BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT
R.S.B.C. 1996, CHAPTER 473

And

British Columbia Hydro and Power Authority
British Columbia Utilities Commission Inquiry
Respecting Site C

VANCOUVER , B.C.
October 14th, 2017

TECHNICAL INPUT PROCEEDINGS
VANCOUVER

BEFORE:

D.M. Morton,	**Commision Chair/Panel Chair**
D.A. Cote,	**Commissioner**
K.A. Keilty,	**Commissioner**
R.I. Mason,	**Commissioner**

VOLUME 14

Allwest Reporting Ltd.
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ERRATA

Volume 14, October 14th, 2017

Page 1472, Line 19	"hopefully" should read "helpfully"
Page 1475, Line 1	"relevant" should read "irrelevant"
Page 1482, Line 9	"some" should read "sunk"
Page 1591, Line 22	"dispute" should read "despite"

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VANCOUVER, B.C.

October 14th, 2017

(PROCEEDINGS COMMENCED AT 9:00 A.M.)

THE CHAIRPERSON: Good morning. Thank you for joining us at the second and final technical input presentation session. My name is Dave Morton, and I am the Panel Chair for the Site C Inquiry. I am also the Chair and CEO of the British Columbia Utilities Commission.

With me today are my fellow Site C inquiry panel members: Dennis Cote on my left, Karen Keilty on my right, and Richard Mason on her right.

These technical presentation sessions are intended to provide the panel an opportunity to ask questions and hear further submissions of parties who submitted during the first phase of the inquiry. The panel's priority today is to ensure that our questions are answered, and as such in some cases our questions may precede or interrupt presentations. So please, bear with us.

Those presenting today have all been invited by the panel to do so. While these sessions are open to the public, there will not be additional speaking opportunities beyond those that have been pre-arranged, and in addition members of the audience will not have an opportunity to question the presenters.

Before we begin, I just want to mention that Mr. Bemister's Allwest Reporting team is here, and they will be transcribing this session. Live audio can be streamed from our website at SiteCInquiry.com and following these sessions all presentations will be transcribed and posted along with the rest of the inquiry documents.

The panel is aware of the circulation of the unredacted Deloitte report filed in the first phase of the inquiry. The information redacted in that report was done so to ensure that current and future negotiations between BC Hydro and its suppliers was not compromised as a result of this information being publicly available. We still consider the information confidential, despite its inappropriate disclosure in the press. So therefore, we may redact or refuse presentations or portions thereof that contain specific reference to that confidential information in these sessions today.

We ask that each individual or representative of an organization who is presenting, or answering questions, to please identify themselves by stating their first name and spelling their last name for the transcription record.

With that, we are ready to open this technical input session in Vancouver on October 14th,

2017.

Mr. Swain, are you ready with your presentation?

Proceeding Time 9:07 a.m. TO SUBMISSIONS BY MR. SWAIN (#0300):

Proceeding Time 9:07 a.m. TO

MR. SWAIN: Yes, thank you, panel members. It's a pleasure to meet you at last. Not since the last papal election has the -- have the opinions of a secret conclave been so eagerly anticipated.

My name is Harry Swain, S-W-A-I-N, and I am the former chair of the long defunct Joint Review Panel on Site C. I am speaking today on behalf of no one but myself. With me are two colleagues who have assisted in the preparation of this material. On the far right is Eoin Finn, who is retired partner in KPMG and an expert, among other things, on LNG, and on the accounting standards -- and on accounting standard.

And on my immediate right, Mauro Chiesa, C-H-I-E-S-A, who is a pro on project finance, has worked for investors from banks and for many years for the World Bank on large power and other projects around the world.

Now, I guess more than most, I appreciate the pressures of time and a somewhat odd set of terms of reference on your work. I thank you for hiring

Deloitte, for the immense amount of work you and they did in a short time, and for your own preliminary report and for the many pointed questions you asked of BC Hydro.

You have asked speakers not to repeat the past written arguments and for the most part I won't. However, one, since I first analyzed BC Hydro's case in favour of Site C, now going on -- now four years ago, and found the project unsupported on the present schedule, the price has gone from 7.9 billion to 9.5 billion, which quite dramatically tilts the case away from Site C.

Further, as your own work points out, it is unlikely that F1-7 of October 4th will be the last awkward letter that Chris O'Riley will have to write.

Two, likewise, on the demand side, LNG has largely gone away and is unlikely to materialize given the current market glut and low prices. Even if it did, there is currently not a single LNG export plant in the world that uses grid electricity for its basic power.

Recent decisions by Pacific Northwest LNG and Aurora LNG to abandon their projects, and the indefinite postponement announced by LNG Canada prove the point. B.C. LNG is unlikely ever to be cost competitive in a commodity market.

1 You had earlier asked Eoin Finn to expand
2 on this point and he did in a submission to you last
3 week.
4 Three, the stark lessons of Nellcor and
5 Manitoba Hydro — don't build until you have power
6 purchase agreements and regulatory approvals in place
7 — have demonstrated the wisdom of doing investment
8 grade analysis before gambling billions of public
9 dollars on the basis of, if you build it, they will
10 come. Hydro Quebec learned this lesson well and no
11 longer builds dams on speculation, a policy which
12 contributed to their recent upgrading by the rating
13 agencies. There is a -- Mauro tells me there was an
14 article on Bloomberg yesterday on that very topic.
15 THE CHAIRPERSON: Excuse me, sir. Is there some
16 evidence that you could point to about Hydro Quebec's
17 decision, as you put it, not to build it until they
18 come?
19 MR. SWAIN: Yes.
20 THE CHAIRPERSON: Is it a policy direction from
21 government or is it --
22 MR. SWAIN: Well, Mauro, perhaps you could answer that
23 question.
24 MR. CHIESA: It's a policy decision taking by
25 government. It's part and parcel of the recent
26 upgrade of credit quality to 2A.

1 THE CHAIRPERSON: Okay. Thank you.
2 MR. CHIESA: Most recently there's a Bloomberg article
3 and I believe it was in yesterday or prior days
4 publication on how Hydro Quebec is holding off on
5 building several new projects until they get affirmed
6 PUC approved PPAs from the American side. Because the
7 demand-side is -- the domestic demand-side is flat.
8 THE CHAIRPERSON: Right. Okay, thank you, sir. My
9 apologies for interrupting
10 MR. SWAIN: Now, I'll see if this works. Ah, there we
11 are.
12 THE CHAIRPERSON: Sorry. Could we have some TV here,
13 please? Thanks. We have a blank screen.
14 MR. BEMISTER: They automatically power off to save
15 energy.
16 MR. SWAIN: Power smart at work. Is it on now?
17 MR. BEMISTER: It's just coming up right now.
18 MR. SWAIN: Okay.
19 THE CHAIRPERSON: Thank you. Okay, we're in. Thank
20 you.
21 MR. SWAIN: Now, a normal utility approaching capital
22 markets would do a number of things before it tried to
23 raise big debt.
24 **Proceeding Time 9:12 a.m. T03**
25 It would squeeze all its assets first. It would
26 refurbish or modernize all existing assets. It would

1 deploy all the most costly assets that it had. It
2 would aggressively deploy demand-side management. It
3 would probably, if it's a large project, have off-take
4 arrangements for the early years to avoid the losses
5 which are anticipated in the case of the Site C.
6 And it would have an understanding, at
7 least, on tariffs that would cover O&M sustaining
8 capital expenditures and new capital.
9 And a fourth point that I didn't put on
10 there, because I thought it was kind of obvious, but
11 it would also have its financial house in order, with
12 plenty of equity to support and de-risk their loan
13 application. And I say this from personal experience.
14 The function of equity is as a buffer against the
15 slings and arrows of normal construction and so on.
16 That's why construction financing costs more than
17 operating financing. That's why banks like my old one
18 make a nice pile of money when we transfer them from
19 construction finance to long-term debt.
20 I'll bring this up later, but I think that
21 the point is that there is equity risk in every
22 project. And to claim that you don't have it, because
23 you can finance a project at 100 percent debt for 70
24 years, is merely a confession that you have
25 transferred that risk to your shareholders, to their
26 owners and so on. In other words, it hasn't gone

1 away. It is there. And moreover that recognition
2 should be part of the calculation of alternative power
3 portfolios. In other words, you must properly account
4 for equity risk rather than, let's say, the details of
5 potential financing in an *ex ante* examination of
6 projects.
7 Now, that's what a normal utility would
8 look like. BC Hydro, however, has scaled back its DSM
9 substantially, even though there are, depending on
10 whose results you like, one or two Site Cs available
11 in DSM alone. It has few fully-refurbished assets.
12 It has, for example, an interesting little portfolio
13 of pre-nationalization assets, which we calculate
14 could be producing about 12 percent of the total
15 production, rather than the current 8 percent.
16 It has assets which are not fully deployed.
17 Revelstoke 6 is a 1980s project, still hasn't got a
18 turbine but they're still talking about it. Duncan, a
19 1960s project, still has no generation at all. And of
20 course the CRT, the Columbia River Treaty entitlement,
21 has been rejected for the spot price, which in effect
22 has cascaded through to the provincial balance sheet.
23 It has no export power purchase agreements.
24 It has no cost recovery in its tariff structure. Its
25 current structure cannot recover its costs. The
26 required structure will further reduce demand. There

is no pledge of equity as a buffer against risk. In fact, they have transferred the risk to the general taxpayer.

This morning, I'll focus on just one part of the problem; BC Hydro's consistently over-enthusiastic load forecasting. The whole project rests on blindly accepting these forecasts as ostensibly your terms of reference oblige you to do. These terms look like they were written by BC Hydro, not an objective seeker after truth. But as I argued in my initial submission, there are ample avenues for the panel to interpret this particular term with a grain of salt.

I will show that the present load forecast still seriously overestimates likely demand. If we proceed with Site C, we will be building an asset that will be stranded for decades to come, at great cost to taxpayers, in money and in jobs across the provincial economy.

Proceeding Time: 9:17 a.m. T04

BC Hydro's forecast methodology is well known and has been approved by this Commission as recently as 2008. But year in and year out their methods grossly mischaracterize industrial demand, and underestimate the conservation and substitution consequences of rising real prices for all classes of

1 customer. They have done this by assuming, not
2 observing, an almost complete overlap between demand
3 side management and price elasticity, to the point
4 where after DSM the effect of elasticity is supposed
5 to be only minus 0.05. This is wrong, and in three
6 principle ways.
7 The large industrial component, which in 12
8 years has gone from one-third to one-quarter of
9 demand, as per connection demand has plummeted from
10 117 gigawatt hours to less than 70 gigawatt hours.
11 While customers have increased from 136 to 191. More
12 customers buying less power. This reflects dramatic
13 and permanent change in the mining and forestry
14 sectors, particularly. These are generally baseload
15 customers, whereas the new chaps, residential and
16 commercial, have more of a peaking character, and are
17 thus much more amenable to time of use pricing.
18 Second, DSM has active measures which
19 require expenditures by BC Hydro to induce
20 conservation. I think there is a tendency to, if I
21 can be pejorative, to say on the part of engineers to
22 say that if you don’t bribe somebody to do something,
23 they won't do it. Not true.
24 So, DSM, in their view, includes the active
25 measures which require expenditures to induce
26 conservation. It directly impacts cash flow. It

1 includes time of use pricing, PowerSmart, load
2 shedding agreements, changes to codes and standards of
3 life.
4 These focused expenditures produce
5 detriments and demand for both capacity and energy,
6 which compare favorably with the costs of new supply,
7 and should be pursued to the point of equilibrium.
8 DSM is a good thing, but most people don't need to be
9 bribed to save money, at least in the long term.
10 Elasticity should be applied to demand before supply
11 alternatives, including DSM are considered.
12 Third, more important and more long lasting
13 than DSM is customer response to rising real prices.
14 The Joint Review Panel report observed that B.C. was
15 coming off of four decades of low and stable real
16 electricity prices, making it hard, four years ago,
17 for BC Hydro to accurately estimate the effect of
18 rising prices on demand. But we've had five years of
19 increases, and we'll have more ahead as far as the eye
20 can see. The literature abounds with empirical
21 studies in other places, some quite like B.C. in
22 important respects. As noted in my earlier
23 submission, the long-run price elasticity demand for
24 electricity is typically between minus .2, and minus
25 .7, with the central clustering around minus .4.
26 Recent B.C. experience has been at the low end of the

scale with residential at minus .08, commercial at minus .04, and industrial at minus .21. These figures need to be viewed cautiously, as real rate increases haven't started to bite very much yet. Commodity prices strongly affect industrial demand, and the overlap with DSM was unresolved during the measurement period.

To summarize, core demand has not risen above 51.3 terawatt hours per year since 2008. The pit of the great recession. And 10 years later, is at 50.2 terawatt hours per annum. This is after a decade of population and GDP growth that has been stellar in Canadian, if not Chinese terms. A deep rethink of BC Hydro forecasting is overdue. Accepting the current BC Hydro forecast for a $9 billion investment is deeply imprudent.

The better approach to calculating demand is to estimate the effect of the more general cause first, and then add on in the money DSM and other supply alternatives. The best approach would require using more than one method, and thinking hard about the reasons for any different results.

The problem with an elasticity approach is it calculating the effect of price elasticity requires an estimate of future prices. This in turn requires a long-term financial model of BC Hydro. Now, I am sure

1 that such a model exists, as it is fundamental to BC
2 Hydro's business, and BC Hydro is a competent and
3 professional organization.
4 **Proceeding Time 9:22 a.m. T05**
5 But I am equally sure that its publication
6 would so alarm the electric longevity in office of BC
7 Hydro's owner would be threatened. The assumptions
8 that current low interest and zero real increases
9 after 2024 can repair the financial condition of BC
10 Hydro must be the corporate idea of a joke.
11 Now, my colleagues, Eoin Finn, Mauro
12 Chiesa, Roger Bryanton and I have neither the
13 resources nor the inside information to construct such
14 a model, but we can make reasonable assumptions, and
15 on that basis construct a plausible scenario. It is
16 open to anyone who doesn't like the results to change
17 the assumptions or improve the model. Our working
18 paper is being sent to you and BC Hydro and is
19 obviously available on request.
20 Here are the main assumptions. The present
21 financial condition of BC Hydro, an artifact of
22 previous public policy more than BC Hydro management,
23 cannot continue, or worse, be allowed to deteriorate
24 further. Its debt equity ratio is perilously high at
25 4.55 to 1, it's deferral accounts are enormous, it's
26 equity very oddly defined, and its free cash flow a

1 long way from being free.
2 If it were a regular publicly-owned
3 company, its stock would be delisted by now and its
4 credit rating below investment grade. Hence, at a
5 bare minimum we assume in the modelling a debt equity
6 ratio of 3 to 2, one and a half to one, to be achieved
7 over 20 years, all current deferral accounts to be
8 paid off by 2024 which is BC Hydro's current plan, and
9 any new ones, say for Site C itself, have a maximum
10 term of five years, with the aggregate not to exceed
11 six percent of sales. Pension account arrears
12 disappear in a leisurely 20 years, and are kept
13 current thereafter. This is more for ease of
14 calculation now because it meets any regulatory
15 minimum, and BC Hydro is freed of the nonsensical
16 prescribed accounting standards and reverts to IFS
17 based Canadian GAAP by 2020.
18 I would note that this requires the
19 restoration of the independence and authority of the
20 BCUC by then as well.
21 Price elasticity and demand is set very
22 conservatively at minus .15 for all classes of
23 customer, taking effect in the fifth year after the
24 causative real price increase is observed. Both the
25 numbered and the lag time can be varied to test
26 sensitivity.

BC Hydro's assumptions about population growth and GDP are used. An arbitrary but generous allowance of 580,000 vehicles by 2037 is made for electric cars, noting that their rate of market penetration may be slowed by rising electricity prices, but that gasoline prices are increasingly determined by policy rather than production cost.

The long-term real cost of debt increases to 4 percent real at 1 percent per year until 2022 and is constant thereafter. We believe that the U.S. Fed is a better predictor of long-term interest rates than BC Hydro. And sales of surplus energy are at the mid-C prices given by Robert McCullough and at U.S. 40 per megawatt hour thereafter.

Surplus energy in 2024 is all of Site C and then some. Not so much an assumption as a consequence of analysis.

Now, the basic equation in our model is that revenue requirement that of BC Hydro must cover all costs, including those involved with getting back to a normal utility financial structure over a period of time. I would note those costs include personnel costs, the only factor to have risen faster than BC Hydro's two percent load forecasts. If head count had risen at only 2 percent since the flattening of the load curve in 2005, then by 2015 it would have had

5,123 employees. In fact it had 5,692, an eleven year increase of 35 percent on declining production.

It is astonishing that with all these people, BC Hydro is unable to produce quarterly reports in a timely fashion. We were very interested in these for the purposes of updating our modelling, but at the time of writing we are well into the third quarter of 2018 but no report for the first quarter has yet been published, 115 days after the end of the quarter.

Proceeding Time 9:27 a.m. T06

Now, the revenue requirements -- sorry. No, I just wanted to explain what's in the revenue requirements.

The revenue requirement in any given year is as shown. Operations and maintenance and cost of sales. CAPEX, both sustaining CAPEX and new, and there is some flexibility in the new, certainly; debt service; non-net non-domestic sales. Payments to governments. The retirement of deferrals. And a payment to repair the debt/equity ratio over a period of 20 years.

Normally you would insist that revenue requirements be balanced for each particular year, but we relaxed the annual balance feature so that this long period, 20 years, is allowed for restructuring.

After all, it took a long time for the last provincial government to contrive the present misery, and realistically one would want to minimize rate shocks.

But only after 2037 in this model is there room for any return on equity. There are no dividends. There are no special payments demanded by midnight Order in Council for the province. There is only enough in retained earnings to get back to a debt/equity ratio of one and a half to one by 2037.

The basic assumption is that BC Hydro should mirror generally accepted practices, both financial and governance, among publicly-owned electrical utilities. And Hydro Québec, I think, is a good example.

Now, here's how the model works. First off, we just extrapolate on a straight-line basis, demand in gigawatt hours from last year to this year. We measured the real rate increase that occurred five years earlier. And we apply that -- we apply elasticity to the demand for the 20 years following. We calculate the rate revenues, the revenue requirements for the present year. And therefore the rates. Then we start all over again. We extrapolate demand for year N+1, and we iterate the process for 20 years.

Now, this elasticity-based model, which is

1 strongly driven by cost of capital in this capital-
2 intensive industry, yields the following domestic
3 demand curve, I think. There it is. Sorry, gives the
4 following rate scenario.
5 I think I've got this -- let me go forward
6 one. All right. Yields the following domestic demand
7 curve. You'll note that residential and commercial
8 demand rise only slightly over the 20-year period,
9 meaning that, per connection demand continues the
10 trend that has been apparent for some years now.
11 Industrial demand continues the steep decline
12 experienced since 2005, and total demand at the end of
13 the 20-year period is only 44 terawatt hours.
14 The wild card, if there is one, is large
15 industrial. But here, the replacement for declining
16 forest, pulp and paper, and mining activity is not
17 apparent. We have over-cut our forests and the
18 Americans, despite the demand caused by the recent
19 hurricanes and fires, are determined to lessen our
20 exports.
21 Paper mills, depending on newsprint, as we
22 heard yesterday, face a world in which newspapers are,
23 alas, increasingly relics of a pre-digital age.
24 Miners, in addition to the vagaries of global
25 commodity prices, face increasingly large problems of
26 permits and social license in British Columbia. And

we've already spoken of LNG and the electrification of the Montney play is an uphill struggle at best.

Proceeding Time 9:31 a.m. T07

Now, these demand curves do not increase the debt, or the cost to return BC Hydro to a healthy financial condition. Fixed costs are paid for from a diminishing amount of electricity sold. Rates go up.

Now, let's see if I can go back one. Yes.

Rates go up about 4 percent per year for 20 years in real terms, or more than a factor of two in real pre-inflation terms.

Now, several observations. Under this scenario, with population growth, with electric cars and with DSM, and with a highly conservative price elasticity of minus 0.15, the total domestic demand falls from 50.2 terawatt hours in 2017 to 44 in 2037. Even if we are completely wrong about industrial and it flattens out, which I don't think anybody believes, we're still faced with needing less power in 20 years than we use now.

Industrial demand falls all the faster with price increases. The traditional heavy resource industries are supplanted by less energy intensive businesses which continues a trend that's been going on for more than twenty years. Flat or declining demand confronted by rising costs to cover past and

forecasted CAPEX, replacing capital abstracted by the B.C. government, and the steadily increasing cost of personnel means that revenue requirements, and therefore rates, increase a lot faster than demand, and faster than inflation. These real rate increases drive customers to conserve or to substitute, but run directly against section 2(f) of the *Clean Energy Act* which asks for competitive rates, and 2(h) switching to lower greenhouse gases.

At 4 percent rates double in 18 years, and these are real rates. Add two percent or so for inflation to estimate the pocketbook effect. Nominal rates will double every twelve years.

Our plausible scenario includes the current 9 billion and rising debt of Site C from 2025 onwards. What would happen if there were no Site C, if it were cancelled at Christmas?

Well, only 3.1 billion, not 10, would be added to BC Hydro's long-term debt. B.C.'s domestic needs would continue to be met without BC Hydro exaggerated and unnecessary replacement portfolio. Lower debt would mean lower rates, therefore a greater propensity for consumers to substitute electricity for gas or oil and for industrial investors to create jobs.

No replacement source would be necessary

for many years, but if and when the time eventually comes, there are much cheaper sources than Site C, even costed at a supposed marginal cost of 6 billion, current net exports at about 3,700 gigawatt hours a year.

The Columbia River entitlement. Further DSM which has really a very great deal of potential, some of the renewables, all of these are shapely, to coin a phrase, and all are able to be acquired as and when needed without heavy early year losses. I note that recent BC Hydro DSM results save power at $20 a megawatt hour. It's a wonderful bargain.

And IPPs coming off their first contracts with their initial capital retired, are in a position to negotiate much cheaper prices and still pay taxes on their profits.

Our plausible scenario obviously differs from BC Hydro's forecast. While its assumptions can be changed to match new evidence as it becomes available, it should really be done not as a substitute for traditional forecasting but as a complement to it. The differences should stimulate deeper reflection, more empirical research and better forecasts.

And that's the bottom line. We don't need Site C and we don’t need a replacement portfolio. If

1 BC Hydro had used proper economic tools in their
2 forecasting, as well as trying to anticipate every
3 twist of technology for decades to come, their
4 accuracy would have improved greatly, and this
5 particular version of resource development would never
6 have become, after the shamerical 100 billion dollar
7 LNG industry, the loadstar of a star-struck provincial
8 government. We got sucked in by shiny balls without
9 the kind of reality check that the Utilities
10 Commission should provide.
11 Thank you.
12 **Proceeding Time 9:36 a.m. T08**
13 THE CHAIRPERSON: Thank you, sir.
14 A question about the load forecast, if you
15 could go back to the other slide, please. I think it
16 was the following slide, actually.
17 I'll just ask -- it's okay. I can
18 establish the question. Did you say that you had
19 driven next year's load forecast by using last year's
20 forecast and then the rate elasticity, and that drove
21 next year's forecast?
22 MR. SWAIN: By using the unreduced previous forecast.
23 That is, a plain extrapolation.
24 THE CHAIRPERSON: Right. So that then didn't take into
25 account any, you know, long-term views of, for
26 example, of industry, about pulp and paper, and LNG,

1 and so on. It was just purely based on rates and the
2 elasticity in response to rates?
3 MR. SWAIN: It would take into account the expected
4 elasticity behaviour of those industries.
5 THE CHAIRPERSON: Right.
6 MR. SWAIN: Faced with those prices. It is not based on
7 the kind of one-on-one interviews --
8 THE CHAIRPERSON: Right.
9 MR. SWAIN: -- that BC Hydro has traditionally done.
10 THE CHAIRPERSON: Right.
11 MR. SWAIN: Those are two quite different methods. And
12 frankly, relying on one alone is imprudent.
13 THE CHAIRPERSON: Right. Right. Okay. Thank you, sir.
14 COMMISSIONER MASON: Yeah, essentially a follow-up
15 question to the previous one on the load forecast.
16 You did suggest that looking at the differences
17 between multiple models could be instructive. I think
18 it's fairly obvious that the biggest difference here
19 between your modeling exercise and that of BC Hydro's
20 is the industrial load forecast.
21 I just wanted to understand again how you
22 were modeling the effect of price elasticity of
23 demand. Did you say that was based on the price
24 increase, or the level of price five years ago?
25 MR. SWAIN: Mm-hmm. Yeah.
26 COMMISSIONER MASON: So for example the 2018 number here

1 would actually be based on the level, or the price,
2 that was set five years prior to that?
3 MR. SWAIN: Yeah. The relevant price elasticity is the
4 long-term one. And the -- I mean, the normal
5 expectation is that the economy and households react
6 slowly to these kinds of changes. It is generally
7 modeled as an increasing curve that flattens out.
8 That was more complicated than we could
9 handle on our Excel spreadsheets, and so we just said,
10 "Okay, let's assume that the effect of price changes
11 aren't felt at all for five years, and then they come
12 in." All right? So it's -- our function looks like
13 that, rather than that.
14 COMMISSIONER MASON: Okay. So there was nothing unusual
15 about the data that we can't see from this graph that
16 occurred four or five years ago that might trigger
17 your algorithm to start a self-reinforcing reduction.
18 MR. SWAIN: No. No. I mean, the number for 2018, as you
19 properly observed, is based on the observed real price
20 increase that occurred in 2013, whatever the rates
21 were that you approved at that time.
22 COMMISSIONER MASON: Okay, thank you.
23 THE CHAIRPERSON: Thank you very much, gentlemen. Much
24 appreciated.
25 MR. SWAIN: Thank you.
26 **Proceeding Time: 9:41 a.m. T09**

THE CHAIRPERSON: Please go-ahead sir.

SUBMISSIONS BY MR. HENDRIKS (#0301):

MR. HENDRIKS: Okay, good morning, good morning to the panel. Thank you for the invitation to present here today in Vancouver. My name is Rick Hendriks, Hendriks is spelled H-E-N-D-R-I-K-S. I am the director of CAMERADO Energy Consulting. Myself and my colleague Phil Raphals, who will present to you shortly, are here on behalf of the UBC program on water governance.

The program on water governance is co-hosted by UBC's Department of Geography, and Institute for Resources, Environment, and Sustainability. Dr. Karen Bakker, professor and Canada research chair at the University of British Columbia is the co-director of the program, which has a mandate to conduct research to inform public policy debates. Dr. Bakker commissioned the submissions which we have filed with the Commission. Due to a pre-existing travel commitment, Dr. Bakker could not be here today in person, and she sends her regrets.

The submissions made by the program on water governance were funded in part by academic research grants. Dr. Bakker acknowledges funding support from the social sciences and humanities research council of Canada. And program support from

UBC. The authors are solely responsible for the contents of the reports, the reports do not reflect the views of the University of British Columbia, or of the funder.

Okay, this is a brief outline of my presentation this morning, I'm going to touch on a number of issues. The presentation that I will give is a little bit different than the ones you've seen. I've tried to target specific questions that the panel has had, and specific questions that the panel has had, and specific issues that have come up during the proceeding. With the exception of the first issue, which was an issue that did not come up during the proceeding. We felt that it was within the scope of the panel's mandate.

So, I will touch on four issues. Employment, GHG emissions, the LNG load forecast, and I will spend the bulk of the time speaking about electrification in light of the questions that had come from the panel about electrification, price effects, the 70 year forecast. Or the 70 year period for Site C, excuse me.

In terms of employment, the terms of reference indicate that the panel must advise on the implications of continuing, suspending or completing Site C. And that given the energy objectives of the

1 *Clean Energy Act*, what if any other portfolio, et
2 cetera. One of those objectives is to encourage
3 economic development and the creation and retention of
4 jobs.
5 We did an analysis that compares the
6 employment related to the clean alternative, and the
7 Site C project. We looked at construction employment,
8 operations employment, and we calculated cumulative
9 person years of employment over the life of Site C.
10 So, we push this out to 100 years. What you see on
11 this table, there is a few numbers, and I will explain
12 them. First the construction total, so this is BC
13 Hydro's estimate for a clean portfolio against Site C.
14 This is taken from earlier documentation. Of course
15 the portfolios that BC Hydro has in its Appendix Q are
16 a little bit different from each other, but they all
17 contain a very common element. They contain a great
18 deal of wind energy, and pump storage. And so there
19 isn’t much of a difference between the portfolios in
20 terms of their constituents resources.
21 And then we looked at the construction
22 remaining. So in terms of doing an economic
23 comparison, the employment that has already occurred
24 on Site C is sunk employment. What we need to look at
25 in terms of comparing employment between the clean
26 alternative and Site C is what will happen going

1 forward. We did not have detailed year-by-year,
2 quarter-by-quarter employment figures for Site C, so
3 we made what we thought was a reasonable estimate of
4 the amount of employment that has already occurred.
5 And we estimated that to be about one-quarter of the
6 total employment. And that leaves the number that you
7 have there, 33,000 or so for Site C, compared to
8 30,000 for the clean alternative.
9 Keep in mind that these are blocks.
10 **Proceeding Time 9:46 p.m. T10**
11 So, similar to the spreadsheet that we have
12 received from the panel, we looked at blocks of
13 resources in the clean alternative. 5100 and change
14 of energy and 1100 and change of megawatts of
15 capacity.
16 So what we see in this instance is that
17 over time, because of the operations employment
18 differences between the two portfolios, the employment
19 for the clean alternative rises much more quickly than
20 it does for Site C. And you can see this graphically.
21 So in the early years, we're in 2017, from
22 today forward if Site C were to be continued — that's
23 the red line — Site C employment continues until the
24 completion of construction. And then it stays
25 relatively flat because operational employment is very
26 low. On the other hand, the alternatives rise for a

1 period of time over the next ten years as construction
2 employment takes place. And then operational
3 employment follows from there. So in the long-term
4 what we found was that the clean alternative portfolio
5 produces significantly more person-years of
6 employment.
7 GHG emissions. Again, we turn to the
8 inquiry terms of reference which indicate that the
9 alternative portfolios require "…maintenance or
10 reduction of 2016/17 greenhouse gas emission levels."
11 We note that this does not apply to Site C, yet Site C
12 has emissions which would increase the 2016/17
13 greenhouse gas emission levels.
14 We don't think it was the intention of the
15 writers of the terms of reference to use this as a
16 reason to exclude Site C. None the less, what we did
17 in response to that was we included the emissions of
18 Site C within our portfolios, that Mr. Raphals will
19 speak about. We applied a social cost to those
20 emissions. And what we did here is we compared,
21 again, a clean portfolio against Site C in terms of
22 GHG emission benefits and costs. We concur with BC
23 Hydro that the OIC means emission levels and not
24 intensities as was initially the interpretation of
25 Deloitte. We find that we agree with BC Hydro on
26 that.

So, again, here are the numbers. I'll just walk you through the table. This is the table that was originally put in Appendix G by BC Hydro. So what you see on the first line is the generation from Site C over 100 years. So that's basically 5,100 that was originally in Site C multiplied by 100. And then BC Hydro at that time, when they prepared this information, determined the amount of energy that would be used domestically in B.C. and the amount that would be exported.

And then they compare that to the GHG emissions of the clean alternative, and at that time of what were called clean plus thermal portfolios. As I said, we understand those clean plus thermal portfolios are no longer being considered. So the lines that matter here are the first two. And the difference that matters is the 34,000, and that is 34,000 kilotonnes. So that's 34,000 million tonnes that BC Hydro determines is the GHG emission benefit of Site C.

In order to update the comparison we made several observations. First of all, in conducting the initial comparison BC Hydro assumed that Site C's emissions are zero. On the other hand, they filed detailed information about what they believe the Site C emissions actually are. And they outline two

1 scenarios: a likely scenario in which it's 4.3 million
2 tonnes, and a conservative scenario which is 5.8
3 million tonnes.
4 We also looked at the Appendix Q
5 portfolios, which are the updated portfolios. And the
6 clean generation, the alternative portfolio in there,
7 does not contain any municipal solid waste generation,
8 which was the source of quite a bit of emissions in
9 the earlier analysis that BC Hydro filed under
10 Appendix G. So that's not there anymore. So the
11 emissions for the alternative portfolio go to zero.
12 We also updated the surplus generation numbers. So
13 the numbers that had been filed by BC Hydro were out
14 of date. We used updated numbers.
15 **Proceeding Time 9:51 a.m. T11**
16 Finally we updated the emissions intensity
17 in the export market.
18 THE CHAIRPERSON: Sir, excuse me.
19 MR. HENDRIKS: Yeah?
20 THE CHAIRPERSON: What causes the greenhouse gas
21 emissions from Site C over a hundred years?
22 MR. HENDRIKS: The emissions from Site C are a result of
23 decomposition inside the reservoir. So it's land
24 flooding, basically. It's detailed in an appendix to
25 the EIS.
26 THE CHAIRPERSON: Right. But that -- there's a peak in

1 the early years, is there?
2 MR. HENDRIKS: Yes, there is a peak in the early years.
3 THE CHAIRPERSON: But it doesn't go to zero after that.
4 MR. HENDRIKS: It doesn't go to zero, no. There's about
5 ten kilotonnes, subject to check, per year.
6 THE CHAIRPERSON: Yes, okay.
7 MR. HENDRIKS: After that.
8 THE CHAIRPERSON: Thank you.
9 MR. HENDRIKS: But granted, the bulk, as BC Hydro also
10 notes, is in those first ten to fifteen years.
11 THE CHAIRPERSON: Right. Right, thanks.
12 MR. HENDRIKS: In terms of the WECC emissions intensity,
13 BC Hydro filed a number. We looked at that number;
14 that number was from 2008. So, WECC is the Western
15 Coordinating Council; you're all familiar with that,
16 I'm sure. And so we looked at updated information
17 from the EPA in the United States, and we projected
18 that forward in anticipation that emissions within the
19 electricity sector in the west would continue to
20 decline. And there's a lot of policy support for
21 that. Many states have renewable portfolio standards,
22 et cetera. So we would expect those emissions to
23 continue to decline.
24 So when we did that, we returned to BC
25 Hydro's table. So this is a bit of a modification of
26 the first table. I didn't include the energy figures

here. So what we have now is, there are two scenarios, the likely emissions from Site C and the conservative emissions from Site C. There are no domestic benefits because the clean alternative now has no municipal solid waste generation. So domestically, both portfolios produce the same emission profile.

On the export -- oh, sorry. Other than type C emissions, which I will add in a moment.

The Site C export GHG reductions are reduced considerably. And this occurs because the surplus is smaller than the one that BC Hydro had used, and the emissions intensity is much lower. And then we add in Site C's emissions.

So what we end up with is a modest GHG cost for Site C. We don't believe that this cost is meaningful. If we used a somewhat higher WECC GHG intensity, these numbers would reverse in the opposite direction. So the WECC intensity on the export market influenced these numbers. But we don't believe it's material to the OIC. And the reason I say that is because the total emissions in B.C. are 64.5 million tonnes per year. And keep in mind that these are emissions over 100 years. So both the clean alternative and Site C produce very little emissions.

So we felt it was important to correct the

1 Appendix G and update it for the panel's benefit.
2 THE CHAIRPERSON: Thank you.
3 COMMISSIONER MASON: And just for clarity, what are the
4 units you're using on this slide?
5 MR. HENDRIKS: Oh, excuse me. Those would be millions of
6 tonnes over 100 years.
7 Oh, sorry. Not millions of tonnes;
8 kilotonnes over hundreds of years. So that would be
9 -- 587 is 0.587 million tonnes. Yes, excuse me.
10 Thank you for that.
11 Okay, moving on to forecast load for LNG.
12 When we looked at the LNG issue, we read the filings
13 from BC Hydro, we read the comments from other
14 submitters. I have not read the most recent filing
15 from Mr. Finn that was referred to in a previous
16 presentation.
17 The key question that we asked ourselves
18 from a load forecasting perspective is, what has
19 changed, or will change, in future years that will
20 favour development of B.C. LNG exports over LNG
21 exports from competing regions? In our view, this is
22 the key question.
23 BC Hydro filed information indicating that
24 there was both a completion and a timing risk related
25 to LNG. But the completion risk did not seem to be
26 factored into the forecasting as the projected

1 emissions for -- or, excuse me, the projected
2 requirements in terms of electricity requirements for
3 all three facilities are included in the load
4 forecast.
5 They also indicated that there will be
6 future global LNG demand, and we don't take issue with
7 that. We think that's a necessary condition for
8 including LNG in a load forecast. But it's an
9 insufficient condition. It's not solely a reason to
10 include it. The project milestones that BC Hydro
11 indicates with respect to the project are also
12 necessary but insufficient.
13 In reality, the B.C. LNG to date has been
14 out-competed. U.S. and Australian LNG export
15 facilities total 100 million tonnes per annum over the
16 last decade. That's built and under development.
17 **Proceeding Time 9:56 a.m. T12**
18 That's more than six times the capacity of LNG Canada,
19 Woodfibre and Tilbury. One could view this as B.C.
20 LNG losing to the opposition seven times in a row. No
21 information was provided on how the competitive
22 disadvantages that we've seen to date will be
23 addressed.
24 Nonetheless, to be conservative, and
25 recognizing that BC Hydro could not do a probabilistic
26 load forecast as they would normally do for industrial

load, we did include Tilbury and Woodfibre in our modelling. And we had made this decision, and we noted also that Deloitte made a similar decision in their model. So they came to the same place that we did.

