMS: And not just the
7 long-term planning, but the day-to-day, minute-by-
8 minute, hour-by-hour planning as well, sir?
9 MR. PATRICK BOWMAN: Yeah, for cost-
10 of-service purposes, I would say the more important
11 one is the long-term planning. Most of the costs
12 we're talking about allocating here are -- are fixed
13 costs, and certainly most of the particularly
14 challenging ones.
15 So that -- that -- those are driven by
16 long-term plans and not by -- by day-to-day, but --
17 but yes, in -- in both components.
18 MR. BYRON WILLIAMS: There is an
19 intimate connection both in terms of long term, and
20 day-to-day, and minute-by-minute operations, agreed?
21 MR. PATRICK BOWMAN: Yes.
22 MR. BYRON WILLIAMS: And export
23 revenues, sir, is a fundamental part of Manitoba
24 Hydro's overall business, agreed?
25 MR. PATRICK BOWMAN: It's a

1 fundamental part of their generation and transmission
2 business. I don't think it's any part of their
3 distribution business as -- as an example, but that
4 part, it's absolutely fundamental to the -- the bulk
5 power system.
6 Lots of utilities run distribution
7 systems that don't deal with that issue.
8 MR. BYRON WILLIAMS: Before we leave
9 the NFAT, Mr. -- Mr. Bowman, in terms of Conawapa, you
10 were a little less bullish, or optimistic about
11 Conawapa as compared to Keeyask, for the purposes of
12 the NFAT.
13 Is that correct, sir?
14 MR. PATRICK BOWMAN: Well, the
15 Conawapa request in NFAT properly framed was not like
16 the Keeyask request. The Keeyask was permission to
17 build. Conawapa was did it look good enough to keep
18 spending some money on. It wasn't -- or -- or nobody
19 in their -- in their right mind would say that we had
20 all the information needed for someone to decide
21 build, don't build.
22 So I think they were -- they were
23 different questions. But, you know, I -- I eventually
24 concluded that -- that Conawapa had -- had, you know,
25 passed a certain threshold for a short leash to keep

1 exploring and see if you -- you had something there.
2 It wasn't anywhere near the Keeyask type of
3 conclusion.
4 MR. BYRON WILLIAMS: Thank you. And -
5 - and indeed, sir, you recommended that they keep, at
6 least with some limited expenditures, to preserve that
7 window of opportunity for a need date of 2026,
8 correct?
9 MR. PATRICK BOWMAN: Yes, and -- and
10 limited being underlined, yeah.
11 MR. BYRON WILLIAMS: And I'm correct
12 in suggesting that, in terms of that window of
13 opportunity, your advice to Manitoba Hydro was that
14 all reasonable efforts should be directed towards
15 locking in fixed price contracts for Conawapa output
16 in the MISO market or elsewhere, agreed?
17 MR. PATRICK BOWMAN: Well, sure. I
18 don't think anybody would say build 1,300 megawatts on
19 spec.
20 MR. BYRON WILLIAMS: And, in your
21 view, securing a greater quantity of Conawapa's output
22 under firm contracts would materially improve the
23 economics of Conawapa, agreed?
24 MR. PATRICK BOWMAN: Well, it would
25 materially improve the business case of Conawapa at a

1 point in time. Whether it ultimately would improve
2 the -- the economics would depend on what the prices
3 you locked in versus those you might have gotten if
4 you waited, but it would take away significant
5 uncertainty, which is -- which is the issue you have
6 to deal with at the point you make the decision.
7 MR. BYRON WILLIAMS: Okay. Thank you.
8
9 (BRIEF PAUSE)
10
11 MR. BYRON WILLIAMS: Now, Mr. Bowman,
12 I can pull up the reference, but you -- you -- this I
13 think you probably do have memorized prob -- given how
14 hard you work. You recall producing for the Public
15 Utilities Board Undertaking number 33?
16
17 (BRIEF PAUSE)
18
19 MR. PATRICK BOWMAN: I recall doing
20 three (3). I forget which one was --
21 MR. BYRON WILLIAMS: Okay.
22 MR. PATRICK BOWMAN: -- which was
23 which, so just give me a moment.
24 MR. BYRON WILLIAMS: Yeah. Certainly.
25 Take your time, sir.

1 MR. PATRICK BOWMAN: Thirty-three
2 (33), yes, I have it.
3 MR. BYRON WILLIAMS: And in -- in
4 Undertaking 33 MIPUG took the position, not you, Mr.
5 Bowman, but MIP -- MIPUG took the interim position,
6 it's page 4 if you need it, that further consideration
7 was required in terms of the concept of doing away
8 with the export class.
9 Is that right?
10 MR. PATRICK BOWMAN: I -- yes, it's
11 written down. It was asked of us what MIPUG's
12 positions were at that point. That's why I put them
13 down. The -- when we discussed the -- the issues of
14 the cost of service study with the members there was
15 some questions raised about why all this fuss about
16 the export class, why isn't it simpler to just --
17 export revenues have come from the generation
18 transmission system, part of the transmission system
19 and be done with it and cut out a whole bunch of this
20 cost and fuss of the hearing.
21 So that -- that's where they -- they
22 would have focussed on -- on that question --
23 MR. BYRON WILLIAMS: And --
24 MR. PATRICK BOWMAN: -- rather than
25 get into these debates about NERs and other advanced

1 topics.

2 MR. BYRON WILLIAMS: And -- sorry, Mr.

3 Bowman, I apologize.

4 MR. PATRICK BOWMAN: That's fine.

5 MR. BYRON WILLIAMS: And indeed your

6 members were interested in exploring the concept of --

7 of having those revenues exclusively credited back to

8 transmission and -- and generation, agreed?

9 MR. PATRICK BOWMAN: Well, let's be a

10 bit careful here. We're talking about this fair --

11 fairly nebulous concept of net export revenues. When

12 we -- when we sit with these fellows and say we're

13 going to now talk about net export revenues, which is

14 the profits Hydro is raking in from export markets,

15 and they look at you like you have three (3) heads

16 because they -- they work in export energy markets

17 too.

18 And they're saying, What do you mean

19 you're making money out of export markets right now.

20 The markets are terrible, and you're building $6

21 billion hydro dams. How do you have any profits to

22 even talk about? Like, maybe there'll come a day

23 where we can talk about how to share these things but,

24 what do you mean.

25 So I think the -- the idea that we're

1 debating something that -- that they would say isn't
2 this de minimis, isn't this negative, isn't this zero
3 at the moment, or at least until you pay down Keeyask.
4 MR. BYRON WILLIAMS: Okay. Thank you.
5 And at that point in time -- I guess from your
6 evidence today, Mr. Bowman, that's a concept that you
7 as well consider the -- that the Board should be
8 reflecting upon. Agreed? You're going back to the
9 future and -- and suggesting that we -- we go back to
10 the allocating exclusively those revenues to
11 generation and transmission.
12 MR. PATRICK BOWMAN: Mr. -- Mr.
13 Williams, I -- I'm not there entirely, and you'll see
14 it in the prefiled testimony. I'm not there entirely
15 because of two (2) reasons. One (1) is because it --
16 it feels to me that if someone said, Let's just put
17 net export revenue against generation and
18 transmission, the next questions is, Why do we bother
19 to have an export class in the first place?
20 We can just put all of the dollars
21 against generation and transmission. We don't have a
22 pole rental class where we credit the Shaw or MTS
23 revenues we get from renting them pole space in our
24 distribution cost of service. We just credit the
25 revenues against the asset.

1 If we do that, why do we need an export
2 class in the first place? And that would save a lot
3 of fuss in the hearing. The members might like that
4 it would save a lot of costs for participating in the
5 hearing. But my concern is, I think there was some
6 logic to generate an export class in the first place.
7 I -- I was skeptical we could do it.
8 Having done it, I think there is some
9 useful information that comes out of it. And so I
10 would hate toe see aspects of that unravel.
11 The other part is even if someone
12 concludes that NER is negative, zero, nill, minimal
13 right now, I think it's entirely possible that it
14 won't be at a future date. And -- and if it is a
15 positive number at a future date, I feel that we'll
16 get back into some of the same debates that we were at
17 in '04, '05, '06 which says that, This is all just
18 subsidizing people.
19 And by the time we are -- done those
20 debates and we create an export class, we learn that
21 there's not a whole lot of this subsidization going
22 on. Even if someone says, But look, you know,
23 remember the debates in '06 that led to the crazy
24 hearing in '08 about the energy intensive rate. They
25 said, look, our -- our export markets are worth six

1 (6) cents and we're selling power to industrials at
2 three (3). And we brought in evidence that said
3 what's new? Every -- just about every jurisdiction in
4 North America is selling embedded power below marginal
5 cost. Like that -- building new stuff is very, very
6 expensive.
7 MR. BYRON WILLIAMS: Okay.
8 MR. PATRICK BOWMAN: That's not --
9 that's not new for anyone. Hydro-Quebec, I believe,
10 had industrial rates of four (4) cents and a marginal
11 cost at ten (10) at the time. There was nothing
12 unique here. But it got us into this weird debate
13 about, oh, this NER is a subsidy somehow.
14 So as much as they might like the
15 simplicity and they might say at this point it's a
16 practical solution, I -- I -- having been through the
17 wars I -- I worry that that's just what's old is new
18 again, and we start the -- the entire debate over
19 about whether we need a class, let's eliminate the
20 class, then we're into NER is a subsidy in the -- I
21 believe the quote of, you know, what's piggy gets the
22 slop, or something of that nature.
23 That -- that -- those were not -- I
24 think we made progress from that era, and I wouldn't
25 want to go back to it.

1 MR. BYRON WILLIAMS: Okay. Thank you,
2 Mr. Bowman. Just going to CA Energy/Christensen
3 Associates, and back to this efficiency theme. In
4 terms of cost allocation and focussing on the
5 efficiency criteria, you have identified historic
6 challenges with allocating net export revenue based
7 exclusively on G&T, agreed?
8 MR. MICHAEL O'SHEASY: Yes, that is
9 correct.
10 MR. BYRON WILLIAMS: And while you
11 hardly consider the broader dis -- dis -- allocation
12 of net export revenue to GT&D, 'D' meaning
13 distribution, as perfect you do see it as superior
14 from an efficiency perspective to that limited --
15 having a smaller cla -- allocation back to G&T?
16 MR. MICHAEL O'SHEASY: From what I was
17 told, that was a solution that helped a problem that
18 surfaced back in '04, or shortly thereafter, and to my
19 -- to our knowledge it continues to be a methodology
20 that lessens the likelihood that that problem could
21 occur again.
22 I haven't looked -- we haven't done an
23 analysis to see whether if you were to do it on the
24 original approach whether that problem would still be
25 as acute as it was back then, but we are comfortable

1 that the current total cost allocation methodology is
2 reasonable.
3 MR. BYRON WILLIAMS: And it would be
4 fair to say that the problem, as you politely phrased
5 it just now, Christensen and Associates (sic) has
6 described as a perverse effect in terms of reducing
7 some rates, classes, prices below incremental costs.
8 MR. MICHAEL O'SHEASY: I hate to use
9 the word "perverse." That -- that sounds very
10 negative. It's illogical effect.
11 MR. BYRON WILLIAMS: Now, Mr. Bowman,
12 we can -- we can pull up from the NFAT pages 28 and 29
13 of -- sorry, of the NFAT order. I apologize for that.
14 The -- I guess it wasn't an order, the NFAT report. I
15 was perhaps giving a bit more authority to the Public
16 Utilities Board than it had. Page 28. Oops, sorry.
17
18 (BRIEF PAUSE)
19
20 MR. BYRON WILLIAMS: If you could keep
21 scrolling down, please. Keep scrolling down, please.
22 Perhaps go down to the bottom of page 29. Excuse me.
23 Madam Chair, if I could stand down just
24 for one (1) minute, I wanted to grab the correct page
25 reference.

1 (BRIEF PAUSE)

2

3 MR. BYRON WILLIAMS: Sorry, members of
4 the panel. I did have the right page reference, but
5 it's been a long day and I'm sorry about that.
6 Mr. Bowman, you're familiar with this
7 report, clearly?
8 MR. PATRICK BOWMAN: Yeah, I may have
9 read it once or twice.
10 MR. BYRON WILLIAMS: The dilemma that
11 the Public Utility (sic) Board is commenting on here
12 is the reasonable prospect that there would be an
13 approximate doubling of rates by 2032, agreed?
14 MR. PATRICK BOWMAN: Yes.
15 MR. BYRON WILLIAMS: And you see
16 advice from the Public Utilities Board or a
17 suggestion. If you could scroll to the next page, you
18 see a concern by the Public Utilities Board of the
19 adverse effect of this doubling of rates on -- on
20 ratepay -- player -- payers, agreed?
21 MR. PATRICK BOWMAN: Yes.
22 MR. BYRON WILLIAMS: And not just
23 residential, but all classes of ratepayers, correct?
24 MR. PATRICK BOWMAN: Yes.
25 MR. BYRON WILLIAMS: And you see here

1 the Board suggesting a relaxation of Hydro's debt to
2 equity ratio to smooth out rate increases, agreed?
3 MR. PATRICK BOWMAN: Yes.
4 MR. BYRON WILLIAMS: And as you know,
5 sir, the debt-equity ratio exists for a number of
6 reasons, but one (1) of them is -- is in essence as a
7 reserve against adverse effects, adverse events,
8 agreed?
9 MR. PATRICK BOWMAN: Yes.
10 MR. BYRON WILLIAMS: Now, Mr. Bowman,
11 a while ago you indicated you -- you were not sold on
12 the allocation of net export revenue back exclusively
13 to generation and transmission. I don't want to
14 repeat that discussion, but you recall making that
15 statement, sir, or making that suggestion, whether it
16 was an exact statement or not?
17 MR. PATRICK BOWMAN: Well, I -- I did.
18 We don't have to repeat the discussion but I -- I get
19 -- the first part of that sentence was that -- was
20 about whether you allocate it here or allocate it
21 there. You'll note from my -- my testimony in regards
22 to cost-of-service study, I think it's a -- a bit of a
23 -- of a mug's game in a way to allocate it at all,
24 because it's not a cost-of-service topic, but...
25 MR. BYRON WILLIAMS: And -- and your

1 view, sir, is that the best solution would be to -- to
2 leave the NER, being net export revenue, out of cost
3 and ser -- out of cost of service entirely, correct?
4 MR. PATRICK BOWMAN: Yes. The -- the
5 purpose of the cost-of-service study is to add up
6 Hydro's costs and allocate those costs to the various
7 classes. And NER is a revenue question. It's like --
8 it's like the uniform rates, it's a revenue question.
9 It's not a -- it's not a cost question.
10 MR. BYRON WILLIAMS: And, in essence,
11 as I understand from your written evidence -- I don't
12 think you need to go there, but it's at, I think, page
13 48 and 49. In -- in that evidence, you proposed a
14 separate account classified as retained earnings. Is
15 that correct, sir?
16 MR. PATRICK BOWMAN: Well, the -- the
17 page you've taken me to is elaborated on in
18 Undertaking 32, following on my discussion with the
19 then-chairman at the workshop. And it seems to be a
20 topic that can spin out very quickly when you say,
21 well, then, what are we going to do with this money.
22 In the presentation today, I went
23 through and I showed you can run a cost-of-service
24 study and get some results that are useful and not get
25 yourself caught up in -- in how am I using this money

1 or that money or what -- where -- where do I
2 distribute these -- these benefits.
3 You can measure the costs. You can see
4 where you need to do your rate changes. And then in
5 an overall context of revenue requirement, you can
6 think more broadly about -- about the -- the corporate
7 issues of -- of things like reserve levels, and -- and
8 debt equity ratios, and that type of thing. That
9 doesn't have to be part of your -- your cost-of-
10 service methodology that you solved.
11 MR. BYRON WILLIAMS: It may not --
12 MR. PATRICK BOWMAN: This -- this
13 quote that you've taken me to, though, is from a cost
14 of -- is from the 2006 hearing, where we gave an --
15 similarly, we gave an example of saying, Here's
16 something you can think about, but don't -- it's not a
17 cost-of-service issue, let's talk about it in a GRA,
18 and, as a matter of fact, it did lead to the Board
19 eventually giving some orders and saying, We want to
20 do a big review of -- of Hydro's risks.
21 MR. BYRON WILLIAMS: And, Mr. -- Mr.
22 Bowman, the risk -- the concern, you'll understand,
23 from the perspective of residential ratepayers, is --
24 is, if that money is put into some notional separate
25 reserve, it may not be there to protect and to

1 mitigate against lower rates or to mitigate against
2 higher rates in the short-term.
3 You understand that, sir?
4 MR. PATRICK BOWMAN: Absolutely. And
5 -- and I've said the same thing on the record. If you
6 look at back in, I think, going back to 2003, that you
7 have to be very careful with this concept of net
8 export revenue and -- and, you know, slop and -- and
9 piggies and -- and whatever else, I'll call it gravy,
10 because there could be all kinds of things that people
11 line up and say, Let's spend it on this, let's spend
12 it on that, when you're sitting here saying, Hydro can
13 barely get its equity levels where it needs to.
14 It's building plants. It's not going
15 to be able to pay for it for many years. They're --
16 they've got huge mortgages in the early years. Let's
17 be careful about what we call above-cost extra
18 recoveries that we can put against the distribution
19 system to which it bears no linkage, just because it's
20 a place to shove some dollars. That -- that's the
21 problem we get into. You and I share that exactly.
22 Why -- as soon as you identify a pot
23 and say, There's no longer any principles for this,
24 let's just go find a way to -- to shove it against
25 some -- some costs, things get -- get very

1 questionable, especially at a time when Hydro is not
2 at a point where -- where there's any sort of
3 universal agreement that they've -- that they've got
4 the -- the level of -- of reserves and the like that -
5 - that they might need to get to in the next twenty
6 (20) years. And they're using that as a justification
7 to make rate increases.
8 MR. BYRON WILLIAMS: Okay. Thank you,
9 Mr. Bowman. And, in essence, the concern you're
10 articulating would be that this money would be -- not
11 be available to mitigate against already double the
12 rate of inflation rate increases, agreed?
13 MR. PATRICK BOWMAN: Frankly, Mr.
14 Williams, if you really get into it, the concern I'm
15 articulating is that if somebody could identify a net
16 export revenue and call it dollars that aren't needed
17 to pay for generation and transmission assets today, I
18 don't think the second priority for that is to pay for
19 generation, transmission, and distribution assets
20 today.
21 I think the second priority for that if
22 we really get into it is to work on helping to deal
23 with the stability of rates, the reserves needed so
24 that we -- the -- all customers, including your -- the
25 -- the residentials that you deal with can have more

1 stable rates in the future if we get walloped by a
2 drought in the next two (2) or three (3) years, or
3 five (5) years, or ten (10) years while we're trying
4 to integrate some very big and costly plans.
5 That's the type of thing that I've -- I
6 had my mind on.
7 MR. BYRON WILLIAMS: It sounds indeed,
8 sir, that you're -- you're talking about starving the
9 revenue requirement for that sort of -- of reserve,
10 are you?
11 MR. PATRICK BOWMAN: We have had this
12 discussion in a -- in another hearing, as I recall,
13 Mr. Williams, where you talked about the regulator's
14 dilemma. And you basically said to me in -- in an
15 exhibit I'd be happy to -- to re-file and you and I
16 were absolutely ad idem that one (1) of the challenges
17 that a Board has, this Board has in particular, is
18 that they control Hydro's rates, but they don't
19 control how they spend the money.
20 And so if they think that Hydro's both
21 spending too much and not good enough reserves, what
22 do they do? Do they raise rates and reward the
23 spending? Do they lower rates and squeeze the
24 reserves? How -- how do they deal with that?
25 And you and I talked about whether

there was a way to create two (2) levers for the Board to control rather than one (1). In other words, could they both control rate increases and control how much money is being set aside. And we concluded, as I recall, in that cross-examination that the only way to do that is if somebody created a -- a third way that didn't currently exist in the revenue requirement hearing.