Okay, just move onto electrification. In your report you made a request, identify any potential downside risks to the load forecast. And the question was asked in the context of electrification, so we've spoken to it in that context. We noted that in Table 20, the benefit of Site C continuation in the base case is 7.3 billion, and the electrification case is quite a bit higher. It's 11.1 billion, so this is a material consideration, in our view, for the panel.

So low carbon electrification. Low carbon electrification really consists of two components, decarbonizing the electricity generation and using the decarbonized electricity to then offset fossil fuel uses across the economy. Most of the discussion and most of the submissions that have been put into the Commission focus on the second of these.

Secondly, I'd like to clarify that electrification is part of decarbonization. The two terms, "electrification" and "decarbonization" have been used interchangeably at times in this proceeding, and that is not quite accurate. Decarbonization

consists of a number of activities, including electrification, but also the use of renewable fuels, additional conservation, et cetera.

With this kind of definition, or with this definition of low carbon electrification, the process really began in B.C. ten years ago with the B.C. Energy Plan. That was a decision to decarbonize the electricity generation in the province. That was a conscious decision to move away from least cost planning. That decision, in our view, contributes to, and will continue to contribute rate increases.

As such, BC Hydro suggests that there will be real rate increases, since there have been no real rate increases in the past 50 years. Our concern here is that the past 50 years may not be the indicative period for concluding that there will be no future real rate increases.

The decision made as a result of the 2007 B.C. Energy Plan, and other policy since that time, to develop higher cost, low carbon resources is a pivot, a shift.

Have we entered a new era with respect to price effects? We ask that as a question. We need to understand the low carbon electrification context of the past ten years, as this will also be the context moving forward. We need to understand the

1 price effects of long-term rate increases under
2 electrification. Has the negative 0.05 applied during
3 the past ten years? How will it apply going forward
4 in an electrification context?
5 The elasticity study recommended by GDS,
6 which I understand BC Hydro has initiated, will be an
7 important contribution to this discussion. However,
8 it's too late for that study to inform a short-term
9 price elasticity issues that this panel is dealing
10 with, and it might actually be a little bit too soon
11 to fully understand the long-term prices of elasticity
12 under electrification.
13 As we know from the literature, long-term
14 price elasticities from electrification, as you heard
15 from your prior speaker, tend to be hot. Well, tend
16 to be more negative in the long term.
17 We also took a look back at the only
18 electrification study that we're aware that BC Hydro
19 has produced, at least recently, and that was in the
20 IRP. And so that was what we'll call the MKJA study,
21 and that study looked at two key factors, GHE prices
22 and natural gas prices. And on each of those
23 continuums -- or each of those issues, excuse me, gas
24 prices were looked at in a low context, a medium
25 context and a high context, and the same for natural
26 gas prices: low, medium, high. I have not

1 reproduced their full table, which is in our report.
2 I've only produced a low-low, which will be the
3 extreme in one direction, the mid-mid and the high-
4 high.
5 And what represents where we are at right
6 now best, which is mid-low. We're on a mid-GHG price
7 trajectory provided that we continue with increases
8 after 2022 and we're actually on a lower than the low
9 price forecast for natural gas, so we're actually
10 outside of the extreme.
11 Keep in mind that the study that was done
12 for the IRP was done -- I believe it was done in 2010,
13 2011, so the full effects of, you know, natural gas
14 price declines probably weren't foreseen at the time.
15 And then we have BC Hydro's submission. So
16 this is the mid-load forecast and the electrification
17 forecasts. And these are changes in requirements of
18 energy in a 20-year period. So between 2020 and 2040.
19 What we see in this table is that the mid-load
20 forecast seems to be very consistent with the current
21 trajectory.
22 **Proceeding Time 10:02 a.m. T13**
23 And I will say there are challenges to
24 making this kind of a comparison. And I'm not going
25 to pretend that they are not real. There are real
26 challenges. The biggest one is that the load forecast

is not the same load forecast in the two studies.

The 2010 load forecast, which is more or less the one used in the MKJA study, is somewhat different than the current load forecast. We did this comparison really as a magnitude calculation, to look at BC Hydro's electrification forecast and to ask ourselves, is this realistic? Would we develop 20 -- or 40 new terawatt hours per year? Would there be 40 new terawatt hours per year of demand, over the next 20 years? How realistic is that forecast? Because that number is what largely drives the difference that you saw at the beginning of this section, between continuing Site C in the base case versus in the electrification case. That difference of 3.8 million is driven by how much energy requirements are projected to grow over that 20-year period.

So in our report we go into this in much more detail. But here, we just raised a concern that the number that BC Hydro is using here seems high. We don't know the reasons. We don't have enough information about the electrification forecast to understand what they may have done differently here. What were the assumptions that were used? How did they cost the changes? We raised a number of questions in our submission about this. We saw these numbers and they just didn't seem to add up for us.

1 Do I have a couple more minutes?
2 THE CHAIRPERSON: Go ahead.
3 MR. HENDRIKS: Yeah. Finally, I was asked by Dr. Bakker,
4 and in response to the panel's concern about
5 disruption, to try to look at a particular technology
6 that would be familiar to the general public. And in
7 terms of decarbonisation. And so I picked two, but
8 I'll speak only about one today, which is water
9 heating, excuse me.
10 And this one I picked because Deloitte had
11 raised concerns about whether or not space and water
12 heating would actually be electrified. And we share
13 those concerns. During the RRA, BC Hydro filed some
14 material indicating that they envisioned almost no
15 fuel-shifting in these two areas in the next 20 years.
16 And it raises the question about whether or
17 not this is something that can be electrified. And
18 there are a number of submissions made that we will
19 have a very high level of electrification in order to
20 decarbonize, and we don't dispute the increase in
21 electrification. There will be an increase. The
22 question is, what will be the magnitude? And what are
23 the other alternatives that may evolve for
24 decarbonisation?
25 But I'll just explain this graph. This is
26 the annual cost of heating water using different

technologies. So the first column is natural gas, tankless. So, using a natural gas system that doesn't have a tank, an instantaneous heater. And then a natural gas, tank. An RNG tankless, and then an RNG tank, which is renewable natural gas. And the prices used there are the prices -- are the actual cost prices for RNG. Not the recurrent price, the $7 per gigajoule as per your proceeding, I believe a couple of years ago you set that price. We've tried to use an actual cost price, or actual cost, excuse me. And then there's the Tier 1 and the Tier 2 rates.

So depending on how much electricity you're consuming, you may be paying for your hot water at the Tier 1 rate; you may be paying for it effectively at the Tier 2 rate.

What we see in this picture is that it is quite a bit more affordable to heat with natural gas. And this is consistent with submissions by BC Hydro that it was about four times more expensive to heat water with electricity. And these numbers bear that out.

We then projected forward. We used the EIA's forecast for natural gas, the Energy Information Administration in the United States. We inflated the RNG cost by 1 percent real. And then we inflated electricity prices by 1 percent real, and we did a

1 couple of sensitivities in our report. And those were
2 placed in the appendix of our report.
3 The intent of this was to show that even
4 with -- and we imposed a cover price, of course.
5 Increasing at $20 per year, beginning in 2022. And
6 that number represents the Conference Board of
7 Canada's mid scenario in their recent report regarding
8 the costs of decarbonisation, which came out just this
9 past month.
10 And what we find is that heating water with
11 electricity stays more expensive than heating it with
12 gas.
13 **Proceeding Time: 10:07 a.m. T14**
14 And this will now be the only technology
15 that will be difficult to decarbonize, even with a
16 strong carbon price. We looked at increasing it by
17 40, it would require an increase of about $40 per year
18 beginning in 2022 before we saw a cross-over point.
19 We questioned whether or not that kind of a carbon tax
20 would be politically or socially acceptable. So, it
21 raises some interesting and difficult questions in
22 light of what the panel has heard so far of the last
23 two days.
24 On the one hand, there is concern about
25 affordability for households, and the conference board
26 certainly raises that as a major concern in their

report. Obviously we have climate change objectives that we need to meet. So, to me that space between the high cost of electricity that is clean, and the lower cost natural gas that is not, I would call that the innovation space. And the question becomes, what happens with renewable natural gas which sits in that innovation space? I don't have the answer to that question. That would require significant study beyond the scope of time we have for this proceeding. But electricity does not have a monopoly on innovation. The gas industry will be innovating as they move forward.

We outline in our report some activities that are already occurring with respect to renewable natural gas. We also have a natural gas system of pipelines that is there in place. It was very expensive to put in place, so to remove that, and to lose that asset has a cost as well. And renewable and natural gas can make use of that system without an additional requirement to build infrastructure. You are simply replacing the fuel.

BC Hydro's MKJA study also shows that we will need substantial biofuels, renewable fuels under any scenario. And finally, the European Union is looking at this issue very differently as we do here. They are moving towards power to gas. So, using

electricity to produce fuels. And you'll say, "Well that may drive up electricity requirements." It might, but most of the approach that is being used in Europe is to use electricity from renewables, at very, very low cost. Curtailment electricity, solar power as it becomes much, much cheaper.

So, the point here that I'm trying to make is that we shouldn't assume that decarbonization and electrification are interchangeable terms. There will be innovation, there will be new technologies that come in place that will bridge the gap between the high cost electricity that is clean, and the low-cost fuels that are not clean. And I think I will leave it there.

Thank you.

COMMISSIONER MASON: I wonder if I could take you back to probably one of your first couple of slides where you were talking about the job impacts -- or sorry, the job consequences of -- thank you, slide 5. I note there that you're predicting that under the alternative there is almost 1000 operational job years --

MR. HENDRIKS: Yes.

COMMISSIONER MASON: -- compared to 74 for the Site C project. I'm just wondering, did you model any kind of improved efficiency over the 100 years in terms of

how many people would be required to operate alternative energy solutions?

MR. HENDRIKS: No, we did not. Those are BC Hydro's numbers.

COMMISSIONER MASON: Okay.

MR. HENDRIKS: So, the 998 and 74, are BC Hydro's numbers from their clean portfolio used in the IRP.

COMMISSIONER MASON: Thank you.

THE CHAIRPERSON: And I have a question also. In your discussion of substitution for water heating, have you considered at all the -- this is probably more for multi-use buildings and single family dwellings, but have you considered things like district energy systems and ground source heat pumps on an individual basis to provide domestic hot water and heat?

MR. HENDRIKS: Yes, we -- in our appendix to our report we discussed ground source heat pumps. The most recent study that we looked at was one done by the ISO, that was done just this summer. It was done for Ontario, so there was some differences, there was some climatic differences, but the capital costs of ground source heat pumps are very prohibitive relative to the cost to heat water, and to heat space.

THE CHAIRPERSON: So are they in that innovation space you spoke of?

MR. HENDRIKS: They are also in the innovation space.

1 Absolutely. They would be in the innovation space as
2 well. But keep in mind, if you look at this graph
3 that's on the screen there, the first who will uptake
4 that technology will be the electricity users. So
5 that would actually lower electricity requirements,
6 not increase them.
7 THE CHAIRPERSON: Right.
8 MR. HENDRIKS: Right? So.
9 THE CHAIRPERSON: Okay, thank you for your presentation,
10 sir.
11 We'll take a short break now, say we'll
12 come back at 10:25 A.M.
13 **(PROCEEDINGS ADJOURNED AT 10:12 A.M.)**
14 **(PROCEEDINGS RESUMED AT 10:25 A.M.)** **T15**
15 THE CHAIRPERSON: Please be seated. Please take your
16 seats.
17 Please go ahead, sir.
18 **SUBMISSIONS BY MR. RAPHALS (#0302):**
19 MR. RAPHALS: My name is Phillip Raphals, R-A-P-H-A-L-S.
20 I'm the executive director of the Helios Centre, which
21 is a non-profit energy research group in Montreal, and
22 this report was also prepared, like Mr. Hendriks'
23 report, at the request of the UBC program on the law
24 and governance.
25 By way of preface I'd just like to mention
26 to you that more than 20 years ago, 1995, I was

1 commissioned by the Quebec Ministry of Natural
2 Resources to prepare a report on the BCUC and on
3 regulations in British Columbia. So in 1995 I spent
4 two weeks here, a very rainy November two weeks, in
5 your offices talking to everyone about how you do
6 things, and I think that actually it was a significant
7 input into the creation of the Quebec regulator.
8 THE CHAIRPERSON: Oh, that's interesting, sir. Thank
9 you.
10 MR. RAPHALS: So it's really an honour and a pleasure
11 for me to have a chance to contribute to your work
12 here.
13 THE CHAIRPERSON: Welcome, sir. Thank you.
14 MR. RAPHALS: I assume you've read my first report. I
15 wonder how much time you've had to read the second.
16 You've only had it for about a day and a half. So
17 what I propose to do is to go in very over-view terms
18 over what I've done to try to show you big picture
19 aside from the details.
20 THE CHAIRPERSON: Thank you.
21 MR. RAPHALS: So I'll review the question methodologies,
22 which is a significant challenge and then explain the
23 analysis that I did, and then some very brief comments
24 on your portfolios that you made public a few days
25 ago.
26 THE CHAIRPERSON: Thank you.

MR. RAPHALS: So looking at this file, I see there are essentially three types of analysis are described. The portfolio present-value analysis. It seems to me everyone agrees that this is the primary tool, this is the main way to compare resources. BC Hydro says that in different places, in different ways. I think Deloitte did, and I believe that you did as well, in your preliminary report.

At the same time there is also the unit energy cost analysis, which is described as being secondary, described as being essentially an illustrative tool to make it easier to understand, but generally is not regarded -- and also by the way, I noticed Dr. Jaccard's report, I thought made a very focussed explanation of why unit energy cost is not a particularly relevant way to go about making resource decisions.

And then there's the ratepayer impact analysis which BC Hydro presents, which, in a sense is the same the numbers, but from a rates perspective, and in particular does so over a 70-year period, which, as I'll explain later, I think is extremely problematic.

So the beginning of my work in this came out of the IRP, and in particular the portfolio present value analysis that was presented in the IRP

which I assume you're familiar with.

In Appendix 6A of the final IRP there were 91 portfolios presented, and these were all outputs of the system optimizer program, in which very specific policy constraints were set to define each one, including a load forecast, whether it includes Site C, whether or not to include thermal resources, and some other factors, and then it would spit out the optimized resource additions with their dates and their unit costs, and then it would also, in the section that I've circled here, indicate the present value for that run over the twenty-year period of analysis.

And at the end of the day, those present values were compared, and this table, which is buried in Appendix 6A but it's results are also prominently presented in the IRP, essentially demonstrates that Site C was preferable to the alternatives and that F2024 was better than Fiscal 2026 based on this twenty-year system optimizer analysis, using present value to compare the incremental costs of each scenario against each other.

So I understood this to be a fairly settled approach. Methodology, a very specific and concrete and quantitative methodology for comparing complex portfolios which are very different in many ways. And

so I was very surprised to see in Appendix Q very similar outputs from the same system optimizer tool that, for a particular scenario, do indeed show the same -- or show the appropriate list of resources that were selected, but don't say anything about the present value of that scenario.

Proceeding Time 10:31 a.m. T16

And I have to say I'm perplexed, and I remain perplexed, as to how the same tool produces outputs with and without present values. And I would have liked to have had the opportunity to pose the question to BC Hydro, and perhaps this afternoon, I respectfully suggest if you're interested in doing so, to ask them about that. Because it seems to me it's a very critical piece of information that would be necessary to compare the portfolios that they have examined. So, there are 11 portfolios presented in Appendix Q, and then later on in responses to your IRs there's a whole other set, I forget the number, but it's quite a number of scenarios. And I think that having the present value of each one would be a very valuable addition to the file.

So then as I said before, the unit energy cost analysis, I think we all agree, is sort of a summary of the others, which is easily digestible but not particularly enlightening. And in that light, I

1 found it somewhat surprising that it became the
2 central focus of the presentation in BC Hydro's
3 submissions. There are comments that one could make
4 about exactly the way that the adjustments were made.
5 It seemed to me there was some double-counting, in
6 terms of termination costs that were on both sides.
7 But in the end, I didn't address that very
8 much. We didn't address that deeply in our report
9 because ultimately it's secondary. That's not really
10 the basis for decision-making. Either of the utility
11 or, I presume, of the Commission.
12 So then we get to the rate impact analysis.
13 And here, I was very grateful to have access to the
14 spreadsheets that were provided to me in response to
15 your Information Requests. They weren't easy to work
16 through. It turns out that there is a separate
17 spreadsheet for each scenario, so it's not that
18 there's one that has different variants and then
19 comparing which numbers are the same, which are
20 different in them, and seeing what comes from where.
21 But I found a number of things that I found
22 problematic. One is that -- I mean, my first question
23 before I saw the spreadsheets was, well, how can you
24 possibly do this? You don't have a 70-year load
25 forecast. You don't know what resources are going to
26 be needed. You don't know what -- you know, you don't

1 really know anything, even 20 years out. 20 years is
2 a really long time. Generally humans are not very
3 good at knowing what's going to happen more than a
4 couple of decades in the future. And 70 years is a
5 really long time.
6 But so now having the benefit of examining
7 the spreadsheet, so, the load forecast, there is a
8 load forecast through to 2036 or 2040, which is
9 documented elsewhere, and then if it increases -- it's
10 not entirely clear to me. It's at a fairly constant
11 growth rate, but not precisely constant growth rate,
12 so I don't know how they extended it. I think to 2056
13 or so, I'd have to check in my report.
14 And then after that, load growth is flat.
15 There is no load growth, I believe, from 2070 -- from
16 the 2060s or 2070s on, there is simply no load growth.
17 No explanation, no -- I don't know why.
18 Then there is DSM. There is a line that
19 shows reductions, which I assume are from DSM, which
20 increase. And that's what this little graph shows.
21 This is the incremental DSM, which increases fairly
22 dramatically until about 2030, and then declines
23 fairly dramatically, and then again is exactly zero as
24 of 2064.
25 And then what I think is the most important
26 issue with respect to these 70-year forecasts is the

1 line that's called the increase in the cost of energy.
2 Because, so far as I can tell, that's the line that
3 essentially drives the results. There is a few --
4 there are a few smaller numbers that are added to it,
5 and it's manipulated in certain ways, but the heart --
6 you know, the key driver that produces those upward
7 graphs of rate impact come out of this line increasing
8 the cost of energy.
9 And for 70 years, there is a number typed
10 into each cell. And I have absolutely no idea where
11 that number comes from. There is no documentation,
12 there is no model, there is no -- I mean, presumably
13 it comes from somewhere, I'm sure. I don't think they
14 made up these numbers. But I really have no idea
15 where they come from.
16 And so given their determinative effect on
17 the total result, I don't see how that's an analysis
18 one can rely on.
19 **Proceeding Time: 10:36 a.m. T17**
20 There is black box that is producing a bunch of
21 numbers, which produces the rate impact, but we have
22 no way to know whether or not those numbers are the
23 right numbers or the wrong numbers.
24 So, which leads me to the conclusion, and I
25 admit it's a fairly drastically phrased conclusion,
26 and I apologize for that, but I have to conclude that

there simply isn't any probative value attached to this 70 year rate impact analysis, in my view.

Which leaves us in the uncomfortable position, now stepping back from BC Hydro's submissions, that there isn't any quantitative, rigorous analysis to compare the three scenarios, complete, terminate, suspend. We have the absent present value portfolio analysis, we have the rough give us your UEC analysis, and we have the rate impact analysis that has unfortunately a very major black box in the middle of it.

So, what to do? What we decided to do, in hoping that it would help inform your reflections and deliberations, is to try to carry out in our own rough way, obviously without a copy of system optimizer, and without the resources that it would take to use it, but that type of analysis, looking at 20 year portfolios, based on all the different parameters available to us, and sensitivities of all different sorts. Estimate with costs attached to each one, estimating the incremental costs each year of each. Computing the present value based on a discount rate, and seeing what that has to say about those different options.

Which -- I'll jump a little bit now to the end, is a very different exercise than the one that I

1 understand you've undertaken in the portfolios that
2 you've presented for comment. And if you'll forgive
3 me, perhaps unfortunate metaphor, as I understand it
4 you are looking with a great deal -- with great care
5 at a part of the system plan. You are looking at a
6 block of energy and capacity equivalent to Site C, and
7 with all the appropriate tools, with capital costs,
8 and with depreciation, and with each individual
9 resource modeled. You are looking at part of the
10 elephant in great detail. And what we've tried to do
11 is look at the whole elephant, but it's a much fuzzier
12 picture. And none of our elements have anything like
13 the detail that is present in yours. Which, perhaps,
14 in the best case, would suggest that they're
15 complimenting approaches and that one, they may each
16 contribute to your deliberations on ultimately the
17 implications of these different options.
18 So, now to go a little bit into how our
19 approach works, again we have not tried to duplicate a
20 cost of service. We've essentially treated I think
21 all of the resource editions, other than Site C, as if
22 they were PPAs. So as if they have a constant dollars
23 per megawatt in real dollars that stays the same over
24 the term.
25 The one exception to that I believe is wind
26 power, where because of the significant -- excuse me,

1 wind and solar photovoltaic where, because of the
2 significant unit costs decreases expected over time,
3 we've had -- we use a decreasing cross curve.
4 Individual projects are not detailed, and
5 we also do not have access to a very sophisticated
6 optimization process, and we built a fairly complex
7 Excel model, which also has some manual adjustments.
8 So, for instance, to find the best timing for the Mica
9 offline, and for Revelstoke, and for pump storage, we
10 essentially used a trial and error, tried at different
11 times and see which one produces the lowest present
12 value cost. So, it would have been nice to automate
13 that, but time ran out.
14 But again, we believe that this is a useful
15 first order approximation of the impacts of these
16 different approaches.
17 Now, to step back, one of the key inputs
18 into this is of course Site C. And the question of
19 what costs to use and how to model them was a very
20 challenging one, which occupied a lot of our time.
21 And that had several aspects, which I will go over
22 quickly, but I think they are important, and need to
23 be mentioned.
24 One is, first of all, what capital costs
25 should we use? So, in the first iteration, which was
26 before the Deloitte report, we started out with the

1 budget estimate of $8.335 billion, but then came
2 across in one of the attachments a -- I believe it was
3 a BC Hydro finance report which showed year-by-year
4 actual capital costs outlays for Site C.
5 So, if you know how much is being spent
6 each year, and you know what the cost is of the AFUDC
7 rate, then you can make a balance each year that
8 increases by what you spent this year, plus the
9 carrying costs of what you spent in the past. So,
10 these two spreadsheets, I won't ask you to read here,
11 but they're in the report, carry out those
12 calculations to the best of our abilities, also taking
13 into account the deferral account.
14 **Proceeding Time 10:41 a.m. T18**
15 And in the first report which simply
16 assumed 7 percent because that's the discount rate and
17 that's the weighted average cost of capital that
18 seemed to be in the file, and somewhat surprisingly
19 that came to a figure much higher than the budget
20 figures. It came to $10.6 million.
21 So then digging a little deeper realizing
22 that BC Hydro assumes that the project is all debt
23 funded, so there is no equity component, so it's not
24 based on its weighted average cost of capital but on
25 the cost of debt, which I believe is 3.43 percent, so
26 this on the right we see the same calculation using

1 the figure, and it still doesn't come out to the same
2 number. I don't really know why. And I'm a little
3 bit surprised that in all of the thousands of pages
4 that are now in this file, that there isn't somewhere
5 a little table that shows -- similar to this, that
6 shows amounts spent each year and financing costs
7 adding up in the end to a total budget capital cost.
8 And again, that seems to me that that's
9 just sort of a basic data point that it might be
10 useful to have going forward.
11 So the other very difficult question is --
12 oh, I should also mention that for Site C we assumed —
13 which I think is also BC Hydro's assumption — that it
14 would financed on sort of a mortgaged-based constant
15 nominal dollar, and so since all the rest of our
16 analysis is in real dollars, we then deflated that
17 over time to produce a stream of annual costs in real
18 dollars, based on the remaining capital cost to be
19 paid, and that at a 6 percent nominal discount.
20 So the question is what do you do about the
21 sunk costs, what do you do about the termination
22 costs? The sunk costs, it seemed to me it was
23 straight forward. The purpose of the exercise, as I
24 understand it, is to make an economic comparison
25 between these different options, to find out which
26 really has greater overall costs to ratepayers,

1 perhaps largely defined.
2 Sunk costs really are sunk, so from that
3 perspective, that money is gone and it's not in the
4 costs of -- that's the approach we've taken. The sunk
5 costs are not in any of the scenarios, the Site C
6 scenarios or the alternative scenarios.
7 The next problem are the termination costs.
8 Termination costs are incurred in the terminate
9 scenarios and not in the Site C scenarios. Now, BC
10 Hydro modelled them based on traditional regulatory
11 recovery. In our first study we made the assumption,
12 which BC Hydro criticized, and with good reason, I
13 have to admit, that they would be recovered the same
14 way as Site C, over seventy years. It's true. In a
15 regulatory context, that doesn't really seem to be an
16 option.
17 At the same time, I think it's very
18 important to not create a situation where the means of
19 recovery of these costs determines the outcome. We're
20 trying to determine which of these -- which courses of
21 action really has the lowest long-term costs, and so
22 if you do that with a method that tilts the table
23 based on the recovery method, then you're not going to
24 get the real answer to the economic question.
25 So we looked for a way to handle the
26 termination costs in a way that is equitable between

the two scenarios. And this isn't from a textbook. You know, we offer this approach for your consideration and you may think that it's just a mistake and just ignore it. But the approach that we found to be the most useful is first of all, in the case of termination, to say that these costs are not ratepayer costs. First of all, the project wasn't approved -- the big picture, regulatory compact, the whole idea is that ratepayers are the hook for costs because they have been approved by a regulatory Commission in which ratepayers have a voice. It seems to me that's sort of the basis of the whole regulatory world.

So by exempting this project from the Commission's consideration, we sort of took it out of that world. Essentially the shareholder made a decision to proceed. And furthermore, and going now back to Mr. Swain's presentation, the project risk doesn't disappear. So if you finance the project only on debt, it's because the shareholder is absorbing the risk.

Well, if you terminate the project partway through, that's a pretty major risk. So the idea that that billion dollars is really a shareholder cost rather than a ratepayer cost, I think, is defensible.

Now, then the challenge is, how do you --

1 you don't want to tilt the table the other way either.
2 If you say that the shareholder is going to pick up
3 the termination cost so we can just ignore it, then
4 you've also create an inequity.
5 And so the solution that we found is to
6 essentially regard it as an equity injection from the
7 shareholder, which, in the case of termination, goes
8 to pay for the termination costs. And in the case of
9 continuation/completion, goes to reduce the cost of
10 Site C, the ratepayer cost of Site C.
11 **Proceeding Time 10:46 a.m. T19**
12 So we've essentially taken a $1.1 billion
13 reduction of the cost to complete of Site C, to
14 account for the shareholder contribution. Which
15 dramatically reduces the cost of completing Site C in
16 this present line calculation.
17 I see questions in your faces, and with
18 good reason. I agree this is not a very normal way to
19 go about solving this problem, but frankly all the
20 other ones led to -- it's the only solution that we
21 could find that actually led to a level playing field
22 between -- for an economic analysis between complete
23 and terminate. So, we submit it for your
24 consideration.
25 THE CHAIRPERSON: That's fine.
26 MR. RAPHALS: So quickly on some of the data that's gone

1 into this; in our August submission we had to guess
2 about a lot of things because there were no numbers
3 anywhere. So, for instance, to know the high and low
4 load forecast, we had to take the small and large gaps
5 from the RRA, and subtract things out of them and, you
6 know, did the best we could. Fortunately in response
7 to your IRs, there's a great deal more data available
8 so that we now have load forecasts for high and low
9 forecasts.
10 Also regarding DSM, we had to sort of make
11 up approach. BC Hydro criticized it, and with reason.
12 We said a more aggressive DSM approach could be based
13 on the same principle as the *Clean Energy Act*. Take a
14 date in the future, and assume that -- and require
15 that a certain percentage of load growth be met by
16 DSM. I think the *Clean Energy Act* it's 66 percent.
17 We said 50. But I agree with BC Hydro, that's
18 essentially arbitrary. Fortunately now in the IRs
19 they gave us year-by-year energy gains and total
20 resource costs for the two scenarios -- well, for
21 three scenarios. For the RRA, for the incremental of
22 the IRP scenario against the RRA, and for the
23 incremental of the IRP-plus against IRP. And so,
24 putting those together and doing some math, we came up
25 with incremental energy gains as well as marginal
26 costs, total resource costs, for each of those two

scenarios, which we've used in this modeling.

And for the termination and completion costs we've relied both on the Deloitte report and when your preliminary report had numbers, we got on them as well.

So I won't take your time to go through our report about wind, the way we modeled wind, and solar, and the basis for those costs. But I would mention energy storage because there is some new information here that you won't have seen elsewhere. So first, in our August submission we had presented information -- forecasts based on the Energy Storage Association's documentation, showing current capital, capital costs, and also unit costs and their expected evolution till 2020. So, four years forward.

First of all in gross costs, and then secondly in net costs, taking into account the other system benefits that usually flow from adding storage to a system, which I think they correctly regard as credits that -- if there is distribution benefits out of it.

And then, so that came to about $800 Canadian per kilowatt, installed, by 2020. And then we, just to be conservative, bumped that up to a thousand.

In our current submission, BC Hydro

1 criticized that as saying that they need ten hours of
2 storage. We have some questions about that. It seems
3 to be that they're sort of saying, "Well, pump storage
4 gives us ten hours, so to compare apples to apples, we
5 need ten hours." Whether the system really needs ten
6 hours of storage, I have my doubts, but it would take
7 a much more detailed analysis to -- so we assumed that
8 ten hours is what's needed.
9 So, multiplied by two and a half, and you
10 get $2,500 a kilowatt.
11 At the same time, I know some companies
12 that work in this field, and one told me that while
13 they couldn't make -- put on paper or make a
14 submission, but that the cost today, if somebody
15 wanted to order 100 megawatts, 1,000 megawatt hour
16 system, would be on the order of $5 million. So,
17 $5,000 a kilowatt today. For ten hours.
18 Which is, if you assume the same
19 improvement over the next four years, is substantially
20 better than what the ESA was talking about.
21 **Proceeding Time 10:31 a.m. T20**
22 Secondly, everyone is talking about battery
23 storage, but there's also this world of compressed air
24 storage up there which is moving forwards very
25 rapidly. And a company called Hydro Storer provided
26 us with -- they call it, I think they call it an

1 indicative cost estimate. It's not a proposal but
2 it's still a -- it's on paper, it's real numbers, it's
3 sort of a rough term sheet which is I think the
4 Appendix A to our report, which essentially says that
5 today they could provide a compressed air energy
6 storage system, 100 megawatts, 1,000 megawatt hours
7 for 17.50 U.S. a kilowatt, which is very dramatically
8 lower than the battery, the lithium ion numbers that
9 we can see. So I present that for your consideration.
10 So then we dumped all this stuff into our
11 model and ran it through a lot of different variants.
12 I'm running out of time and I'll try to be quick.
13 This is just the resource additions for one scenario
14 which is middle of the scenarios.
15 Oh, I didn't mention and it's important to
16 say this. I'm sorry, I have to go back. Suspension.
17 In our August submission we treated suspension in the
18 same way as termination. We're using the same tools.
19 Reflecting on BC Hydro's comments in Appendix M, which
20 we responded to separately, we came to the conclusion
21 that there really is a problem with trying to treat
22 suspension with the same methodology. The reason is
23 that suspension of Site C comes in service six or
24 eight years later, and when you have only a 20 year
25 period and you're discounting, that is very material.
26 And so the result is that using this method, Site C

always looks cheaper with suspension than without suspension, which we know isn't the case. It's more expensive than suspension. And the conclusion we came to is simply to drop it out of this analysis, and to suggest that you see it -- to look first at the question of completion versus termination and then, if termination is interesting, then to think of the additional cost of suspension as essentially an insurance policy. If you spend a little bit more you can retain the option to change your mind later, perhaps after the expiry period or whatever. But to think of it in a second step. So we had not further addressed the question of suspension.

So, so this is one of the portfolios that Vester described in the report. This is what it looks like graphically. Capacity and energy. I didn't put this in the report because they take up too much paper, but I can now put these through any one of the portfolios if it's of interest. This is based on the current mid-load forecast, so both energy and capacity there's substantial surpluses in the initial years, and then eventually resource additions are timed to match needs.

Then for each scenario we have a present value breakdown for resource by resource. This is showing the medium scenario, both the complete,

1 complete Site C and terminate, A-1 versus A-2.
2 Leaving out the Canadian entitlement, leaving out cost
3 overruns, and for each item, as you can see, the cost
4 as Rick Hendriks mentioned, we applied a greenhouse
5 gas cost to Site C because it really does have
6 emissions which are very detailed and known, and
7 whether or not there's going to be a bill that's
8 actually paid, again from the principle of an economic
9 analysis the cost is there so it should be accounted
10 for. And in this particular comparison we see that
11 the terminate option is less expensive in Site C by on
12 the order of $200 million.
13 THE CHAIRPERSON: And just to clarify, I'm sorry. You've
14 probably stated this, but the Site C completion costs
15 are the costs from January 1, 2018 to complete,
16 correct?
17 MR. RAPHALS: Minus --
18 THE CHAIRPERSON: The incremental costs from now to --
19 essentially from now to completion.
20 MR. RAPHALS: Yes, minus $1.1 billion for the equity --
21 THE CHAIRPERSON: Exactly, thank you.
22 MR. RAPHALS: Yeah, that's right. And this is, so this
23 is the -- the part of those costs that fits in the 20
24 year analysis window, which -- again I should mention
25 this because in the IRP it was the same 20 year
26 analysis window and the same problem is there, that a

1 lot of the cost and the value of Site C is outside of
2 it, but that didn't seem to be a reason not to pursue
3 that.
4 So this is a summary of the differential
5 costs.
6 **Proceeding Time 10:56 a.m. T21**
7 In the mid and low scenarios there's a benefit for
8 terminate. In the high scenario -- and I have to say,
9 these results are very sensitive to the inputs, so I
10 wouldn't -- there is a lot of sensitivity in these
11 results.
12 And so in this -- for the high scenario the
13 complete comes out less expensive than to terminate.
14 And then we did two sensitivities, one
15 adding 50 percent of the current downstream benefits
16 from the Columbia River Treaty. Fifty percent is
17 based on the notion that, yes, that treaty can be
18 called into question.
19 My understanding of the actual benefits on
20 the American side are such that it's very unlikely
21 that it will be abrogated, but it certainly wouldn't
22 be surprising if the Americans come back and say,
23 "We're giving you too much, we want to give you less,"
24 and so we thought that 50 percent was a reasonable
25 margin. And they're priced at the price that we
26 obtained for the power.

And so adding that benefit, in some scenarios it doesn't really change very much, but when there is a resource need without it, it often allows to defer that need for several years, which in fact leads to a significant reduction in present value cost. So with the Canadian entitlement we see that directionality is always favouring terminate.

And then the other sensitivity he did was based on cost overruns, and here -- I should say regarding Site C cost, since Mr. O'Riley's letter, which it makes the range left within the Deloitte low range to be fairly small, and so we've used the Deloitte mid-range as the Site C cost for the rest of the analysis. And here we explored the -- sorry, let me back up.

In each case we've used the mid-point of the Deloitte range. So the bulk of the analysis is on using the mid-point of Deloitte's medium range, and this is a sensitivity based on using the mid-point of Deloitte's high range, which I think is 10 point something, maybe 11 billion. I'd have to check.

And so not surprisingly that essentially adds an increment of, I think, $489 million to each of the Site C cases and increases the differentials.