But we're way into GRA issues and far beyond the scope of Cost of Service now, but it -- it's fascinating stuff. I'm happy to keep talking about it if you like.

(BRIEF PAUSE)

MR. BYRON WILLIAMS: Mr. -- Mr. Bowman, the logic of your evidence and the logic of Undertaking 32, I would suggest, is that by starving the revenue requirement, you would be putting consumers, like residential customers, not only at risk of double the rate of inflation rate increases, but rate increases over and above that.

Is that fair, sir?

MR. PATRICK BOWMAN: No, not necessarily. Because the numbers you were quoting

1 which say double the rate of inflation rate increases
2 are from a model that was run by Manitoba Hydro during
3 the NFAT. I'm sure Madam Chair will remember the gory
4 tables, which were from the financial model, and they
5 showed long-term projections, forty (40) years as I
6 recall, and the average rate increase needed to get
7 Hydro to lows it needed to be.
8 But it only focussed on the average
9 rate increase. What it missed was that -- the NFAT
10 related pressures that were discussed in that report
11 were for things like Keeyask, the MMPP transmission,
12 and Bipole. Those are not necessarily average costs.
13 Those are generation and transmission
14 costs. So if you're looking at those numbers and
15 you're seeing 3.95 percent in -- in Hydro's numbers
16 going off into the future, you'd want to ask what --
17 whether that really needs 3.95 percent across the
18 board for those forty (40) years or whether those
19 pressures will be concentrated in -- in one (1) -- in
20 one (1) class or the other.
21 And -- and I can tell you from the
22 numbers we have before us, Hydro's current costs for
23 its entire generating compliment is about $1.2 billion
24 a year, 1.1, it's in Hydro's slide. That's going to
25 double in the next five (5) years.

1 There's almost a billion dollars in
2 annual costs being added to that. That's -- that's
3 the next five (5) years that's going to double, not --
4 not over some horizon of twenty (20), or thirty (30),
5 or forty (40) years. What happens to the residential
6 rate?
7 Well, the resident -- residentials pay
8 about -- between seven (7) and eight (8) cents, but
9 about four and a half (4 1/2) of that or something is
10 to pay for the distribution system. They're only
11 paying about three (3) something towards the
12 generation system.
13 They actually pay less for generation
14 than industrials do when you get right down to it.
15 And -- and if only that three (3) is the part that's
16 doubling that we're talking about, it means industrial
17 rates will double, but it doesn't mean the
18 residentials will double.
19 They -- their rate of seven (7)
20 something might go up to ten (10) something and the
21 remainder will depend on what happens with the
22 distribution investment. And that's an entirely
23 separate -- separate discussion we're not -- we're not
24 really talking about here.
25 MR. BYRON WILLIAMS: So you're

1 disagreeing with the suggestion that the logic of your
2 proposals are to exacerbate and to compound the rate
3 impacts already likely to be experienced by
4 residential customers?
5 MR. PATRICK BOWMAN: The -- the end
6 results of the proposals we put down, and is in -- in
7 my evidence and is shown, is that the RCC ratios for
8 the entire system, which show that -- that
9 residentials currently are -- are underpaying by about
10 ten (10) cents -- or 10 percent, sorry. About 10
11 percent. And that's in the presentation today and I'm
12 -- I believe the table is from Undertaking 32.
13 Other classes are paying about 100
14 percent of costs. So on average you would see a bit
15 higher than average rate increases coming to the
16 residentials until you end up running that cost of
17 service study five (5) years from now, or six (6)
18 years from now, when it has Keeyask in it and Bipole
19 in it, and there you're going to se major erosion,
20 even under the methods I'm talking about, major
21 erosion in the industrial and -- and the classes that
22 use generation and transmission as a key part of their
23 -- their cost.
24 You won't necessarily see the ero --
25 same erosion in the residentials because it also

1 depends on what's going on in the distribution system.
2 And I -- I'm happy to recall issues from that but I
3 know that in the distribution system people have been
4 doing other things that mitigate the costs, like
5 longer lives for dist -- or for depreciation and --
6 and that sort of thing.
7 So I -- I don't know that you'll see
8 the same average cost increases on residentials in the
9 next five (5) or six (6) years that you will see on
10 the industrials coming out of these next few times we
11 run cost of service.
12 MR. BYRON WILLIAMS: Now, to
13 Christensen and Associates, you -- you disagree with
14 Mr. Bowman, and you argue that the allocation of net
15 export revenue back to domestic customers is -- is a
16 cost of service question and not a rate design
17 question. Is that fair?
18 MR. MICHAEL O'SHEASY: I'm not sure I
19 understand his -- Mr. Bowman's points exactly but the
20 issue about NER and whether it is indeed allocated
21 back to domestics or not, we said in our report that
22 there are different ways to handle it.
23 And what we concluded was that the pre
24 -- present way of doing so, allocating it back to net
25 export revenues, was a reasonable practical thing to

1 do and we would recommend that it be continued.
2 MR. BYRON WILLIAMS: Okay. There's
3 one propo -- go ahead, sir.
4 MR. MICHAEL O'SHEASY: No, I -- I was
5 done.
6 MR. BYRON WILLIAMS: I might come back
7 to that in just a second. There is one of your
8 proposals for allocation of net export revenue that I
9 don't think was very well canvassed in the course of
10 this proceeding, and that was a -- the proposal to do
11 a lump sum bill credit.
12 MR. MICHAEL O'SHEASY: Yeah. What we
13 would suggest -- we -- we weren't really proposing it
14 but we were -- we were noting there are different
15 methodologies. Now, one of the -- that methodology
16 was indeed a lump sum credit, and the advantage of
17 doing so is to avoid price distortion in the rates for
18 the domestic class.
19 When you allocate back your NER, if you
20 allow that to affect the cents per kilowatt hour for a
21 particular rate, then the rate is lower than it would
22 otherwise be. And we've seen in the past where we get
23 prices that are below marginal cost. That's not a
24 good thing.
25 So one way that you could -- now,

1 there's complications to this -- a myriad of
2 complications but we just wanted to put on the table,
3 one way that you could think about taking NER back to
4 the rate classes would be a lump sum customer credit.
5 So it would basically lower a customer's bill from
6 what it would otherwise be but it wouldn't necessarily
7 lower the price per kilowatt hour that he was being
8 charged.
9 MR. BYRON WILLIAMS: And how would you
10 determine that allocation, sir?
11 MR. MICHAEL O'SHEASY: We didn't get
12 that far. We're just putting on the table that there
13 are ways to do so. You would have a myriad of
14 problems with it because you have obviously large and
15 small customers, and you would have impacts on big
16 customers versus small customers. I think that would
17 be a challenge for another day. We -- we don't have
18 an answer for that right now. We just wanted to put
19 the thought on the table.
20 MR. BYRON WILLIAMS: One last question
21 for you, and then I haven't been very generous to
22 giving other persons on the panel an opportunity, so
23 I'll see if I can do the reach for the top just for a
24 couple moments.
25 In terms of the logistics of a marginal

1 cost of service study, if one were to be undertaken by
2 Manitoba Hydro, can you give any sense of the time
3 frame that that would require, sir?
4 MR. ROBERT CAMFIELD: If you're
5 suggesting a marginal cost study as we would typically
6 do it for a utility, perhaps three (3) months. You've
7 got to get close to the planning processes,
8 particularly in transmission and that would involve a
9 load flow study to deal with the issues of marginal
10 lane losses and how they're distributed around the
11 system.
12 There's -- there's some details in
13 distribution that require distribution information
14 data acquisition and analytics. You have to look at
15 the loads historically and how loads are distributed,
16 particularly the distribution of peak loads across
17 months, and seasons, and all that's part of it.
18 MR. BYRON WILLIAMS: Thank you. Mr.
19 Todd, I -- I know you're heading out to Toronto. I
20 did review your -- your comments this morning in terms
21 of the net export allocation. You've heard, I hope, a
22 bit of an interesting discussion.
23 Anything you want to add, or any
24 comments you may have?
25 MR. JOHN TODD: Without a specific

1 question, nothing. No.

2 MR. BYRON WILLIAMS: No, that was too

3 -- too easy.

4 MR. JOHN TODD: I won't make my plane

5 if I say everything I've got on my heart.

6 MR. BYRON WILLIAMS: Sir, in terms of

7 the -- the relative merits of a narrow -- narrower

8 application, or a broader application, I know you've

9 suggested that's up to the Board, recognizing the --

10 the stresses already put on consumers by -- by the

11 NFAT decision and the expenditures, is there anything

12 you -- you wish to -- to add?

13 MR. JOHN TODD: This entire area is

14 driven by fairness and fairness is driven by judgment.

15 You know, clearly there's no right or wrong to it.

16 There are policy objectives that are trying to be

17 achieved.

18 And my understanding of the history of

19 this is that there's a goal of giving a dividend back

20 to the customers. My understanding of it, or concept

21 of it is it's kind of like a co-op. I buy a few

22 things at Mountain Equipment Coop because I like to do

23 hiking. I get a dividend cheque back.