Now, some very quick comments on your portfolios, which I have not had very much time to

1 really understand, but I'm starting to -- I think I'm
2 starting to see where they --
3 As I understand it, you are responding to
4 the requirement in the terms of reference to provide a
5 portfolio that provides the same benefits, if there is
6 one, at lower cost. And these three present value
7 costs are the ones from your spreadsheets for the
8 three scenarios. Now, the question is, what do you
9 compare them with?
10 From the original BCUC IR, which I
11 understand was the model for your spreadsheets, it has
12 separate pages for excluding both for sunk costs only,
13 for sunk and terminate.
14 If you exclude the sunk costs, which I
15 think is appropriate because your scenarios going
16 forwards don't have the sunk costs, it's twenty-three
17 forty-six which is more than the alternate portfolio
18 for the mid scenario, but less for the high and the
19 low.
20 The question remains, what about the
21 termination costs. Again, we submit for your
22 consideration the thought, the notion, the
23 relationship of the shareholder and the ratepayer in
24 this picture.
25 And I'd just like to end on the note of
26 again the terms of reference, but focussing on the

1 fact that Section 3A, the overall structure, as I read
2 it, of this paragraph, is that your mandate is to
3 advise on the implications of these three options, and
4 in doing so, you should specifically respond to the
5 following questions. And most of the documentation
6 that I've seen is focussed on those questions. It's
7 on the cost of termination -- in billions; the cost of
8 termination, the costs related to suspension, and now
9 with the spreadsheets, the other portfolios. But in
10 our view the notion of implications is much broader
11 than that, and I'll echo many people that have sat
12 here before, that I'm happy not to be in your shoes.
13 Because I think it's a very very difficult challenge
14 that you have, and we hope to have contributed to it.
15 Thank you.
16 THE CHAIRPERSON: Thank you. That was very good.
17 Thanks. Thank you, sir.
18 Good morning, gentlemen.
19 **SUBMISSIONS BY B.C. SUSTAINABLE ENERGY ASSOCIATION**
20 **(#0303):**
21 MR. ANDREWS: Good morning, Mr. Chairman and members of
22 the Inquiry Panel. My name is Bill Andrews, A-N-D-R-
23 E-W-S. I represent the B.C. Sustainable Energy
24 Association. With me is Tom Hackney, H-A-C-K-N-E-Y.
25 You know from our written submissions that
26 BCSEA has serious reservations about the Site C

1 project. These include concerns like environmental
2 impact, loss of agricultural potential, inhibiting
3 small generation projects in partnership with First
4 Nations and local communities, and unresolved First
5 Nations issues.
6 Notably, BCSEA also has serious
7 reservations about the in-scope financial costs for
8 ratepayers of Site C, including in very brief summary
9 and certainly not complete, the fact that energy
10 efficiency and conservation has great potential to
11 reduce the need for additional supply side generation,
12 and that supply side resources like wind and solar
13 power are rapidly declining in costs.
14 Another reservation is, of course, that
15 once in service, Site C would create an immediate
16 oversupply of electricity that would have to be sold
17 into the market until domestic capacity and energy
18 needs catch up. And then of course the likelihood of
19 a Site C project cost overrun.
20 **Proceeding Time: 11:04 a.m. T22**
21 Now, BCSCA has filed a lengthy written
22 submission, and my purpose today is not to summarize
23 it. My purpose is to respond to specific issues
24 raised in the preliminary report. I've selected five
25 points to address. The first is that BCSCA strongly
26 supports the panel's approach in the preliminary

1 report to set aggressive input assumptions for the
2 portfolio sensitivity analysis. The inquiry is not a
3 planning process. There should be a planning process,
4 and I would echo Mr. Swain's comment earlier this
5 morning that a deep rethink of BC Hydro's load
6 forecast is long overdue. But the inquiry is not the
7 place that that is to be done.
8 The panel does not have enough evidence or
9 enough time to produce or approve a revised load
10 forecast to estimate the actual cost of completion of
11 Site C, or to resolve how to deal with the comparison
12 of the cost of capital between BC Hydro projects and
13 IPP resources or what is the exact cost of new wind or
14 solar resources. Instead, the panel, and in the
15 preliminary report, identified what I would call
16 realistic worst case scenarios, meaning worst case
17 tending to increase the cost of Site C to ratepayers
18 or reduce the cost of an non-Site C portfolio to
19 ratepayers.
20 And so the panel required Hydro to test the
21 sensitivity of these portfolio costs, of assuming and
22 not as findings of fact, but for the purposes of
23 analysis. For example, of 50 percent Site C cost
24 overrun. The low load forecast which extends the
25 period of selling surplus power from Site C into the
26 market. Low market prices which reduce the revenue

1 from selling surplus power in from Site C into the
2 market. New IPP generation projects being financed at
3 the government's reduced Site C financing costs.
4 Reductions in the cost of new wind energy, solar
5 energy, and battery storage, and so on. These are the
6 kinds of aggressive input assumptions that the panel
7 will have to use to get an accurate picture of the net
8 outcome of all the moving pieces.
9 Now, having said all that, the question
10 still arises whether BC Hydro's portfolio model is
11 something that the Commission should have full
12 confidence in, and Mr. Raphals' evidence and
13 presentation just now, strikes me as addressing that
14 question specifically. That is, he has evidence to do
15 with the results of Hydrdo's portfolio analysis that
16 need to be resolved for the Commission to be able to
17 use the results of the portfolio sensitivity analysis
18 provided by Hydro in response to the aggressive input
19 assumptions.
20 My second point concerns future load. Now,
21 the timing -- this is at a very simple level. The
22 timing of future need for energy, for new capacity has
23 a big impact on the costs of the alternative
24 portfolio. And in the Site C portfolio, on how long
25 surplus power will be sold into the market.
26 Now, the Commission in my submission does

not have enough evidence, let alone enough time, to redo and approve a whole new BC Hydro load forecast. The Commission will have to focus on the factors that will push load downward compared to the load forecast, and the factors that will push load upward compared to the current load forecast. The fact is that there are genuine, realistic factors that push down, and that push up. Pushing down, we have the fact that there is ample room for BC Hydro to do much, much more cost effective energy and conservation measures than BC Hydro has been doing, or that it proposes to do.

There is the prospect of behind the meter customer self-generation, which is minor now, but which may well turn into a flood when small scale solar PV installations get to the one or two-year payback period in relation to retail rates.

There are many other factors pushing downward. The greatly diminished likelihood of a large LNG export facility. The history of over forecasting, and so on. And BCSEA has made submissions on these points, and there is many other excellent submissions on the record that BCSEA commends to the panel.

On the other hand, pushing load up beyond whatever is or should be the mid-load forecast as traditionally produced, is low carbon electrification.

1 Climate change is the dominant environmental challenge
2 of our age. Meeting B.C.'s share of Canada's climate
3 action commitments will require drastic policy
4 measures to reduce fossil fuel combustion. And this
5 will have to be achieved not only through aggressive
6 energy efficiency measures, but also -- and the
7 increase in biofuels and clean alternative fuels, but
8 also massive substitution of clean, renewable
9 electricity for fossil fuels.
10 **Proceeding Time 11:11 a.m. T23**
11 And I commend to you Dr. Jaccard's report,
12 filed in this proceeding. He is superbly qualified,
13 and his report takes a quantitative modeling approach
14 to the impact of concerted climate policy initiatives
15 on BC Hydro's electricity load.
16 I also agree with the way that Mr. Raphals
17 expressed it, that decarbonisation -- that low carbon
18 electrification is only one component of
19 decarbonisation, and certainly he referred to clean
20 bio-fuels. I would add to that, energy efficiency.
21 That reducing the use of fossil fuels directly is also
22 a critical component of decarbonisation. But we're
23 focused here on the load -- the electricity load
24 impacts.
25 I want to be very clear that while low
26 carbon electrification will push up BC Hydro's energy

1 load, Site C is not the only way to achieve low carbon
2 electrification. Site C's -- the panel's received
3 abundant evidence that an alternative portfolio
4 without Site C could quite adequately provide the
5 energy, the capacity, and the system resources that
6 B.C. will need to achieve major low carbon
7 electrification and the reduction of fossil fuel
8 usage. The issue for the panel, of course, is the
9 cost. And on that, as Dr. McCullough said yesterday,
10 you need to be driven by the data.
11 My third point concerns the inquiry's terms
12 of reference, and the government's requirement that
13 the alternative portfolio provide "maintenance or
14 reduction of the 2016-17 greenhouse gas emission
15 levels". The panel in the preliminary report made a
16 preliminary finding that this means that the
17 alternative portfolio must not increase the greenhouse
18 gas intensity of B.C.'s GHG emissions, as measured in
19 tonnes of CO_2 equivalent per gigawatt hour generated.
20 BCSEA respectfully disagrees with that interpretation.
21 In the GHG policy world, there is a
22 fundamental and well-understood difference between GHG
23 emission levels and GHG emissions intensity. The
24 intensity interpretation would mean that in the
25 alternative portfolio BC Hydro's GHG emission levels
26 from electricity generation could increase,

1 corresponding to an increase in the amount of energy
2 generated. And at least as the forecast currently
3 stands, an increase in electricity generation can be
4 expected, given that the after-DSM current load
5 forecast, even in the low case, is upward-sloping. So
6 in BCSEA's view, the maintenance or reduction of 2016-
7 17 greenhouse gas emission levels' constraint is
8 intended to deliberately prohibit inclusion of new
9 gas-fired generation in the without-Site-C portfolio.
10 And this constraint is new. And it's
11 significant, because new gas-fired generation played
12 an important role as a potential resource for planning
13 purposes in the 2013 IRP. In particular, new gas-
14 fired generation was a resource option that was used
15 to provide a dispatchable capacity resource in the
16 "without Site C clean plus thermal generation
17 portfolios".
18 THE CHAIRPERSON: Mr. Andrews, when you say that this is
19 -- I can't remember your exact words there. You said
20 that this is new. It's -- is it a new policy, or is
21 this a term of the OIC, or is this a constraint within
22 the OIC only? What are you referring to?
23 MR. ANDREWS: I think it's a constraint within the OIC,
24 and it is, I submit, and it's just simply a submission
25 --
26 THE CHAIRPERSON: Yes.

1 MR. ANDREWS: It's a hint. It's a signal that this
2 government does not want the question of Site C's
3 costs to ratepayers determined on the basis of
4 consideration of new gas-fired generation. And
5 whether that -- I mean, I think that probably is a
6 hint that they don't want to go to new gas-fired
7 generation. But specifically they want the costs
8 analysis to be done without consideration of new gas-
9 fired generation. That's at least my submission.
10 THE CHAIRPERSON: Thank you, sir.
11 MR. ANDREWS: How that should be interpreted.
12 **Proceeding Time 11:15 a.m. T24**
13 Now, my fourth point concerns project costs
14 from the final investment decision, FID, in December
15 '14, between then and the June 30th actuals, June 30th,
16 2017 and December 31, 2017, and I do have some
17 overheads to show the issue here.
18 And this is something that BCSEA raised in
19 its submissions and the panel responded hopefully on
20 October 10th in Exhibit A-20, but I do want to
21 respectfully come back to this issue, because I don't
22 think it's fully resolved, and the issue concerns the
23 -- I think, the number that is to be used between the
24 spend between FID and June 30, 2017 and from FID to
25 December 31st, 2017.
26 These are project costs and they are also

1 characterized as sunk costs. And what I have to say
2 isn't hinging on whether they are properly considered
3 sunk costs or even whether those numbers are accurate,
4 but just what the numbers are that we are talking
5 about.
6 So one of the numbers that fits into this
7 whole discussion is the $500 million in the expected
8 balance of the Site C deferral account as of December
9 31, 2017. That number is not at issue. We assume
10 that that's correct, a half a billion dollars in that
11 account and also that that would be included in the
12 term "total sunk costs".
13 So the starting point is that in the
14 preliminary report the panel said that it had accepted
15 Hydro's figures that as of December 31, 2017 there
16 will be a balance of about 500 million in the
17 regulatory account for expenditures prior to FID, and
18 1.6 billion in project costs since FID, and I'm going
19 to go later to confirm, but to December 31st, 2017 for
20 a total sunk cost of 2.1 billion.
21 Now, this slide -- in the previous quote it
22 didn't actually say. It says "costs since FID". It
23 didn't say costs to December 31st, 2017. This slide
24 completes that phrase, and the underlying portion is
25 saying that that estimate is FID of 1.6 billion is to
26 December 31, 2017. So that's like one approach, like

one concept, one number, is that you've got the 500 in the regulatory account, and you've got the 1.6 between FID and December 31st.

Where I see a disconnect in the evidence is that BC Hydro says on the second page of its August 30th submission, "We have spent 1.8 billion of the budgeted 8.33 billion as of June 30th, and we forecast by 30 December we will have spent 2.1 billion. Now, that's 2.1 billion, as I understand it, apples to apples, with 1.6 billion that was accepted by the panel in the preliminary report.

And the support for that different interpretation is in Appendix D, Table D2, which shows -- the table itself is "Total Project Expenditures Summary", and it's titled "Actual Compared to Plan at Final Investment Decision" and under "Total Project Cost actual to June 30, 2017" it says "1.8 billion". That's the 1.8 to June 30th on which there's 300 million added to come to 2.1 billion at December 31st, 2017.

Proceeding Time 11:20 a.m. T25

And in the preliminary report itself, the Panel references this other alternative set of numbers where it says that BC Hydro states that it spent 1.8 billion to June 30, representing a portion of the budget. And the rest of the sentence there, the

1 paragraph for completion is relevant to my point here.
2 But my point is that in the preliminary report itself,
3 the Panel has accepted 1.8 billion to June 30th. It's
4 silent here on the other 300 million to December 31st,
5 but if you add that in you come to 2.1 billion from
6 FID to December 31st of 2017. And I'm not making an
7 argument that one figure is correct compared to the
8 other, but I'm saying that is a half a billion dollar
9 discrepancy, at least apparently, that certainly
10 deserves reconciliation.
11 My fifth point concerns the costs of a
12 suspension, that scenario. BC Hydro assumed for the
13 purpose of its analysis that it would be possible to
14 restart the Site C project after a seven-year period
15 of suspension. And to be fair to Hydro, that was what
16 they were asked to do. However, BCSEA respectfully
17 submits that the Panel should reject that assumption.
18 A resurrected Site C project seven years after
19 termination would require new regulatory approvals at
20 both the federal and provincial levels. The federal
21 environmental assessment process is already more
22 rigorous than it was at the time of the joint review
23 panel examination, and in my submission it would be
24 illogical for the government to suspend the
25 construction of a Site C project without providing a
26 decision to recommence construction will be made in

1 the context of a comprehensive BC Hydro integrated
2 resource plan independently reviewed by the BCUC.
3 So in conclusion, BCSEA's view is that Site
4 C should not be allowed to proceed without a full
5 integrated resource planning process independently
6 scrutinized by the Utilities Commission in a full
7 public proceeding. BCSEA does not consider the
8 current three month limited scope inquiry to
9 constitute the full planning process that is required.
10 Nevertheless the inquiry is the best and only
11 opportunity for a sober second look at even the one
12 important aspect of the options for the future of Site
13 C, which is the financial implications to ratepayers
14 of completion, suspension or termination.
15 Now, you the inquiry panel, have received
16 thousands of pages of technical data and analysis.
17 You've heard from dozens of people at eleven community
18 sessions and three First Nations sessions. You've
19 received more than 500 separate submissions. And I
20 commend the Commission for achieving a remarkably
21 productive process in the amount of time and with the
22 complexity of the issues. We are now two and a half
23 months into a three month inquiry process, and this is
24 the single most significant energy regulatory
25 proceeding in B.C. since, it's probably safe to say,
26 since the Commission's original hearings on Site C in

1981.

The inquiry findings will contribute to a government decision that will not only profoundly affect the Peace River environment and agricultural potential and communities and First Nations in the area, but it will irrevocably alter B.C.'s electricity system and options for reducing GHG emissions for generations into the future. The stakes are high. And I think it's fair to say that everyone involved in the inquiry feels an intense responsibility. This includes Commission Staff, the BC Hydro staff, interested parties, consultants, presenters at community and First Nations sessions, and obviously you the members of the Inquiry Panel.

The outcome of your findings are expected to be financial conclusions, and generically these can be expressed and determined in terms of numbers and in terms of the exercise of judgment.

Proceeding Time 11:26 a.m. T26

In terms of numbers, you have, as I have submitted earlier, the results of the portfolio analysis sensitivities, with the caveat that BC Hydro's portfolio analysis model has been questioned by Mr. Raphals and the results therefore need to take that into account.

In terms of judgment, I would come back to

1 the Keeyask and Muskrat Falls situations. I'm not
2 contesting at all the conclusions of the preliminary
3 report that what matters more is the situation to do
4 with Site C specifically. But those two experiences
5 in recent Canadian history do provide reason to be
6 very cautious.
7 And with those comments, those are my
8 submissions, and I certainly welcome any questions.
9 THE CHAIRPERSON: Thank you, sir. I do have a question.
10 Just a few moments ago I heard you to say that the
11 project should not be allowed to proceed without a
12 full planning review, looking at the load forecast and
13 costs and so on. Is that correct?
14 MR. ANDREWS: That's correct.
15 THE CHAIRPERSON: So does that mean that you would
16 support the suspension case?
17 MR. ANDREWS: No. That position is fundamentally
18 directed at the government. And that position -- and
19 so actually on the topic of -- my submissions today
20 are focused on the cost of the three options.
21 THE CHAIRPERSON: Right.
22 MR. ANDREWS: And in terms of the analysis of the costs
23 of the suspension option, I think Mr. Raphals had a
24 very valid point that BCSEA, I think, either said in
25 an earlier submission or considered saying but left it
26 out, but still believes, which is that fundamentally

1 the choices between the -- for the government is
2 between continuing Site C or terminating it, and that
3 the most important financial information relevant to
4 that decision will focus on those two outcomes.
5 In the event that the government was to
6 decide to terminate Site C, recognizing that that
7 doesn't necessarily mean the same thing as what the
8 Commission determines the financial consequences would
9 be, in the event that the government decides to
10 terminate Site C, that would be the point at which to
11 examine whether suspension is the appropriate way
12 forward.
13 And one of the things that I think is --
14 and I think Hydro has acknowledged this, is that
15 severely limited on the evidence is exactly what it
16 would look like to terminate this project that's now
17 done a whole bunch of alteration of the terrain and so
18 on in that particular area. And there would have to
19 be an entirely new development, conceptual
20 development, of what the area is going to look like at
21 the end of it, and how much that would cost, and
22 whether it should be designed so as to retain future
23 possibilities. And all of those things, in my
24 submission, are matters for a later date.
25 THE CHAIRPERSON: Yes. I appreciate that, sir. I guess
26 what I'm just wondering, how the project could get a

1 fuller review, a more fulsome review, which you
2 yourself have indicated would take significantly
3 longer than the 12 weeks for this inquiry. So, how
4 that would fit in with the construction schedule that
5 it currently has. It would seem to me that one would
6 have to pause the construction schedule if you were
7 going to engage in any more fulsome review than this
8 -- than will be provided by this inquiry.
9 MR. ANDREWS: That may well be the case. I have no
10 instructions on a position on that.
11 THE CHAIRPERSON: Okay. Thanks.
12 COMMISSIONER KEILTY: I have a question. You've talked
13 about the load forecast, and that there are certain
14 factors that would push it towards -- push it down
15 towards the low, and factors that would push it up.
16 Does BCSEA have a position as to what direction it
17 might land overall?
18 **Proceeding Time 11:30 a.m. T27**
19 MR. ANDREWS: No, that's the outcome of a quantitative
20 analysis and at this point we don’t have the
21 resources, and it's not clear that there's even the
22 evidence to determine what the outcome would be
23 between these downward pressures and upward pressures.
24 You've got evidence by people that have
25 attempted to provide you with that kind of analysis,
26 but we have not tried to reconcile the conflicting

1 evidence in terms of the actual amounts by which the
2 load would be expected to be lower than forecast
3 versus higher than forecast because of low carbon
4 electrification.
5 There's an enormous amount of uncertainty
6 involved in many of those calculations. Not all of
7 them, but many of those calculations.
8 COMMISSIONER KIELTY: Thank you.
9 COMMISSIONER COTE: Just so I'm clear on the financial
10 concerns you raised at the outset about the 500,000
11 that was in the deferral account and the numbers that
12 were quoted. Are you saying that the -- as I
13 understand, the numbers were replaced. There was
14 500,000 in the deferral account, there's 1.3 million
15 in costs since FID and then there was a further 300
16 billion, and of the 300 million to the end, totalling
17 up 2.1 billion, are you questioning the 1.3 billion is
18 a number different than that?
19 MR. ANDREWS: Yes.
20 COMMISSIONER COTE: Is that what -- that's the basis of
21 what you're saying.
22 MR. ANDREWS: Yes, I am, and I'm not saying it's wrong
23 but I'm saying that whereas --
24 COMMISSIONER COTE: It could be interpreted a couple of
25 ways.
26 MR. ANDREWS: -- the evidence that Hydro provided in that

1 location is that the number is not 1.3 but 1.8. And
2 --
3 COMMISSIONER COTE: I hear you. Okay. I just wanted
4 to make sure that that's what you said.
5 MR. ANDREWS: That's what I'm focused on there. The way
6 this came up was that we were trying to calculate the
7 cost to completion from January 1st, 2018, and this is
8 a number that's notably missing from Hydro's
9 presentation and yet, if you treat some costs
10 appropriately, it's really the most important number
11 in terms of the cost of Site C completion. And so we
12 were trying to figure out what the -- what number to
13 subtract from the 8.335 billion, which was the number
14 at the time of the FID budget, what number you should
15 subtract for monies spent to date, and that's where we
16 countered different evidence about what exactly had
17 been spent to date, or the actuals to June 30th and the
18 projected to December 31st.
19 THE CHAIRPERSON: Okay, thank you, sir. Thank you
20 both.
21 Is the Canadian Geothermal Association
22 here? We'll just take a couple -- please come on up,
23 we'll just a couple of minute break and we'll be right
24 back.
25 **(PROCEEDINGS ADJOURNED AT 11:34 A.M.)**
26 **(PROCEEDINGS RESUMED AT 11:37 A.M.)** **T28**

THE CHAIRPERSON: Please go ahead, ma'am, whenever you are ready.

MS. THOMPSON: Thank you. Good morning.

THE CHAIRPERSON: Good morning.

SUBMISSIONS BY CANADIAN GEOTHERMAL ENERGY ASSOCIATION (CanGEA) (#0304):

MS. THOMPSON: And we appreciate the panel's invitation to the Canadian Geothermal Energy Association. My name is Alison Thompson, T-H-O-M-P-S-O-N, and just to clear things up, we are not the ground-source heat pump association, so we are the Geothermal Energy Association.

THE CHAIRPERSON: Understood, yes.

MS. THOMPSON: I appreciate that difference.

Also thank you to the First Nations whose traditional territory that we are on today. And I equally bring you greeting from the Kitselas First Nation out of Terrace. One of their projects that they are developing is called Lakelse Lake and that will be described today in detail.

What I bring to the panel today is a mixed experience. I both have industry development experience, globally as well as in Canada, in Saskatchewan, Alberta, Northwest Territories, and British Columbia, as well as association and government experience most recently as an expert

reviewer of American projects for the U.S. Department of Energy.

I think what brings us today, and where the invitation came from, is that a lot of people are trying to understand if these costs, these levelized costs of electricity for geothermal are replicable in British Columbia, and so I'll start with this as a framing slide. You can see these numbers are not industry numbers, these numbers are from the United States Energy Information Association. They are valid as of August 2016 and they are for projects coming in service in America in 2022. And you'll see, of all the dispatchable and high capacity fuels, geothermal is coming in just under $40 U.S.

Just to make the point that geothermal new builds right now have a capacity factor anywhere from 95 to 98 percent, and we have some developers in Oregon, which is not too far away from here who are actually experiencing 100 percent availability and reliability of their equipment.

I'd also point out that yes, all technologies, you know, wind and solar, run-of-river, storage, and geothermal are reducing in cost, but to still look at those natural gas numbers which I know is not under consideration for B.C., but those numbers were also taken at a very low gas price environment.

So this is a very relevant and recent comparison.

Just to cut to the chase before I get on with the rest of my presentation, I've italicized questions that were directed asked by the panel, so if you see italics at the top, that's something that's been asked by the panel.

So how much has BC Hydro spent in the last 15 years in exploratory drilling for geothermal resources? We believe this number to be zero, and I don't believe BC Hydro said anything different in their submissions.

Before we go on, though, with the rest of the presentation, I do want to address very quickly some things that the panel took interest in this morning from Rick Hendrik's presentation. He was talking about jobs, so I'll quote again the United States Department of Energy and they say that there is 1.7 jobs created for every megawatt installed. So 1100 megawatts of Site C, but they are only at 53 percent capacity, so to normalize that capacity, 660 megawatts of geothermal could be built, which would address the 1100 megawatts of capacity that's provided.

Those amount of jobs --

THE CHAIRPERSON: Excuse me, ma'am, is that a construction job is or that is a sustainable job.

1 MS. THOMPSON: No, thank you. That is a permanent job.
2 I appreciate the clarification. So I'll do some math
3 right now.
4 660 at 98 percent capacity geothermal,
5 would result in 1,122 permanent jobs, and that is
6 about fifteen times more than Site C that was quoted
7 this morning at 74 jobs.
8 And if you think about a 30 year project
9 lifetime, that adds up to about 33,000 person years of
10 jobs, and again those are U.S. DOE numbers.
11 Something else that Rick said, before I
12 move on, is he was using the water heating example and
13 looking for alternative, disruptive and innovative
14 technologies. Obviously geothermal is hot water.
15 It's hot water first and then it can be made into
16 power, but even after it's made into power, what comes
17 out of the power plant is hot water. So for example,
18 we believe that geothermal energy is a fuel that can
19 decarbonize as well.
20 But I want to be very clear about the
21 projects I'm speaking about at length today. Canoe
22 Reach out of the Valemount area and Lakelse Lake again
23 for the Kitselas First Nation out of the Terrace
24 areas. Those project sites had been chosen exactly
25 because those communities intend to use not just
26 geothermal power from the grid, but also the hot water

1 to displace and replace fossil fuels. Valemount, for
2 example, is serviced by trucked-in propane versus
3 having access to a natural gas grid.
4 **Proceeding Time: 11:42 a.m. T29**
5 So, I'm excited to hear that it is four
6 times more expensive to heat water with electricity
7 because we believe that our cost for heating water
8 actually are below natural gas costs, and so it is
9 certainly an opportunity for decarbonization.
10 I'm trying an attempt at humour. I heard
11 Robert McCullough try humour yesterday as well, so I
12 will make a couple cracks right here, but we were
13 pleased yesterday to hear from the Clean Energy B.C.
14 Association talking about the elements of a fuel
15 should have both capacity and flexibility. And in
16 their words they called that a rock star. I thought
17 that's great, because we're rocks, and we believe that
18 we're rock star because we absolutely provide 100
19 percent dispatchability and almost 100 percent
20 capacity.
21 We also heard from Robert McCullough this
22 time, British Columbia's resources. Now, he was
23 talking about wind, their costs are inconsistent with
24 real evidence. I'd like to continue on with that
25 statement, and also apply that to geothermal. So if
26 you'll bear with me for the next couple of slides,

like Robert McCullough was saying that the workforce and the talents in technology and resources they don't stop at the border. Well, neither does geology. And so this is a depiction of all the geothermal power plants in North America, including the trial that was done at Meager Creek in British Columbia.

If we zoom into that we can see that the cluster in the United State. So where good resource meets good policy you'll find the industry flourishing. And again, those projects that touch B.C. are up in Oregon and Idaho. And in our submissions, we have referred repeatedly to the costs. They're actually incurred for those projects.

So, not to say that again that geology doesn't continue on up, to draw your attention, all the round black dots, those are hot springs that exist in British Columbia. And in the northeast of the province, that shading there which looks like a continuous patchwork quilt, those are actually drilled wells by the natural gas industry. So, I think we actually have excellent data in British Columbia given the amount of money that we've spent on exploration. The yellow and the red areas have also had a limited amount of exploration, but as you can see, the footprint is -- when you start looking for geothermal, it is pretty easy to find.

So, this perplexes us when we hear in a submission that the exploration to date has not identified any viable geothermal resources. We refute that and think that there is in fact remarkable potential for geothermal development in our province. And in particular Canoe Reach near Valemount, and Lakelse Lake near Terrace, they have proceeded to the drilling stage, and they are currently undergoing well design right now and have well authorizations at Valemount to continue.

But I think I'll leave this to the question period, I hope you do ask me a question on this. B.C.'s geothermal regulations, which are apart from BC Hydro, so this is from the Ministry of Energy, Mines, and Petroleum Resources and the B.C. Government at large, are not coordinated with BC Hydro's procurement system. And so there has been permit delays that have impeded geothermal developers from responding to the standing offer program, and from open calls in the past, and obviously now in the present. And again, I have examples of that for question period.

So, in their executive summary from a recent submission, BC Hydro was maybe remarking on the Deloitte, you know, from your panel's direction, was assuming that the BC Hydro could build more geothermal resources that currently exist in Iceland. And we

1 found that to be a really perplexing comment to make,
2 because of course we feel that the example they should
3 be using is the United States. And so let me just
4 tell you about a little bit the United States.
5 The United States is the largest producer
6 of geothermal energy in the world. They currently
7 have 3,567 megawatts online. They currently have
8 1,272 megawatts in development. So, they are head and
9 shoulders above everyone else. And when you add in
10 Mexico as well, our continent, even minus British
11 Columbia, is the largest continental contributor to
12 geothermal energy production in the world.
13 Coincidentally, again these are American
14 colleagues who are developing as projects. 1272
15 megawatts is close to 1100 megawatts of Site C.
16 However again, these megawatts are baseload capacity
17 at 95 to 98 percent on time or capacity factor. And
18 you can see that again, in U.S. dollars to build out
19 1272 megawatts in geothermal in the United States
20 costs about $4.5 billion. Which converted into
21 Canadian, is still much less than the Site C project.
22 Now, until more work is done, it is hard to
23 determine how many megawatts our continent part Canada
24 will have. However, I want to relay to you that
25 beyond the 3500 megawatts or the 1200 megawatts there
26 are a lot of megawatts that have already been found in

various levels of exploration.

Proceeding Time 11:47 a.m. T30

And so again, these are not CanGEA numbers. At this time, it's the United States Geological Survey, they refer to themselves as the USGS. It's in our submission that the USGS believes that there are over 30,000 megawatts of geothermal in the United States. And so the extension, we believe that there is considerable amounts of megawatts available to us in B.C. as well, and I show you that map to show where we would start looking for them.

THE CHAIRPERSON: Did that map have a number on it?

MS. THOMPSON: This map here?

THE CHAIRPERSON: Yes.

MS. THOMPSON: It does not have a map number, we assume one of our references. So CanGEA did this mapping exercise a few years ago, and so we believe that there are about 5,000 megawatts in the entire province.

THE CHAIRPERSON: 5,000?

MS. THOMPSON: About 5,000 megawatts entire. Now, that's been done with a very limited budget, and you know, given some more concerted effort, perhaps you could find more. But I think that's plenty for what we're talking about today.

THE CHAIRPERSON: Okay.

MS. THOMPSON: Okay. So do the capital costs as provided

1 by the Canadian Geothermal Association also include
2 exploration costs? Yes, all of our capital cost
3 information are inclusive of exploration costs. And
4 just to give you more of a graphical picture, the
5 first three columns, you're looking at the pre-survey,
6 exploration, and test drilling. Those three
7 categories would be what we would consider exploration
8 costs. So, not just the exploration category but the
9 pre-survey, exploration, and test drilling.
10 And you see that when once you get through
11 those three steps, your project risk falls to 50
12 percent. Or the 50 percent probability that you'll
13 have the megawatts that you're looking for.
14 Numerically, what we've done with this,
15 which is also in the submission, is that on the left-
16 hand side we have taken all of the probable sites that
17 Geoscience BC came up with. And again, Geoscience BC
18 were the ones advising BC Hydro.
19 And what we did is, we applied not the
20 Geoscience BC numbers; we absolutely refute the
21 numbers that they were coming up with for exploration,
22 and I'll discuss why we feel that way later. But if
23 you apply the global, which was the -- going back a
24 slide -- was the ESMAP. Energy Sector Management
25 Assistance Program. This is a global, I guess
26 protocol of how to develop geothermal projects.

If you apply those numbers and that methodology, that exploration methodology, what you come up with is, each of those sites -- and you can see very clearly what is exploration, what is -- FS is feasibility study, that's for the engineers like me get involved. What is true drilling -- so this is drilling out your field, construction, start-up, and operating expenses.

The one change that we've made to the Geoscience BC data is at the very bottom. You'll see that Canoe Reach, out of Valemount, and Lakelse Lake, out of Terrace, those two have higher megawatts recorded compared to what Geoscience BC stated. Now, that's because there has been some work done on those properties, again by those developers, Boyle, Geopower, and Kitslis Geothermal Inc. And they've been able to find even more megawatts. Once that little bit of exploration has been done so far.

And because of that, the installed capital predicted cost has also fallen from -- ESMAP has a high, mean, and low. So to be conservative we've chosen the high. The high is $5.5 million per megawatt, U.S., installed. At this point, those two projects - Lakelse Lake and Canoe Reach - are tracking at about $4.15 million per megawatt installed.

If you take that chart and you just break

it down to answer the question that you were asking, so you were asking if BC Hydro were to accelerate the development of the geothermal industry in B.C. by undertaking exploratory drilling, please estimate the size of the budget that would reasonably be required. And so what we put forward is, again, that the Geoscience BC low-hanging fruit sites, and we have edited that to update and increase the amount of megawatts that have already been found at Canoe Reach and Lakelse. And then we show which the costs will be.

As an industry association, we suggest that the first thing BC Hydro does is take those sites and overlay them on their existing transmission system, and to find out where truly the low-hanging fruit is. Again, the intersection of having projects that may be underneath or very near transmission lines, plus now having geothermal resources found, can give you an idea of where to start to perhaps get up to 200 megawatts.

The panel also asked, "Please explain whether there has been or is expected to be a significant reduction in drilling costs compared to those assumed in the 2015 Geoscience BC report, and how this could affect both the probability of locating economic reserves by 2025 and 2035, and/or the cost of

1 those reserves."
2 So, like all technologies, our industry
3 continues to improve as well, mainly on exploration
4 techniques and drilling costs. You can see our
5 drilling costs are coming down. We believe that the
6 drilling costs reported in the Geoscience BC report
7 are outdated and extremely high. And we also -- with
8 reduced drilling costs increases the probability of
9 locating economic reserves. But this doesn't tell the
10 whole story.
11 **Proceeding Time 11:53 a.m. T31**
12 This second slide and the last slide on this topic is
13 really where I want to focus on, is that the
14 methodology, the exploration methodology chosen by
15 Geoscience B.C. assumed — and I'm sorry, I don't have
16 a graphic, so I'll have to physically show you —
17 assumed that large production wells would be drilled
18 for confirmation. That is simply not modern
19 technology. Modern technology allows what is call a
20 slim well to be drilled to a depth of 2.5 kilometres.
21 Those occur at a very low cost compared to drilling
22 large diameter wells for confirmation.
23 And so part of the Geoscience BC report,
24 we're using outdated and very high drilling numbers,
25 but they are also assuming that these large diameter
26 wells would need to be drilled, and that is not how

1 modern developers, including the ESMAP standard
2 develops projects.
3 COMMISSIONER COTE: What is the difference in cost
4 between the two methodologies?
5 MS. THOMPSON: Millions of dollars. So for example, a
6 2.5 kilometre well that's a slim well could be
7 anywhere from 2 to 3, 4 million dollars and Geoscience
8 BC was estimating at the high end, $12 million to
9 drill those big wells.
10 COMMISSIONER COTE: So two and a half times. Or no--
11 MS. THOMPSON: Yeah, five times, or at times maybe even
12 10 million more, and then of course multiply by how
13 many wells they assumed it would take to find the
14 resources.
15 THE CHAIRPERSON: Presumably, there's some exploration
16 done before the wells are drilled, though.
17 MS. THOMPSON: Absolutely. So back to this chart here.
18 So there's pre-survey, which is surface survey, and
19 then exploration, which is maybe, you know, ground
20 penetrating radar and (inaudible). All these
21 different techniques, and then you have test drilling
22 which are core holes, much like is done in the mining
23 industry and then as well as these slim wells. But at
24 this stage, there's no need to be drilling large wells
25 for confirmation. Thank you.
26 Okay. So please estimate the probability

that by 2025 and by 2035 BC Hydro would reasonably be able to locate 200 megawatts of cost effective geothermal energy if BC Hydro were to develop the resource in partnership with industry.

We believe the probability is very high if you consider the Canoe Reach and Lakelse Lake which are CanGEA member projects are included industry partnership. I'd like to back that up.

I'd like to back that up with these two properties have had two international independent reviews, and the most recent one that looked at the majority of the data, the recent data that's been from the pre-survey and from the exploration stages of development. I'll talk about that there are now 58 megawatts out of P90, and P90 simply means that 90 percent probability level compared to what has been found in other parts of the world with the same type of results found today.

So at the P90 level, 58 megawatts have been found at Canoe Reach and at a cost of Canadian $300 million. If you take that on a capital intensity basis, that's 5.1 Canadian million dollars per megawatt, and if you take that through a 30-year life, the capital only contribution to the energy cost would be about $21 a megawatt hour. So to get the true energy cost you need to add the operating cost, and

the operating cost should include the financing charges, as well as the profit, but it should also include the ancillary benefits, the geothermal that very high capacity may bring to the grid. And so we look forward to having a credit added to that energy cost, because of course, we'll be stabilizing the grid.

At Terrace, at the P90, if you do the similar math, you're looking at $120 million — again this is total cost, this isn't just exploration cost — for 23 megawatts that's been found and verified by a third party. And that's similar of 5.2 million of megawatts, and the capital cost contribution again is about $21 a megawatt hour.

We're running our models on 30 year life. BC Hydro has chosen to run their models on 20-year lives. We believe that to be too conservative. We have power plants now in Iceland and in New Zealand who are well past 50 years of operation. There's a field in Italy that's well past 100 years in operation. We are not a new technology. We've just suffered from there's lots of other fuels to choose from and so we haven't penetrated the Canadian market as of yet.

That's at the P90 level. I want to keep answering your question. Again, these are third-party

1 verified reports. I brought them with me if the panel
2 would like to have a look at them. CanGEA members,
3 coincidentally, have already located approximately 200
4 megawatts of geothermal capacity. At the Canoe Reach
5 site the P50, so probability 50 with the work done
6 today is already at 139 megawatts, and Lakelse Lake,
7 their P50 is at 54 megawatts. Added together is 193
8 megawatts.
9 Asking me how long it would take to
10 reasonably locate, we believe it would be reasonable
11 that BC Hydro can located 200 megawatts in one year,
12 because of the work that's already been done by
13 private developers on these sites.
14 **Proceeding Time 11:57 a.m. T32**
15 And with the other properties, of course,
16 that pre-survey and that exploration would need to be
17 done as well. We think that if other sites were
18 needed there would be even more megawatts at play.
19 But about 200 megawatts have already been found.
20 So the other thing we did with the GSI's
21 B.C. report is they listed out on the left-hand side
22 of the original GSI's B.C. numbers, if you add them
23 all up it's about -- at their P90, their probability
24 90 without going through any real field work, they
25 thought there'd be about 270 megawatts available in
26 the province. However, what we've done is because the

company and CanGEA's membership have actually done that pre-exploration, that pre-survey exploration work, we've merely taken the areas that we found and upsized the same rating to the other properties. And so to try to make that point a little bit better, GSI's B.C. thought there were these many megawatts given their limited exploration. Once on the ground exploration happens, you can see that Lakelse Lake has a little bit of money spent on it, it's gone off to 23 megawatts. And Canoe Reach has had more money spent on it for that pre-survey exploration, has gone from 15 megawatts to 58. And so if you take that type of area scaling and apply it to the other properties, you'll see that if you have a portfolio from a 270 level you can possibly go up to 585 and even beyond. Again CanGEA thinks that with exploration there's about 5,000 megawatts in the province. But these would be the low hanging fruit properties.

So in a submission very recently on October 11th, BC Hydro talks about expecting material amounts of geothermal electricity generation in B.C. by 2026 unrealistic. To address the Commission's request, though, that they did try to model 200 megawatts. So we want to take aim at the phrase being unrealistic by 2026. The applications from Lakelse and Canoe Reach that went into the standing offer program have online

1 dates of 2020.
2 But further, as opposed to always relying
3 upon American numbers, because I can present this
4 slide of how quickly the Americans are developing. I
5 thought instead I would choose Turkey. I think we can
6 all agree that Turkey is experiencing geopolitical
7 struggles with war happening in and around their
8 country. And as well, I don't believe anyone on the
9 international market would stand up and say that
10 Turkey is a centre of exploits for drilling. Western
11 Canada on the other hand could credibly say and claim
12 that they are a centre of excellence for drilling and
13 drilling technology.
14 So even given these, I would call them
15 adverse conditions in Turkey and what they have to
16 work with, even they have been able to, again with
17 intentional policy and the megawatt resources found
18 through examples I've already showed that we've
19 already done in British Columbia, they were able to
20 bring on 1,000 megawatts in ten years.
21 And so when we're asking about can we bring
22 on -- first of all can we find 200 megawatts. I think
23 I've proven that we've already found that. And how
24 quickly can you bring them on? Absolutely it's
25 realistic to expect that by 2025, 2035, or in our case
26 with Lakelse and Canoe Reach, that by 2020 these

1 megawatts are available.
2 Our plan for that is again, addressing your
3 comment of 200 megawatts, is that we believe that from
4 possibly only two or three existing identified
5 locations, it's absolutely reasonable to expect that
6 40 megawatts per year could come online starting in
7 2020, and by 2024 you'd have your 200 megawatts
8 online.
9 Now, geothermal projects that we believe
10 should move ahead regardless of the Panel's Site C
11 decision due to the immediate benefits. We talked
12 about natural gas displacement and decarbonization
13 using hot water. We started the presentation talking
14 about that. But even more, I think at home, akin to
15 BC Hydro's situation is that some of these sites are
16 sitting in areas of transmission that actually need
17 baseload projects. Again baseload defined as 95 to 98
18 percent capacity factor.
19 At the Canoe Reach project in Valemount
20 they literally at the end of a 300 kilometre line,
21 they have many brownouts and it stifles economic
22 development given the capacity available on the line
23 for new businesses. And at the Lakelse Lake Terrace
24 location it's at the junction of several gridlines.
25 And adding baseload capacity versus moving tower there
26 would shore up those lines.

1 Just to numerically show you what I mean by
2 shoring up those lines, the Valemount line itself is
3 the province's singular least reliable line, and
4 Terrace is not far behind at number 9.
5 So there's been so many benefits of
6 building out baseload versus just having megawatts on
7 the system. It's where you have megawatts on the
8 system that also matters, that hasn't yet been a focus
9 of the Panel's decision today.
10 BC Hydro was responding to a comment that
11 Deloitte made. Deloitte had been using Geoscience BC
12 reports, and Geoscience BC did not comment on the road
13 costs for certain projects. And we believe that BC
14 Hydro rightfully said, hey, your costs don't include
15 certain aspects of development such as roads.
16 **Proceeding Time 12:02 p.m. T33**
17 Geoscience BC did, though, include
18 transmission costs. However, CanGEA believes that
19 they are incorrect, and incorrect by a great deal. So
20 for example for the Canoe Reach site, they said it
21 would be $16 million worth of transmission. I'm
22 showing you actual photographs of the power plant that
23 is expected to be built at Canoe Reach, is literally
24 right beside a road and underneath a -- sorry, a
25 distribution line.
26 Geoscience BC suggested that there would be

about $12 million of transmission costs for the Lakelse property. Again, that's the property that's at the junction of many different distribution and transmission lines, and as you can see on the other photographs to the right I'm looking at, they too fit underneath again distribution and transmission lines, and have road access. And so we believe the Geoscience BC report is flawed in many ways, but in particular BC Hydro's concerns. This is one of them that in fact costs are less than what they're saying.

I'm winding up here. Please provide an update of the $81 per megawatt hour in 2018 dollars, estimated costs of the two geothermal projects identified by BC Hydro. And so these are the ones that are around the Pemberton area. And one of them is Meager Creek, where the trial went forward about 20 years ago.

That particular property has had a landslide happen to it, so we believe that property is out of play right now as far as access to it. And the other property at Pemberton, which is locally known as the Pebble Creek property, they're not a CanGEA member. We know that they have applied for a standing offer program, and we don't know much more about that project.

However, we do know that there are the

1 Lakelse Lake and Canoe Reach member projects that have
2 also advanced to the drilling stage, and this is a
3 phrase that you haven't heard yet. But we want to
4 call upon both BC Hydro and the other Crown
5 corporation in the province, which is the Columbia
6 Power Corporation, to work with CanGEA to study better
7 the Pebble Creek, but certainly the Canoe Reach and
8 the Lakelse Lake, and to derive an updated levelized
9 cost of electricity.
10 So I've presented today the capital
11 component. I think that we can work together to
12 figure out what the operating cost component is, and
13 also that the credit to the transmission system, given
14 that we're baseload power.
15 Columbia Power Corp. is being cited here.
16 It's because up and down the kind of left-hand side of
17 the east side of British Columbia -- sorry, right-hand
18 side of British Columbia, is the Rocky Mountain
19 Trench. That is their natural operating area and
20 there's a whole lot of geothermal available in their
21 area. And so it may not make perfect sense for BC
22 Hydro to be that co-developer. In fact, it may be the
23 other Crown corporation.
24 And again, talking to something I spoke
25 about before, there may be a basket of low-hanging
26 fruit projects. That was based, we think, purely on

1 geothermal potential. But when you overlay the
2 transmission system, some projects rise to the top.
3 And so we encourage that type of selection process,
4 which is how the Canoe Reach and Lakelse projects were
5 chosen in the first place. They both have road access
6 and transmission access, so as I mentioned they also
7 have local communities willing to take the hot water
8 and use it as a displacement fuel to what they're
9 currently using for fossil fuel, be that propane or
10 natural gas.
11 So for that capital cost you keep seeing me
12 talk about today, you actually get a two-for-one.
13 There is no more capital you need to spend. Actually
14 get another free hot water fuel that can be used for
15 further decarbonisation, and actually taking some load
16 off BC Hydro providing any of that hot water heating
17 through electricity. It can be done as a free by-
18 product from a geothermal project.
19 This is my last slide. It was something
20 the panel suggested, working together. So CanGEA
21 members absolutely look forward to an industry and BC
22 Hydro and/or Columbia Power Corp. partnership. And
23 with that, I'm interested in your questions.
24 Thank you for your time.
25 THE CHAIRPERSON: Thank you. I have a couple of
26 questions. Generally speaking, the projects that

you've shown us in your lists, are they on Crown land, or on private land, or is it a mixture?

MS. THOMPSON: Excellent question. And here is a good list. So for example, Canoe Reach currently is 100 percent on Crown land. And Lakelse Lake was on Crown land as well.

THE CHAIRPERSON: Okay.

MS. THOMPSON: The Kitselas First Nation are co-developing, and have traditional claims, so that's they're our co-developer.

THE CHAIRPERSON: Okay. So, is there -- I guess that's managed through the Ministry of Energy and Mines, then, permitting for drilling on Crown land?

MS. THOMPSON: That's right. Thank you.

THE CHAIRPERSON: And if it was on private land, you would have to negotiate with the land owner, would you?

MS. THOMPSON: Sure. This is -- thank you for asking that question. So, Canoe Reach for example is undergoing a permit expansion at the moment.

THE CHAIRPERSON: Yes.

MS. THOMPSON: And we've had 98 percent of private land support. The 2 percent represents one person who didn't actually go against the project, they just didn't say anything in favour of the project. And so all of that 98 percent, which is basically 100 percent

1 support for the project from private land owners was
2 provided to the Ministry of Energy through a referral
3 process, and we are anxiously awaiting to have that
4 permit expansion granted.
5 **Proceeding Time 12:08 p.m. T34**
6 THE CHAIRPERSON: So who owns underground geothermal
7 resources? Is there -- where I'm going is, is there a
8 royalty issue if it was on private property? So a
9 potential royalty issue.
10 MS. THOMPSON: So much like oil and gas for mining, the
11 reservoir itself is owned by the province. And so
12 it's called the *Geothermal Resources Act*, and that *Act*
13 is administered by the Ministry of Energy, Mines, and
14 Petroleum Resources.
15 THE CHAIRPERSON: Okay.
16 MS. THOMPSON: And so there is a tenure process, where
17 it's a competitive bid process; again, much like oil
18 and gas.
19 THE CHAIRPERSON: Right.
20 MS. THOMPSON: Where a developer gets the permit. And
21 all the water that's above 80 degrees Celsius, which
22 is considered the temperature that's a minimum
23 temperature that you need to produce power, is owned
24 by the Crown. And so any royalties would go back to
25 the Crown.
26 THE CHAIRPERSON: And can you use horizontal drilling

1 techniques if you've got it on private land?
2 MS. THOMPSON: Absolutely. And I think that's really
3 important. I'm not speaking about LNG today. A lot
4 of people are talking about how LNG prices have come
5 down, obviously, through horizontal drilling. That's
6 exactly what would geothermal would be able to use as
7 well, so slant drilling and horizontal drilling.
8 That's why the Geoscience BC numbers are not just so
9 inflated with all the cost factors we would have
10 leveled out in our submissions, but they have failed
11 to even contemplate modern technologies and modern
12 approaches to exploration.
13 THE CHAIRPERSON: Okay. And my last question. Is there
14 any notion of a life of a geothermal -- what do you
15 call them, "wells" or "basins" or whatever they're
16 called?
17 MS. THOMPSON: Absolutely. Like a reservoir?
18 THE CHAIRPERSON: Yes. A reservoir.
19 MS. THOMPSON: Okay. So there is probably three parts
20 you want to talk about. So there is the physical
21 power plant. And the ones in New Zealand and the
22 United States literally are still working, although
23 with modern technology those operators have bolted on
24 other pieces that are more efficient, for example.
25 Then you want to discuss the wells. So the
26 wells themselves may -- much like oil and gas, may

1 need well-workovers. But if designed correctly, they
2 should last the life of the plant.
3 However, you may want to drill more wells
4 again with the different technology, or different
5 learnings that you have.
6 And then you have the reservoir itself.
7 And absolutely, like every industry, be it batteries,
8 or wind, or sold, or geothermal, there have been some
9 bad operators who have misused their reservoirs.
10 However, to be renewable, you need to produce and
11 inject. There are always at least two wells in the
12 geothermal system.
13 If you're producing and injecting, what
14 you're doing is you're keeping the reservoir water
15 whole. You're also reducing your operating costs
16 because you're keeping the pressure of the reservoir
17 whole. So again, these are modern ways to develop a
18 reservoir.
19 THE CHAIRPERSON: Okay. Thank you very much.
20 MS. THOMPSON: Thank you.
21 THE CHAIRPERSON: Thank you very much.
22 So we'll take a break for lunch now. I
23 realize it will shorten our lunch a little bit, but I
24 think we should get back at 1:00 because we've got a
25 few more submissions this afternoon. Thank you.
26 **(PROCEEDINGS ADJOURNED AT 12:10 P.M.)**

1 **(PROCEEDINGS RESUMED AT 1:02 P.M.) T35**
2 THE CHAIRPERSON: Thank you. I hope you've all helped
3 yourselves to some cookies, courtesy of the panel, at
4 the back. Courtesy of one of our panel members, at
5 least.
6 This afternoon we're going to be hearing
7 from David Vardy, and then the Commercial Energy
8 Consumers, followed by BC Hydro. However, just to let
9 you know, we did ask Mr. McCullough to come back. He
10 was asked a question yesterday about his response to
11 Appendix C in the BC Hydro's final submission, and
12 he's agreed to come back and provide an answer. And
13 we're going to slot him in just before BC Hydro. Is
14 that right, Mr. McCullough?
15 MR. McCULLOUGH: Yes, thank you very much.
16 THE CHAIRPERSON: Okay, I just wanted to let you all know
17 that.
18 So, on that note, Mr. Vardy, please
19 continue.
20 **SUBMISSIONS BY MR. VARDY (#0305):**
21 MR. VARDY: Thank you very much. My name is David Vardy,
22 that's V-A-R-D-Y. And I'm glad to be here today.
23 Having been a commissioner myself, I share your pain,
24 and understand the challenges that you face in this
25 daunting task.
26 I am here as a private citizen, speaking on

1 behalf of myself. I'm a former public servant, an
2 economist, and worked in the government of
3 Newfoundland, prior to which I was a faculty member in
4 the Economics Department of Queens University and
5 worked in the federal government. I am trained as an
6 economist.
7 Within my home province I served as
8 Secretary to the Cabinet and as well as Chair of the
9 Public Utilities Board. And as I said, I'm an
10 economist. But I think what you need for this task
11 more is a military historian, because I think that the
12 issue here is, how does one beat a strategic retreat?
13 And Mr. McCullough, yesterday, used some
14 military analogies, and it made me think back to the
15 battles of the Somme during the First World War. And
16 there was one in particular, at a place called
17 Beaumont Hamel, on July the 1st, where 800
18 Newfoundlanders fought and few of them came back. And
19 I hope that Muskrat Falls does not provide the same
20 kind of battleground, but it's certainly looking that
21 way.
22 In both Newfoundland and Labrador and B.C.,
23 hydroelectric power reigns supreme. 90 percent of
24 your power is hydroelectric. On the island of
25 Newfoundland, 64 percent is hydroelectric, but for the
26 province as a whole, including Churchill Falls, it's

over 90 percent of the power, including the giant plant at Muskrat -- at Churchill Falls, which represents 5,428 megawatts.

Most of the energy produced at Churchill Falls is sold to Quebec. So island capacity is in the order of 2,000 megawatts compared with 10,000 megawatts in British Columbia.

Unlike BC Hydro, Nalcor Energy is not regulated. Its wholly-owned subsidiary, Newfoundland/Labrador Hydro, is regulated by the Public Utilities Board.

Now, I'm going to be talking about Muskrat Falls and how the lessons we have learned may bear upon your decision here, and I wanted to begin by giving you some sense of order of magnitude in the relationship between these projects. Muskrat Falls will add 824 megawatts, and 4,900 gigawatt hours, to our provincial system. Now, while Muskrat Falls is similar in size to Site C, its impact on the province is much greater than the impact of Site C on B.C.

Site C represents 3.5 percent of your province's GDP; 21 percent of your net debt. Muskrat Falls represents 42 percent compared to 3.5 percent of GDP, 85 percent of our net provincial debt. So this is quite a massive undertaking and that's why I invoked the analogy of the battle of the Somme.

1 Muskrat Falls is a complex project which
2 has a number of different components. While its
3 capacity and power is slightly less than Site C, it
4 does include transmission lines as well. It includes
5 1400 kilometres of transmission lines. It includes a
6 sub-sea crossing through the Strait of Belisle, which
7 is an iceberg-infested strait. It also includes a
8 crossing, the Cabot Strait, to Nova Scotia. And the
9 link there is known as the Maritime Link, but most of
10 the numbers I'm going to be relating to you relate to
11 the Newfoundland and Labrador component, and don't
12 include the Nova Scotian component. So, in terms of
13 the cost numbers that I'm going to be citing, they
14 relate not to the Nova Scotian costs but mostly to
15 ours.
16 **Proceeding Time 1:08 p.m. T36**
17 I have provided the Commission with a full
18 submission in August and I provided a few days ago a
19 shorter abbreviated version. The original version
20 includes 14 recommendations, the abbreviated version
21 contains three. And I'm hoping you have a copy of
22 that in front of you because I'm going to be referring
23 to some of the charts and tables that are in that
24 document.
25 The impact on power rates will be enormous.
26 Rates are currently projected to double as early as

2021. They'll go from 12 cents per kilowatt hour to 22.9 cents. 2021 is the first year of full power. My understanding is that Site C will not trigger a large rate increase when it comes on stream in November of 2024, but that there may be increases prior to that, and one of my difficulties was in getting a clear reading as to what the rate impact was going to be with Site C. And I appreciate a lot of the comments that were made this morning with regard to the issue of rates and how perhaps more attention should have been given to the rates, particularly in light of the fact that rates are a driver of consumption, and I'll come back to that.

But I'm going to focus on essentially four issues here. One is planning timeframe and intergenerational equity, number one; number two, under estimation of costs; number three, over estimation of consumer demand; and fourthly, the business case for Muskrat Falls.

The planning timeframe which was chosen by Nalcor was fifty years. It was actually fifty years plus construction period which originally was going to be seven years. It was a 57-year planning horizon and the project was advanced as a long-term project to deal with a perceived energy problem.

If we did have an impending energy

shortage, we expected it would have been relieved by 2041 because we have a 65-year contract with Quebec which provides access to Quebec to 5428 megawatts, and that power will be available to us when that contract concludes in 2041.

We do currently have 525 megawatts of access to that power from Churchill Falls, but we will have access to all of it after 2041. So my contention has always been that the planning horizon we should have chosen was actually the period up to 2041. When I look at the Site C project, I see a 70-year planning horizon which causes a lot of problems for me in terms of any difficulty, the difficulty of anticipating what is going to be the cost and market situation 70 years down the road. And I found the comment yesterday about a 70-year contract for a cell phone to be a very informative comment, because it really illustrates how rapidly technology is changing and how difficult it is to make these kinds of decisions over a 70 or 50-year period.

This project, that is to say Muskrat Falls, needed a long payback period because of the enormous cost, and that's why the 50-year time frame was chosen. And it was chosen primarily to shift costs into the future through various devices, and when I look at what's happening here in B.C. and in

1 Newfoundland, I see various different devices being
2 used to shift costs into the future. Deferral of
3 expenses, as I understand it here, being a major
4 instrument. In Newfoundland we're using back-end
5 loading instead of using cost of service, which is the
6 traditional way of costing public utility
7 infrastructure, cost of services supplied to
8 transmission but not to generation. So the generation
9 costs, capital cost are essentially being shifted into
10 the future, 30, 40, 50 years into the future in order
11 to soften the blow at the early years.
12 So the result of that, of course, is that
13 intergenerational transfer, or it has the potential
14 for an intergenerational transfer. So they chose to
15 backend load the cost and to defer payment into the
16 future but they did adopt normal cost of service
17 accounting for transmission costs.
18 **Proceeding Time 1:13 p.m. T37**
19 Which means that the capital cost expense
20 for generation assets in the last 20 years, that is to
21 say from 2050 to 2070, are enormous. With rapid
22 technological change, large power plants are easily
23 rendered obsolete. In 2069 Muskrat Falls is likely to
24 be superseded by more efficient energy sources, but
25 the result of the levelization of cost is that
26 ratepayers in 2069 will be paying in real terms

1 exactly what they will be paying when the project
2 comes on screen. So the cost will be level. In real
3 terms it will be level, and which is not the way we
4 operate with hydro projects because we tend to pay off
5 projects within -- in short periods of time. And this
6 has the potential, as I said, for it shifting the cost
7 to future generations.
8 Will the same be true -- question, will the
9 same be true for Site C when the planning horizon is
10 70 years? And is it fair to future generations to
11 impose those costs upon them?
12 Now, I wanted to deal with the question of
13 cost estimates, and what I've done is I've taken a
14 table which was reproduced in a report that's online.
15 It's in the submission I provided to the Commission
16 and it's taken from what's called the Oversight
17 Committee. It's a government committee. And this was
18 a report that was placed online within the last 30
19 days and it includes data up to the end of June. It's
20 a report up to the end of June. What this shows is
21 that there were seven -- there have been seven cost
22 increments, seven cost increments.
23 Now, I go back to 2010, and for me the base
24 is 2010. And so my measurement of cost increases goes
25 back to then, and the reason for that is because in
26 2010 the project was announced, it wasn't sanctioned

1 but it was announced, and it was the data from 2010
2 which are based on cost and class 4 estimates. Those
3 are the data which were used by the Public Utilities
4 Board in a reference that was made to them in 2011.
5 So those were the data that were used, and they --
6 basically the cost estimate was $6.2 million when
7 announced by Premier Danny Williams in November 2010.
8 And it has escalated, the cost has escalated,
9 including allowance for funds used during
10 construction, from $6.2 billion to 12.72 billion in
11 June of 2017.
12 So these data come from the Oversight
13 Committee and they show this increase which represents
14 105 percent. The largest increase announce was --
15 announced about a year ago when there was a change.
16 The previous president stepped down or resigned, and a
17 new president, Stan Marshall, took over. And within
18 three months of his taking over, and this was June of
19 2016, he announced that there would be slippage in the
20 schedule by two years. And the date for full power
21 was the second quarter of 2018. The date now for full
22 power is 2020. It's September of 2020. But when it
23 was released a year ago or in June of 2017, full power
24 would be in the second quarter of 2020. It's now
25 slipped within the last month to September of 2020.
26 So a lot of slippage there, major slippage.

1 So if you look at the -- what I've shown is
2 a step by step, and so the -- in December when the
3 project was sanctioned it was then sanctioned based on
4 class 3. There was class 3 estimate and that class 3
5 estimate was $7.4 billion, up from 6.2 it went up.
6 And then a year later, at the date of financial close,
7 it went from 7.4 billion to 7.73. And then less than
8 a year later, in June, it went to $8.29 billion. And
9 then eight months after that -- no, sorry, it was 15
10 months after that it went to 8.95 billion. And then
11 nine months after that to 11.43 billion, which was the
12 largest increase. And then there have been two other
13 subsequent increases, one in December of last year and
14 then another one in June of this year, a small
15 increase.
16 **Proceeding Time 1:18 p.m. T38**
17 The increase that was announced a year ago
18 in June of 2016 was based on the slippage, primarily
19 based on the slippage, in a major contract that was
20 awarded to a company, an Italian company, which Marc
21 Eliesen mentioned yesterday, Astaldi. And Astaldi has
22 never operated in Canada. It never operated in a
23 Canadian climate before, and they were chosen because
24 they were the lowest bidder. And unfortunately that
25 hasn't worked out. So, the delay in the schedule,
26 that was caused by their inexperience, there was a

1 two-year delay in the schedule. And that resulted in
2 financing costs, AFUDC, increasing from $1.3 billon to
3 $2.3 billion. So that's how we got up to $12.7
4 billion.
5 And the delay was the result of problems by
6 this major contractor, who was awarded to build the
7 power house and associated civil works. And in
8 December of 2016, Stan Marshall, the new CEO,
9 announced that the contract with Astaldi had been
10 renegotiated, raising the contract from $1.1 billion
11 to $1.83 billion, an increase of 66 percent.
12 There also was, in June of 2016, an
13 increase in the operating costs. Their update, June
14 of 2017, showed that the earlier cost estimate was
15 increased from $39 million to $109 million. And that
16 would increase again in 2021.
17 So, one of the things you people need to
18 look at very carefully is the operating and
19 maintenance cost. In the case of Newfoundland, of
20 course, the project -- this is a very large project,
21 and it's the first DC line we've ever had. So, 1150
22 kilometres of the 1,400 kilometres represents DC
23 lines, or new DC lines, and those impose the need for
24 additional operation and maintenance costs.
25 Now, there are many complex reasons for the
26 cost escalation. A former Nalcor employee stated,

about eight months ago, that cost estimates were falsified in order to secure project sanction. This gentleman was an anonymous person. His name is not disclosed, but media, CBC, felt confident that this was -- this could be reported, because they found corroboration of this particular witness from another person. And the original person to make this statement said, "I could not put up with falsifying information any more. To begin with, the original cost of 6.2 billion on which the project was approved was a complete fabrication. The estimate was deliberately kept low, below 7 billion, so as to appear favourable relative to the cost of thermal power generation," which was the alternative considered at the time.

"The likely costs were known about three years ago, but Nalcor management kept it a secret, steadfastly denying that there were major schedule delays and cost overruns, until it was no longer possible to hide the true status with the election of a new provincial government."

So that's one of the things that happened when the -- after the new government came in power and a new CEO was appointed, this information was disclosed. There was a big update in cost. And this has led to a call for a forensic audit and a public

1 inquiry.
2 The provincial government has announced
3 there will be such an inquiry, and they will be
4 appointing an inquiry into the escalating costs to
5 determine the reasons. Now, to a large extent, these
6 escalating costs go back to the inexperience of
7 Nalcor, because Nalcor is a corporation which includes
8 Newfoundland and Labrador Hydro as a subsidiary, a
9 wholly-owned subsidiary. And Newfoundland and
10 Labrador Hydro has had some experience in projects,
11 but nothing of this magnitude.
12 So, one of the conclusions, I think, is
13 that Nalcor really should not have been the project
14 lead on this project. They should have selected a
15 project manager. You look at the Upper Churchill
16 project, it was completed in 1974 ahead of schedule.
17 The project manager was Canadian Bechtel, who brought
18 the project in on budget ahead of schedule. And
19 Nalcor ought to have similarly engaged an experienced
20 project management firm, rather than taking on the
21 lead project management role itself.
22 So, that's the cost. Now, while costs were
23 vastly underestimated, the converse was true for the
24 demand estimates. In the 20-year period prior to
25 2010, provincial energy demand had risen and fallen
26 back again, largely because we experienced the

1 phenomenon similar to you, namely the collapse of the
2 pulp and paper industry. We lost two paper mills, and
3 we experienced the downsizing of a third.
4 **Proceeding Time 1:23 a.m. T39**
5 And the cost of industrial load was offset
6 by continuation of a trend toward increasing
7 penetration of electric space heating in the
8 residential and commercial sectors. At the beginning
9 of this 20-year period, our consumption was about
10 7,000 gigawatt hours, and at the end it was about the
11 same.
12 Back in 2012 Nalcor was forecasting that
13 energy consumption would reach almost 10,000 gigawatt
14 hours by 2030. So that's going from 7,000 to 10,000
15 by 2030. In June of 2017, Nalcor provided an update
16 which use that energy use fell initially after
17 interconnection and has risen very slowly, and they
18 are anticipating that it will only reach 7,200
19 gigawatt hours by 2030, so the chart -- you'll see two
20 charts there in my presentation. One is a comparative
21 energy forecast and those are Nalcor projections and
22 they show that in -- one of the projections was from
23 2010, another from 2012, but both of them show that by
24 the end of 2030 the level of energy consumed would
25 reach 10,000 gigawatt hours.
26 Then the next one, underneath that chart

shows the new management of Nalcor has produced new numbers, and they show that the base indeed is 7,000 gigawatt hours, and then we had a drop. They are showing a drop in the initial years, a drop associated with rate shock, and then a continuation of growth, but by 2030 it was still only back to 7200 gigawatt hours. So incredible, incredible over-estimation of load growth. Incredible.

Now, the new cost numbers, the blended numbers including existing facilities, and Muskrat Falls, we're going to go, as I mentioned earlier, to 22.89 cents per kilowatt hour when this project comes on stream, and that's going to increase in subsequent years. And to a large extent, the cost is high because we are using so little of Muskrat Falls. The big problem is that without the growth, a very small energy base has to cover these costs. And so that's in terms of the load growth.

And then I want to just give a little bit of history. We had two reviews. Two reviews. One was done by a joint environmental panel and another was done by the Public Utilities Board on a reference, similar to the reference you people have before you.

The Muskrat Falls project was exempted from the jurisdiction of the PUB but in 2011, as a result of an intervention to which I was a party, the

1 government made a limited reference to the Board.
2 Because under normal circumstances their legislation
3 would provide a review of this project in terms of
4 their capital project review mandate. They were not
5 allowed to do that. So what they did was they did a
6 limited reference to the Board and the Board had to
7 choose between Muskrat Falls and the isolated island
8 option, which was a combination of small on-island
9 hydro sites as well as continued thermal generation.
10 The cost estimates at the time were class 4
11 estimates and these were based on engineering design
12 work of 5 to 10 percent of the engineering design had
13 been done, and the demand projections were
14 unrealistically high, particularly in a province which
15 had lost 80,000 people because of the collapse of the
16 fishery.
17 The consultants of the Board were Manitoba
18 Hydro International. Those were the consultants the
19 Board had retained. The consumer advocate had another
20 consultant, Knight Piesold, but the consultants to the
21 Board, MHI, were persuaded by Nalcor and its
22 consultants to endorse the project, as was the
23 consumer advocate, but the PUB took their own position
24 and essentially they took the position of indicating
25 that the numbers before them did not allow them to
26 make a definitive ruling.

I made a quote here in my submission to some comments that my colleague and I, Ron Penny and I made some years ago, and what we said was that the risks that we identified in terms of capital cost overruns, volatile oil and gas prices, over-estimation of load growth, under-estimation of load growth from emerging new industrial users of electricity, volatile electricity prices in potential export markets, changes in demography which may have an impact on load growth, we talked about family formation, low family formation, low new home construction, and a number of risk factors.

Proceeding Time 1:27 p.m. T40

And we basically felt that the isolated island alternative contained a series of smaller projects which allowed Newfoundland Hydro and Nalcor to move forward and supply power, maintain system reliability, and thereby provide ample time to mitigate the risk associated with Muskrat Falls and explore other options.

The board concluded that it couldn't render a recommendation based on incomplete information filed in the hearing. The low growth forecasts were insufficiently precise. The cost estimates were based on insufficient design work. So what they said was the information provided by Nalcor in the review is

not detailed, complete or current enough to allow the board to determine whether the interconnected option represents the least cost option for the supply of power to isolate to island interconnected customers over the period 2011 to 2067, as compared to the isolated island option.

So they did not reach a conclusion and they remained agnostic on the options. The Joint Environmental Panel, which had reported prior to this, they reported in August of 2011, they were equally unconvinced of the merits of the project. And what they said was the Panel concludes that Nalcor's analysis, which showed Muskrat Falls to be the best and least cost way to meet domestic demand requirements, is inadequate and an independent analysis of economic energy and broad-based environmental considerations of alternatives is required.

Is there any similarity between the situation faced in 2012 by the Newfoundland Labrador PUB and that faced by the BCUC today? I quote Marc Eliesen who said, "There never was a business case for the start-up of construction of Site C, and there is not a business case to support its continuation for postponement." This is similar to comments made by former Fortis CEO, Stan Marshall, who took on the role

of CEO of Nalcor back a little over a year ago, and he described the project as a boondoggle. But he confirmed -- not only did he confirm it was a boondoggle but he said he never supported the project because it was speculative, overbuilding capacity instead of increasing capacity incrementally to meet demand.

So in my written submission to the BCUC I made 14 recommendations. I remain committed to all of those recommendations, but I'm going to restate only three that I think are really important. And first is that the BCUC must be vigilant and reflect the interest of present and future generations. Your mandate is to protect the ratepayer and the OIC you're dealing with relates to the impact on ratepayers, and one has to infer that that includes future -- present and future generations.

The present generation has an obligation to protect our assets, including our environment, for future generations. We also have an obligation for the services, to pay for the services we consume, including electric power, and not to foist our costs upon future generations through byzantine financial arrangements which amortize costs well beyond the lifetime of people living today, as epitomized by the 70 year time horizon in B.C. for Site C and the 50

1 year plus time horizon adopted in Newfoundland and
2 Labrador for Muskrat Falls, combined with the back end
3 loading of cost.
4 Number 2, do not overbuild the system.
5 Build according to your need. This is particularly
6 appropriate in an era of rapid technological change.
7 When we need to design a system that is adaptable to
8 change for Newfoundland Labrador, Muskrat Falls was
9 far too large for our needs and far too expensive.
10 Thirdly, ensure that project costs and
11 schedules are tightly controlled. As noted earlier,
12 the cost estimates for Muskrat Falls have been revised
13 seven times to date. Seven times. That's the death
14 by a thousand cuts. The largest project for the power
15 house and other civil works was awarded for 1.1
16 billion and has been renegotiated to 1.83 billion. It
17 was alleged at the time that the original contract was
18 a lump sum contract. Instead it was cost plus, and
19 the more labour used the higher the cost. So that's
20 not a model for building a project. And so one of the
21 things I think that's very important here is to look
22 at the cost, look at the schedules.
23 Now, back to the muddy bottom. I'm just
24 going to finish up with muddy bottom, which is going
25 to Dr. McCullough and the whole question of are we so
26 in the mud, are we so stuck in the mud we can't

1 retreat? And the thing one has to realize here is
2 that this is a very big, complex project. This is a
3 very, complex project and one has to look at this --
4 and one of the things that we have to look at is the
5 fact that we may be able to finish this project.
6 **Proceeding Time: 1:33 p.m. T41**
7 In fact, the Muskrat Falls project right
8 now earned progress, is 80 percent of the total
9 project. The transmission component is well hid of
10 generation. Generation is 68 percent. So there is 32
11 percent that needs to be done. There is a lot of work
12 that needs to be done on the generation side. But,
13 you know, there is still a lot of risk. There is
14 still a lot of risk that has not yet been mitigated,
15 and much of this risk resides with the geotechnical
16 problems.
17 There are major geotechnical problems. And
18 I think the scale of those geotechnical problems was
19 not well known when we embarked on this project. As
20 we got more and more into it, it became clear that
21 this was going to be a big cost driver, these
22 geotechnical risks. And so as we got more and more
23 into the project, it disclosed itself. Even though we
24 were operating from a class 4 -- class 3 cost
25 estimate, and the engineers said this is well designed
26 project, does not prevent a risk from coming into the

1 project.
2 So, what I have to say to you is that you
3 can be well across that creek that Dr. McCullough
4 talked about, and very close to seeing the other side,
5 but you have to bear in mind that there still -- there
6 may be a deep trench as you approach the other side,
7 and you might not reach the other side.
8 And the other thing we have to bear in mind
9 is we might be able to build it, but we might not be
10 able to operate it. Because if you apply a 40 percent
11 elasticity factor, that is to say a coefficient of
12 elasticity of minus 0.4, which Dr. Swain said was in
13 the middle of the pack, and he is right about that.
14 It's in the middle of the pack. That represents -- if
15 we're going to double our prices, the rates, that is
16 going to have an impact over time, not immediately, it
17 is going to be a lagged effect. It will reduce
18 consumption.
19 Now, we're starting at 7,000 gigawatt
20 hours. If we drop that by 40 percent, that's going to
21 go from 7,000 gigawatt hours, down to 4200. And you
22 know what that does? It wipes out any demand for
23 additional power. So, the elasticity effect in our
24 context is enormous. And it really raises the
25 question of can we afford to operate this project?
26 The export price, if we don’t have a domestic market,

then we're looking at export into the New England market, short-term market, probably 3 cents a kilowatt hour. And we're probably going to have to pay transmission costs out of that. So we're going to get very little benefit. So we're going to have a real question as to whether that project is going to be able to finance itself.

The other thing is we as Canadians are all wearing this, because there is a $7.9 billion guarantee associated with this project. This is one of the joys that British Columbia has not experienced, which is a federal loan guarantee. So, this $7.9 billion is incorporated, because it was originally 5 billion, now it has gone to 7 billion, $7.9 billion. And the prospect of the government -- of the debtholders recovering that money from the project, the prospects are very remote in my humble opinion. But, the prospects of getting paid by the federal government are very good, because the Canadian government has got the best credit rating in all of Canada.