24 The more I buy from them the bigger my

25 dividend cheque. So I'm thinking of this as this is a

1 Crown corporation working for the province and it's
2 seeking to identify an opportunity to provide a
3 dividend to the customers.
4 There are many ways you could do that.
5 There's a mechanism in place. And in doing so you
6 want to have a design which in the judgment of the
7 Board does it in a fair and equitable manner. That's
8 my understanding. That's is not an -- it really isn't
9 an expert opinion, because this is a judgment matter
10 that is reflective of partially government policy,
11 partially Board policy.
12 MR. BYRON WILLIAMS: And just to, Mr.
13 Chernick, any -- anything you want to add?
14 MR. PAUL CHERNICK: I think you've --
15 you've canvassed the -- the issues pretty -- pretty
16 well here. I could go over some ground if you'd -- if
17 you'd really like me to, but...
18 MR. BYRON WILLIAMS: No, if -- if
19 there's something unique you -- you really have and
20 same with --
21 MR. PAUL CHERNICK: Nothing I'm
22 burning to say.
23 MR. A.J. GOULDING: I think the only
24 thing that I would add, and I -- I liked John's
25 comments about the dividend, you know, in terms of

1 thinking about how the shareholder could determine how
2 -- how to use this particular surplus and in providing
3 customer dividend.
4 I think the other concept that is
5 important is that, you know, if -- if we look back at
6 the revenue requirement we can take a simplistic view
7 that only a certain proportion of customers paid for
8 transmission or particular transmissions lines, or
9 paid for the bulk of the transmission lines, and a
10 certain portion of the customers paid for the
11 generation.
12 But ultimately it's the financial
13 strength of the entire organization that gives it the
14 ability to engage in these large projects. And so
15 when you look at the residential and you look at the
16 GSS and GSM customers, you'll -- you'll note that
17 you're talking about, you know, approximately 75
18 percent of the -- of the revenue requirement, and that
19 particular 75 percent is, you know, going to be the
20 customers that are paying particularly for
21 distribution.
22 And so when we think about the overall
23 financial strength of the enterprise and the fact that
24 these customers are providing 75 percent of the
25 revenue requirement, it would seem appropriate, you

1 know, in addition to the concept of the customer
2 dividend, to assure that these customer classes also
3 get an appropriate allocation of the net export
4 revenues.
5 MR. BYRON WILLIAMS: Thank you. And,
6 Madam Chair, I believe I'm actually on time, so thank
7 you.
8 THE CHAIRPERSON: Thank you, Mr.
9 Williams. Mr. Gange, please.
10 MR. BILL GANGE: The Green Action
11 Centre has no questions. Thank you.
12 THE CHAIRPERSON: Me. Monnin...?
13 MR. CHRISTIAN MONNIN: GSS/GSM has no
14 questions either. Thank you.
15 THE CHAIRPERSON: Mr. Orle...?
16 MR. GEORGE ORLE: No questions, Madam
17 Chair.
18 THE CHAIRPERSON: So we get a break.
19 And I think we can take fifteen (15) minutes. We can
20 come back at about twenty (20) after.
21
22 --- Upon recessing at 4:08 p.m.
23 --- Upon resuming at 4:24 p.m.
24
25 THE CHAIRPERSON: Me. Hacault, s'il

1 vous plait.

2

3 CROSS-EXAMINATION BY MR. ANTOINE HACAULT:

4 MR. ANTOINE HACAULT: If -- if I

5 might, the experts are having a lot of fun, I see.

6 Hopefully it'll be as a good experience when we're --

7 we're having a discussion.

8 Now, I'll start with Mr. Todd on this.

9 And I just -- as Mr. Bowman was explaining, I -- I

10 have a lot of difficulty understanding things, so I

11 try to dumb it down sometimes and -- if I'm looking at

12 fairness issues.

13 So let me put this example to you.

14 I've got two (2) businessmen. They both invest equal

15 amounts in a business that generates revenue. Follow

16 me so far?

17 MR. JOHN TODD: I don't have any

18 partners, but I can conceive of that --

19 MR. ANTOINE HACAULT: Okay.

20 MR. JOHN TODD: -- partnership

21 arrangement.

22 MR. ANTOINE HACAULT: One (1) guy

23 decides he needs a 4,000 square foot house, and that's

24 a personal cost. He spends a million dollars. It's

25 not money he's invested in -- in the business. And

1 the other fellow's a little bit more modest. He goes
2 in a 900 square foot home. He spends about two
3 hundred thousand dollars ($200,000), and that's,
4 again, an expense that's personal to him, it only
5 serves him.
6 I'm asking you, sir, would it be fair,
7 given that both businessmen have invested 50 percent
8 into the earnings part of the business, that they
9 decide to share the revenue from that business based
10 on the personal investments, the things that only
11 benefit them, the million dollar house and the two
12 hundred thousand dollar ($200,000) house, so that the
13 person who's spent a million dollars on assets that
14 only benefit him gets to get a greater share of the
15 business's revenue? Would that be fair?
16 MR. JOHN TODD: Well, the one (1)
17 thing I like about analogies is, is it makes a very
18 simple answer. It -- with that fact situation, it
19 would appear to me and most people to be unfair. The
20 question is whether that fact situation is relevant to
21 the issues being addressed by the Board.
22 MR. ANTOINE HACAULT: I would suggest
23 to you that the reason why some people might think
24 it's unfair is that we look at the investment into the
25 business and what causes the revenues to be generated,

1 because the homes themselves do not cause revenue to
2 be generated.
3 Would that be a fair statement?
4 MR. JOHN TODD: The homes do not cause
5 a revenue to be generated. If I had a partner, what
6 would cause the revenue to be generated is the work
7 that is done by the partners, the effectiveness of
8 their work, the reputations they establish and so on.
9 So I think it would be equally --
10 partnerships -- I don't have a partnership, because
11 partnerships run into the same kinds of problems of
12 perception of fairness. If I'm busting my ass and my
13 partner's not and we've got a fifty (50)/fifty (50)
14 share, I'm going to see that as unfair for the reason
15 you're talking about.
16 Is because I'm going to look at the
17 cause of the revenue being things that I do versus the
18 things that my partner does.
19 MR. ANTOINE HACAULT: And let's take
20 it to a more pure form of investment. If that
21 investment that I talked about being fifty (50)/fifty
22 (50), was each partner had put half a million dollars
23 in the business and had shares that gave dividends on
24 those shares, again, we wouldn't say, Well, because
25 I've got a million dollar home you're somehow entitled

1 to more dividends on your half a million dollar
2 investment.
3 There's not a link between the home and
4 the half million dollar investment.
5 MR. JOHN TODD: Correct. If I'm in --
6 if -- if two (2) people are putting money into a
7 mutual fund and they put the same amount in, they
8 would each expect to get the same amount out.
9 MR. ANTOINE HACAULT: Now, Mr. Harper,
10 am I right in understanding that in the utility
11 industry we can in fact have two (2) separate types of
12 entities, one (1) entity that would run generation and
13 transmission, correct?
14 MR. WILLIAM HARPER: Yes, you can have
15 energy that just ran generation and transmission.
16 MR. ANTOINE HACAULT: And then a
17 totally separate entity which runs the distribution to
18 all the residential customers or general service
19 customers, generally distribution?
20 MR. WILLIAM HARPER: Yes, you -- yes,
21 there are -- you can have, and there are entities that
22 are just distribution utilities.
23 MR. ANTOINE HACAULT: And in Manitoba,
24 what we have is an entity that runs all those
25 functions under one (1) umbrella, correct?

1 MR. WILLIAM HARPER: Yes, that --
2 that's correct.
3 MR. ANTOINE HACAULT: Okay. And when
4 we did the review for Keeyask and the generation and
5 transmission systems, we were talking about the
6 investments in generation and transmission, and
7 whether those investments made sense in doing
8 hydraulic plants as opposed to, we saw turbines,
9 correct?
10 MR. WILLIAM HARPER: That was one (1)
11 of the considerations going on in the -- in the
12 package of investments that -- that was in the plan,
13 yes.
14 MR. ANTOINE HACAULT: Okay. We didn't
15 discuss the type of revenues and returns that would be
16 generated by the distribution system of Manitoba Hydro
17 in those hearings, did we?
18 MR. WILLIAM HARPER: Actually, no, and
19 that's because what we were doing as opposed to doing
20 sort of, any sort of analysis or embedded cost
21 analysis, we were doing basically a financial or
22 economic analysis that was looking at investments.
23 And since the money is being spent in
24 generation and transmission it was cash flows and
25 benefits and costs associated with those specific

1 generation and transmission assets. That's correct.
2 MR. ANTOINE HACAULT: So in a sense,
3 we were segregating the homes, the distribution to the
4 homes from the things that generate revenue, the
5 generation and transmission, correct?
6 MR. WILLIAM HARPER: Gee, when you say
7 separate the homes, I'm -- I'm getting confused as to
8 whether we're still talking about the utility talking
9 about it, or you're getting back to the analogy you
10 were having with Mr. Todd in terms of two (2)
11 different types of houses.
12 MR. ANTOINE HACAULT: We're -- we're
13 talking about the Utility, and the distribution and --
14 and generation --
15 MR. WILLIAM HARPER: Okay. So --
16 MR. ANTOINE HACAULT: -- and
17 transmission.
18 MR. WILLIAM HARPER: -- so when you
19 say "homes" you merely mean the distribution business?
20 MR. ANTOINE HACAULT: Yes.
21 MR. WILLIAM HARPER: Oh, okay. I was
22 just trying to --
23 MR. ANTOINE HACAULT: Yes.
24 MR. WILLIAM HARPER: -- understand the
25 question. So -- so, no. No, there was no -- there

1 was no discussion about, you know, costs and their
2 distribution in the -- excuse me, I -- I should
3 probably cor -- correct myself on that in the sense
4 there was no specific discussion on cash flows around
5 that.
6 I think it's fair to say though that
7 investments and distribution were part of the overall
8 capital expenditures that went into the broad picture
9 as to what was the future financial expenditures for
10 Manitoba Hydro going forward, and how that was going
11 to impact their overall financial position.
12 So I think at some level distribution
13 spending did go into the consideration of some aspects
14 of -- of the -- of the analysis overall, but on the
15 specific economic and financial analyi -- excuse me,
16 economic analysis I would agree, no.
17 MR. ANTOINE HACAULT: Okay.
18
19 (BRIEF PAUSE)
20
21 MR. ANTOINE HACAULT: But the
22 distribution incidental expenses would have been
23 consistent throughout the various options we were
24 considering, whether it was the CCT, Keeyask in '24,
25 Conawapa, correct?