But this is a big concern, and due diligence. There should have been more due diligence by the federal government, and by the provincial government before we embarked upon this project. So I hope that one of the recommendations that comes from

1 the BCUC, in addition to the measurement of the cost
2 of continuing the project, as well as the cost of
3 stopping it, the cost of terminating, the cost of
4 suspending, I am hoping that one of the
5 recommendations -- and it came up this morning, is
6 that there is a recommendation for a full fledged
7 review by the BCUC of whatever -- of all the load
8 growth estimates, doing it, and taking whatever time
9 it takes to do this right.
10 So, that, Mr. Chairman is my presentation.
11 I'd be glad to respond to any questions.
12 THE CHAIRPERSON: Thank you, sir.
13 COMMISSIONER MASON: I wonder, I think you mentioned that
14 the first class 3 estimate that you saw or you've seen
15 information on for Muskrat Falls was just above $7
16 billion. Are you aware of the breakdown of the amount
17 of contingency that was in that?
18 MR. VARDY: Yes.
19 **Proceeding Time 1:38 p.m. T42**
20 COMMISSIONER MASON: Could you share a little bit of
21 information perhaps on the amount, and also the degree
22 to which the overruns could have been either allocated
23 to either poor estimating or poor creation of a
24 contingency number? The differences between the two,
25 please.
26 MR. VARDY: The original base cost was increased by 15

1 percent for contingency, and 15 percent for
2 escalation. Okay? And now I don't remember offhand
3 what those numbers translate into, but there were
4 contingency numbers built in there. And those
5 contingency numbers were eaten up very quickly. Those
6 contingencies were eaten up.
7 And I was intrigued by the comment about
8 attributing the lower capital cost to contingency,
9 because that's of course quite inappropriate to do
10 that. It's inappropriate in British Columbia and it's
11 inappropriate in Newfoundland. But the contingency
12 for this project was probably, given the level of
13 engineering that needed to be done, and the risks
14 associated, I think that the contingency should have
15 been much higher, probably between 20 and 25 percent.
16 Now, and I think a lot of the problem -- I
17 mean, there's the allegation of falsification of
18 costs. And that will have to be tried through a
19 forensic audit, to find out how much substance there
20 is in there. But I think two major factors are
21 responsible for the problem that we've had. Number
22 one is that we needed to have a better understanding
23 of some of the risk components, and the -- we have a
24 problem called the North Spur, and the North Spur is a
25 natural dam which is one kilometre in length. And
26 it's fundamental to the project, the integrity of the

1 project, in the sense that if you had to put that one-
2 mile -- one-kilometre dam in place, it would cost a
3 lot of money. People wouldn't consider Muskrat Falls
4 as a viable option. But it was there.
5 But the problem is, there are a number of
6 layers of sandstone, and glacial clay, glacial marine
7 clay, which can liquefy. And so a lot of money has
8 gone into the remediation of that problem, and to make
9 sure. Because if it liquefies, this whole one-
10 kilometre area is subject to collapse. And there were
11 a lot of landslides. And the Geological Survey of
12 Canada came and appeared before the joint
13 environmental panel back in 2010 and said, "This is a
14 highly risky situation. You guys really need to look
15 at this very carefully."
16 And so, as we got into this project, I
17 think this became a bigger problem. And so a fair bit
18 of money has gone into remediation. And then -- so
19 that's one factor is, we didn't have -- the design
20 work wasn't sufficiently refined, and not sufficiently
21 complete.
22 Factor number two, I think, was that we
23 were -- we didn't have the project management team,
24 and the people that were doing this work hadn't done
25 it before. And we started out with a relationship
26 between SNC Lavalin and Nalcor, where most of the

1 design work was done by SNC, and where most of the
2 project decisions on awards of contracts were jointly
3 made by Nalcor and by SNC Lavalin.
4 And then as problems developed,
5 internationally with the reputation of SNC, Nalcor
6 decided to reduce the level of their participation,
7 which meant that they were exclusively responsible for
8 the decisions. They didn't have the capacity to do
9 it. So I think that was -- that's a big problem. And
10 that's one that you'd need to look at very carefully
11 as well.
12 The other thing that I find interesting is
13 -- and it's a problem that bundled, I'm told -- and
14 I'm not an engineer, but I'm told that there is wisdom
15 in not bundling too many projects into a big bundle,
16 because it reduces the number of potential contractors
17 who can bid. And I am told, and I can't quote chapter
18 and verse on this, but I am told by one of my project
19 management friends, that Hydro-Québec has a rule that
20 $50 million is their maximum contract award. That's
21 soft information.
22 I'm also told that when the Upper Churchill
23 was being built, and I think this comes from good
24 authority, they had a rule, and the rule was, nothing
25 bigger than $75 million. No project was awarded for
26 more than $75 million.

But what we did was we bundled what ultimately became a $1.83 billion bundle, and it seems to me BC Hydro's doing something similar with this consortium. And so I look at that and I say, is that a good idea to do that? And why would you hand out such a large contract? Because then you're really vulnerable once you go down the road, you're very vulnerable. That contractor, in our case it was Astaldi, and I can't remember the name of the company in your case, but I know there's a tripartite group, and one of the parties has gone -- has disappeared.

But so the question then becomes, you're then hostage to this group. And so that's -- I think those are some of the lessons that would well be listened to.

COMMISSIONER MASON: Thank you very much.

MR. VARDY: Thank you.

THE CHAIRPERSON: Thank you, sir.

Proceeding Time 1:43 p.m. T43

THE CHAIRPERSON: Please go ahead, sir.

MR. CRAIG: Thank you. I have paper copies of the presentation if you'd like them to make notes on.

THE CHAIRPERSON: Thank you.

MR. CRAIG: And for you.

THE CHAIRPERSON: Please go ahead.

SUBMISSIONS BY COMMERCIAL ENERGY CONSUMERS (#0306):

MR. CRAIG: Thank you, Mr. Chairman and Panel. For the record, my name is David Craig, C-R-A-I-G. I'm with the Commercial Energy Consumers Association of B.C. and have been before the Commission for many years.

Mr. Weafer, who is usually in this position, is out of town. So I'd like to coordinate with the Commission to find out if he's usually out of town on all the big events.

THE CHAIRPERSON: Only the ones that happen on Saturdays.

MR. CRAIG: Yes. So my presentation is going to stick to dealing with your report — I think that was the requirement — and the items in it. It's going to stick to dealing with the financial aspects of it and particularly the ratepayer consequences of the various decisions and I'm particularly going to focus on, at least one and maybe a couple of other things that are in the Commission report that I think should be changed. I think you've got it wrong and I want to have a discussion with you about that.

And there's one particular item that I'm going to deal with in terms of ratepayer impact that is nowhere in the materials from anybody, and I think it's a real item and it's very large, and I think you need to hear about it, and we need to have a discussion about it. I think it needs to be part of

your advice to government. And there will be other parts.

Also what I'm planning to do with this presentation is deal with the fact that all of us have been looking at a massive record. You've been processing an enormous amount of material in a very short period of time, and a huge credit to you for doing that. I'm going to try and rise up a level and deal with only four key areas that I think are of strategic importance in your advice to government, and the areas that I want to talk about that have very significant impact are contained in those areas.

So I think with that said we'll move on and start into the presentation.

Proceeding Time 1:48 p.m. T44

The first part that I want to talk about is that we currently are going into this decision with approximately 5,000 gigawatt hours of surplus already on hand. We acquired that at very expensive prices and it now has to be sold into electricity markets at much lower revenue returns. It's a significant impact and it’s the type of issue that we had before us as Site C came forward in the IRP process.

The Commercial Energy Consumers at that time thought that Site C should be deferred because the benefits of deferral were much higher than the net

1 situation that we were going to face. At that time it
2 was quite evident that we were into underperforming
3 the forecasts and we had flat loads.
4 It's important, in your advice to the
5 government, to let them know that they have some tools
6 for managing the impact of Site C if it were to
7 proceed, or in fact anything else, and it comes in the
8 form of a decision between reducing acquisitions that
9 are in the current BC Hydro plan ongoing or leaving
10 them in place. If they are left in place by the end
11 of the planning period, we have 2,500 gigawatt hours
12 from standing offer program. We have 5,000 gigawatt
13 hours from renewal of IPPs. Those are two very
14 different resources in that the price that we are
15 acquiring SOPs at is in the hundred, hundred and ten
16 range, and the consequence of that, to the extent that
17 that's part of the surplus that's sold into markets,
18 is about a two and a half billion dollar impact to
19 ratepayers. So it's a big issue and to the extent
20 that can be managed, it mitigates costs and impacts on
21 ratepayers.
22 Renewals are quite different. If they can
23 be renewed at market, they can be acquired and sold on
24 market with no impact on ratepayers and they can
25 become available if there's increased demand and the
26 need for it. And they are essentially the tail-end

of having purchased that power over twenty years or longer at much higher prices. But at this point in time, their alternative is to go to electricity markets and that's the price that they should come at.

To the extent that they come at a higher price than that, then there would be an additional impact to ratepayers. To the extent that these surpluses continue, which is what's anticipated in the event of continuation of Site C, and it's certainly what's anticipated if we have continuation of the flat loads that we've been seeing.

So in summary on that one, setting the context, and there's probably a number of other decisions that government and perhaps Utility Commission can play a role in in setting the context in which the future unfolds, whether that includes Site C or not. But certainly including Site C, it's an important issue and an area where you can give advice to government that there are tools for mitigating impacts.

The second area is load management decision making, which is also setting the context. And the choice is between a flat load with a fairly sustainable future. We're on that course now, a very flat load. A growth rate in the order of zero to 200 gigawatt hours a year would be fairly flat. It would

have low impacts. And that would be augmented by a lot of activity that impacts load. Demand response activity has been talked about, it's on the record. Solar evolving to displace load, as a distributed source, increasing efficiency in the economy, a lot of DSM activity aimed at energy and capacity, codes and standards, market transformations are going on.

Proceeding Time 1:53 p.m. T45

This is the situation that exists in B.C. at the moment. It's also the situation that exists throughout the developed world. The U.S. loads for commercial, residential, are virtually flat in the EIA data. Similarly, in Europe, the loads have been declining and they declined further. In both cases, the U.S. loads were increasing steadily as ours were, but about 2007 they flattened out. Same situation in Europe. Same situation here. There's something that distinctly happened at that point in time, and we are seeing a different world. Things have changed. And it's in that area.

So this is a possible scenario of active management relative to load, and it would be accompanied by a BC Hydro forecast that would be adjusted down to reflect more of the path that we're on with declining loads per use for accounts.

There is an alternative future view to be

1 looked at, and it's more consistent with a BC Hydro
2 forecast where we may see significant growth tied to
3 electrification activity of transportation, heating,
4 various industrial processes, or perhaps use of non-
5 firm energy, of which we'll have a considerable amount
6 to establish new uses in the province.
7 In terms of ratepayer impact, the flat
8 sustainable future has very low impacts on ratepayers.
9 And it's a sustainable route to go. And if you have
10 increases in the way of 500 to 1,500 gigawatt hours a
11 year, in the future, you'll be facing additions of
12 resources that will give rise to substantial rate
13 increases for ratepayers.
14 These are not mutually exclusive. The
15 flat-load future can also be part of the growth
16 future, and should be. We should explore having all
17 of that activity going on to mitigate impacts. And
18 likely if we pursue a growth future with all of these
19 electrification scenarios, it will evolve at a
20 reasoned pace, hopefully, so that the rate impacts
21 would not be too much. Some of the presentations have
22 advocated for very substantial amounts of additional
23 electricity, and coming with those would be very
24 significant rate impacts, and very significant
25 consequences to existing and future ratepayers.
26 But nevertheless, in terms of advice to

1 government, this is an area that has very substantial
2 uncertainties. It's not something that you're going
3 to be able to get analytical information that tells
4 you exactly what the outcomes are going to be. It's
5 integrated with government policy, utility policy, and
6 the society in general, where it's going to allow
7 things to go.
8 But it's important that your advice to
9 government makes sure that we understand that there is
10 different futures available, and it's government
11 policy integrated into the utility that will as much
12 impact ratepayers as anything else.
13 And I think at this point those are the two
14 key context-setting pieces of advice that I recommend
15 that you explore and provide advice to government,
16 that they have active roles to play in both of those
17 in terms of setting the context for this decision that
18 they've asked you to evaluate.
19 **Proceeding Time 1:58 p.m. T46**
20 With that said, I want to look at the
21 decision itself. This is an area where we start with
22 what is the cost to complete Site C, and we have an 8
23 to 9 billion dollar cost in front of us at the moment,
24 and it's important that BC Hydro would be advocating
25 that it can complete at that cost level, but it's
26 important for your evaluation to look at cost to

1 complete in the 10 to 12 billion dollar range. And
2 that's the evidence that's on the record that I've
3 been reading that's in front of you.
4 Many years ago, when I was working for BC
5 Hydro I was a part of BC Hydro's application to the
6 Utilities Commission for approval of Site C. In that
7 role I did analysis of every single large dam project
8 that BC Hydro had built since its inception, and in
9 that analysis the cost overruns were 25 percent to 75
10 percent. There were no underruns. And those were
11 from pre-construction budgets.
12 That was at a time when interest rates were
13 rising quite substantially, so some of that cost was
14 related to the context in that so I would decrement
15 those numbers to some extent. But I think your advice
16 to government should be this decision should be
17 evaluated in the context of the 10 to 12 billion
18 dollar overrun and for the purposes of doing it
19 conservatively we need to look at the $12 billion case
20 at a minimum to understand what kinds of impacts we're
21 looking at.
22 The key decisions here are to complete or
23 terminate. You'll notice that I've dropped the
24 suspend and either proceed with later or terminate
25 later. And the reason for dropping that is that the
26 benefits for deferral at this case do not exceed the

1 costs and that is because we've come some distance
2 into the process. It's no longer, in our evaluation,
3 of relevant process, and that's because completion of
4 Site C in part can be covered in terms of impacts from
5 this stage by sales into electricity markets, and so
6 it has a cash value at its remaining cost to complete.
7 It didn't have that at the beginning and
8 that's why I was advocating deferral at that time. At
9 that time the cost benefits to deferral were very
10 significant, and in our opinion, and it's on the
11 record, the risk of surplus was substantial and was
12 not worth taking.
13 The costs of termination is an area also
14 where I want to put on the record something that is
15 not before the Commission in terms of ratepayer
16 impact. Nobody has presented it to you, but it is
17 very real, and I would like to see it in your advice
18 to government.
19 There are the sunk costs that we've talked
20 about, the 2.1 billion. There can be a range on that,
21 there's no absolute certainty about it. A billion for
22 termination and rehabilitation. There's a range on
23 that at some point and we don't have absolute
24 certainty, but these are relatively knowable numbers.
25 And I've added one, which is a ratepayer
26 impact on the cost of recovery, and so I want to have

1 a discussion with you about that to give you some idea
2 as to why this needs to be added to the picture.
3 When we go to recover costs from
4 ratepayers, you recover $3 billion from ratepayers,
5 but ratepayers get zero benefit for paying that cost.
6 And whenever you are in a transaction where you pay
7 something and you have zero benefit, that cost has to
8 come out of your assets. It comes out of your bank
9 account, it comes out of your investment portfolio, it
10 comes out of your time. And those all have values.
11 Those are called opportunity costs and they come into
12 play when a transaction has zero benefit for making a
13 payment.
14 **Proceeding Time: 2:03 p.m. T47**
15 The opportunity costs of the ratepayers
16 putting up the money to cover those costs end up
17 representing payments that they have to make at their
18 cost of capital. And they essentially have to take on
19 the role of financing that 3 billion as they relieve
20 the utility of continuing to finance it. It is a
21 critical item, and to put it in numbers, if they have
22 to make a million dollar payment and it comes out of
23 their investment portfolio, they are losing both the
24 return on that capital that they may be getting in
25 dividends of some kind, and the potential appreciation
26 on that capital. And those are very real ratepayer

1 impacts.
2 Also when it comes to a residential
3 ratepayer paying these, they have to pay that out of
4 after tax income. It is a significant additional
5 impact. A business taking on a cost where there is no
6 benefit being provided, it comes right off the bottom
7 line for that business. They would have to then
8 invest in the business to get additional revenue to
9 cover that cost. Those are the opportunity costs.
10 Another way of looking at the opportunity
11 costs will flow out of the presentation that my
12 colleague ratepayer groups made to you, the AMPC
13 group, when they said if there is a termination of
14 cost of Site C, that they will be looking for a
15 prudence review of that. That is not just an academic
16 statement they are making. They're saying that the
17 impact of that on them would be sufficient that they
18 would not want that in their rates. And if we've
19 proceeded with Site C, and at this stage of investment
20 into Site C, it is terminateable, there will be
21 questions of prudence.
22 If it is terminated and written off, the
23 size of the write off for just the three billion takes
24 up a very substantial portion of the retained earnings
25 of BC Hydro, which are in the four something billion
26 range. If you add in the impact on ratepayers, and

that's all relieved, you take the retained earnings of BC Hydro to zero.

Now, the important thing in terms of this rate impact when you hear that, we take those down to zero, you might thing that you've written that off. Which you have. But what is remaining in BC Hydro is the debt that was acquired to spend that three billion. And that has ongoing interest costs. And if the ratepayers are now absorbing that, that has a present value cost in the order of a couple billion dollars.

So it's an important issue for ratepayers, that is it is not just the capital amount that is dealt with. There is an opportunity cost to ratepayers, and it is a very substantial piece of evidence that you need to take into account in your advice to government.

When we deduct the cost of terminations from the cost to complete, we get some relatively low costs of energy remaining. And those costs, as they have been presented by BC Hydro, included both energy and capacity. So, they are such that they represent very low to no rate impact to customers from this stage, relative to the termination costs. And that is all that we're dealing with in front of the Commission at this point. We are not re-prosecuting the decision

about whether we should have got into this. I already have my opinions about that.

Proceeding Time 2:08 p.m. T48

What happened here? Well. Okay. So this is a very technical presentation.

The ratepayer impacts of recovering those costs from the ratepayers, including the opportunity costs that they will face, will be the effective level of about 17 percent. It's a very expensive price. And so it's important that that's part of the context when we make the reverse side of that decision as to what is the cost to complete and what are the mitigating revenues that are potentially available to offset that, and avoid this impact on ratepayers.

Moving on to the last piece. One of the things that has changed substantially in this picture is the cost of capacity. We are out of the cheap capacity. We built Mica 5, 6, Revelstoke 5, Revelstoke 6 is in line, planned to come on. Those were the cheap capacity at $55 a kilowatt-year.

From there, in both the integrated resource plan and in the evidence in front of you here, we go up to costs of single-cycle gas turbines, or pump storage. And those are in the integrated resource plan. We've known about this for a long time. The Commercial Energy Consumers have been advocating that

we need to build that into our long-run marginal cost views. And now what's changed is, they are now present. They are now starting to be an impact on decision-making.

When we come to where is the next energy going to come from, your advice to government is critical. The portfolio that's been put forward by BC Hydro is wind power. And I'm looking at an alternative being geothermal, which has the potential to be low cost, and particularly so because it carries its own capacity. There are only a few renewables that have that capacity with it, and as capacity becomes a very expensive commodity in the system, this becomes an interesting alternative to see if it can be developed.

And if it can, with those levels of values, it has a lower impact on ratepayers. So it's in our view something worth exploring in the future.

The wind portfolio is an intermittent asset. On the positive side, it has the potential for cost reductions that could be $5 to $45 a megawatt hour of reduction. But when the costs of the capacity get added in, it's still a resource that, when it fills the future, is going to add rate impacts, as an alternative.

And in this case, in looking at these

1 alternatives, I have left the DSM consideration to
2 what can be done in terms of mitigating the load
3 impacts and I think it's critical that we have the
4 situation where we maximize the total amount of DSM
5 that we can obtain before we take on future resources.
6 And it's critically important that as we add
7 resources, we try and get to a situation where we can
8 add them in time frames of response between the
9 addition of resources and load growth that we have the
10 flexibility to avoid large potential surpluses, which
11 are very costly to ratepayers.
12 **Proceeding Time 2:12 p.m. T49**
13 The last thing I'd like to go back to is in
14 evaluating the cost to complete Site C, there's an
15 issue with regard to financing costs, and the
16 proposition has been put to you that it's
17 inappropriate for BC Hydro to use its low cost of debt
18 for financing.
19 And I want to make a clear distinction here
20 in terms of what I think needs to be corrected in your
21 report. At this point your report views this as a
22 potential distortion. And I want to make the
23 distinction between evaluating projects for their
24 economic worth absent the financial decisions about
25 who is going to do what. When you are doing that,
26 it's appropriate to have either no costs for financing

1 or a common cost for financing, and that's how we go
2 about evaluating the merits of a project, one against
3 another.
4 But once we are into the financial
5 investment decisions as to which projects are going to
6 proceed done by whom, we never try to equalize the
7 financing costs between them. For instance, among
8 IPPs there's no process by which we go to each
9 individual IPP and say, "What's your cost of capital
10 and let's have them all equal," and somebody going to
11 balance that out for you. And it's the same when we
12 are dealing with Hydro with its ability to finance
13 with the low-cost debt.
14 There's a context in which all of this
15 occurs that makes it important that the financing cost
16 is the real cost that will impact ratepayers, and the
17 importance of that context has a multiplicity of
18 attributes. The first is that under the current
19 context in which we do the utility planning, nobody
20 else can invest in heritage hydro assets. And not
21 only that, it would be very difficult to do a project
22 of that size as an independent party. They will
23 always require government backing of some kind.
24 And this boils down, essentially, to the
25 use of the credit of the province. The province has
26 always backed BC Hydro borrowings as a credit. That

has enabled BC Hydro to provide affordable power. That was the origin of BC Hydro. BC Hydro started as an expropriation of the private sector. It got government backing and the government credit behind it, and it then invested in major facilities and lowered the cost of energy very substantially from that time period.

It has almost always been the case that BC Hydro has used its low cost of debt to finance, essentially the heritage hydro system. Without that, we would not have the very significant storage capacities in the system, the very significant capabilities of that hydroelectric system.

And it's very important when we look at the comparison to the other side of this, the independent power producers, that we understand that BC Hydro is not permitted to go and build those types of projects. Those have been allocated to the independent power sector.

And when those independent power producers come to get their EPAs, the primary reason that they can be financed is because they have an EPA from BC Hydro which has the backing of the province. So the full credit of the government is passed through to the IPP industry, in their EPAs. They would not be able to compete in just an open market and they are very

1 clear about needing those EPAs to get financed.
2 Furthermore, the IPP industry takes the
3 benefit of the hydro expenditures on major assets.
4 All of the capacity required to bring the IPP industry
5 on board has been supplied by the credit of the
6 government at low cost borrowing through Hydro.
7 **Proceeding Time: 2:18 p.m. T50**
8 There has never been a complaint about
9 that, but when you're competing to try to displace and
10 asset, then you raise a concern about it. But the
11 whole industry depends on it. So, in our view, when
12 you give advice to government, it's important that at
13 a minimum you reflect that there is two views, and not
14 that you call one view a distortion. In our view, it
15 would be a distortion for BC Hydro to be allocated a
16 cost of debt that it does not have to pay, and the
17 ratepayers do not have to pay. And it would be
18 inappropriate to lower the cost for an IPP resource,
19 and still have us pay the full cost of their
20 financing.
21 It is a critical point with regard to how
22 we calculate the end costs coming out of this, and it
23 is important that the financial decisions about what
24 ratepayers pay for is how these costs are evaluated
25 despite our academic interest as we look at the
26 economic comparisons of projects which we do before we

1 get into them at all.
2 So, that concludes my presentation. I'd
3 like to see at least a balancing with regard to
4 calling this financing distorting. I don't believe it
5 is, and I think you should reflect at least those
6 perspectives. And I think it's critically important
7 that you get the ratepayer cost of recovery reflecting
8 what the ratepayers will actually be incurring in
9 terms of opportunity costs.
10 So, I have tried to keep it at a high level
11 with the major strategic areas that you need to
12 provide advice and focused on key elements of your
13 report in terms of how I think they should be
14 reviewed. My presentation is concluded and I am open
15 for questions if you'd like.
16 THE CHAIRPERSON: Thank you, sir. Karen?
17 COMMISSIONER KEILTY: Just a question on your comment
18 that things have changed in the existing surplus. To
19 get from there to the growth mode, is it -- am I
20 understanding you correctly that that would be as a
21 result of government policy changes? That in the
22 absence of that the surplus remains?
23 MR. CRAIG: That's a good question, and it's a little
24 complicated. So, what we have been seeing as the
25 loads have flattened out is that in the last 10 years
26 we have absorbed 200,000 new customers into the BC

Hydro system with no requirement for increased electricity. All of the commercial businesses that have come into the province in support of all of that activity, the same, we've absorbed all of that. That is being absorbed in large measure in my analysis as a consequence of DSM spending. And our DSM spending as it cumulatively rose to impact, got to be very substantial, and cumulatively made quite an impact around about 2007/2008. And so that has been a major contributor.

In the background to the load forecast, we have forecasting based on the population growth, and anticipated growth in the economy. One of the things that is not in BC Hydro's forecasting methodology is understanding of the make-up for the demographics in the forecast of the population and what it requires.

The baby boom represents a major portion of what drove growth at the time that the growth was occurring. And the baby boomers at that time went up what's well known as a spending curve. As they aged and got more wealth, their spending peaked in the range of 50 to 60.

Proceeding Time 2:23 p.m. T51

And after that their spending declines and that's occurring in all of the industrialized countries. And it's an impact that's not in the forecasting system,

that's a background piece of demographics that demographers understand, but it's not part of our forecasting methodology. But it's very much attached to what's required and what ends up in the requirements for load.

There are a whole variety of other factors that have been part of damping demand, including the manufacturing of North America moving overseas, and requirements for reduced load. Our industrial sector here has been declining substantially and has been forecast to be declining for over 20 years, but those forecasts rarely find themselves into the BC Hydro load forecasts, and they tend to show up as a surprise. Nobody anticipated this.

It's not true. These were anticipated. Up to twenty years ago, I read reports from BC Hydro numerous times from consultants that anticipated all of this coming.

When the forecasting takes place, there's a good deal of impact if you write into your forecast that an existing customer purchasing from you may not be there at some point in the future. BC Hydro has started making adjustments to begin reflecting some of that. I don't believe that we've got sufficient into the load forecasting at this stage, and as a consequence it's very much the case that we, and much

of the developed world will end up seeing relatively flat loads as just a background consequence of all of the things going on in our societies.

Government policy will be a huge influence on whether or not we maximize that conservation and efficiency activity to the benefit of current and future ratepayers, and also whether or not they adopt movement into this growth scenario and electrification. And probably both are important. Probably some balance of those will come out as being our contribution to greenhouse gas reduction and showing the way. And it's important advice to give to the government. They have choices to make and their policies will determine key background to whether or not to proceed with Site C. If we were only on that sustainable future, I would say you wouldn't take the risk of completing Site C because it's got other kinds of consequences.

It remains a judgement about very uncertain information as to whether or not these will be the background activities and whether or not government policy will support one of those views or another. And in that context I think your advice has to be, as a government you may choose this view, and you may choose this view. If you're heavily onto flattening it out and retaining rate impacts low, then you need

1 to have a very serious consequential discussion about
2 the Site C termination issues. But absent that, Site
3 C has a very low cost that's recoverable in the market
4 place.
5 And the last comment on that would be,
6 while nobody is going to say that they can forecast
7 the timing of a recession, we all know that they are
8 coming. They are like earthquakes. And what do you
9 do for earthquakes? You prepare for them.
10 We are right now in a situation where our
11 housing growth is substantial. We are up at 40,000
12 units and every time the B.C. economy gets up in that
13 range and goes a little higher, it will peak, and
14 interest rates will come up and it will collapse, and
15 there are numerous bubbles around the world that have
16 been financed by central banks and sovereign debt
17 issues.
18 We have somewhere in our future, something
19 that will look like the last time, and that will
20 contribute to flattening load in and of itself. I
21 think it's just important that we understand the
22 uncertainties and that you reflect judgment decisions
23 in the context of those uncertainties.
24 COMMISSIONER KIELTY: Thank you.
25 THE CHAIRPERSON: Thank you, Mr. Craig.
26 **Proceeding Time: 2:29 p.m. T52**

THE CHAIRPERSON: Mr. McCullough? Thank you.

SUBMISSIONS BY MR. McCULLOUGH (Continued) (#0290):

MR. McCULLOUGH: Thank you very much. I appreciate the opportunity to speak to the panel, thank you.

THE CHAIRPERSON: Thank you.

MR. McCULLOUGH: Thank you very much for this opportunity, here are our comments. And I have them on powerpoint as well.

THE CHAIRPERSON: Thank you very much. Go ahead any time sir, please.

MR. McCULLOUGH: Very good. Thank you very much, chairman, and especially thank you very much Commissioner Keilty for raising this issue. So much has been filed that I had not gotten to the end of F1-12. After your comment, my staff went through it, we reviewed it very carefully, and we have detailed comments in front of us. But before that I want to clear the air.

There has been a misapprehension at British Columbia Hydro. They misspoke when they said that we had referred to this particular report. We did not characterize the report, we did not quote the report. We did not interpret the report. In F35-11 you will find no quotation, no summary. No analysis.

We did have one footnote. The one footnote

1 identified a single number from the report, and that
2 number was used simply as a corroboration of our own
3 analytics, and that was the $1300 for MTPA. So that
4 entire discussion is in fact simply was misspoken.
5 So, I will not spend any time on rancor or
6 debate, that would be an inappropriate use of your
7 time. I will talk about the two narrow issues in
8 this. I will try to go very quickly, I know how busy
9 you are and quite frankly I suspect I know how tired
10 you are. I am very tired too.
11 So, Appendix C criticized LNG and the
12 forest products. Interestingly so, because that issue
13 is really behind us. Both the Deloitte and the staff
14 are talking about the load reductions far more
15 significant than ours.
16 So, what did they not address? Well the
17 vast majority of our submission. In a traditional
18 regulatory process at this point counsel would stand
19 up and say, expert testimony has not been rebutted, so
20 it should be admitted. Obviously, we are not in a
21 traditional process. They did not address our export
22 price forecast which are very important. They did not
23 address our analysis of alternative resource prices
24 which are very important. They did not address our
25 analysis of potential savings, 2 to 4 billion, which
26 are in fact at this point lower than what other

1 parties and the Commission staff have analyzed.
2 They did not address our analysis of the
3 sunk cost fallacy, and yes, I will not comment on the
4 previous speaker. But that has not been rebutted.
5 They did not address our detailed identification of
6 factual and computational errors in the British
7 Columbia Hydro's answers to the Commission's
8 questions, those were extensive.
9 What they did address was two very narrow
10 points. The first was our LNG studies, and second,
11 very narrow comments on pulp and paper.
12 Now, as you probably already guessed, the
13 LNG studies were not developed for this proceeding.
14 They were developed for our LNG clients, both here and
15 on Wall Street. You don’t develop a major Monte Carlo
16 model in the short time horizon we've had. I wish I
17 could have.
18 **Proceeding Time 2:33 p.m. T53**
19 So we're very happy to talk about LNG. But
20 it is important to note that pretty much where we are
21 is exactly what it appears. We are stalled. And they
22 proposed some increases in LNG and oil and gas. We'll
23 get to that in a moment. But they surprised us all.
24 And they also proposed different situations in pulp
25 and paper. Those surprises. And that's why I
26 addressed it.

So, we've talked about this quite a bit. The skepticism of the hockey-stick load forecast. We are not going to see pulp and paper and LNG leading those expansion. I think everyone really agrees on that. Materials from Deloitte and the staff argue authoritatively for lower load forecasts, and they've done far more detail and far more work than we have.

So, how did we get here? Well, on LNG, British Columbia Hydro said, "We have three people who signed up." Then they also said, "We're not going to do any complex analysis on this. We're simply going to accept the three." Well, that's fine.

When we look to their filing in F1-1, what we discovered was, there were some significant increases in forestry and oil and gas. That surprised us. We still don't quite know where those came from. We still don't have the level of detail. The Commission might. Your staff might. I don't know if they do. But the other parties, we're still puzzled over why we would have growth in those areas. And this is the chart directly from F1-1.

On LNG, there really is very little mystery on this. LNG is an industrial process. It applies a technology which compresses and refrigerates a gas into a liquid. The capital cost is the primary driver. It is a huge machine, billions of dollars.

1 In fact it dwarfs Site C.
2 Second question is, processed energy,
3 electricity versus natural gas for the compression and
4 refrigeration step. Third is natural gas availability
5 and cost. Fourth is travel time to Asian markets.
6 Fifth is tax incentives. We've actually worked on all
7 of these.
8 When we looked at Appendix C, we saw
9 immediately there were some basic misunderstandings of
10 fundamental commodity market concepts. They referred
11 to our analysis of forward prices as spot market
12 values. Now, as it turns out in the industry, these
13 are very different things. And I've just put up
14 industry definitions. Spot markets are cash. They're
15 immediate delivery. The spot market is never a
16 forward market. A futures market is entirely
17 different. It is the future delivery of a commodity
18 of financial insurance in the future.
19 Now, this is sometimes surprising to folks
20 who are not in commodity trading. You can actually
21 buy natural gas in 2027 and, yesterday, a lot of
22 people did so. And you can sell natural gas in 2027,
23 and yesterday a lot of people did so. Why is that?
24 Because people are balancing out production and
25 development plans years into the future. If you are
26 trying to make an investment in natural gas, you might

1 actually want to lay off those prices, if you thought
2 this was a good deal. This is what financial markets
3 are for. The fact is, some of the largest financial
4 houses in the world -- okay, sorry. Like the Chicago
5 Mercantile Exchange, and the International
6 Intercontinental Exchange, handle these contracts
7 every day. And thousands of them every day.
8 So what we're talking about here when we're
9 doing these analyses is we're not dealing with
10 forecasts, and we're not dealing with spot prices.
11 We're dealing with people who are gambling billions of
12 dollars that these are the right numbers.
13 Now, I think that's fairly correct. I
14 don't know. However, I would never disregard them.
15 They are the best evidence of what we'll see in our
16 future.
17 So this chart, which is compressed a little
18 to get it on the screen, is the CMA's summary of
19 yesterday's transactions.
20 **Proceeding Time 2:38 p.m. T54**
21 And at one point, British Columbia Hydro said, "Well,
22 there are no transactions out there for it." And if
23 your eyesight is better than mine, and I have to take
24 my glasses off to see it, you will notice that there
25 are an enormous number of transactions in 2027.
26 There weren't any transactions in November

2026. This is a natural evolution of markets. Marketplaces occur when traders come to one place. The phrase "Wall Street" was because that's where the traders met. As it turns out in natural gas, they choose certain months far into the future and all the trades occur in those periods.

So why am I raising this? It's just because it was the first step of a very intricate, very well thought-out attempt to determine FID probabilities for some of our clients.

So BC Hydro has said, "The sector is unique in that it has not yet developed. There are only three proponents and therefore they can't discuss it. They can't have a probabilistic load forecast." If you worked for Wall Street, which we've done many years, this would not cut it. You could not walk into Morgan Stanley's commodity group and say, "By the way, there aren't a lot of them so I'm not going to give you any advice on the possibility of success." Every bank, every trading house, every investor makes this decision. This is one of the jobs we have, and we, I believe, do it very well.

In terms of LNG forecast, a lot of it has to do with forwards, hubs, and a Monte Carlo analysis. Now, I know you know what a Monte Carlo analysis is, but just to recount, this is where you take all the

elements, you run through many, many different cases and you attempt to get a Bell curve to determine what the probability of the outcome is. Why do you do that? Simply because we don't have a very good magic-8 ball. My magic 8-ball is no better. This allows us to have a better sense, allows us to take care of the case of a black swan, because the black swan is in that Monte Carlo.

The fundamental issue going on here is that British Columbia is a fine place for LNG. However it's not ahead. It is behind several other locations. They already have the equipment in place, they are making sales, their costs are very low.

If you are sick and you want to go to a doctor, you go to the doctor who has the most patients and the most experience. That is the front-runner advantage. That's what we're facing today. That shows up in our Monte Carlo.

So, this article that we're accused of misconstruing actually is very careful. It's four years old by the way, it's nothing we would depend on as a forecast. I've got to admit to you, four years ago, I might have felt differently. We would not have been behind Shaneer and other LNG.

On the left side they say they are challenges facing, but the overall assessment is the

opposite. Fine. But what they really did was say resource producers are still weighing the benefits of developing this capacity against the significant capital costs and risks associated with future market uncertainty. This is just common sense. It's what they did. That's where we are today.

The one part of the article -- and by the way, we never quoted any of this. But when I reread it last night I found very interesting, and they said something you've heard from me now several times, "the first mover advantage".

> "The current amount of liquification capacity is set to outpace demand. As each new project is built, the construction and proposed projects become more unlikely."

This is not rocket science. You don't want to be second in a race. You don't get the gold prize if you do. And that, sadly, is where we are today.

I'm not going to waste more time on that but I have slides on this.

Okay, so what does our Monte Carlo model do? Well, we take 2 million cases, and yes, they can't be run on your telephone. This is a huge enterprise. And we consider a wide variety of different costs and we end up with a probability distribution of possible outcomes.