1 MR. WILLIAM HARPER: Yeah, but they
2 would have contributed to the overall problem that was
3 being exhibited about the level of equity ratio at a
4 particular point in time.
5 MR. ANTOINE HACAULT: Okay. Now,
6 industrials, and I'll get back to Mr. Todd on this,
7 face a situation I would suggest that are analogous,
8 and I'll get into it, to the City of Winnipeg in the
9 sense that we talked about in the workshop system
10 extension policies so that if a big industrial user
11 wants to connect to major power lines Hydro might ask
12 them, you know, $15 million to do it.
13 The only difference in my simplistic
14 mind is that they don't have the luxury of saying,
15 Hydro, please, finance it over a long term and direct
16 assign the cost to me. Are you following me so far?
17 MR. JOHN TODD: I'm -- I have not
18 specifically looked at policies on capital
19 contribution for Manitoba Hydro but it is standard
20 that for customers in any class, if the cost of
21 connection is not going to be recovered by the rates
22 being charged that a customer has to make a
23 contribution.
24 In most jurisdictions that I'm aware
25 of, Ontario, New Brunswick, so on, Newfoundland, a

1 residential customer, if they are a farm for example
2 and there's five (5) poles that have to be put in to
3 get to them, they have to pay a contribution to do it.
4 My property up north, remote, Hydro
5 went and said: We're glad to connect you. Give us as
6 cheque for a hundred thousand dollars ($100,000). So
7 we put in a solar system instead.
8 So there's no difference between
9 industrial customers and small volume customers except
10 the scale of the cost of connecting them, and
11 therefore the capacity of the Company to recover that
12 cost in rates and therefore hold all other customers
13 whole and not subsidize this new customer coming onto
14 the line.
15 MR. ANTOINE HACAULT: So the customer
16 that isn't in a fortunate enough position to have
17 Hydro pay for the line going right up to his building
18 wouldn't be in the total cost analysis that you've
19 advocated where you go not only allocated cost but all
20 the direct cost because this is the type of customer
21 that that may have to pay $15 million out of his
22 pocket, but that wouldn't be considered a direct cost
23 and it wouldn't be considered an allocated cost.
24 Is that correct?
25 MR. JOHN TODD: The typical practice,

1 and I -- again I've not reviewed exactly what's done
2 in the accounting system of Manitoba Hydro. The
3 typical practice is that the cost of -- the cost to
4 the Company of connecting the customer has the capital
5 contribution deducted from it.
6 So, yes, only the net cost to the
7 Company is what would go into the rate base and
8 therefore be part of a cost allocation study and part
9 of a revenue requirement.
10 MR. ANTOINE HACAULT: So although I
11 guess it was London Economics saying, Well, listen,
12 we've got all these customers, so they should all --
13 you know, if they're contributing towards distribution
14 and -- and connecting to their businesses, if we go
15 down that path of allocated costs, direct costs, we've
16 missed one (1) class of customers who aren't fortunate
17 enough to be in either the allocated costs or the
18 direct costs.
19 And they would be out of the loop on
20 the type of allocation that's being acted -- advocated
21 for, correct?
22 MR. JOHN TODD: I'm going to speak
23 generically again because these are specific --
24 sometimes specific to companies. I have clients where
25 they have had, for example, a Ford motor plant built

1 in their area. There is dedicated facilities going
2 from the transformer station connecting to
3 transmission to the plant.
4 Because it was a dedicated facility,
5 those costs were directly allocated to the class. And
6 in fact the class is create -- created of the one (1)
7 customer. So in effect, they had directly allocated
8 costs. The -- the rates were recovering those costs
9 over time, and so an industrial customer can have
10 directly allocated costs just like anybody else.
11 All customers can have directly
12 allocated costs. It's not a function of the customer
13 class or the type of customer. It's a function of
14 whether the facilities being provided are -- in the
15 accounts are used only by one (1) class.
16 MR. ANTOINE HACAULT: Okay. So my
17 next question is going to be directed to Mr. O'Shea
18 (sic). Could you bring up PUB-MFR-14, please, Diana,
19 page 3? Maybe the first page before so we see what
20 the document was. It was Appendix A, terms of
21 reference for external review of Manitoba Hydro's cost
22 of service study.
23 That would have been what set out the
24 terms and conditions of your scope of work, sir?
25 MR. MICHAEL O'SHEASY: Yes, sir.

1 MR. ANTOINE HACAULT: And at page 3 of
2 that scope of work in the second last paragraph, and
3 I'm quoting:
4 "Manitoba Hydro is indicating its --
5 in its document that Manitoba
6 Hydro's practice, prior to 2006, was
7 to credit net export revenue to
8 customer classes on the basis of
9 their share of generational
10 transmission costs. The basis of
11 this allocator was that it was the
12 generation and transmission assets
13 that make possible the export
14 sales."
15 End of my quote. Do you agree with the
16 second sentence, that the generation transmission
17 assets are the ones that make possible the export
18 sales?
19 MR. MICHAEL O'SHEASY: Functionally,
20 yes.
21 MR. ANTOINE HACAULT: And it's those
22 assets which enable or cause the export revenues,
23 correct?
24 MR. MICHAEL O'SHEASY: Correct.
25 MR. ANTOINE HACAULT: Distribution

1 assets have no direct contribution to be able to
2 generate export revenue, correct?
3 MR. MICHAEL O'SHEASY: The
4 distribution function is not used to make those export
5 sales.
6 MR. ANTOINE HACAULT: So analogies
7 always break down, but if I've spent $5 billion in
8 distribution, or $1 billion in distribution, going
9 back to my home analogy, it really doesn't matter what
10 I spent on distribution and what investments I make in
11 distribution.
12 It doesn't contribute or enable me in
13 any way to generate the export revenue, correct?
14 MR. MICHAEL O'SHEASY: I think we just
15 agreed, yes. The distribution function does not serve
16 a role in selling those export sales.
17
18 (BRIEF PAUSE)
19
20 MR. ANTOINE HACAULT: Diana, could you
21 go to the Board book of documents, please?
22
23 (BRIEF PAUSE)
24
25 MR. ANTOINE HACAULT: And in

1 particular to page 12.

2

3 (BRIEF PAUSE)

4

5 MR. ANTOINE HACAULT: Now, Mr. Harper,

6 have you seen this type of table in the past, and

7 would you be able to assist me in -- if I ask a couple

8 questions in explaining what the system surplus

9 numbers mean at the bottom?

10 MR. WILLIAM HARPER: That's the one

11 (1) part of the table that I have the most difficulty

12 with. And I -- I've seen the table, I'm fam -- I'm

13 familiar with it in principle and I can -- I can

14 follow the math like three (3) minus six (6) minus

15 seven (7) at the bottom.

16 Let -- let me try and help you and I'll

17 see where --

18 MR. ANTOINE HACAULT: Okay.

19 MR. WILLIAM HARPER: -- where my

20 understanding isn't sufficient.

21 MR. ANTOINE HACAULT: So firstly we

22 have a heading on table "System Firm Winter Peak

23 Demand." What would that tell me as to what season

24 we're looking at?

25 MR. WILLIAM HARPER: Oh, that would

imply to me you're -- you're looking at the winter. You're looking at the -- the firm demand of Manitoba Hydro.

MR. ANTOINE HACAULT: So it might give me some idea of -- of what Hydro is thinking it needs on that minus forty (40) day when it needs to keep the lights out -- or lights on for everybody, because it doesn't want any lights out, yes?

MR. WILLIAM HARPER: Yeah, it would give you some idea. Like I said, I think typically looking just at one (1) day is a -- at one (1) hour in this case is probably a simplification of what system planners go through at -- at a -- sort of at a more sophisticated level, but it's a fairly -- it's fairly representative in a good way of trying to picture it simply, yeah.

MR. KURT SIMONSEN: About ten (10) minutes, Mr. Hacault.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: And when we try -- when we look at capacity and peak demand and we're trying to reflect that through the allocators, that's when we see things like the 2CPs and 1CP and whether you choose fifty (50) of the highest peaks.

1 That's what we're trying to capture?
2 MR. WILLIAM HARPER: Well, yes, you --
3 you'd be trying to capture the extent to which --
4 you've got a peak demand here. What -- what reason
5 are different customers contributing to that and
6 that's why -- you're talking about 2CP, you're talking
7 about more than one (1) hour.
8 And that gets a bit into the -- the
9 types of issues I was talking about, yes.
10 MR. ANTOINE HACAULT: Okay. And in
11 the very bottom we'll see that there are -- we're just
12 talking about the capacity here. There's a difference
13 between capacity and energy, right?
14 MR. WILLIAM HARPER: Yes, there'd be a
15 separate set of tables for -- for dependable energy.
16 MR. ANTOINE HACAULT: Okay. So the
17 table talks about peak demand about midway through
18 after the line number 3 where it says "total power
19 resources." We've got all the existing hydro. We see
20 there's thermal. We see there's contracted imports.
21 And it tells us what we've got available for capacity.
22 Is that fair?
23 MR. WILLIAM HARPER: Yes.
24 MR. ANTOINE HACAULT: And then it says
25 "2015 baseload forecast," and then there's a line that

1 says "Manitoba net load." Do you see that line?
2 MR. WILLIAM HARPER: Yes, I do.
3 MR. ANTOINE HACAULT: Okay. And then
4 under that system planning is showing contracted
5 exports --
6 MR. WILLIAM HARPER: Yes, and --
7 MR. ANTOINE HACAULT: -- that --
8 MR. WILLIAM HARPER: -- and that goes
9 to the point I made in my presentation today that when
10 it comes to planning those are the -- the contracted
11 firm exports that they put in their tables and plans
12 for system planning purposes, yes.
13 MR. ANTOINE HACAULT: Okay. And it
14 even goes as far as saying further under line number 4
15 where it says "Manitoba let noad" they've got -- or
16 "net load" it says "contracted exports," and then
17 "proposed exports." Do you see that?
18 MR. WILLIAM HARPER: Yes, I do.
19 MR. ANTOINE HACAULT: So it -- they're
20 feeling after Keeyask comes into play they can
21 actually sell some capacity somewhere, and they're
22 actually planning for that.
23 MR. WILLIAM HARPER: They'll --
24 they'll have additional firm capacity over and above
25 domestic load that they'll be able to hopefully make

1 contracts for and sell, yes.

2 MR. ANTOINE HACAULT: And then they

3 want to be really safe so there's a line number 7

4 called "reserves." Do you see that?

5 MR. WILLIAM HARPER: Yes. And that's

6 usually done as a mathematical calculation based on

7 demand, yeah.

8 MR. ANTOINE HACAULT: Okay. And for

9 every year too and including 2020 -- 33, we have a

10 system surplus. They've planned on that system

11 surplus.

12 MR. WILLIAM HARPER: Based on not only

13 the generation resources but also the -- the DSM

14 resources based on additional capital spending -- DSM

15 spending during that period that they've planned for,

16 yes.

17 MR. ANTOINE HACAULT: But we're seeing

18 that they're going to be capacity short unless

19 something happens. Unless they add a generator, or

20 something.

21 MR. WILLIAM HARPER: Yes, and that's

22 typically what the purpose of these tables is, is to

23 say what's our existing picture given the resources we

24 have, and if we don't do anything more when do we

25 expect we're going to get capacity short which then

1 triggers to people this is the -- this is then what's
2 commonly referred to as the need-date, at least from a
3 capacity perspective. Yes.
4 MR. ANTOINE HACAULT: Okay. So this
5 would help us understand that in 2023 Hydro expects to
6 have to build more capacity to meet peak demand.
7 MR. WILLIAM HARPER: At 2033, I think,
8 yes.
9 MR. ANTOINE HACAULT: Thirty-three
10 (33), sorry. If you go to page 13, and that'll end my
11 line of questioning, we've got a different table.
12 It's entitled 'System Firm Energy, Demand, and
13 Dependable Resources'. That was the second table you
14 said you thought should exist.
15 MR. WILLIAM HARPER: Yes.
16 MR. ANTOINE HACAULT: And it also
17 helps us understand whether or not this other concept
18 that newbies like me are having trouble to understand,
19 this is energy concept. Whether or not after all
20 these contracted exports and proposed exports, those
21 are at line 4 at the bottom, whether after all those
22 contracted exports and proposed exports, and less
23 adverse water, whether we're going to plan on system
24 surplus that we're going to be able to sell, correct?
25 MR. WILLIAM HARPER: Well -- well, I'm

1 not too sure if it's sys -- system surplus you're
2 going to be able to sell because in -- in there you
3 already got contract and proposed exports already
4 built -- built into it. I guess this would be
5 additional dependable energy over and above what we've
6 already made or plan to make commitments for, yes.
7 MR. ANTOINE HACAULT: I think Hydro
8 would probably view this surplus as non-dependable.
9 It would be the opportunity energy. Would you agree
10 with that?
11 MR. WILLIAM HARPER: No, I wouldn't
12 because I think at the top of the table my
13 understanding is this is dependable resources. So
14 this -- so this is my -- my understanding of the
15 table, subject to being corrected by somebody from
16 Hydro, is this is the surplus dependable energy that
17 would be available for -- for sale.
18 MR. ANTOINE HACAULT: Okay. And if we
19 look across the table right to the very right, we see
20 at no time do we have to plan to build new generating
21 stations or adding turbines to deal with energy.
22 MR. WILLIAM HARPER: Yes. It would
23 like from this it's probably maybe the next year after
24 that you're probably starting to see a red number as
25 opposed to a black number, that's right.

1 MR. ANTOINE HACAULT: But you'd have
2 to build for capacity first, capacity issues. And
3 then it would naturally follow that if you put a new
4 generation, you're going to have more energy, correct?
5 MR. WILLIAM HARPER: Yes, yes. And
6 depending upon the -- the type of -- I guess type --
7 type of facility you build, you may get more kilowatts
8 per kilowatt hour for some types than others sort of
9 thing. So that will affect where -- where the
10 crossovers come again in the future, yes.
11 MR. ANTOINE HACAULT: Okay. Thank
12 you. Those are all my questions.
13 THE CHAIRPERSON: Thank you.
14 Mr. Fernandes, or is it going to be Ms.
15 Ammond -- Hammond?
16 MS. ODETTE FERNANDES: It will be
17 myself. Thank you.
18
19 CROSS-EXAMINATION BY MS. ODETTE FERNANDES:
20 MS. ODETTE FERNANDES: I apologize.
21 I'm losing my voice a little bit, so you'll be happy
22 to know that most of my questions have already been
23 addressed. And I do have I think only a couple of
24 questions for Mr. Harper, just to confirm your -- a
25 couple of your statements you made this morning.

1 If I could please take you to slide 25
2 of your direct presentation. Now, I note that on
3 slide 25, you've indicated that you believe NER should
4 be included in cost-of-service study.
5 Is that correct?
6 MR. WILLIAM HARPER: Yes, I do.
7 MS. ODETTE FERNANDES: Okay. Now,
8 would you agree that the NER, while it's surplus to
9 the cost of the export class, it's still an integral
10 part in meeting Manitoba Hydro's revenue requirement?
11 MR. WILLIAM HARPER: Yes. I think if
12 you look at the -- well, if you look at the overall
13 revenue requirement, it -- it's made up of revenues
14 and costs. And a substantial portion of the revenues
15 are -- are export revenues. And if you took those
16 out, well, the net income would be negative.
17 MS. ODETTE FERNANDES: Okay. And
18 would you also agree that if the net export revenue is
19 somehow taken out and placed into some type of reserve
20 fund or -- would it, in effect, make the revenue
21 requirement dependent on what happens in the cost-of-
22 service study?
23 MR. WILLIAM HARPER: I'm sorry, I'm
24 trying to make -- make a link be -- between the two
25 (2), because I -- I'm not too sure. I --

1 MS. ODETTE FERNANDES: Well --
2 MR. WILLIAM HARPER: When you say,
3 "take it out," I wasn't too sure whether you mean take
4 it -- take it out just from purpose --
5 MS. ODETTE FERNANDES: Of the cost-of-
6 service study. Like, if you --
7 MR. WILLIAM HARPER: Oh, the cost --
8 you mean for purposes of calculating the revenue-to-
9 cost ratios or -- when you say, "take it out," I just
10 didn't understand within what context you meant take
11 it out.
12 MS. ODETTE FERNANDES: Segregating it
13 into a reserve fund.
14 MR. WILLIAM HARPER: Then -- then
15 again, and I think I spoke to this in -- at -- at the
16 June workshop, I think it would depend on what the
17 purpose of that reserve fund was and whether that was
18 just another -- just another label you put on net --
19 net income. So I call it -- it's -- it's viewed as
20 net income, maybe allocated that way in the cost-of-
21 service study.
22 I think, before I could answer your
23 question, I'd have to understand a lot more about what
24 -- how -- what -- what that reserve fund was, how it
25 was set up, what it was going to be used for. I'm

1 sorry.

2 MS. ODETTE FERNANDES: Okay. That's

3 fine. Thank you very much, Mr. Harper.

4 Thank you, Madam Chair.

5 THE CHAIRPERSON: Mr. Peters, batting

6 clean-up.

7

8 (BRIEF PAUSE)

9

10 MR. BOB PETERS: Thank you very much,

11 Madam Chair.

12

13 CROSS-EXAMINATION BY MR. BOB PETERS:

14 MR. BOB PETERS: You can tell by the

15 attempt at humour, we're getting late in the day.

16 But, Mr. Todd, I'm going to turn to you to start,

17 because I believe your counsel was persuasive enough

18 to move this issue of the treatment of net export

19 revenue to the first key issue to address, as that's

20 the only key issue you're planning on addressing,

21 correct?

22 MR. JOHN TODD: Correct. And please

23 be careful with the bat when you throw it in the air.

24 MR. BOB PETERS: Kansas City and Texas

25 are still sore about that, but we'll -- we'll deal

1 with that, Mr. Todd.

2 Your position this morning through your

3 slide deck was that Hydro should credit net export

4 revenue based on total class costs, not just Manitoba

5 Hydro's allocated class costs, correct?

6 MR. JOHN TODD: Correct.

7 MR. BOB PETERS: And at the end of

8 your evidence, you suggested that it's probably more

9 fair to include the luminaires for now. But if

10 Manitoba Hydro finds an invoice that they paid to buy

11 the luminaires, that might be a -- a cost that could

12 be excluded in terms of the allocation of net export

13 revenue?

14 MR. JOHN TODD: I think I said it's

15 more practical, less effort involved, not necessarily

16 that it would be more fair. The slide that mentioned

17 perfection, said perfection would have them separated

18 out, we do not have the data. One could use an

19 approximation or management judgment, or one could

20 say, Let's just keep the bundle as a bundle.

21 MR. BOB PETERS: So until -- until

22 Manitoba Hydro finds that data, your suggestion was

23 just leave it as is and in -- included luminaires in

24 the -- in the total cost?