1 **Proceeding Time 2:43 p.m. T55**
2 Here, by the way, is the Federal Energy
3 Regulatory Commission's image of what prices are.
4 Now, you'll notice the prices in Asia are the highest.
5 That makes sense. But you'll also know that the
6 overall world price of LNG has fallen dramatically.
7 And there's a reason for this.
8 In Japan, in 2011, a major nuclear accident
9 following an earthquake and a tsunami caused the
10 closure of their nuclear plant sector. At that point
11 they went to backup generation. Suddenly the whole
12 world market had to adjust to a major industrial
13 country switching their fuel choice. As you'll notice
14 on the chart, the price went through the roof. There
15 was nothing magical about this. Suddenly the Japanese
16 were bidding on every supply of natural gas they could
17 find. They had to. They had no other choice.
18 What happened? People built more LNG
19 facilities. They explored more energy -- Indonesia,
20 Australia, the U.S., all tooled up to meet that
21 demand. And then you'll notice that as the process
22 went on, the price again collapsed. We were able to
23 meet the Japanese demand. There have been some re-
24 starts of nuclear units in Japan; it's not complete.
25 But the fundamental market distortion caused by that
26 earthquake led to a perception that there might be an

1 enormous ongoing option for LNG.
2 Before I leave this, how do you forecast
3 the Japanese landed natural gas price? Though Japan
4 is a major country, it does not have a financial
5 market sufficient to provide derivatives and forwards.
6 As it happens, its primary alternative fuel is Brent
7 Crude. Brent Crude does have that. When you make an
8 adjustment from one fuel to another when you're
9 trading, this is a basis adjustment. There is a basis
10 adjustment to go from Brent Crude to Japanese LNG.
11 How do you develop that? It's with a statistical
12 model. You actually factor in the various parts and
13 then the outcome, if it's statistically significant,
14 you use it. That's standard market procedure in
15 commodity trading. That's what we use for Japanese
16 LNG.
17 Same thing with Alberta. The Alberta ASO
18 price is large by Canadian standards, but very small
19 by Henry Hub standards. The two prices are virtually
20 totally correlated. The ASO price is approximately
21 one dollar less than the Henry Hub price and that's
22 because the production in Alberta is far from the
23 market. By the time the Alberta natural gas gets to
24 Sumas on the U.S. border, the price is beginning to
25 approximate the Henry Hub price. And all of that is
26 the common sense. If you have to transport it

1 hundreds and hundreds of miles, you have to pay a
2 price differential for it. Therefore, to get our
3 forward prices for Alberta, we use that basis
4 adjustment again through a statistical technique.
5 By the way, the statistical technique here
6 is amazing. 99 percent of ASO price differential can
7 be explained by Henry Hub. It's one of the benefits
8 of effective commodity trading. The moment there is a
9 differential, the traders move in and grab it.
10 So what do we do with this? Well, the
11 first thing is to determine what's the chance to buy
12 low and sell high. Well, the chance to buy low and
13 sell high was great during the Japanese crisis. But
14 it has diminished, and it is now staying diminished in
15 forward prices. In other words, you can buy these
16 commodities in the world markets. You can nail down
17 that price today.
18 Now, from the analysis we've done in
19 British Columbia, you probably need $11 in British
20 Columbia to get to FID. Now, that's not a fixed
21 number. It's not like it was written down. That's
22 where the Monte Carlo comes in.
23 And so at this point we do not assume that
24 we know tomorrow's LNG. We actually analyze, what's
25 the chance of getting the FID. Here is the Bell curve
26 for the Monte Carlo model. It takes those two million

1 cases, then feeds each of the two million cases
2 through a financial model of an LNG terminal. At the
3 end of it we have the expected return at FID for two
4 million cases.
5 **Proceeding Time: 2:48 p.m. T56**
6 This Bell curve is a summary of that. It
7 comes out to approximately 3 percent chance for a
8 terminal that is capital cost twice what we have in
9 the gulf coast.
10 Now, there are other changes. We save a
11 week on shipping. The week on shipping is probably
12 worth a dollar. And that takes it through the Panama
13 Canal, and then takes it to Japan and China, and
14 India. And there are other issues too. In the gulf
15 coast, Cheniere and its other plants are sitting next
16 to the fields. We are not talking about an LNG
17 terminal on the island getting its pipeline from
18 Alberta, we are talking about someone who is next to
19 the well.
20 Cheniere gets its natural gas at less than
21 Henry Hub. I never heard of that before, because we
22 never really had this situation before. So, it does
23 explain one point that British Columbia Hydro said
24 well, if it is so hard for us, why it's so easy for
25 them? Well the bottom line on this is, we know it is
26 easy for them, because they close the deals. They

have the long-term deals. They're expanding the long-term deals. They're laying down the additional trains today, they're selling from the new trains today. This is not hypothetical. You can simply check their audited financial statements and track each transaction, which is public, and each investment, which is public.

Now, simply through a bit of rancor and I'm not going to read these to you, I did look up the press yesterday on what is happening on LNG at the Calgary Energy Roundtable. I don’t frankly view this as evidence in a regulatory proceeding. But the fact is, I'm not the only person who has doubts today.

So, the other point they made is, well there will be a lot of LNG demand. Well that is a perfectly reasonable hypothesis. But the point is, it doesn’t have to be served from here. If you make more money serving it from another location, be it Australia, or the gulf coast, the new plants get built there. Again, as I said, no one did anything wrong in British Columbia. They simply stole a march on British Columbia.

By the way, this is a Canadian Energy Board, and frankly the matter is they have their jobs too, and I'm not going to waste time on that.

So, our analysis proceeded Deloittes, our

1 conclusions are more conservative than theirs are on
2 loads. They are more conservative on what we see on
3 A-22. I am not exactly sure why British Columbia
4 Hydro brought this up this late date, but they are
5 actually now firing at people whose forecasts are more
6 conservative. They are the more authoritative
7 forecasts from your staff and from Deloitte.
8 Pulp and paper. Basically they have about
9 10 pages on pulp and paper, of which two or three are
10 substantive, and the rest are a long list of how many
11 people they employed. That is fine. I'm sure every
12 person they employed was very smart. I have no doubt
13 about that. I know some of them, and they are
14 certainly as smart or smarter than I am. But the
15 point of the matter is not who they were, it's when
16 they did their opinion.
17 You've heard again and again that things
18 have changed. One of the things that has changed the
19 most is that we have a tremendous downturn in pulp and
20 paper. I put a list up of their experts, every one of
21 those experts are fine with me. I'm a little
22 uncertain why they were complaining about me with
23 pestilence, wildfires, and log supply. That's far
24 from my forecast. But even Mr. Schuetz is excellent.
25 I tried to date their studies. They seem
26 to be between 2010 and 2016. British Columbia Hydro

did not date, they did not explain where those put in. Basically that is a *tabula rasa*. The only piece of evidence that showed up in Appendix C on pulp and paper was this chart. You'll notice at the top I said a reduction of 500 six tonnes. The fact is, I think they meant 500,000 tonnes. You'll also note that the charge is for 25 years, but it ends at 2035. This is insignificant. This is just in evidence of how stressed we all are, that two large typos would appear on one chart. So, I have no doubt that this is a 25 year chart, and I am no doubt that that is 500,000 tons.

The problem is, so far this year the industry is down by a million tonnes. This year. We are not talking about a hypotheses. The area in yellow, both in the US and Canada are major mills contracting or going out of business.

Proceeding Time 2:53 p.m. T57

This is musical chairs and the firms are losing the game. What is means is that of those two industries that we saw in their initial filing, what we have is an argument that neither of them are going to see extensive growth. And again, load forecast, more detail, more authoritative than ours have been tabled to you, and they should be respected. But there is no logical argument that we're going to see

1 growth in pulp and paper or LNG and its associated oil
2 and gas use.
3 And I'm just going to mention this. The
4 situation is so harsh that we've now just started a
5 trade war between the two best friends over the paper
6 business. This is going to be hard fought. Not only
7 do we have a U.S. president without the judgment to
8 understand how important our partnership is, but also
9 we have companies that are facing immanent failure.
10 So why does this matter at this late date?
11 It really doesn't. We had an argument here that
12 should have been tabled weeks ago. There's not much
13 merit to the argument. I've walked through what we've
14 done, why we have very detailed models, why we have
15 excellent evidence. The fact is the bottom line is,
16 you've heard again and again from your staff, from
17 Deloitte, from other experts, the alternatives are
18 less expensive. That's the bottom line. And they are
19 environmental. Arguing about the component of the
20 load forecast, frankly, we crossed that bridge.
21 No one has successfully rebutted the
22 alternative resource estimates. The fact is, as the
23 very excellent presentation this morning on geothermal
24 noted, the Rockies don't stop at the Canadian border.
25 And that's certainly also true of the wind.
26 We also know that no one has rebutted our

evidence on the Big Columbia. We are not going to be able to sell that surplus at anywhere near its cost. Again, it's no one's fault. Last year was the lowest price on a mid-C in history. Next year is lower. The following year is lower. Those aren't forecasts. You can pick up your phone and buy and sell that energy today. And those are deep markets.

The only new evidence in A1-12, Appendix C is vintage and it's opinion. But it's not based on fact and it's not going to be constructive in you finding your answers. There's no reason for rancor. In a proceeding this intense, there are always moments when people misspeak. But the bottom line is these issues are not in debate. We have some economic challenges in front of us. And by the way, they occur on both sides of the border. The U.S. paper industry is in just as much danger as yours. But to ignore that data is simply inappropriate.

And if you allow me one more minute, and I've tried to be very fast because I want to respect your schedule. You know, you have an almost impossible task in front of you. You invited 17 wise men, 16 had very similar discussions. The last one was quite different. I have no doubt about his beliefs and honesty and hard work. But the issue is this simple. It looks like we have about 9 and a half

billion dollars out there. We could argue about the decimal places. We know we have sunk costs of about $2.1 billion. That puts us somewhere in the $7 billion go ahead price. That is not requirement a Monte Carlo model or the level of analysis here. This is simply being knee deep in the big muddy.

By the way, a lot of people liked the metaphor but none of them got it right.

And the alternatives as we've gone through them -- I was so impressed this morning by the geothermal presentation, and I'm not an expert on geothermal, but the alternatives have gotten so rich, there's been so much technological change in the last few years. I never heard of slim drilling before. And the issue of wind projects being announced, 2,000 megawatts of wind projects are under discussion on the U.S. side of the border at the moment. I mean, who would have dreamed five or ten years ago such a thing would occur.

We have Duke building the first utility grade scale solar array in North Carolina, filed with the Commission, prices to be reviewed. Not guessed at, not forecast, but actually reviewed by the Commission. So the wealth of alternatives and our ability to avoid what may well be a disaster is just enormous. And the best part of it is, all these

things are deployable. You need another wind farm, you literally can order it. Not quite on Amazon.com yet, but you can actually pick up the phone and purchase the turbines coming off the assembly line. This is a tremendous possibility.

Proceeding Time 2:59 p.m. T58

You've been very kind to me, Chairman, Commissioners. I'm very grateful for this chance to talk a second time. If you have any further questions I'm happy to answer them.

THE CHAIRPERSON: Thank you very much for making that supplementary presentation to answer our question. Thank you, sir.

MR. McCULLOUGH: Thank you very much.

THE CHAIRPERSON: Is BC Hydro -- we'll take a couple of minutes. Come on up and get ready and we'll just be back in a couple of minutes, thank you.

(PROCEEDINGS ADJOURNED AT 3:00 P.M.)

(PROCEEDINGS RESUMED AT 3:05 P.M.)

THE CHAIRPERSON: All right. The reluctant Commissioner is back, so we'll begin then, please.

SUBMISSIONS BY BC HYDRO (#0307):

MR. GHIKAS: I'll start. Thank you.

My name is Matt Ghikas, G-H-I-K-A-S, and with me as counsel is Bridget Gilbride, sitting over there, G-I-L-B-R-I-D-E. To my immediate right is Tom

Bechard, B-E-C-H-A-R-D. To his right is Randy Reimann, R-E-I-M-A-N-N. To his right is Michael Savidant, S-A-V-I-D-A-N-T, and to his right is Chris O'Riley, O apostrophe capital R-I-L-E-Y. And on the end is Andrew Watson, W-A-T-S-O-N.

And I will introduce them more formally in a moment, Mr. Chairman.

THE CHAIRPERSON: Thank you.

MR. GHIKAS: First of all, BC Hydro is very pleased to be here today to answer questions face to face. How we intend to organize our time today is I will introduce the panel and then the panel has a presentation that they'd like to make, and then finally we'll open things up to questions. But obviously during the presentation if there's any clarifying that needs to be done.

THE CHAIRPERSON: Thank you.

MR. GHIKAS: In terms of the presentation itself, we're cognizant of, you know, what you said earlier, Mr. Chairman, that the purpose of this ultimately at the end is to make sure you have the questions you have answered. We have organized the presentation to try to hit some of the key points that were raised in the information requests, and also we've been busy at work over the last couple of days trying to incorporate a lot of the things that we've heard coming up from the

1 various presentations, and we will deal with those as
2 best we can.
3 On that note, I would add that it became
4 apparent to us this morning, listening to Mr. Swain's
5 presentation and discussion of his analysis, that we
6 weren't aware that there was actually an analysis, and
7 I believe it's just a delay in posting some of the
8 things on-line. But I would ask that the Commission
9 consider allowing us to have an opportunity to read
10 that once it's posted and in the event that we have
11 anything further to say, I'd ask that you consider
12 that we be allowed to comment on that, or if there's
13 any others which we are unaware of.
14 THE CHAIRPERSON: As long as we can ask that you do it
15 as soon as possible, say by end of day Monday, that
16 would be appreciated.
17 MR. GHIKAS: Understood. Understood. And thank you very
18 much.
19 So with that, what I'll do is introduce the
20 panel members. We submitted a letter on Friday, it
21 hasn't been posted yet but expect it will be Exhibit
22 F1-13 that has more detailed bios. And what I intend
23 to do is just really highlight a couple of points just
24 to make sure that you are aware of why these
25 individuals were selected to be here today.
26 THE CHAIRPERSON: Yes.

1 MR. GHIKAS: So I'll start with Chris O'Riley towards the
2 end. Chris is the president and chief operating
3 officer of BC Hydro and he's an electrical engineer
4 with 27 years of energy industry experience, and in
5 his various senior roles he's managed plant
6 maintenance and operations, risk management,
7 environmental management, employee safety, dam safety,
8 dispatch planning and gas and electricity purchases to
9 meet load, and since 2015 Mr. O'Riley's been
10 responsible for BC Hydro's capital projects including
11 Site C.
12 **Proceeding Time 3:09 p.m. T59**
13 Mr. Reimann, second over here, is also an
14 engineer and he has 35 years of experience in the
15 electricity industry. Mr. Reimann is the director of
16 energy planning at BC Hydro. And he's held that
17 position for 12 years. He and his team are
18 responsible for developing the load forecasts and also
19 for resource planning.
20 Tom Bechard, to my immediate right, is the
21 managing director and head trader at BC Hydro's power
22 trading and marketing subsidiary, Powerex. And he's
23 been in that position for seven years. Mr. Bechard
24 has over 30 years of experience in the energy industry
25 and has extensive knowledge of Western electricity
26 markets.

1 Michael Savidant, in the middle, is an
2 analyst and project manager, and he has 15 years of
3 experience in the energy industry. He was the
4 commercial manager of Site C from 2007 to August,
5 2016, and he is responsible for the risk management
6 and the economic comparison of Site C to alternatives
7 at that time. In his day job, he's the finance and
8 risk lead on the Waneta transaction and in his spare
9 time he's leading BC Hydro's efforts on this inquiry.
10 Andrew Watson is a professional engineer
11 with 18 years of experience, and since 2007 Mr. Watson
12 has been the engineering division manager for Site C.
13 He is responsible for the technical design. And Mr.
14 Watson is the senior technical lead for the Site C
15 project, and previously he was also involved in the
16 design of other facilities and upgrades, including
17 Lajoie, Ruskin, Coquitlam, Mica, and Revelstoke. And
18 obviously, Mr. Chairman, there is a team of people
19 behind these folks that have been responsible for the
20 resource planning and project decisions.
21 You will hear, Mr. Chairman and
22 Commissioners, the conviction of these individuals
23 that based on their experience completing Site C is
24 the right thing to do for ratepayers, and no other
25 resource portfolio has the same combination of
26 flexible clean energy and dependable capacity. And

their conviction being based on three broad considerations: the first is cost; the second is relative risk; and the third is meeting the province's greenhouse gas targets. And under the terms of reference, Mr. Chairman, all of those considerations, in my submission, should inform the Commission's deliberations regarding the implications to ratepayers.

So with that, I would like to turn things over to Mr. O'Riley to start the presentation.

MR. O'RILEY: Good afternoon, Mr. Chairman, Commissioners, participants. We really appreciate the opportunity to address these issues today; the issues arising from the government's terms of reference. These matters have great importance to BC Hydro and we believe to our customers.

I've enjoyed the great privilege of spending my entire career at BC Hydro, starting as an engineer in training in the plants, and then through to my appointment as president and Chief Operating Officer in July. Over this time, I've done a range of jobs within the company, and with a strong tie to our hydroelectric plants.

Over my career, I've spent about a decade in generation, operations, working on and leading various aspects of operations, maintenance, and the

1 long-term stewardship of these assets. Between 1997
2 and 2004, I worked at Powerex during a period of rapid
3 growth as we successfully marketed the surplus
4 capability of the Hydro system in the export market.
5 And since 2005 I've had a growing role in
6 overseeing the delivery of capital projects for BC
7 Hydro, initially for generation and then since 2015
8 for transmission as well. And these projects have
9 ranged from a few million dollar projects, small
10 projects, to the one billion dollar John Hart
11 generating station redevelopment.
12 As with many BC Hydro employees, my career
13 has intersected with Site C at several points. In
14 2006 I led a small team that conducted a review of the
15 project as part of the so-called Stage 1 of the
16 project development process. Between 2013 and 2015, I
17 oversaw the energy planning group at BC Hydro, and
18 supervised the completion of the 2013 integrated
19 resource plan.
20 In January, 2014, I appeared before the
21 Joint Review Panel in Fort St. John into the Site C
22 project where I testified, or spoke, about a number of
23 the same questions that we're dealing with today. And
24 Mr. Savidant and Mr. Riemann joined me there as well.
25 **Proceeding Time: 3:14 p.m. T60**
26 And then during the summer and fall of 2014 I oversaw

the development of load forecast scenarios, and portfolio analysis that we provided to the government in support of its decision around the final investment.

Since mid-2015, I've been responsible for the construction of the Site C project as deputy CEO in charge of capital infrastructure project delivery. This is my 20th opportunity to appear before the Commission either as a witness or the executive responsible for the application, or in some cases both.

The value of hydroelectric generation has been a theme throughout those many proceedings. My first experience before the Commission was in the 2003 Heritage contract inquiry, where the question before the Commission was how to treat the imbedded economic value associated with our hydroelectric fleet, what became known as the "heritage value."

Among those 20 proceedings were five sustaining capital projects for the generators and dams, including the GM Shrum turbine replacement project, and the Bennett Dam riprap project. These were important projects to address the effects of aging on those assets, and they were examples of how we can, through careful, surgical investments, continue to enjoy the benefits of these very valuable

1 assets.
2 Also on the list of 20 proceedings were the
3 John Hart Generating Station and Ruskin Dam
4 redevelopment applications. In these two proceedings,
5 the Commission explored the end of life issues
6 associated with these hydro assets. And the outcome
7 demonstrated that these assets have long term economic
8 value to ratepayers, even beyond the physical lives of
9 the equipment. Which, in the case of Ruskin was 80
10 years, and in the case of John Hart was 70 years.
11 In 2010 I led the Waneta Transaction
12 Application where we acquired one-third of the dam,
13 and the question in that proceeding was the long-term
14 value of what was then a 53 year old dam. And then
15 finally in my most recent proceeding, that was the
16 salmon river diversion decommissioning project. This
17 was a low value dam that didn't merit reinvestment,
18 and our recommendation was to remove it, and the
19 Commission concurred with that, and that work was done
20 in September.
21 So, all of that brings me here today and to
22 the question of Site C. My work at BC Hydro has
23 impressed upon me a tremendous value of hydroelectric
24 generation, and the foundation it has provided for the
25 prosperity of our province. I have come to appreciate
26 that hydroelectric dams are unique assets in our

economy due to their long life and the continuous stream of benefits that they provide, particularly including low greenhouse gas emissions. No other production in our economy lasts so long and provides such valuable output without degradation over generations. For comparisons, I think you have to look beyond production facilities to major infrastructure such as highways, railways, and seaways.

The long life and the stable stream of benefits allows the twin forces of amortization and inflation to reduce the cost of the output over time, both in absolute and real terms, providing growing ratepayer benefits. None of the other resources we might consider as an alternative to Site C enjoy this fundamental characteristic, and I believe this is the underlying reason why the portfolio analysis for Site C are so strong, even before considering the sunk costs.

Before we get into the slides, I do want to acknowledge the impacts of hydro dams, and of this one in particular. While the benefits I spoke of are enjoyed broadly across our society and our province, the impacts are extremely hard felt under the footprint of the dam, the reservoir, and the transmission lines. And this is especially so for the

First Nations whose traditional territories are impacted, and for the folks such as Mr. and Mrs. Boon will have to move if the dam goes forward.

I know these impacts are not the focus of this inquiry, nor the questions before the panel today, but I do want to acknowledge them as we work through the material. The fact that we are not talking about them today, does not make them any less real.

Proceeding Time 3:19 p.m. T61

So here is the agenda for today. I'll start and I'll provide a current status of the project. Mr. Reimann will lead us through the load forecast and portfolio analysis. While this project is being built for domestic supply, an important part of our risk mitigation plan is how to deal with any surplus that arises. Mr. Bechard, the head trader at Powerex, will take us through the opportunities to sell energy and capacity from Site C in the export market, and then I will provide a short conclusion.

What I hope to leave you with, by the end of our presentation, dispute the challenges that we face, continuing with Site C is by far the best option for our ratepayers and we remain confident in our ability to deliver the project.

The Site C portfolio is superior to any

other portfolio of resource alternatives, and this is true before and after accounting for sunk costs. By taking advantage of the full capability of the upstream storage behind Bennett dam, Site C will provide a long-term source of firm, beneficially shaped energy, as well as valuable capacity that's critical to meeting system reliability.

As we've experienced with our existing hydroelectric fleet, the annual cost of Site C will become progressively cheaper for our ratepayers over time as the asset is amortized, and this is in contrast to our IPP contracts which typically increase in cost with inflation.

Finally, Site C is an extremely valuable instrument in the fight against climate change. This is because in part its own low GHG emissions, but also because it facilitates the integration of intermittent renewables into our system.

COMMISSIONER COTE: Mr. O'Riley, I hate to interrupt. By any chance do you have copies of your presentation? If you do, I'll take notes. If not, I'll pick it up later.

MR. O'RILEY: We could certainly provide them.

COMMISSIONER COTE: Yeah, okay, that's fine. Go ahead. I'm sorry. If you had them and you were give them at the end, I'd rather have them now.

1 Thank you, so that's fine. Sorry to
2 interrupt.
3 MR. O'RILEY: With Site C in our portfolio we will be
4 well positioned to support low carbon electrification
5 which is critical to B.C. and Canada meeting its
6 climate change commitments.
7 Site C is the lowest cost option by a
8 considerable margin. In present value terms, the
9 portfolio containing Site C has $7 billion lower cost
10 than the comparable alternative, and while we evaluate
11 portfolios in terms of NPV benefits, or net present
12 value benefits, I note that what ratepayers will
13 actually experience is the actual benefit, not the
14 discounted benefit that we see today, and the actual
15 benefit will, of course, be much greater than the $7
16 billion amount.
17 And this is a robust conclusion. We've
18 looked at quite a range of scenarios in response to
19 the Commission's request, and ratepayers are still
20 better off, in all cases, with the Site C portfolio.
21 THE CHAIRPERSON: Mr. O'Riley? You may be getting to
22 this and if you are, please just continue. But I've
23 looked at a lot of the 60 different scenarios, but
24 I've not seen a scenario that shows the ratepayer
25 impact of Site C if it's completed on time and on
26 budget. Is that one of the scenarios that's been

1 provided either in the application or in any other
2 form? All the scenarios seem to be a comparison to
3 something.
4 MR. SAVIDANT: So that's correct. We currently
5 forecast, do detailed rate forecasts out to fiscal
6 '24, which is one of the reasons we've focussed on
7 differential rate impacts in our analysis.
8 THE CHAIRPERSON: Right.
9 MR. SAVIDANT: That tends to be one of the more easy
10 ways to compare alternatives. We have done, for
11 previous proceedings, including the joint review
12 panel, we've updated the analysis for this proceeding
13 on what the actual impact of Site C is itself. So
14 what would happen to rates the year that it comes in
15 and the following years. So this is not a
16 differential rate impact.
17 And we have two scenarios we tend to look
18 at, one of which is if it's not smoothed out, if it
19 just occurs as a full cost recovery at the time it's
20 incurred and another scenario where it's smoothed out
21 over a period of ten years, the initial rate impact
22 using a regulatory account.
23 Using the smoothing option, what you would
24 see if Site C came in is a .5 percent rate increase in
25 fiscal '25, following .5 percent further rate increase
26 in fiscal '26 and then roughly flat rates for the rest

of the ten-year period. After that ten-year period is over, we expect the cost of Site C to be below the revenue we would be receiving from customers at that time, and we would expect the rates to immediately drop down 2 percent below where they are today -- sorry, where they would be at that time.

Proceeding Time 3:23 p.m. T62

And that gap would expand over time as Site C costs decreased. If we don't smooth it, we see an initial rate impact of roughly 5 percent in fiscal '25, and that would gradually decline to that same 2 percent after roughly ten years, and then continue to decline after that.

THE CHAIRPERSON: Okay, thank you, sir. Sorry.

MR. O'RILEY: We can certainly provide that in writing if that's the request.

THE CHAIRPERSON: I think that would be helpful if you could.

MR. O'RILEY: Yes, absolutely.

INFORMATION REQUEST

THE CHAIRPERSON: Thank you. Please go ahead.

MR. O'RILEY: Yeah, okay.

So if we were to terminate the project, ratepayers would pay $3.2 billion with nothing to show for it. And that of course includes the sunk costs, which are recorded today on our balance sheet, and the

1 termination amount. And those sunk costs must be
2 dealt with one way or another. They can't stay on the
3 balance sheet.
4 So at the risk of stating the obvious, $3.2
5 billion is an enormous amount of money in the context
6 of our revenue requirement, even if it were spread
7 over multiple years. And it would be an incredible
8 burden for our ratepayers.
9 We talked a lot about the risks with the
10 Site C projects and the challenging we were
11 experiencing, and rightly so. It's important to
12 remember, though, that the alternatives to Site C
13 contain risks as well, many of which have already been
14 addressed for Site C and are now behind us. The risks
15 in the alternative portfolio start with the
16 termination/suspension cost estimates. Both Deloitte
17 and BC Hydro estimated these costs to be greater than
18 $1 billion based on conceptual estimates, and the
19 actual costs could of course be much higher, given the
20 range.
21 The alternative resource portfolios would
22 require procurement processes which we know from
23 experience carry significant risk around the market
24 response and attrition. Individual projects would
25 face their own regulatory risks, consultation
26 requirements, and in some cases litigation.

We are concerned that many of the portfolios proposed in the preliminary report and in the October 11th letter rely on low probability, higher risk assumptions particularly around the development of technology. Having participated in three integrated resource planning processes myself, I do notice that in this process we seem to be giving a higher degree of consideration to unproven resources by which I mean resources that do not have commercial precedents in B.C. or in Canada. Examples would be geothermal and utility-scale batteries, which don't exist commercially today. And while it's -- here in Canada. And while it's important to cast a broad look at alternatives, I believe more weight should be given to proven resources.

We have a growing province and notwithstanding some weakness in our industrial sector in recent years, we believe that demand for electricity will continue to grow. And this is especially true given the fight against climate change. The move to a low carbon economy will require greater use of electricity, which is not reflected in our current load forecast. And this transition will require Site C in addition to other clean resources.

And we need capacity as well as energy. Capacity allows us to meet our peak loads and

1 integrate renewables into our system. The options for
2 clean capacity are much more limited, with resources
3 such as Revelstoke 6 already accounted for in our
4 plans.
5 I'm going to turn now to recent project
6 developments and their significance, and why I'm
7 confident that we can deliver the projects. As I've
8 said, I do have a long history with the project and I
9 remain closely involved in its execution. In
10 particular, I've been working closely and attending
11 all the senior executive meetings with the partners
12 that make up the main civil contractor, Acciona and
13 Samsung.
14 Next. I believe it is important not to
15 lose sight of how much we have accomplished on the
16 project to date. We are really 13 years into a 20-
17 year project, all of which started in 2004. First
18 Nations consultation has been going on for a decade,
19 and has been tested and upheld in courts. And we have
20 six agreements with First Nations impacted by the
21 project. We have key regulatory authorizations on the
22 project, and have more than 200 individual permits in
23 hand, 60 percent of the total.
24 **Proceeding Time: 3:28 p.m. T63**
25 Procurement is well advanced with key
26 contracts in place. The second largest procurement,

the generating station, spillway contract, is in the final stages with pricing available in November. And the designs are well advanced for the packages as well. And on July 27th as we began to prepare for this inquiry, we passed the two-year anniversary of construction. Significant progress has been made on the site, including with the key excavations. The important point being that as we have worked through these stages, the cost to complete is reduced, and the ratepayer risk associated with completing Site C goes down.

As a result of the disappointing news about missing the 2019 diversion milestone, we have postponed diversion to 2020. This will still allow us to complete the project by November 2024, as we've included one year of float in the schedule. Unfortunately it will increase the cost for the project forecast to be 610 million.

We included the one year of owner's float as part of our program of project risk management measures for Site C. We've included Owner's float at other key points as well, and this is a common practice on our projects, particularly aware there is seasonality affects, or outage dependent work. And recent examples include the Mica 5/6 project which we finished recently, and the Bennett Dam riprap project

which is underway. My experience has been that if you don't include float you won't stay on schedule.

There were many risks on the project, and of course it is a challenging project. But we do have resources and processes and partners in place to manage them, including the available contingency which remains significant and healthy.

I'm going to respond now to two questions. One was a question raised yesterday suggesting that there might be multiple budgets for the project. And I want to confirm that there is one budget for the project, and that budget is $8.335 billion, plus the $440 million risk reserve, full stop.

Throughout the project there have been, and will continue to be forecasts of cash flows for the work, and we expect those forecasts to change over time as we get better information. And we require those cash flow forecasts for all of our projects, including Site C, in order to manage corporately our cash and our debt requirements and to interact appropriate with the province. Cash flow forecasts are not budgets, and there is no budgetary approval that can be exercised through the forecasting process.

Given we've missed the 2019 diversion milestone, we will require a budget revision for the project, and we anticipate this process occurring in

1 November, and involving our board and the provincial
2 government.
3 The second question I want to address
4 relates to transparency, our transparency around the
5 announcement of the diversion milestone. Yesterday I
6 understand there were questions that raised doubts
7 about this transparency, as it was discussed in our
8 August 30 filing. So, I want to go through that
9 timeline in some detail.
10 On September 27th I met with senior
11 officials from Acciona and Samsung, where we concluded
12 that we would not meet the September 19 diversion
13 milestone. And this was due to the cumulative effect
14 of the geotechnical setbacks on the left bank earlier
15 in the year, and poor production in August and
16 September. These ultimately came to a head at the end
17 of September due to commercial differences between the
18 parties, and failure to reach an acceleration
19 agreement. Through the summer a joint BC Hydro
20 contracted team worked on options to re-sequence the
21 work and modify approaches to achieve the critical
22 milestone. We made good progress on this, through
23 early September, including development of an agreed
24 upon set of measures and a feasible schedule. And
25 this was signed off by the working group members on
26 September 7th, with the intent that it be recommended

to a sub-committee of executives from the parties in advance of the September 27th meeting I referred to.

One meeting was held where further work was identified to finalize the recommendation. A subsequent meeting was scheduled for September 25th, which the contractor did not attend. On September 27th, the CEO of Acciona expressed to me his view on behalf of the contractor, that the milestone could not be met do a concern about the risk profile around the acceleration measures and unwillingness to incur any costs for acceleration. Absent any agreement, I could only conclude that the milestone would not be met.

Proceeding Time 3:33 p.m. T64

To confirm, this delay has nothing to do with the delay in commencing of Highway 29 work over the summer. The Ministry of Transportation and Infrastructure, at the request of the provincial government is working on mitigation options for that delay to avoid impacting the project.

I was, of course, extremely disappointed at not meeting this critical milestone despite our best efforts and intense efforts to meet it. Two days later on Friday, September 29, we advised our Board and on Wednesday October 4th we advised the Commission through our IR responses.

I've gone back to review our August 30

1 submission to the Commission where we discuss this
2 issue. It's on page 37 of the filing and I believe
3 the submission is absolutely correct based on what we
4 knew at the time, while also conveying the outstanding
5 risk. And I stand by our submission.
6 BC Hydro and the contractor do hold
7 different views about the cause of the issues on the
8 left bank. Acciona and Samsung believe it's entirely
9 BC Hydro's responsibility, and we believe that
10 contractual responsibility for the issue is shared.
11 Going forward, we are developing a plan to incorporate
12 the contractors haul road, temporary haul road into
13 our final design for the left bank slope. We need to
14 disentangle the commercial issues and conflicting
15 claims and settle the costs, and we are proposing a
16 facilitated process to get through that.
17 There is one more question that was raised,
18 another instance where we were described as not being
19 transparent on this file, and it related to whether or
20 not the main civil work contract was on budget at
21 award, and I'm going to ask Mr. Savidant to respond
22 very briefly for this question, as he was responsible
23 for making that assessment.
24 MR. SAVIDANT: Thanks, Chris. So when we estimate at BC
25 Hydro we estimate a base budget which is our best
26 guess of what a contract will cost and then we

1 estimate contingency for a contract as well. So when
2 you see our risk assessment, there will be an
3 individual risk assessment for each contract.
4 That risk assessment isn't just for
5 construction, it covers design risk and procurement
6 risk as well. When we award a contract we actually do
7 expect, on average, to use some contingency. What
8 we've done at that stage is we've crystalized
9 procurement risk and in many cases we've transferred a
10 substantial amount of risk to the contractor as well
11 and reduced the amount of contingency we require.
12 So when we award a major contract like the
13 main civil works, we take a look at what the bid price
14 is that we received from our contractor and what we do
15 is we update the Monte Carlo analysis of the risks
16 that we retain after we've awarded the contract to
17 determine if that amount is within budget. That's
18 what we did on the main civil works, and when we look
19 at the bid price and the amount of contingency we
20 require for the residual risks, the budget was an
21 acceptable amount for that scope of work.
22 MR. O'RILEY: Thank you, Mr. Savidant.
23 So here is some implications we've listed
24 for the postponement.
25 There are several areas of work that are
26 not contingent on the river diversion and they now

have an additional year afloat for their execution, and these include completion of the placement of roller compacted concrete and the powerhouse excavation of the spillway and placement of roller compacted concrete in that area as well.

The additional float also provides more time for the generating station and spillway contractor to complete their work, and the delay in the diversion reduces scheduled risk and allows more flexibility in managing future issues.

Construction challenges are not unusual on large multi-year infrastructure projects and they were not unexpected on Site C. We knew going into this project that there risks to the project and we made sure we had the resources and contingencies to manage the project. This is why we had one year of flow to address the risk of a diversion delay.

There are additional cost risks on the project. We still have one major contract to procure the generating station and spillway contract, and we have about seven years of construction to go. However, nothing has occurred that would suggest to us we are facing the type of large overruns that have been speculated by some participants in this process, and in the Deloitte report.

We've made excellent progress on the

1 project to date and despite the delay in the
2 diversion, we still have the resources to complete the
3 project successfully on time.
4 I'm going to turn the presentation over to
5 Mr. Reimann now who will go through the critical load
6 forecast and portfolio analysis slides.
7 **Proceeding Time 3:38 p.m. T65**
8 MR. REIMANN: Thank you, Mr. O'Riley. My name is Randy
9 Reimann. I'm the director of energy planning. I'd
10 like to thank the panel for the opportunity to address
11 them today.
12 I've been responsible for load forecasting
13 and resource planning over the -- well, the resource
14 planning for the last 12 years. On our load
15 forecasting side, we have a team of experienced
16 engineers, economists, and statisticians whose entire
17 job is developing load forecasts. Similarly, our
18 resource planners are experienced engineers and other
19 technical specialists.
20 In addition to that, my energy planning
21 team works with teams across BC Hydro, including the
22 Site C team, Powerex, the demand-side management
23 group, rate designers, generation optimization
24 engineers, and transmission planners. And it is that
25 team, working together, with specialists from across
26 the company, that produces our integrated resource

plans.

Over my career I have seen many worlds. Starting in Alberta, where it was a gas and coal power system, and it was all about gas and coal. I've seen the market reforms and the introduction of competition, and the driving out of efficiencies. And now to a world where carbon has become more important than just economic efficiencies. And it's this fight against carbon that is driving the coal power plant retirements across North America and the world, and it is a driving factor behind the fast-paced development of clean resources.

My job is to ensure that we have an adequate supply of clean and reliable electricity, provide options and recommendations to our executive at BC Hydro, to achieve those objectives. And while we can talk about many possible futures that we can imagine, ultimately we must have resources that we can rely upon. These resources need to help the province move to a clean future, and Site C is one of those resources that will be needed.

I'd like to start off with a few comments about our load forecast. The next slide, thank you.

This graph was updated from the original August 30th application, and what it shows is the relative timing that we're talking about with the

1 range of load forecasts that have been included and
2 discussed. And the point of the slide really is that
3 we're talking really at the front end of Site C's 70-
4 year life. And you can see how the timing shifts,
5 based on our mid, low, and high load forecasts.
6 And as we've said many times, the capacity
7 is our greater concern. It's capacity that keeps the
8 lights on for the system. Energy is something that
9 you need to buy, but you can source that. It's
10 capacity at winter time when the nights are dark and
11 there's a cold snap over the area, and everybody has
12 high loads, that we need to be sure that we have an
13 adequate supply.
14 We've included in this graph the Deloitte
15 supply -- or load forecast scenario, net of the DSM.
16 Included in this, is the base DSM that BC Hydro is
17 pursuing. And we note that it falls between the low
18 and the mid forecasts.
19 Next slide. Now, this slide shows the
20 three major sectors that BC Hydro has in terms of the
21 forecast history over the last 15 years. And it shows
22 the impact of the 2008 recession, and what we take
23 away from this graph is that it's large industrial is
24 the most volatile load in the BC Hydro system. And I
25 think Deloitte and the Commission have both agreed
26 with that, that relatively speaking the residential

and commercial loads are stable. And they still are increasing.

We've noted in there where the weather events -- that's warm-weather events -- can have a short-term deviation to the load. But on average, and during colder winters, that load is still growing.

What happened in 2007 was a major shake-out in the pulp and paper sector, and we've heard a fair bit about that, and it is a North America-wide phenomena. And the degree of that economic recession, and the failure of the U.S. financial sector had a couple of effects: declining demand, but also exchange rates. And what that precipitated was a very major shut-down of pulp mills in B.C. at a rate higher than we'd anticipated. And pretty much that entire drop in the industrial load forecast was a result of four pulp mills going down and that continued again in the fiscal '16/'17 timeframe with Howe Sound Pulp and Paper.

This slide then shows over the past five decades what the load has been doing for BC Hydro.

Proceeding Time 3:43 p.m. T66

And again, it shows the 2007 and the impact of that industrial drop-off. But when one looks at the after load drop-off we are still seeing that and believing that load is going to increase. And we've made

1 adjustments for pulp and paper and what future
2 expectations are for further drops in our load.
3 The other thing that we're looking at in
4 here is that there has been a number of recessions
5 over the last five decades and it hasn't had that big
6 an impact on the load. The load keeps growing. What
7 happened in 2007/08 was an oddity and it is actually a
8 fundamental restructuring of a sector, the pulp and
9 paper sector. And really the question then becomes is
10 what is going to happen going forward?
11 THE CHAIRPERSON: Excuse me, sir. What are you
12 suggesting that that graph is showing, then? That --
13 MR. REIMANN: So if you look at '82 and early '90s you
14 can see the little blips in the curve.
15 THE CHAIRPERSON: Yeah.
16 MR. REIMANN: Those were actually -- '82 was a very
17 significant recession. And what I'm trying to suggest
18 is that that -- those recessions haven't stopped load
19 growth and changed the world. It was a slowdown, but
20 growth continues. We believe that what's happening
21 with 2007 now, this was a major shakeout of lots of
22 pulp mills, that's what explains it. The underlying
23 sectors outside of pulp and paper, residential,
24 commercial, light industrial, other industrial
25 sectors, continued to move up in growth.
26 THE CHAIRPERSON: So you're suggesting that, say, roughly

1 from 2006/2007 onward it appears to flatten out, is
2 actually still growing upwards, is that what you're
3 suggesting?
4 MR. REIMANN: That's correct. So if -- what shouldn't be
5 done is you shouldn't take the load right before the
6 recession and say that is the normal world, and now
7 look to the right and say the load stopped.
8 THE CHAIRPERSON: Right.
9 MR. REIMANN: It's not the load that stopped, it's a
10 whole bunch of pulp and paper mills that have shut
11 down because of that restructuring in that industry.
12 THE CHAIRPERSON: So they would've had that significant
13 an effect on the --
14 MR. REIMANN: Almost that entire drop from 2007 to 2009.
15 Virtually that entire drop is caused by four pulp
16 mills closing.
17 THE CHAIRPERSON: And then subsequent to 2009 it appears
18 flat, flatish subsequent to 2009?
19 MR. REIMANN: There was the one other major drop in the
20 2016 timeframe, which was the Howe Sound Pulp and
21 Paper.
22 THE CHAIRPERSON: Okay.
23 MR. REIMANN: And that shut off as well. But if you get
24 back up, like, for a second --
25 THE CHAIRPERSON: Yeah.
26 MR. REIMANN: So what we're suggesting -- and want to

1 point out that these graphs are an after DSM view of
2 the world. But if you take it from after the effects
3 of the recession and then start looking off to the
4 right, so outside of that grey band it is more modest
5 growth than what we saw before, but both the blue and
6 the red lines, residential and commercial, are
7 growing, albeit slowly. And we have reflected that
8 slower rate of growth, that's being seen now post-
9 recession onto our low forecasts.
10 THE CHAIRPERSON: So is that -- the other graph we were
11 just looking at, is that a weather normalized graph or
12 that includes the effects of weather?
13 MR. REIMANN: That is not weather normalized to my
14 understanding. I'd have to check that. I believe
15 it's not weather normalized. And that's --
16 THE CHAIRPERSON: Right. So if you took the weather
17 effects out it wouldn’t look quite so flat, is that
18 what you're suggesting?
19 MR. REIMANN: So I think you can -- sorry. You can see
20 it easier in the prior graph. The two years of '15
21 and '16, you can see that those were warm winters and
22 that dropped it a fair bit. '17 got back to more of a
23 normal winter. So, again, I'm trying to take it from
24 the 2010 timeframe out of 2017.
25 THE CHAIRPERSON: Okay. Sorry, I don’t want to belabour
26 the point. That's --

1 MR. REIMANN: Yeah.
2 THE CHAIRPERSON: Thanks.
3 MR. REIMANN: Okay. And so what this slide shows is now
4 what are the 2016 RRA forecasts on the basis of this
5 proceeding. It shows the band of the forecast and the
6 expected midpoint. And so, BC Hydro does -- the load
7 is uncertain. Forecasting is a difficult exercise and
8 we do always try to talk about a band. And we've done
9 our analysis, we've gone and done the calculations
10 across the band to see what the different load impacts
11 would be. We do try to be unbiased in our midpoint,
12 to say it should on average have an equal expectation
13 of up or down.
14 **Proceeding Time 3:48 p.m. T67**
15 Of course, I don't think anybody saw what
16 was coming in the 2007 recession and it took a number
17 of years for us to correct that.
18 COMMISSIONER MASON: Sorry, can I just clarify that.
19 You are saying that your midpoint forecast is an
20 unbiased estimate.
21 MR. REIMANN: That's what we strive to achieve.
22 COMMISSIONER MASON: Okay. So I can't remember the
23 exact year that Deloitte started their analysis but I
24 know it predates the significant recession, and I
25 think their calculation was something like 500 out of
26 700 points were over-estimates. How would you respond

1 to that?
2 MR. REIMANN: Yeah, when they looked at that, it took
3 the utility industry across North America a number of
4 years to understand just how significant the recession
5 was and what the impacts were going to be. And so
6 utilities -- when the recession first started
7 happening, everybody, not just utilities but financial
8 estimates, economic, econometric forecasts were all
9 saying thing were going to recover in the next year,
10 and so it took a while for the utilities to come down,
11 to realize, no, this recession is going to last for a
12 while and there's a new forward look.
13 But the way I'd respond to that is what
14 it's really showing is the pulp mill shake out and --
15 MR. O'RILEY: Excuse me. He's actually asking about the
16 historic record. I think he was going back to the
17 1964 --
18 COMMISSIONER MASON: I think it goes back to about
19 2000.
20 MR. REIMANN: Okay, thanks, Mr. O'Riley. I guess we
21 should really talk about both.
22 Back in 1964, I think we were at a
23 different point of Hydro's history where there was
24 very much a "build it and they will come" in the
25 development of the two hydro system and the large dams
26 was driving economic growth and it was believed that

that was going to go on for a while. So there's a whole bunch of those forecasts where it was believed that "build it, they will come" was going to drive the economic growth of the province.

I think the other major point now is on the 2007 recession, and when you look at those load forecasts and you look at numerous iterations of them, leading up to it, you can count all the points prior to that point dropping off, and you can count all of those as saying, "Oh, yeah, well you're way over-forecasting." And so it's -- once you realize that recession is happening, we missed it, well, that's one event. I don't see that as a fundamental miss of all the forecasts. And I think when we looked at our residential and commercial that they were a lot more stable.

But the message I would hope to leave people with when we go away from here is that the question is, is now the world has been reset and it's on a new path, and what does that look like, and is this a reasonable look looking forward given what we know today.

COMMISSIONER KEILTY: I have a question. We've heard from a number of participants that since the recession demand has changed and it won't return to the same growth rate. That that change behaviour in all

1 classes of customers. How does that fit with what
2 you're saying?
3 MR. REIMANN: We'd agree. We're seeing that overall
4 load growth in Hydro was somewhat under 2 percent and
5 1.6, 1.7 and I think we're down now about 1 percent,
6 maybe a little bit less, and that's what we have
7 reflected in our forecast going forward. Yeah, things
8 do appear to have slowed down.
9 And there was actually two times that's
10 kind of happened in history. Back in '82 was one sort
11 of fundamental shift where utilities were seeing ever-
12 increasing load growth. At a certain point they
13 stopped, from 5, 6 percent and started down to 2, 3
14 percent. That persisted for a while. It does appear
15 to have done another step down.
16 So I just wanted to make a couple of
17 comments on LNG, that we still do have loads reflected
18 in there. The loads that we have is an ancillary load
19 for one facility and two smaller LNG facilities that
20 would be fully electrified. Our observation would be
21 that there is an electrified LNG facility in the
22 world. That's Stat Oil in Norway, and there is
23 another one, I believe, being built in Oregon south of
24 us that I believe is all being electrified as well.
25 So.
26 **Proceeding Time: 3:53 p.m. T68**

THE CHAIRPERSON: Are those the only LNG facilities in your forecast?
MR. REIMANN: Yes.
THE CHAIRPERSON: There is none -- if you extend further out in your forecast, there is no other LNG load built in to any part of your forecast?
MR. REIMANN: That's correct.
THE CHAIRPERSON: Okay, thank you. And it's not included in electrification?
MR. REIMANN: The LNG load? No.
THE CHAIRPERSON: Like switching from natural gas to electricity is not considered electrification when you look at the effects of electrification in your load forecast. Is that a true statement?
MR. REIMANN: Yeah, so if the question is, does the -- and I'm going to just speak about the green line. During the electrification study, if you're asking whether or not that includes electrifying LNG facilities?
THE CHAIRPERSON: Correct, yes.
MR. REIMANN: The answer is no.
THE CHAIRPERSON: Thank you.
MR. REIMANN: Yeah. So yes, on that green electrification line, that was a study we'd done about electrification potential review for the 2013 IRP, and

it was done by MKJA Associates, which is Mr. Jaccard's -- or was Mr. Jaccard's consulting firm at the time, and they have since gone their separate ways, and it is now Navius. And what they had looked at was different ways that the province would respond to getting to an 80 percent reduction by 2050. This was the upper end of that, but none of those cases actually achieved the 80 percent in that study.

And what we note from that is that by fiscal 36, electrification load could drive up to the top end of our load forecast uncertainty band, and grow from there. And it is our believe that, similar to Dr. Suzuki yesterday with his impassioned plea about needing to do something to save the planet and to move forward with carbon reduction, and I would agree with that view. I don’t necessarily agree with his electricity resource conclusions, but this is something that to our mind is happening, and cities around the world, like the City of Vancouver are leading that charge. And we had highlighted in one of the IRs an additional study that we'd just undertaken with Navius and the City of Vancouver that shows the trajectory under three different ways that they can go to get their carbon reductions and move to their 100 percent renewable energy by 2050.

THE CHAIRPERSON: On that note, I think we heard

1 yesterday, or possibly today I can't remember now, but
2 we've heard that hot water heating is considerably
3 more expensive under an electricity scenario, and
4 we've also heard that replacing electricity with
5 ground source heat pumps in -- certainly urban areas,
6 city of Vancouver, for example. That their zero-
7 emission policy also includes district heating
8 systems. And it would seem to me that that could
9 reduce the amount of residential electricity growth.
10 Is that something that is included in your
11 forecast?
12 MR. REIMANN: Yeah, so the district energy systems that
13 the city is looking at, just to be clear, as my
14 understanding, those aren't intended to be gas fired
15 by heat power.
16 THE CHAIRPERSON: Correct, but they could be sewage or
17 heat recovery, they could be ground source heat pump.
18 MR. REIMANN: Right.
19 THE CHAIRPERSON: They could be biomass, they could be a
20 number of different sources for heat and hot water.
21 MR. REIMANN: Agreed.
22 THE CHAIRPERSON: Which would -- or I should ask you,
23 would that then displace electricity as a source of
24 energy for heat and hot water?
25 MR. REIMANN: Or be a more efficient use of electricity
26 to drive it, because it might need compressors still

in the pump --

THE CHAIRPERSON: Correct, you'd still need electricity, I agree.

MR. REIMANN: That's right, yeah. We tried to look at a broad swath of technologies and different pathways to get to the 100 percent clean energy, and those are hopefully are all reflected in that study.

THE CHAIRPERSON: And they are reflected in your load forecast?

MR. REIMANN: So, I mean, that's a great point. So, what we have not done is put the electrification load into our load forecast within those grey bars. We kept it out as a separate item, believing that this is actually -- in my mind this is a paradigm shift. This is a shifting of the world, moving away from straight economics to saying the environment is more important and we need to reduce those carbons, notwithstanding that will be more expensive.

THE CHAIRPERSON: Right.

MR. REIMANN: And so we put it out there as a separate item for the Commission to consider, but not because we don’t think that that's going to drive load forecast in the future.

THE CHAIRPERSON: Okay, thank you.

Proceeding Time 3:58 p.m. T69

MR. REIMANN: So, I'm going to move on to the portfolio

analysis. Okay, next slide.

So, the message that we'd like to leave the Commission with is that we've ran quite a number of scenarios and tried to be responsive to all of the Commission's requests in terms of those future price decreases that they had requested. And we tried to look at those in combination with cost overruns, low load growth, and what we had viewed as optimistic cost assumptions regarding the alternatives.

And at the end of the day, the results show that there still is a PV benefit to complete a portfolio with Site C in it, versus a portfolio without it. That's kind of our key message.

Just before talking some more about the portfolio analysis, I did want to make a few comments about portfolios versus UECs, and on this question of double-counting. And we hope that we made it abundantly clear, but in our view, you need to do a full portfolio analysis to understand all of the impacts. And I might even say that our portfolio analysis doesn't get all the impacts either, and Mr. Bechard will talk about some of the market values that we don't model. But in order to understand resource timing impact, the characteristic of resources, what happens with surpluses, and how the market value can impact costs, we think that you need to run these

1 portfolios and you need to do so over an extended
2 period. Very short snapshots tend to distort the
3 results you're seeing.
4 There's been a lot of debate about UECs,
5 unit energy costs, and what they should be used for.
6 And we struggled with this for years. And the problem
7 with UECs is that it's very difficult to make
8 adjustments with them to account for some of these
9 factors. And so how do you translate decades of costs
10 into a single UEC number, and have that become
11 meaningful? And those adjustments get difficult.
12 So while we do use UECs as a screening
13 tool, and it can often help to explain relative costs
14 because it's a number, maybe, that people understand
15 the magnitudes of, we find it far easier ourselves to
16 do the portfolio present-value analysis.
17 In terms of the double counting that we
18 heard about, we have in the application done adjusters
19 to the UECs for capacity in a couple of different
20 ways. And so we did the resource options. The
21 resource options report was intended to show the
22 energy costs that a resource would contribute. And in
23 order to make all resources comparable, some resources
24 like biomass have capacity, other resources like wind
25 or solar don't. And so when you look at the cost of
26 the facility, are they equal? And the answer is just

1 no. So what we do is, we give a capacity credit to
2 the biomass and drop the net value of energy, so
3 you've got an energy only product. That's what we've
4 done in our resource options report.
5 In section 5(6), I think, when we did the
6 Site C comparator and we did the block UEC
7 calculation, we now wanted to create an alternative
8 resource UEC. And in order to make it equivalent to
9 Site C, rather than taking a capacity credit to Site C
10 and changing its UEC, we added a capacity cost to the
11 other portfolio.
12 And so the important point of the thing is,
13 you either need to have a capacity energy price and
14 adjust it to be equal, or an energy-only and adjust it
15 to be equal. The important point of that is that we
16 never do both at the same time. Those are done in
17 separate ways for separate reasons.
18 The other area that there was some comments
19 on was about the wind integration cost. And the wind
20 integration cost isn't again another adder to get
21 capacity into the wind portfolio. It's to recognize
22 that wind is a highly volatile resource, and you can
23 never really predict how much it's going to change.
24 And so what you need in a portfolio
25 including wind is, you need to have enough capacity to
26 meet your peak. Once you've got that, if you've got

1 wind in there versus even run-of-river or solar, that
2 are more predictable, you need to reserve part of the
3 system because you don't know what wind is going to
4 do. That requires you to take resources out of your
5 portfolio that you can benefit in the trade markets.
6 And so there's many -- most utilities do
7 wind integration cost adders and we do that to reflect
8 the impact on the market or the trade value of the
9 portfolio.
10 Okay, next slide.
11 **Proceeding Time 4:03 p.m. T70**
12 So we had looked at a low probability,
13 high-risk portfolio in which we tested a 50 percent
14 project cost overrun with load growth and highly
15 optimistic assumptions, and it was really difficult
16 for us to find a scenario in which a termination makes
17 sense. And in order to get to that cross-over, you
18 really have to start shortening the period over which
19 you consider the benefits, and we don't think it's
20 appropriate to do that. Next slide.
21 So this slide shows the range of UECs and
22 it just makes that point that from our initial August
23 30th sensitivities that we still feel are appropriate,
24 the Commission had asked for the sensitivities, and
25 those are over on the right side, and then BC Hydro
26 tested one in between that we tried to judge, and

1 we've answered this in the IRs. If we were to say
2 this is what we would view to be an optimistic low
3 alternative resource cost scenario, that's how far
4 we'd be comfortable to go, but in all of those cases,
5 the portfolio PVs were positive in favour of
6 completing the project.
7 And so what was driving that value, the key
8 factors? One for sure is that Site C is a long-lived
9 asset and its value increases over time as you
10 depreciate the costs and it continues to provide all
11 of those capacity integration and storage benefits.
12 It's also the $3.2 billion of sunk cost and
13 termination remediation cost, and recovering those
14 from ratepayers in the alternative portfolio is a very
15 significant cost to recover.
16 And what we found is, notwithstanding a lot
17 of cost price sensitivities at the Site C project
18 completion was still less expensive.
19 So our view is that, as you do resource
20 planning it should be done on reasonable assumptions
21 about repairs we'll pay, and as we start to rely on
22 probability assumptions -- or low probability
23 assumptions in system planning, it becomes risky and
24 it poses cost risk on ratepayers, and the further that
25 you push what might happen at some point in the
26 future, the higher that risk is, and you need to start

1 thinking about that.
2 So we listed a number of factors that we
3 wanted to highlight for the Commission that we felt
4 were low probability and high risk, the first being
5 Hydro financing and building the IPP projects. We'll
6 come back to that one.
7 The geothermal. Geothermal, I'd hoped for
8 years that we would get geothermal bid into our calls,
9 and I think it would be a wonderful resource, because
10 if you can find it and prove it, it's firm and it's
11 got capacity. But our view on this is that it is just
12 highly risky and that there's nothing that we've seen
13 that any of these reservoirs have been tested, drilled
14 and explored in the province, and we've had failed
15 efforts ourselves. Others have worked on the Meeker
16 Creek in the 2000s and never managed to land it.
17 And we've had over 30 wells drilled in that
18 supposedly prime location and it's never gotten to the
19 point of a confirmed geothermal resource.
20 COMMISSIONER COTE: When did you leave that behind?
21 Was that in the early 2000s?
22 MR. REIMANN: Oh, Hydro's efforts in that were in the
23 '80s, and I believe we spent, like, tens of millions
24 of dollars on it at that point. It was picked up by
25 Western Geothermal in the 2000s and we had anticipated
26 that they were going to bid in to the 2006 call, but

1 as I understand it, when they were doing some of their
2 hot water drilling, they ran into fault lines and they
3 lost their water and so they didn't have any hot water
4 reservoir to generate with.
5 COMMISSIONER COTE: Okay, thank you.
6 THE CHAIRPERSON: We heard this morning, though, that I
7 guess there's been a lot of development in drilling
8 technology especially in Western Canada and that
9 perhaps that assessment, you know, could be looked at
10 in light of that evidence. And that there are, in
11 fact, a couple of projects that are approaching some
12 sort of viability. I don't want to restate what the
13 testimony was this morning, but it seemed more
14 optimistic than you are portraying it.
15 **Proceeding Time 4:07 p.m. T71**
16 MR. REIMANN: It always does.
17 THE CHAIRPERSON: Yeah.
18 MR. REIMANN: Yeah. We've heard these stories for
19 decades, but --
20 THE CHAIRPERSON: It's still your position that it's not
21 viable?
22 MR. REIMANN: You know what? If the drilling techniques
23 have improved, and so we've commissioned -- jointly
24 commissioned with Geoscience BC a study in the last
25 couple of years to look at what development could be
26 and try to take our best estimate at that. And

1 Geoscience BC brought in Kerr Wood Leidal, and they
2 brought in a geothermal expert from the States to work
3 with them, GeothermEX I believe is the company.
4 And they have an advisory board of
5 geotechnical experts in the province to advise them
6 about the studies. And what it showed was, and that's
7 ultimately where we assume this 200 megawatts of
8 geothermal possibly could come from, even though we've
9 got no knowledge that it actually exists. But they
10 did their best assessment. If you assume you have a
11 number of skinny wells drilled, and that works well,
12 and then a few more wide-bored wells, and that goes
13 well, and then you finish off in your production. And
14 if that happens, you might get into the $80 a megawatt
15 hour to $120 a megawatt hour. But that all assumes
16 that those drilling costs all go well. And if they
17 don't, well, that's when costs just balloon on you.
18 THE CHAIRPERSON: Okay, thank you, sir.
19 MR. REIMANN: When we did that review, what we'd
20 understood is that the financing costs for these
21 projects, in those initial phases of drilling, is
22 extremely expensive. And that reflects the risk of
23 drilling and finding -- or not proving out that
24 resource.
25 But I did want to add just a couple of
26 comments about Iceland. And it was something that the

1 Commission had mentioned is that Iceland is a
2 geothermal haven. And it's an indication of at least
3 one place in the world where geothermal seems to be
4 successful, and --
5 THE CHAIRPERSON: I don't know if we used the word
6 "haven", but okay.
7 MR. REIMANN: Okay. Maybe that's my word, okay. And you
8 know what? We looked at it and heard some interesting
9 comments about -- that Iceland is one of the few
10 places in the world where the tectonic plates are
11 formed and come together, such that this deep mantle
12 material comes to the surface above sea level. And I
13 take that just to mean, there's a lot of hot rock
14 there, and they've got good green and whatnot. So, I
15 guess you only need to look at the pictures at all the
16 steam rising to realize that there's a lot of
17 geothermal there. So it's an ideal location to
18 develop it.
19 But interestingly, when we looked at it,
20 and I think the least risk development of geothermal
21 is for home heating, and for heating sources, and nine
22 out of ten homes in Iceland, from what I understand,
23 are heated with geothermal energy. And that's an
24 excellent application, because you don't need the
25 really big body of hot water and big reservoir.
26 And they have been working since the 1970s

on developing these geothermal resources. And they now get about 25 percent of their electricity, which I understand is about 650 megawatts, and so they've been developing that since the 70s. And the other three-quarters is by and large large hydro. Which is kind of interesting. And looking at some of their current thinking on this, there's discussion papers out there about needing to do a de-risking of geothermal electricity plant development by doing reconnaissance, geological, geochemical, and geophysical studies.

And so, after decades of doing this, and getting themselves up to 650 megawatts, they are still at a point now where they view this as a very risky undertaking. And they're looking at ways to refine their approaches to try to bring this cost down, is what I'm assuming. But -- anyway, I thought that was interesting. And it really spoke to me about just how much geothermal was, and the pathway they've walked to get there.

Next slide. Oh, sorry. 50 percent cost overrun on Site C, I think that one speaks for itself. Next slide.

In this one, we just talked really about the wind cost declines, solar and battery. The battery declines is maybe more speculative than in terms of what those future costs might be, but wind

1 and solar, in our view -- these are impressive
2 declines. And we've looked at like the International
3 Energy Agency and Enrol doing surveys of experts
4 trying to crystal-ball futures and taking averages of
5 people guessing those futures. And it was our
6 impression at the end of the day that what the
7 Commission was proposing was probably on the upper end
8 of even those crystal-ball estimates.
9 **Proceeding Time: 4:13 p.m. T72**
10 In terms of upgrades to the Hydro facility
11 refurbishments, generally speaking Hydro puts those
12 into a sequence and develops them as it makes sense.
13 And one of the considerations is that most of them
14 require you to take a plant out of service prior to
15 making the refurbishments and bringing it back in to
16 get some upgrade. So, you really have to think about
17 when you do it, and if you try to do all of those too
18 quickly, you will face cost risks. And so we don't
19 think that those can come in as a large block like
20 that.
21 On the biomass side, there is a lot of
22 uncertainty about low cost fibre. It is not so much
23 fibre availability, it is low cost, because there are
24 trees out there, it is just that they are remote, and
25 to cut them and haul them to burn them is not cost
26 effective. It needs to be done in concert with other

forestry ventures like sawmills and pulp mills and taking roadside debris and wood waste. And so to us this is anything over what we've really got identified in there is risky, and we note that quite a number of the biomass contracts that we signed were ten year contracts and I think there is a reason for that. And it is fuel uncertainty.

I'd like to hand it over to Mr. Savidant, he'd undertaken relative portfolio risk assessments in response to a commission request.

MR. SAVIDANT: So, what we've tried to do with this risk assessment is, is really kind of take together those assumptions that Randy has highlight in the previous -- sorry, Mr. Reimann has highlighted in the previous slides, and consolidate those into an overall risk assessment of the portfolio. You will have seen the first two portfolios in our previous filings, but we hadn’t had time in the previous filing to do an overall risk assessment on the portfolios that popped out from when we ran the detailed Commission portfolio sensitivities.

I just want to highlight a few areas of difference here. In terms of availability risk, we don’t actually find the Commission portfolio sensitivities different than the alternatives we've looked at. While we did allow for geothermal to be

1 picked in the scenarios, it wasn't picked up as the
2 lowest cost resource. We still ended up with a set of
3 alternatives which were wind, a bit of biomass, pump
4 storage, just with larger cost declines. Those are
5 generally resources that we believe are available and
6 achievable, and there is not a lot of risk associated
7 with them. If we were to move to a higher geothermal
8 basis in that portfolio, we would anticipate that risk
9 to increase.
10 THE CHAIRPERSON: But that would be based on the risks
11 that you have associated with geothermal though, would
12 it not? The reason that geothermal comes up as more
13 risky is because it is your assumption that it's more
14 risky because the potential isn't there. It is a
15 discussion we just had.
16 MR. SAVIDANT: I'm not sure --
17 MR. O'RILEY: I think what Mr. Savidant said is that in
18 the Commission portfolio, the geothermal was not
19 picked up because there were other lower cost
20 resources.
21 THE CHAIRPERSON: Right.
22 MR. O'RILEY: So I don't think we're making a judgment
23 there on the risk, we're just saying there are other
24 resources that come ahead.
25 THE CHAIRPERSON: We are talking about the procurement
26 risks, now, are we? The availability risk?

1 MR. SAVIDANT: The availability risk.
2 THE CHAIRPERSON: And that's based on costs?
3 MR. SAVIDANT: Availability risk is based on whether or
4 not, if you actually do drill those resources, are you
5 going to find them in a sufficient amount.
6 THE CHAIRPERSON: Right, and it's your assessment that
7 that is a risky venture, is that correct?
8 MR. SAVIDANT: That's correct.
9 THE CHAIRPERSON: So that would be an assumption you've
10 programmed into the portfolio, correct?
11 MR. SAVIDANT: The portfolio, in the portfolio is here --
12 THE CHAIRPERSON: Into the portfolio analyzer?
13 MR. SAVIDANT: The system optimizer product doesn’t
14 consider the risk associated with the project except
15 in the cost. And when we've put in, I think we've put
16 in roughly 200 megawatts of available geothermal
17 resources in those sensitivity scenarios, the costs
18 were based on the cost range that Mr. Reimann talked
19 about early. $120 per megawatt hour. That is
20 assuming things go right. If things don’t go right,
21 and you're assuming that the cost is a lot higher,
22 then the cost would increase. But we haven’t
23 considered that in the system optimizer, which is why
24 we've done the separate comparative analysis.
25 THE CHAIRPERSON: Okay.
26 MR. SAVIDANT: So, the point being, if the system

1 optimizer popped out portfolios with a large amount of
2 geothermal resources in them, we would view those as
3 risky portfolios to go ahead with. We would be basing
4 our assessment base --
5 THE CHAIRPERSON: So to summarize, I think what you're
6 saying is that you're assessing the Commission
7 portfolio as risky because it contains geothermal
8 generation?
9 MR. SAVIDANT: No, in this case we're saying that we did
10 not increase the availability risk. You'll see it is
11 equivalent to our alternatives, because it did not
12 include geothermal. If it had picked up geothermal,
13 we would have assessed the availability risk as
14 higher.
15 THE CHAIRPERSON: Okay.
16 **Proceeding Time 4:18 p.m. T73**
17 MR. SAVIDANT: Regarding procurement risk and moving to
18 that, we are procuring similar products as we would
19 expect in the B.C. Hydro alternatives, but we are
20 making much more aggressive assumptions around cost
21 declines and there we do see higher risk of those cost
22 declines not materializing.
23 So when we look at procuring, there would
24 be a substantial amount of capital expenditures to
25 procure under that scenario, and there would be
26 substantial risk associated with that, and the cost

1 materializing when we actually go out to procure.
2 Then moving to design and permitting
3 construction, under our BC Hydro alternative, we tend
4 to have lower risk under that scenario because we have
5 transferred a substantial portion of that risk to the
6 IPPs who construct those facilities. If, however, we
7 were going to move them back onto our balance sheet as
8 we've looked at under those sensitivity scenarios,
9 that risk comes back to us. So what we would be doing
10 is we would be going out and constructing and
11 financing a large portion of, in this, wind, biomass
12 and pump storage on our balance sheet with the
13 corresponding risks. That increases the risk
14 substantially both because of the volume of spending,
15 it's a substantial amount of money, as well as the
16 fact that we don't really have the in-house expertise
17 to build those facilities. It tends to increase the
18 risk over the other portfolio.
19 The other risks are generally equivalent to
20 our previous assessment. We don't see a substantial
21 change in the operations risk or the load variance
22 impacts. Expiry is something we're still having a bit
23 of difficulty getting our head given the difference in
24 construction model, but it likely wouldn't be
25 unusually high.
26 So that's really taking what Randy took you

through in terms of those assumptions.

THE CHAIRPERSON: A question about the design permitting and construction risk. So according to that, you consider that wind, biomass, and pump storage has a higher design permitting -- has a high risk of design permitting construction, whereas Site C has a moderate risk. Now, is that because Site C has already moved through a of of the design and permitting, or do you feel that the portfolio is inherently more risky than building Site C?

MR. SAVIDANT: It's primarily the former. If you look at the amount of spending left on Site C in terms of today's real dollars, there's also inflation on top of that, it's roughly $5 billion. If you look at the amount of spending we'd have to make under the Commission portfolio sensitivity for wind, biomass, and pump storage, you're roughly 50 percent higher than that. It has a lot more risk.

THE CHAIRPERSON: Thank you.

MR. SAVIDANT: Back to you, Mr. Reimann.

MR. REIMANN: So we'd like to move onto a few comments on the Commission's October 11th scenario and these are the topic points that we will hit. Number one is -- and it's a key point here that when we do our portfolio analysis, there are resources that are low cost and will be built very early on in a portfolio,

and we do our analysis over the 70 years. These low-cost ones will typically be built up in the upfront period, and it's often only a shifting of a number of years as opposed to an alternative resource. And so, that includes that Hydro would be expecting to be doing IRP DSM levels with or without Site C.

And if you just look at those as a comparison, we think you're under-viewing the value. It's too short term and it doesn't really compare the longer term value of Site C as an asset. We've tried to make that point perhaps a little more clear with this graph.

And so this is a graph that shows the capacity additions that would happen by 2047, and what you can see at the bottom is that demand-side management, there would be, by 2047, slightly more because we'd be pursuing those DSM programs earlier, but very similar volumes of DSM. The Revelstoke unit 6 would be built in both. There would be less IPPs on the Site C side, but Site C's capacity would be in there, and the key difference between those two, by the time you get to 2047, is really the amount of pump storage you build.

And so if we were to think about the same thing on an energy side, as opposed to pump storage being the big difference, what you would see is that

it would be wind resources. And so it wouldn't be DSM as the key alternative to Site C. That would be built in both. It would be wind.

COMMISSIONER MASON: So just go back to that slide for a second. So this is capacity you're measuring. Is this the total capacity in your system? What is it?

MR. REIMANN: These are the additions that would happen.

COMMISSIONER MASON: The additions. Between when and when, sir?

MR. REIMANN: 2024 to 2047.

COMMISSIONER MASON: Okay. so the OIC that we're looking at and talked about an alternative portfolio with similar characteristics to Site C, which is the 1100 megawatts, roughly, right?

MR. REIMANN: Right.

Proceeding Time 4:23 p.m. T74

COMMISSIONER MASON: So I'm struggling to see how this quite addresses or in any way invalidates any assumptions that one might have around DSM when looking just at the capacity as an alternative to Site C when you're looking at a much different figure?

MR. REIMANN: Right. And so what we're saying is we really think you need to look over the long-time and think about the changes over a portfolio, because we would be building DSM resources anyway for the capacity, and energy benefits, and the very low cost

they are, so we're arguing that that is not the alternative to Site C.

And what we showed in our very simplified block UEC in section 5-6 was wind and pump storage. And this is why, is at the end of the day it's those resources that would be built to different volumes. We do as much DSM as we think we can reliably deliver. It tends to be low cost, it gets done first, customers love it, it's environmentally benign. So that's kind of being done anyway. Where is the real shift in these two approaches to how we're going to meet the future world?

COMMISSIONER MASON: So you're saying that increasing DSM spending and having an associated reduction in the need for capacity, are you saying that's not a valid alternative to Site C in the early years when one might have a short-term capacity gap?

MR. REIMANN: So if you were going to look at the value in, say, the first five years, then the answer may be yes. If you were going to go from year six to year 70, the answer would be no.

COMMISSIONER MASON: Okay.

MR. REIMANN: There was some confusion about the amount of DSM that was being pursued and people trying to understand whether or not we continue to invest DSM, and we just wanted to make sure that in picking DSM as

1 the alternative to Site C that the Commission wasn't
2 thinking we weren't pursuing Site C -- or weren't
3 pursuing DSM.
4 And so, what this graph shows is how
5 different savings that we've developed from DSM
6 expenditures, savings that we get from customers,
7 there is a period over which we calculate that we've
8 impacted what the load would've been in any rate. And
9 so, if we incent to somebody to buy a new fridge and
10 the fridge is going to last 10 or 15 years, then the
11 savings we've gained last for those 10 or 15 years,
12 and after that a new decision comes.
13 And so, what it shows is that over time the
14 past programs and the savings you get from that, they
15 decline. And so, then what we've done is layered on
16 the additional blocks of DSM that we'd be pursuing and
17 we keep adding to that. And what it shows ultimately
18 is that for a particular level of DSM expenditure, at
19 some point you are investing at the rate that just
20 offsets the -- when the persistence falls off. And it
21 looks like DSM flat lines. It's not. We keep
22 investing in it to get up to that savings level.
23 THE CHAIRPERSON: So just to be clear, what we're looking
24 at here, this is your DSM plan. Is this part of your
25 ten-year rates plan, for example, and beyond? And
26 this will -- and this level of spending will be in

place regardless of whether Site C continues or doesn't continue, is that correct?

MR. REIMANN: That's right.

THE CHAIRPERSON: Okay.

MR. REIMANN: We do have -- like, the RRA level of DSM that we spoke about in the RA?

THE CHAIRPERSON: Is that what this is?

MR. REIMANN: I believe so, yes. And then we did model in the portfolios to go beyond the RA level of DSM to an IRP level of DSM.

THE CHAIRPERSON: Right.

MR. REIMANN: And then we did a sensitivity of DSM plus that looked beyond that.

THE CHAIRPERSON: Okay, thank you.

MR. REIMANN: Okay. Next slide. So this slide really just speaks to Hydro's role is not to develop the resources that IPPs have historically been developing. And we think there's good reasons for this and it's a long-standing policy.