25 MR. JOHN TODD: It might be a -- a

1 good rationale for updating the 1989 study.
2 MR. BOB PETERS: Okay. And, Mr. Todd,
3 in terms of demand-side management costs that are
4 incurred by Manitoba Hydro, should those be included
5 in the net export credit calculation, as well?
6 MR. JOHN TODD: Yes, those are also
7 directly allocated and part of the system costs. They
8 are equivalent -- you know, to me they are equivalent
9 to generation costs, transmission, and so on.
10 MR. BOB PETERS: And on -- Ms.
11 Villegas, on PUB Exhibit 23, which was Board counsel's
12 book of documents that I think Mr. Hacault just had
13 brought up, on page 14, if you could, there was a
14 chart that I'd like to just ask Mr. Todd that, in
15 light of your suggestion as to how Manitoba Hydro's
16 net export revenue should be credited to -- to classes
17 based on total class costs, how should Manitoba Hydro
18 allocate negative net export revenue?
19 MR. JOHN TODD: I have to agree with
20 Mr. Harper on that. I don't know if the City will
21 agree --
22 MR. BOB PETERS: What's good for the
23 goose is good for the gander.
24 MR. JOHN TODD: -- but I -- I -- the -
25 - the view would be, yeah, I mean, the treatment is --

1 is not whether it's positive or negative. The
2 treatment is an approach that's been taken. And if
3 Hydro has been correct in its NFAT projections, while
4 there may be positives and negatives in future years,
5 hopefully we're talking about net positive export
6 revenues, or the Corporation may be in some
7 difficulty.
8 MR. BOB PETERS: But not just from a
9 revenue requirement perspective, but from a cost-of-
10 service study perspective, Mr. Todd?
11 MR. JOHN TODD: Equal treatment
12 regardless of whether the number's positive or
13 negative.
14 MR. BOB PETERS: Okay. And, Mr.
15 Goulding, is that likewise your view?
16 MR. A.J. GOULDING: Yes, it is.
17 MR. BOB PETERS: All right. The same
18 reasons as Mr. Todd and Mr. Harper?
19 MR. A.J. GOULDING: Yes. We -- we
20 can't have one (1) allocation method for a surplus and
21 a different one for -- for a deficit.
22 MR. BOB PETERS: Mr. O'Sheasy and --
23 or Mr. Camfield, you share that view?
24 MR. MICHAEL O'SHEASY: Yes, we also
25 share that view.

1 MR. BOB PETERS: Mr. Chernick...?
2 MR. PAUL CHERNICK: I think that's
3 appropriate.
4 MR. BOB PETERS: Thank you. Mr.
5 Bowman and you...?
6 MR. PATRICK BOWMAN: Check.
7 MR. JOHN TODD: Is that a home run,
8 Mr. Batista?
9 MR. PATRICK BOWMAN: I -- I would only
10 say with the caveat that this is -- if you're going to
11 be allocating by a method, and whether it's positive
12 or negative, you'd follow the same method.
13 MR. BOB PETERS: All right. Thank you
14 for that. Mr. Goulding, at -- at the end of your
15 questioning, or perhaps it was in response to Mr.
16 Williams, you had suggested that there were customer
17 classes that had paid about 75 percent of the revenue
18 requirement, and that they should get recognition for
19 all their expenses in terms of the allocation of net
20 export revenue.
21 Did I understand that correct?
22 MR. A.J. GOULDING: No.
23 MR. BOB PETERS: Okay.
24 MR. A.J. GOULDING: So the point that
25 I was trying to make was that when we think about the

1 net export revenue, if we take an approach that says
2 only generation and transmission is used in creating
3 these net export revenues, therefore, we're going to
4 credit all of that back to solely generation and
5 transmission, I felt that we were missing a larger
6 picture.
7 And if we think about this more
8 broadly, right, the net export revenue is not an IPP,
9 right. It's not a stand-alone venture. These
10 generation stations, transmission stations, were not
11 actually built on a non-recourse basis solely to serve
12 export revenues. They were built as part of a larger
13 portfolio.
14 And so when we look at what supports
15 that larger portfolio, what supports the credit
16 quality of the entity, what allows it to go out and
17 borrow at favourable rates in addition, of course, to
18 its sovereign association, then these customer classes
19 make a larger contribution than is being assumed when
20 it is said that only the generation and transmission
21 attributes are being used in the creation of these net
22 exports.
23 MR. BOB PETERS: So the credit quality
24 is enhanced because some customer classes pay higher
25 rates because those higher rates include distribution

1 costs.

2 MR. A.J. GOULDING: Well, right now,

3 when we look at the overall debt profile, right, and

4 the way in which these assets are funded, the credit

5 rating agencies are looking at the entire bundle. And

6 so the entity itself is viewed as more secure, not

7 just because it has a set of net export revenues, but

8 because it has multiple customers and indeed, because

9 those very assets are serving a set of customers who

10 could only be served if the distribution wires

11 existed.

12 And so to suggest that the net export

13 revenues should only be allocated on the basis of

14 generation and transmission I think oversimplifies the

15 situation as it -- as it exists here in Manitoba.

16

17 (BRIEF PAUSE)

18

19 MR. BOB PETERS: Mr. O'Sheasy and Mr.

20 Camfield, one of the reasons Hydro implemented an

21 export class was to be able to credit the net export

22 revenue to domestic customers based on each classes'

23 share of the GT&D costs. Is that correct?

24 MR. MICHAEL O'SHEASY: I'm not sure

25 that's the reason they created the net export con --

1 revenue concept, but I would agree that they created
2 it and they allocate it on GT&D.
3 MR. BOB PETERS: And previously when
4 they -- be -- before they used the GT&D allocation,
5 they credited export revenues back based on G&T only,
6 correct?
7 MR. MICHAEL O'SHEASY: You're talking
8 about a time that I wasn't around, but what I'm told
9 is that they really didn't have an export class before
10 '04, and that effectively, they were allocating the
11 revenues from exports to everyone. So I think
12 effectively, it's similar to what you're saying.
13 In other words, the generation and
14 transmission revenue requirements were the tool that
15 was used to allocate those export revenues, and
16 effectively what would happen if they did have -- have
17 a NER -- an NER at that time and allocated the NER
18 back on G&T, I think you'd get the same effect.
19 MR. BOB PETERS: All right. And one
20 (1) of the concerns that I believe in your report was
21 that if you allocated it back based on G&T only, some
22 customers would see their rates diminish below the
23 incremental cost to serve those customers.
24 MR. MICHAEL O'SHEASY: Yes, sir.
25 MR. BOB PETERS: Can you explain to

1 the panel why that would be a problem, or would that
2 even be a problem into -- in -- with today's numbers?
3 MR. MICHAEL O'SHEASY: Well, if you
4 had a class that the price for that -- an incremental
5 kilowatt hour was less than the marginal cost, which
6 is what we're speaking of here, then every time that
7 sale was made, the Company would lose money.
8 Incremental costs -- marginal costs
9 would be higher than their money coming in, and that's
10 basically not a good thing. That's not sustainable
11 for an enterprise in the long run, and I'm not sure
12 that's in every -- anyone's best interests but maybe
13 the participant.
14 MR. BOB PETERS: In your materials --
15 just let me back up. You'd acknowledged to Mr.
16 Hacault that the distribution assets did not
17 contribute to or facilitate the export sales --
18 MR. MICHAEL O'SHEASY: Yeah. And what
19 I -- yes, sir. And what I tried -- yes, sir. That's
20 what I tried to clarify. On a functional physical
21 basis.
22 MR. BOB PETERS: Yeah, I got your
23 point. And so it follows, then, that there's not a
24 cost causal reason why the crediting of net export
25 revenue should factor into the allocated distri --

1 distribution cost to each class, correct?
2 MR. MICHAEL O'SHEASY: Correct.
3 There's not a cost causal reason in terms of the PCOSS
4 embedded costs.
5 MR. BOB PETERS: So that, then, goes
6 to what Mr. Todd suggested to the Board when he was
7 answering a question this morning that it comes down
8 to judgment and policy?
9 MR. MICHAEL O'SHEASY: I would agree.
10 MR. BOB PETERS: If -- Ms. Villegas,
11 if it's not too late, MIPUG Exhibit 76 was the
12 presentation by Christensen Associates. And page --
13 let's start on page -- slide 16, if we could, please.
14 Just a couple of quick points.
15 On page 16, which is different than my
16 16 -- the page before that, please. Right. Sorry,
17 it's -- on yours, it's slide 15. There's a sentence -
18 - the last bullet indicate that there is no cost
19 foundation for net export revenue.
20 You wrote that, correct?
21 MR. MICHAEL O'SHEASY: I did write
22 that, correct.
23 MR. BOB PETERS: Well, I'm not saying
24 you wrote it correctly, but you wrote it.
25 MR. MICHAEL O'SHEASY: I did, and

1 that's what I meant to write.
2 MR. BOB PETERS: I'm sure. Now, in
3 this situation, what you have effectively done is you
4 have suggested to the Board that the profit that is
5 derived should be de-linked from the assets that were
6 used to create it.
7 Do you agree with that?
8 MR. MICHAEL O'SHEASY: Now, it's --
9 it's the term "de-linked" that I'm not sure. De-
10 linked for what purpose?
11 MR. BOB PETERS: Well, you -- from the
12 purpose of determining whether there was a cost
13 foundation to create that revenue.
14 MR. MICHAEL O'SHEASY: Yes. Correct.
15 In other words, I'm making the assertion that there's
16 no cost foundation for NER.
17 MR. BOB PETERS: All right. And
18 you've also told the panel that Manitoba Hydro used
19 their generation fleet and their transmission
20 resources to raise that -- that net export revenue?
21 MR. MICHAEL O'SHEASY: Well, Manitoba
22 Hydro used their generation and their transmission
23 facilities to enable export sales and export revenue.
24 And that export revenue had embedded allocated costs
25 assigned -- allocated against it.

1 And what fell out after that was done
2 was NER. That would be what I call possibly the
3 excess revenues that attributed from these export
4 sales beyond embedded cost.
5 MR. BOB PETERS: All right. So you've
6 gone to the point where you've already subtracted out
7 what you say are the cost factors to get the revenue?
8 MR. MICHAEL O'SHEASY: That is
9 correct.
10 MR. BOB PETERS: I've got your point.
11 Mr. Bowman, you were advocating crediting net export
12 revenue outside of the cost-of-service study. And I
13 think your reasons were to the effect that those
14 revenues are not inherently linked to costs.
15 Have I got that right?
16 MR. PATRICK BOWMAN: I think it was
17 stated that, you know, to the extent one identifies
18 revenues that are not linked to the cost, that one
19 would want to think about the best way to use those
20 revenues to the benefit of ratepayers, yeah.
21 MR. BOB PETERS: Well, you said this
22 morn -- or you said earlier today that the net export
23 revenue was really just a revenue question as opposed
24 to a cost question. And that's why you don't want it
25 dealt with in the cost-of-service study.

1 MR. PATRICK BOWMAN: That -- that's
2 right. The -- the question is: What costs do you
3 allocate to the export class, which is what we're
4 going to talk about tomorrow.
5 This -- this net export revenue concept
6 is a little bit like the uniform rates concept, where
7 -- where -- a fairly unique thing, I would say, to
8 Manitoba Hydro. We get all caught up in fighting over
9 -- over dollars coming in or not coming in.
10 I don't -- I don't run into that issue
11 when I deal with cost of service in most other places.
12 You look at a basket of costs and you allocate them.
13 MR. BOB PETERS: And do you agree that
14 these revenues are created by Hydro's generation and
15 transmission assets?
16 MR. PATRICK BOWMAN: Yes.
17 MR. BOB PETERS: And your proposal
18 then is to use the net export revenue to fund a rate
19 stabilization reserve?
20 MR. PATRICK BOWMAN: I -- I think it's
21 overstating it. My proposal in regard to this hearing
22 is to focus on revenue cost coverage ratios that only
23 allocate cost to the export class that can be
24 attributed to the export class and using a fair
25 methodology. And if there's some revenues over and

1 above that, then that -- that's not a cost of service
2 question. We don't need to use that in the
3 calculation of the cost of service.
4 I will look at an export class cost.
5 As a result of that, I will have a residential class
6 cost, and I will compare that to what residentials
7 pay. I will have a general service small cost and
8 I'll compare that to what general service small pays.
9 I'm not going to get into what do I do
10 with this -- this extra bit. It's not a co -- it's --
11 it doesn't belong in the cost of service analysis, the
12 hearing we're dealing with today at all.
13 MR. BOB PETERS: All right. Ms.
14 Villegas, MIPUG Exhibit 25, if I could, please, slide
15 5.
16
17 (BRIEF PAUSE)
18
19 MR. BOB PETERS: You were referring to
20 your response to Undertaking 32 in your last answer,
21 Mr. Bowman?
22 MR. PATRICK BOWMAN: Right.
23 MR. BOB PETERS: And you -- you
24 effectively dodged my question though as to what do
25 you do with the net export revenue that you have.

1 You're saying, well, we don't need to worry about it,
2 we just need to re -- reset the revenue to cost
3 coverage ratios and deal with them on the basis that
4 there's no export revenue included in that?
5 MR. PATRICK BOWMAN: Well, you -- the
6 key word you said is 'have'. Is there a net export
7 revenue you have? Is there surplus dollars in the
8 system? No, there's no surplus dollars in the system
9 right now because the overall system has the costs
10 that would be attributable to the domestic classes of
11 1.414 billion but revenues of only 1.376 billion, and
12 so you don't have $37 million as shown there to -- to
13 play with.
14 You -- you may, over time, if you went
15 on the next step and said, I want to bring up the cost
16 revenues as shown here. Then -- then you would start
17 to free up a certain degree of those and you could
18 have a debate about what to do with them, but they're
19 not. They don't exist now. They're -- they're being
20 used to pay Hydro's cost.
21 MR. BOB PETERS: Your table that you
22 have here in Undertaking 32 has no export revenues
23 credited back to any of the classes, correct?
24 MR. PATRICK BOWMAN: Correct.
25 MR. BOB PETERS: And so you're saying

1 that, based on these numbers, there's a shortfall of
2 $37 million?
3 MR. PATRICK BOWMAN: Correct, from
4 domestic cus -- if you -- if you want to use this set
5 of methods, which is the ones that we've proposed
6 consi -- and give very similar results to what the
7 Board proved last time, you would end up with domestic
8 customers having a cost today of 1.1414 billion and a
9 revenue of amount they pay of one three seven six
10 (1,376), a shortfall.
11 MR. KURT SIMONSEN: Ten (10) minutes,
12 Mr. Peters.
13
14 CONTINUED BY MR. BOB PETERS:
15 MR. BOB PETERS: Have you -- Mr.
16 Bowman, in preparing this then, have you reduced the
17 total cost or the total revenues by the gross extra
18 provincial revenues?
19 MR. PATRICK BOWMAN: We have -- we --
20 we have reduced the total cost by the amount of costs
21 that are attributable to the export class using a set
22 of cost allocation methodologies.
23 MR. BOB PETERS: And your assumption
24 is that there's no surplus over and above that for
25 this table?

1 MR. PATRICK BOWMAN: There is no
2 surplus over and above that for this table, that's
3 right. And, as a matter of fact, that -- the numbers
4 are in that undertaking if you go into them.
5 MR. BOB PETERS: All right. And so
6 now for my question, let's assume that there is net
7 export revenue surplus to the total cost that you show
8 on this table. And the question is: What -- what are
9 the Board's options in terms of dealing with that net
10 export revenue?
11 MR. PATRICK BOWMAN: Well, that's --
12 like, I think the thing that Hydro and I are -- are
13 quite in agreement with is it's an -- it's an issue
14 for another day. And as the Chairman and I discussed
15 at the workshop, because currently ratepayers are
16 paying 97.4 percent and they're already facing
17 increasing costs.
18 If you -- if you bought this -- this
19 approach and this method, what you'd say is -- is
20 we'll keep running these cost of service studies,
21 we'll keep generating a number, and this will -- will
22 tell you that you should start to think about some
23 rebalancing and you should start to eventually think
24 about a degree of rate increase that's -- that allows
25 one to do something, I would say, not unlike what's

1 been done with Bipole III where you get rates up a
2 certain extent, some dollars created in Hydro's
3 system.
4 They don't go to Hydro's net income.
5 They go to something that's a specific purpose. And
6 that purpose could be -- could be discussed about
7 quite how we would -- how we would track it and how we
8 would use it, but it -- it wouldn't be there for some
9 period of time.
10 MR. BOB PETERS: While we have this up
11 on the screen, Mr. Bowman, the total general consumers
12 revenue-to-cost ratio is ninety-seven point four
13 (97.4), correct?
14 MR. PATRICK BOWMAN: Yes.
15 MR. BOB PETERS: And if I understood
16 your evidence when you introduced this today in your
17 slides, your suggestion is that if any class is below
18 ninety-seven point four (97.4), which is the average,
19 that class' rate increases in the future may be above
20 the average rate increase requested by the Utility.
21 Have I got that right?
22 MR. PATRICK BOWMAN: Yeah, but with
23 two (2) caveats. One (1) is if you were to try to
24 work your way towards something, which is -- remember
25 Manitoba Hydro -- regulating Manitoba Hydro isn't like

1 regulating a ATCO or -- or someone who has a very
2 specific revenue requirement to the dollar and -- and
3 we have to give them the rate of return ever year.
4 It's a bit more like steering the super
5 tanker, right. We're -- we're -- we do adjustments
6 that try to track certain trends, but we don't -- we
7 don't have this -- these absolutely precise
8 adjustments that we have to do 37.36 million right
9 now.
10 But the -- the caveat would be you
11 would be trying to work your way towards a -- a set of
12 rates that allows, in this example, the bottom number
13 to get to one hundred (100). In the meantime you
14 would look at those and you'd say, where do I need
15 above average rate increases?
16 You'd still apply things like zone of
17 reasonableness as an example, and -- and I wouldn't
18 necessarily index it to ninety-seven point four
19 (97.4). I think you'd be thinking of indexing it to a
20 hundred (100).
21 So you'd be saying, really, general
22 service large zero to thirty (30) is below,
23 residential is below, everyone else is pretty good.
24 General large greater than a hundred (100) is a smidge
25 above. But other than that you'd be trying to work

1 your way similarly as you're steering the super tanker
2 in -- in towards getting costs into a zone of
3 reasonableness.
4 MR. BOB PETERS: Manitoba Hydro
5 Exhibit 76, please, Ms. Villegas. Manitoba Hydro 76,
6 slide 17.
7
8 (BRIEF PAUSE)
9
10 MR. BOB PETERS: Maybe the slide
11 before this, please. One (1) more before that. My
12 17. Thank you. And, Mr. O'Sheasy, you mentioned that
13 with respect to allocating net export revenue
14 different classes bear different risks. And I think
15 you also said there was not a pro rata share of risk
16 among the classes.
17 Is that a -- a fair summary of what you
18 said earlier today?
19 MR. MICHAEL O'SHEASY: It's probably a
20 fair summary of what I said and I have not done a
21 study to see exactly what those are, but I think it's
22 reasonable to conclude what we just said.
23 MR. BOB PETERS: But if the -- if the
24 allocation of costs and the allocation of net export
25 revenue are on the same basis, is it correct that the

1 class with the biggest benefit from net export revenue
2 would also be the class at the biggest risk that that
3 net export revenue drops?
4 MR. MICHAEL O'SHEASY: Could you
5 repeat the question, please?
6 MR. BOB PETERS: I'll try to rephrase
7 it. If we allocate the costs on the same basis as
8 we're allocating net export revenue, is it correct
9 that the classes that receive the biggest benefit from
10 net export revenue would also be the classes that are
11 exposed to the biggest risk if that net export revenue
12 dropped or went negative?
13 MR. MICHAEL O'SHEASY: Now, I'm going
14 to repeat what I -- I heard you say, I believe. If
15 you were to take N-E-R and to allocate it back to the
16 domestic classes in the same manner in which you
17 allocated costs to the export class, if you were to do
18 that, which we're not doing now, would that then mean
19 that those rate classes that were enjoying the
20 majority of that effect, allocating G&T -- excuse me,
21 N-E-R and G&T, would they bear the biggest risk, and I
22 would say that's -- that's highly likely so.
23 MR. BOB PETERS: Thank you. Madam
24 Chair, with that answer I'd like to thank the
25 concurrent panel of witnesses. I'll wish Mr. Todd

1 safe travels. And I'll just note for the record that
2 Board counsel has delivered this afternoon over an
3 hour earlier than scheduled.
4 THE CHAIRPERSON: We're all grateful,
5 Mr. Peters. So thank you everyone, and we'll resume
6 tomorrow morning at 08:30 for our next concurrent
7 evidence panel.
8
9 (PANEL RETIRES)
10
11 --- Upon adjourning at 5:22 p.m.
12
13
14
15 Certified correct,
16
17
18
19 _____
20 Sean Coleman, Mr.
21
22
23
24
25