And the independent power producer sector developing these many and varied resources really dates back to the 1978 *PURPA*, or *Public Utilities Regulatory Policy Act* in the States that really sought to have third parties look for new generation alternative to help utilities reduce the cost of generation. And in those days if you could beat an

avoided cost you got a contact. And that really set the mold. And in B.C. we have been buying IPPs in that fashion since the '80s. In the '80s we had bought run-of-river resources. In the '90s we bought gas and biomass.

Proceeding Time 4:28 p.m. T75

And since in the 2000s we've had open calls, biomass calls, so we haven't been in this game for decades. And so our belief about this is that resource exploration and development is something that's well-suited to IPPs. They have innovative concepts and they're willing to run around and invest their money and try to explore it. And if they can get a contract, then away they go. And if they don't, they made their bet, they've lost their money.

And we think that sort of innovative and exploration of all different options, and to offer them up to Hydro is something that they're naturally well positioned to do.

THE CHAIRPERSON: Sir?

MR. REIMANN: Yeah.

THE CHAIRPERSON: Can you tell me a little bit about IPP contracts then generally? What's the length of -- typically what would the length of a contract with an individual IPP be?

MR. REIMANN: So the biomass contracts, like I said

earlier, they were typically ten years. And I think that had a lot to do with fuel certainty and perhaps the underlying health of the facility that housed it.

THE CHAIRPERSON: Right.

MR. REIMANN: Wind contracts tend to be 20 - 25 years based on the life of the turbine.

THE CHAIRPERSON: Life of the asset, yeah.

MR. REIMANN: Run-of-river, more like 35 and 40. We're anticipating that pump storage would probably have similar to Site C, a 70-year contract.

THE CHAIRPERSON: Okay, thank you.

COMMISSIONER COTE: We don't have any numbers. Do you have a number that are coming due in the next ten years?

MR. REIMANN: Yes. I don't know if you --

MR. O'RILEY: Yes. Well, we have -- we currently have a number of contracts and these are typically ones that were signed in the late 1980s, that have come up for renewal, and we've been -- that was a matter of discussion in the integrated resource plan in 2013, and we've been actively renegotiating -- or negotiating a price for the renewal of those agreements. And typically our expectation is that we would negotiate a lower price than was there before, because that proponent would have recovered -- should have recovered a fair chunk of, if not all of their

1 capital. And we have been successful, and we brought
2 those forward to the Commission for review and
3 approval as per the requirements. And so you would
4 have seen a number of those decisions come to the
5 Commission.
6 COMMISSIONER COTE: Are they primarily run-of-river?
7 MR. O'RILEY: We've had run-of-river contracts that have
8 come up for renewal. We're dealing with the issues
9 around the biomass, and as Mr. Reimann said, those
10 were quite -- much shorter term. And we're in
11 discussions with the industry about the availability
12 of fibre and the timeline, the profile, of how -- what
13 degree we can rely on that over time.
14 THE CHAIRPERSON: Okay. We've heard some evidence that
15 there has not been much activity in the way of
16 independent projects being developed; in particular
17 wind projects and possibly others too. Could you
18 comment on the impact on this sector of continuing
19 with Site C? So you just said that you want to
20 develop a mix of -- or some words to that effect.
21 And, you know, to have a mix of energy sources and to
22 have some of that come from the private sector and
23 some of that come from your heritage assets.
24 So if you could comment on the Site C's
25 impact on that mix.
26 MR. O'RILEY: Yeah. What I would say is, I would take it

1 back a few into the last decade, and we had a number
2 of very large calls through the zeroes.
3 THE CHAIRPERSON: Yeah.
4 MR. O'RILEY: 2003, 2006, and 2008-10. And we signed
5 billions and billions of dollars' worth of contracts.
6 We have, I believe the number is 120 IPP contracts in
7 service, running, operating. And there is a number of
8 -- I'll call them stragglers from those earlier
9 procurements that are still in construction, and some
10 that arguably stalled out. So, and so we have a very
11 large portfolio of IPP contracts. They make up 25
12 percent of our supply today, and obviously very
13 important in keeping the lights on today.
14 I would say what's curtailed the level of
15 activity in the IPP sector, in our procurement, is not
16 just the development of the Site C project but the
17 fact that the load didn't grow as fast as perhaps
18 people had anticipated, back in the zeroes, and we
19 bought a lot of power.
20 So, we -- yeah, I'll stop there.
21 **Proceeding Time 4:33 p.m. T76**
22 THE CHAIRPERSON: Well, let me ask you tough question
23 then. So there's not enough load growth to justify
24 any more IPP contracts, but there is enough load
25 growth to justify the construction of a large dam
26 project?

MR. O'RILEY: Well, I would go back to the integrated resource plan in 2013 and we'll be updating the IRP going forward. In some ways the exercise we're in today is a mini IRP. We're looking at load growth and forecasts of -- in an IRP you start with the forecast of load and you look out for the gap that exists. Today we have a surplus of power and you are aware of that. We're forecasting growing loads over time, and there is a need, as we showed in the earlier slides, for new resources.

When we made the decision to proceed with Site C, it was made on a similar basis as we are talking today and the cost of the portfolio with Site C was much lower then than what the IPP portfolio was, so it simply made sense.

THE CHAIRPERSON: It was an economic decision.

MR. O'RILEY: It was an economic decision. So I think what we're saying here is there was a suggestion in these analysis that perhaps it made sense for BC Hydro to kind of reverse the policy that had been in place for, you know, almost 30 years and go back to developing all the resources or perhaps financing all the resources, and I think what we're saying is we think that would be a mistake. We think that's not our core competency and we don't think we bring expertise and we think we'd run into a lot of

1 challenges if we were starting to develop small, lower
2 resources around the province. So that's the point
3 we're trying to make with this.
4 What we are doing today is we're at a
5 point, two years into construction of a project
6 deciding should we go forward or should we stop and do
7 something else, and what we are saying is doing the
8 all the calculations, all the portfolios that we've
9 done, it makes sense to carry on.
10 THE CHAIRPERSON: Okay, thank you.
11 MR. REIMANN: I think I mentioned the battery cost
12 before. So I think we've provided this already to the
13 Commission, but when we looked at the portfolio that
14 was provided as the alternative to Site C, it appears
15 that not all of the battery costs were captured in
16 that, and it looked like it was a balance of plant
17 cost that was covered and not the batteries in the
18 power conversion system. And as well, we noted that
19 we don't think that 7 percent energy loss when you use
20 the battery to pump -- to charge it up and release it
21 was covered in the calculation. And our thoughts is
22 that the cost of clients of those batteries, that was
23 assumed, is probably pretty aggressive.
24 THE CHAIRPERSON: With regard to batteries, we've heard
25 evidence of the -- well, I guess it's not
26 controversial that the predicted increase in electric

1 cars, but the fact is that electric cars have
2 batteries and they tend to be plugged in overnight or
3 could be incented to be plugged in overnight and used
4 during the day. So is there some -- what's your
5 thoughts on the amount of battery storage that's
6 available from cars and the effect on capacity?
7 MR. REIMANN: So what's in our load isn't that much in
8 terms of electric vehicles yet. That was more part of
9 the electrification load.
10 THE CHAIRPERSON: Right.
11 MR. REIMANN: So I don't think at this point it would
12 significant. I think there's going to be
13 opportunities in the future if more electric cars are
14 incented and people switch to it en masse for us to
15 have time of use rates for electric vehicles that
16 could incent drawing it out and, you know, drawing
17 from the batteries to support the load. I think the
18 future potential could be there. It's a pretty
19 sophisticated control system. I understand that some
20 entities like PGM are starting to play with that.
21 THE CHAIRPERSON: Because some of the evidence that
22 we've heard is that it could be available, you know,
23 during winter evenings when you may need a peak load,
24 there would be -- you know, there would be cars that
25 could be plugged in and available. But if you haven't
26 considered that, then that's fine.

MR. O'RILEY: Mr. Chairman, if I could just add. That idea has been around for a while. I mean, I recall Mr. Amory Lovins put that idea forward 30 years ago. At that time they were talking about fuel cell vehicles that could form part of the power system, and I think it's a -- still an interesting idea and it's something that could possibly happen, but I think, you know, our general comment about some of these ideas is that they remain speculative and unproven just based on what's done in the world.

THE CHAIRPERSON: Yes.

Proceeding Time: 4:39 p.m. T77

MR. O'RILEY: I think what we are -- where we are focused on electric vehicles is ensuring that there are the proper incentives in the systems to encourage people not to charge them at peak times, because the problem with that is --

THE CHAIRPERSON: Right.

MR. O'RILEY: -- we face, particularly in urban areas in Vancouver and Burnaby, very significant infrastructure cost for serving incremental load in the cities. And we've got a number of projects underway now. So we really need to achieve what you're suggesting, getting the charging done off peak hours to stay even in terms of infrastructure, because of tremendous costs associated with that.

1 THE CHAIRPERSON: Thank you.
2 MR. REIMANN: I would just add to what Mr. O'Riley is
3 saying is that the world in which you would have a lot
4 of batteries available to help shape the load, is
5 actually the electrification world that we're talking
6 about that isn't part of our load forecast in the
7 analysis.
8 THE CHAIRPERSON: Right. Thank you.
9 MR. REIMANN: The time of use, optional time of use rates
10 are somewhat dated. We assume that the 430 megawatts,
11 I believe that came from our draft 2012 IRP, and that
12 information is now outdated. It was a very early stab
13 at a four-hour product, and we got an updated
14 conservation potential review, and we answered in an
15 IR of what we thought we could deliver in terms of
16 time of use savings, and it was more in the 120
17 megawatt range. And we've included a sensitivity of
18 that in the BC Hydro optimistic portfolio sensitivity.
19 But with time of use, voluntary time of
20 use, there is concerns with it in terms of free
21 ridership. Those that can benefit by not changing
22 behavior be likely to jump in, and then the amount of
23 commitment to that that you'd get for what is probably
24 not a lot of value to incentive is very uncertain.
25 We wanted to include this slide to help
26 explain when we are thinking about resource options

1 why we're -- we talked about pump storage and
2 batteries as being something that we wanted to have
3 available for ten hours. And so this is a graph that
4 came from our industrial load curtailment pilot, and
5 what we've done here is we've plotted a winter peak
6 load shape, and then we've put on top of that what our
7 system is capable of.
8 And so what you see is that in the winter
9 time, our loads tend to come up in the morning. And
10 while there is a little bit more of a peak in the
11 evening, really the load is staying high throughout
12 the whole day. And the nature of the system that is
13 being built over the years includes the coastal hydro
14 generating facilities that have limited storage. And
15 so what we find is we've got quite a number of
16 resources that are available for three hours, and then
17 we have some that are available 5, 8, and 16. And
18 what we're finding is that there is not a lot of value
19 to get an additional three hour product, and the
20 product we were looking for from the industrial load
21 curtailment pilot was 16 hours.
22 And so what we're starting to see is that
23 we don't -- the capacity in the system isn't available
24 for long enough to start capturing all the peak load
25 events, including those shoulder hours. And when you
26 start thinking about the different resources that we

are talking about adding to the system, outside of Site C is a valuable capacity resource. But pump storage or batteries, to the extent that you are meeting those peak loads, what you're doing is you're adding loads to the off-peak hours, and you can add so much of that, and you start to end up flattening the load. And so it's just a caution that in many thermal systems, to get an hour or two when thermal outages are there can be quite valuable. It is less so in a hydro system, particularly when we have limited hours in the wintertime.

Now this is a graph of wind cost declines, just takes us through where we've been and where we're going to. It is interesting that one of the things we hear from, CANWEA is that B.C. is behind is wind costs -- or its wind installations. We're falling behind the rest of North America and Canada, and really the reason we haven't got more wind built in the province is it has only recently become more cost effective than what we were buying before that, which was run-of-river and biomass. So, it's not that we haven't been buying clean resources.

And so what the graph shows is the purple box in the top left is the prices that we were paying back in the 2008 to 2010 clean power call that Mr. O'Riley was mentioning. The triangle is the standing

1 offer program that we have now, so prices we're paying
2 for wind in the Peace region. We are acquiring some
3 wind in that.
4 And so what we did is when we wanted to
5 look at what price of wind should we be forecasting on
6 a go-forward basis, we started with the black diamond,
7 which was from the International Energy Agency and
8 Enrel, and they were pretty close on a baseline of
9 what wind was costing in those days.
10 **Proceeding Time 4:44 p.m. T78**
11 Somewhat north of $100 a megawatt hour. And we sat
12 down with different IPPs and interested parties,
13 stakeholders in the province, and had a discussion
14 about forward-looking prices. And it ultimately
15 landed on that prices seemed to be coming down, and we
16 landed on the $85 a megawatt hour. And that's what
17 our base analysis was -- used as a value.
18 Subsequent to that, the Commission had been
19 asking about a drop by 45 percent by 2040, and that's
20 the green line. We had gone out and looked at those
21 that were crystal-balling future price drops, and
22 found that the 22 percent seemed to be a bit more sort
23 of midstream of what people were thinking could be
24 future price drops. And I think that's ultimately
25 what the Commission used.
26 If you go to Hydro financing, it drops to

1 the green dotted line, and as discussed, we don't
2 believe that's realistic.
3 Kind of our summary of that, at the end of
4 the day, is our original analysis that the 85 is
5 probably not unreasonable but we don't think we would
6 go much beyond. And we tested a 15 percent price
7 reduction sensitivity. But we don't feel we should go
8 much beyond that. Next slide.
9 Our electricity market price forecast. And
10 so we were hearing a bit the other day about that this
11 may be unrealistic, and there was some discussion
12 about forward prices. And our reflection on that is,
13 forward prices are not market price forecasts.
14 Forward prices are understood to be prices that people
15 are willing to deal with today to get forward price
16 certainty; it isn't necessarily an indicator of what
17 future market prices will be. It tends to be quite
18 near-term focused.
19 But what we've got, we used the ABB market
20 price forecast, and ABB is a reputable company. It
21 has a hundred customers for its world-wide reference
22 case. And they look at energy systems in North
23 America, including the build-out of the electricity
24 systems, including renewables, and adopting firm
25 policies. And based on that, they set up hourly
26 prices, and they come up with that band of which the

1 blue dotted line is the midpoint. And we've put a
2 number of other forecasts from different other sources
3 on there just to demonstrate that the market price
4 forecast particularly in the 2024 to 2032 time frame
5 is when we have the surplus, that it's not
6 unreasonable.
7 MR. BECHARD: I'd just like to chime in on this one, from
8 a trading perspective. I'm afraid that the Commission
9 may have been left with the wrong impression from a
10 presentation that was done yesterday, about the
11 forward market price, prices for mid-C power, and the
12 liquidity of those markets. The presenter left the
13 impression that mid-C regularly trades in the open
14 market ten years out, and in fact I think he said you
15 could call up on your cell phone and get a ten-year
16 contract today.
17 That's just simply not true. We trade mid-
18 C power every day. We're 20 to 25 percent of the spot
19 trades that occur at mid-C every day. So we watch
20 that market very, very carefully. We have term
21 traders that are constantly looking at those markets.
22 We have -- they're in constant contact with the
23 brokers. They have a broker box on their desk. They
24 hear everything the broker's shouting out. They talk
25 to the brokers regularly. It just requires a touch of
26 a button to talk to a broker in New York.

1 That's a relatively specialized brokerage,
2 so there's only a few brokers that actually do that.
3 And we've been working with the same brokers for
4 almost 20 years now.
5 What really is the case for mid-C power,
6 the front three years trade on a fairly regular basis.
7 And I'd say they're fairly liquid. The fourth and
8 fifth year trade sporadically. 2022 -- our records
9 show 2022 last traded in August. So you'd get a feel
10 for how often that trades.
11 2023, 2024, 2025, 2026, we don't see a
12 record of that ever trading on the exchange. I asked
13 our term trader yesterday, he sits right next to me,
14 to shout over to the broker in New York to see if he
15 sees any trades on -- in history, for 2023, 2024,
16 2025, and '26. His answer was, you know, a flat no.
17 They've never seen that either.
18 **Proceeding Time 4:49 p.m. T79**
19 So, you know, I think it's incorrect to say
20 that you can plot a forward curve out to 2026 based on
21 actual traits. I don't think you can do that. I do
22 think that ICE has some marks for those. I'm not sure
23 where ICE gets those marks from. I suspect it may be
24 nothing more than an extension of the 2021-2022
25 prices.
26 So, you know, that's one thing about that.

The other thing you can say about the forward curve is that it's not really valid to take a snapshot of the forward curve on a particular day and compare that to some market forecast that was done, you know, six months ago or a year ago. You could take a snapshot six months from now and it will look completely different than the snapshot today. Those forward prices tend to be heavily influenced by the spot prices. And so if you're in a period where something has happened, a weather event, a polar vortex for instance, the price might move up. If you are in a warm winter back east, the price might move down because of gas prices moving down and you'll look completely different six months from now than it did today.

MR. REIMANN: So just another slide just to clarify some confusion. This is a -- there's some comments that Site C has little storage and shaping flexibility and the rationale is a small reservoir with small access to storage, and somewhat surprisingly this far down the road, but what this really misses is the essence of what the Site C facility is all about.

It is downstream of the Williston Reservoir and anything that goes through the GM Shrum facility, when the water is released there, it cascades down through Peace Canyon and Site C. And so what really

1 happens is Site C multiplies the benefits that you get
2 with GMS. And this is not an unusual circumstance.
3 Peace Canyon has been there for a long time. The same
4 thing happens with Revelstoke downstream of Mica. And
5 so the plant has a tremendous amount of flexibility to
6 integrate and respond to different sorts of
7 intermittent resources.
8 And so in conclusion we believe that the
9 Site C project is the right project and we think the
10 analysis has shown that. It's a bit of a failure, I
11 think, on my behalf to not have communicated this
12 properly, but it's still -- it's a conundrum for me
13 that so many people, including those who believe in
14 climate change, have come to this point, and don't
15 see, and do not understand that a project like Site C
16 is really the backbone of meeting that green future
17 and integrating resources. You cannot keep the lights
18 on just by building wind farms or solar. You need to
19 have capacity that's available in the winter, in the
20 evening time. Sixteen hours, you're going to need to
21 have ability to integrate resources, and we only have
22 to look at California and Mr. Bechard will tell you
23 some more about that, but the problems that most of
24 the world is having with integrating all of these
25 intermittents is amazing. And Site C is an amazing
26 opportunity.

1 If you want a clean future at a low price,
2 this is your project. Thank you.
3 Mr. Bechard.
4 THE CHAIRPERSON: Before you begin, Mr. Bechard,
5 approximately how long will your presentation be? If
6 we don't interrupt with questions.
7 MR. BECHARD: I would take a guess at around 12, 14
8 minutes.
9 THE CHAIRPERSON: Okay. We're just going to take a
10 short break.
11 MR. BECHARD: Yes.
12 **(PROCEEDINGS ADJOURNED AT 4:52 P.M.)**
13 **(PROCEEDINGS RESUMED AT 5:02 P.M.)** **T80**
14 THE CHAIRPERSON: Unfortunately Commissioner Mason had
15 another appointment. If I'd thought we were going
16 right till 5:00, I would have warned you beforehand.
17 But if you don't mind, we'd be happy to continue
18 without him. Okay.
19 MR. BECHARD: All right. My focus today is to explain
20 our assessment of the opportunities that exist in the
21 market to sell any surplus energy and capacity from
22 Site C in the period when it's not needed by BC Hydro
23 to serve domestic load. Can I have the first slide,
24 please?
25 As Mr. Ghikas mentioned, I've been trading
26 energy, both power and gas, at Powerex since 1997, and

I've been head trader there since 2010. There is two key messages that I want to leave with the Commission today.

Firstly, Site C is a highly flexible resource that can be relied on to provide clean, flexible capacity and energy to Powerex's external customers in the event that it is not immediately needed to serve BC Hydro load when it first comes into service.

Secondly, the need for and value of flexible capacity is growing rapidly in the western markets as our customers retire their base load thermal assets and replace them with intermittent renewable resources.

Powerex has been in the business of monetizing BC Hydro's surplus capabilities in the external markets since 1988. In the past ten years alone, Powerex has delivered $1.35 billion to BC Hydro that has served to lower BC Hydro rates. This is not to be confused with, and is in addition to, the revenue that BC Hydro has received from the sale of its surplus energy.

By some measures, Powerex is the most active market participant in the western North American physical wholesale electricity markets. We purchase and sell wholesale electricity products in

1 yearly, monthly, daily, and hourly markets, with more
2 than a hundred different customers, and in almost
3 every state and province in the western interconnect.
4 Next slide.
5 Now, it's pretty rare for a long lead time
6 project to come into service at precisely the time
7 that it's needed. In addition, hydro-based systems
8 such as BC Hydro's, have a natural variability in the
9 amount of energy that they provide each year, and as
10 such Powerex plays a critical role in managing
11 deficits or surpluses of energy to ensure financial
12 and rate stability.
13 Powerex will be able to market any surplus
14 energy that becomes available as a result of Site C.
15 Furthermore, because of the dispatchability of the
16 project that results from it being immediately
17 downstream from Williston Reservoir, which is one of
18 the biggest reservoirs in the world, we will largely
19 to get to choose the hours in which we sell any
20 surplus. This means that we will be able to match
21 energy export deliveries to the needs of our
22 customers.
23 Our customers throughout the west are busy
24 building wind and solar generation to replace their
25 fossil fuel fleet. These are the best new resources
26 available to them. But we must remember that most of

these customers either don't have the geography to support the build of large-storage hydro, or they've already exhausted the development of it. The flexibility of the Site C generation complements these new resources that our customers are building very, very well, as it can provide clean carbon-free power when the wind isn't blowing or the sun isn't shining.

Now, I just want to take a step back for a minute to address some of the comments that were made yesterday expressing the concerns that we don't have adequate transmission to deliver any Site C surplus to the markets. Let me make this clear; we do not expect to be limited by transmission capacity in our ability to export any Site C surplus energy.

Together, the operational capacity of the export lines from B.C. to the U.S. and Alberta would allow roughly 26,000 gigawatt hours of annual surplus to be exported.

Site C annual energy will average only 5286 gigawatt hours, annually.

Proceeding Time 5:07 p.m. T81

In addition, Powerex has a large portfolio of U.S. transmission rights, including about 2500 megawatts of capacity to move energy from the Pacific Northwest into California. This allows the movement of more than 20,000 gigawatt hours per year of energy

1 to California, more than twice the capacity required
2 to deliver the Canadian entitlement and any surplus
3 that might be available from Site C.
4 This extensive transmission portfolio,
5 together with flexible generation, ensures that we
6 will be able to reach the best energy markets, at the
7 best times, with any Site C surplus energy. Next
8 slide, please.
9 THE CHAIRPERSON: Sorry, when you say "deliver the
10 Canadian entitlement", do you mean deliver the
11 Canadian entitlement from the U.S. into Canada? Is
12 that what you're saying?
13 MR. BECHARD: No, sorry. I didn't mean to be confusing
14 there. It means that we will be able to -- so that
15 the last statement about having 20,000 gigawatt hours
16 of transmission a year into California?
17 THE CHAIRPERSON: Yes. Yes.
18 MR. BECHARD: It means we'll be able to -- there was some
19 concern expressed about our ability to deliver Site C
20 and the Canadian entitlement into California, if we
21 need to do that, if that turns out to be the best
22 market.
23 THE CHAIRPERSON: Right.
24 MR. BECHARD: So what I was trying to say is that the
25 20,000 gigawatt hours of transmission that's available
26 between the northwest -- to us, we have the long-term

1 contracts for that. Between the northwest and
2 California, there's enough to move two times that
3 volume of energy.
4 THE CHAIRPERSON: What happens to the Canadian
5 entitlement now? We don't actually take delivery of
6 it into Canada.
7 MR. BECHARD: We do. We take delivery of it at the
8 Canadian border.
9 THE CHAIRPERSON: Mm-hmm.
10 MR. BECHARD: If we need it, we keep it here. If we
11 don't need it, in the hour, or -- like, not just if we
12 need it, but if it's the best thing to do
13 economically, to keep it here, we'll keep it here. If
14 it makes more sense to export it, we will export it in
15 the hour. And most of these -- I would say most of
16 that energy these days is finding its way to
17 California.
18 THE CHAIRPERSON: Thank you.
19 MR. BECHARD: In addition to being able to deliver energy
20 at times and locations that meet our customers' needs,
21 Site C can provide other services that can help our
22 customers in their efforts to integrate the new
23 intermittent resources -- the new intermittent
24 renewable resources, I should say.
25 One, Site C offers the flexibility to ramp
26 its generation from minimum to full output, or from

1 full output to minimum, in just a few minutes.
2 Two, it also offers reliable capacity that
3 will be in demand as base load thermal resources
4 retire.
5 And three, it offers environmental
6 attributes that would allow us to help our customers
7 integrate their renewables without the use of the
8 carbon-emitting coal and gas generation that is widely
9 used for this purpose today.
10 COMMISSIONER COTE: Could I ask a question?
11 MR. BECHARD: Yeah.
12 COMMISSIONER COTE: You're talking about the capacity to
13 retire rates in Alberta, or the Pacific Northwest as
14 well as down in California. In most cases they're
15 going to replace that with home-grown -- with
16 something that they're developing on their own.
17 That's a fair statement to make?
18 MR. BECHARD: That is fair. In most cases they plan to
19 replace that with renewables that will be home-grown
20 renewables.
21 COMMISSIONER COTE: Yes.
22 MR. BECHARD: Most jurisdictions, including California,
23 are trying to keep the dollars associated with
24 renewables in the state.
25 COMMISSIONER COTE: Yes. Now, in terms of timing between
26 those two, when they're going to retire one and bring

1 another on, what kind of a gap exists between there?
2 MR. BECHARD: Well, I assume --
3 COMMISSIONER COTE: You're talking about --
4 MR. BECHARD: You have to assume that those utilities
5 commissions that apply to those jurisdictions will try
6 to time that in a way that allows for reliable systems
7 to be maintained there.
8 COMMISSIONER COTE: But bottom line is that you're not
9 looking at a long-term capacity deal, in terms of --
10 MR. BECHARD: Oh, I think if you let me proceed onto the
11 next couple of slides, I will explain your question
12 better.
13 COMMISSIONER COTE: Fair enough. I'll hold my questions.
14 MR. BECHARD: All right. So, next slide, please.
15 So to understand just how much the need for
16 flexibility is growing, you really need only look at
17 the situation in California, who is leading the charge
18 in adding renewable generation.
19 California has passed a law that requires
20 33 percent of demand in the state to be served by
21 renewable generation by 2020, and 50 percent by 2030.
22 California is on track and maybe a little bit ahead of
23 schedule in making that 2020 target, and has done this
24 by adding some wind, but mostly solar generation.
25 **Proceeding Time 5:12 p.m. T82**
26 The California ISO now has almost 11,000

1 megawatts of installed grid-scale solar generation in
2 its control area. In addition, another 5300 megawatts
3 of behind the meter rooftop solar generation have been
4 added in the state.
5 This large build of solar generation has
6 caused a well-advertised and much-studied need for
7 flexible capacity. And this is because as the sun
8 goes down, they lose that 16,000 megawatts of solar at
9 about the same time as the dinnertime load begins to
10 ramp up. So, if you think back to Randy's chart where
11 he showed the two humps in the winter, evening load,
12 their load looks a little bit different, the humps are
13 a little more pronounced. The load's going up for the
14 evening load, for the evening dinnertime load, and at
15 the very same time all the solar's coming off, because
16 the sun's going down. And solar doesn't generate when
17 there's no sun shining.
18 To respond to that, the system operators
19 need to bring dispatchable generation, generation that
20 they can control, on line and ramp it up very quickly.
21 The California ISO refers to this flexibility
22 requirement as a three-hour ramp requirement. How
23 much do they have to ramp up the dispatchable
24 generation to deal with the drop in solar generation
25 and the coincident increase in load over three hours?
26 It's a metric they use to explain the problem.

The California ISO has published the actual 2016 three-hour ramp in their forecast for 2020. Those are the two bars that you see in the picture. On top of that, we've added the 2012 load ramp requirements. So you can see how the need has already grown. California is making plans to address this 2020 demand for flexibility but it's going to be a major challenge. If California continues to add solar to meet their 2030 goal of 50 percent renewable, the need for flexibility will double again to nearly 32,000 megawatts of three-hour ramp. It is hard for anyone that's operated a hydro system, or any sort of electrical system, to imagine how you would meet this kind of generation ramp.

Powerex can contribute to this problem using our 2500 megawatts of transmission to California, along with any access we have to flexible generation. We expect California's other opportunities, however, to be very expensive or involve a lot of gas peaker generation, which would be at odds with their greenhouse gas reduction objectives. Importantly, while under today's rules Site C will not qualify for renewable energy credits in California, it will be treated as a zero-carbon resource under California's cap and trade program.

Next slide, please. Site C will be coming

on line in the context of rapid change in external markets. Coal plants are being shuttered, and even natural gas is being declared unwelcome in California's future. These developments are leaving a potential capacity void that will need to be filled with new resources that can provide clean capacity. In the northwest, 2500 megawatts of coal will be shut down by 2025. In Alberta, the plan is to shut down more than 6,000 megawatts of coal by 2030 and replace most of the energy associated with that coal with renewable resources, and most of the capacity associated with that coal with natural gas generation. Although Alberta plans to build its own renewable generation, there is a role for Powerex to play in providing flexible capacity.

We are participating in the design of their new capacity market, which will be complete in 2019. An increasingly stringent greenhouse gas reduction program in Alberta will make it a very attractive market for clean B.C. generation when the wind is not blowing there.

Even with a need for more flexibility in California, they are planning to retire about 7500 megawatts of nuclear and gas generation in the state by 2025, and the California ISO is developing markets for flexible capacity to help them with the three-hour

1 ramp problem I just talked about.
2 **Proceeding Time 5:17 p.m. T83**
3 MR. BECHARD: Finally, our customers are telling us that
4 their options for clean, flexible capacity are
5 limited. Natural gas, while cleaner than coal, is
6 still a significant emitter of greenhouse gas
7 emissions.
8 We also know that siting gas plants poses
9 challenges, particularly in the western coastal states
10 and in B.C. Gas generation is not as flexible as
11 operators would like; combined cycle gas turbines are
12 expensive to start and stop, and slower to ramp than
13 hydro. There aren't many large storage hydro sites
14 like Site C around, and pump storage is difficult to
15 site and expensive to build. Demand response has been
16 shown to work but it will only meet a small part of
17 that flexibility requirement.
18 While people are optimistic about battery
19 technology, it's still considered very costly for
20 meeting this need, and can't come on -- it can't come
21 anywhere close to storing the volume of energy that
22 B.C.'s reservoirs can.
23 To wrap this up, if there is a short-term
24 system surplus as a result of the addition of Site C,
25 we think the external market demand for attributes --
26 for the attributes that it offers, will allow us to

1 sell it at prices well in excess of the average mid-C
2 market price. As the demand for flexibility and
3 capacity grows, Powerex will be able to generate
4 income using its access to residual flexible capacity,
5 including Site C, in two important ways. First,
6 Powerex will be able to sell energy in the higher-
7 priced hours of the year, but also to purchase energy
8 in the lower-priced hours. Activity Powerex has done
9 for many years.
10 Second, Powerex will be able to sell
11 explicit capacity and flexibility products as these
12 products continue to emerge in the marketplace,
13 earning explicit capacity or flexibility premiums in
14 addition to payments for any energy delivery. While
15 Powerex already participates in these opportunities
16 today, they are expected to grow in the future.
17 MR. O'RILEY: Mr. Chair, we have one point that we'd like
18 Mr. Watson to address, and if we could do that very
19 briefly.
20 THE CHAIRPERSON: Yes, please.
21 MR. WATSON: Yeah, thank you. We want to address a
22 comment this morning Mr. Vardy made about unresolved
23 geotechnical issues when he was discussing his
24 reflections on the Muskrat Falls project.
25 Site C has had a staged approach, or BC
26 Hydro has had a staged approach to Site C. I became

1 involved in Stage 2 in 2007, and part of the mandate
2 of each one of these stages was pause and reflect on
3 the previous stage. And at that point, there were a
4 series of outstanding geotechnical and design issues
5 that was -- it was the team that I was working with's
6 responsibility to work through those, so that when we
7 put forward an updated design for the environmental
8 assessment process, which is at what point, the point
9 that -- for the cost estimate. This is prior to the
10 financial investment decision. This is in 2011 we put
11 that forward.
12 So it seems to have been heavily
13 investigated over the years, starting in the '80s.
14 And these three outstanding issues, one of them was
15 around the glacial till for the dam, the source that
16 had been historically identified wasn't -- it was
17 prone to construction problems and we secured a new
18 source of that. Did significant investigations to
19 address that. Several of the other issues associated
20 with the response of the rock to our concrete
21 structures, making sure that we had seismic
22 performance to upgraded -- updated standards that we
23 knew could have a very long and reliable operating
24 life. And also any design changes to the spillway.
25 And so we actually paused at that point in
26 the project and, you know, worked through those so

1 that when we put forward our project description and
2 cost estimate, which was a Class 3 estimate at that
3 time, Mr. Vardy was mentioning I think in the earlier
4 stages when the cost estimates were put forward for
5 Muskrat Falls, it was Class 4.
6 Since that time, to the development -- you
7 know, and concurrent with our environmental assessment
8 prior to the financial investment decision, we just --
9 significant parts of the final design, built physical
10 hydraulic models, making sure we could resolve
11 anything that we could prior to construction.
12 **Proceeding Time 5:21 p.m. T84**
13 Also just wanted to reflect on, you know,
14 the geotechnical performance through construction. We
15 are very disappointed in the effect on our
16 construction schedule, the geotechnical issues, these
17 two tension cracks on the left bank associated with
18 our contractors' temporary haul roads. It's worth
19 reflecting, we agree with Deloitte that there's a lot
20 of terrain that's been opened up in Site C. We've had
21 very large excavations on the right bank. Our Stage 1
22 coffer dams are basically complete, sealed into
23 bedrock, and we can see the performance of the rock
24 there. Large excavations have been done on the left
25 bank.
26 The issues of the tension cracks are not a

1 concern for the permanent function of the facility.
2 You know, but like we've said, we're very disappointed
3 the impact that had on our construction progress. And
4 we're taking a lead role with the contractor to make
5 sure that these construction roads are within
6 effectively project excavations, plan to be removed,
7 to make sure that those are -- the remaining ones are
8 constructed to be reliable, to the appropriate
9 standard of reliability to complete the projects.
10 We have constructed access roads right down
11 from -- on the north and south bank to the valley
12 bottom, and our main civil works construction
13 facilities, these waste areas, are very well
14 established.
15 Not to say there aren't geotechnical risks
16 in front of us, and we've reflected those in the risk
17 profile of the project. You know, as Deloitte pointed
18 out, and I think we agree with them, tunnelling in the
19 diversion tunnels represents an area of geotechnical
20 risk. We'll reflect even back in the '80s, BC Hydro
21 actually took the step of excavating into the left
22 bank and doing what is called a test section of these
23 diversion tunnels. The design of the diversion
24 tunnels has not materially changed since the '80s.
25 That tested the construction method, and
26 the excavated span of those diversion tunnels. So,

you know, almost approaching the level of pre-construction that you can do to mitigate those risks.

So, I just wanted to elaborate on those comments.

COMMISSIONER COTE: Can I ask a related question? I was going to ask it anyway, but in the event there is further delays, would it be fair to assume that will be at a cost of roughly 50 million a month, just taking your 600 and dividing by 12? Is that a reasonable number to work with?

MR. O'RILEY: Yeah, I'm not sure -- well, I think it's coincidental that 50 million a month, which happens to be roughly our burn rate or run rate on the project, matches the one-year delay of $610 million. I think that's a coincidence. I think it was --

COMMISSIONER COTE: I got the right answer for the wrong reasons.

MR. O'RILEY: Yeah. I think we'd have to look at the impacts of it and it can be -- I mean, there could be non-linear one way or the other, right? So, what are the circumstances that led to a delay, and whose responsibility it was, and the like. So what it -- how it impacted the critical path and the like. So I think it's a little more complicated question and answer than that.

COMMISSIONER COTE: Okay.

1 THE CHAIRPERSON: Go ahead.
2 MR. O'RILEY: So we'll just conclude, then. So, first of
3 all, I just want to say we really appreciate the
4 opportunity to discuss these matters, and we hope
5 we've answered any questions that you have. And if
6 not we're happy to take them, any time, and provide
7 answers back in writing.
8 I just want to conclude by restating our
9 firm belief that continuing with the project is the
10 best option for ratepayers, and I think you can hear
11 from us the passion, that we think this is a very
12 valuable product, and very unusual product. And when
13 we look around at other people investing in solar
14 power in California, I think that's because that's
15 what resource is available to them. And I think
16 they'd be really happy to have a resource option like
17 this. It's a fact that they don't.
18 We've talked about the termination option
19 as imposing a very significant cost on the company and
20 the ratepayers, and then putting us on a very
21 uncertain path in terms of acquiring replacement
22 resources. We haven't talked a lot about suspension
23 today, but we believe that would cost even more with a
24 significant risk that the project would not be
25 restarted and an even larger write-off down the road.
26 Site C remains by far the lowest cost

1 resource and, as we said, becomes progressively
2 cheaper over time with ratepayers. It's really a
3 generational investment, as we've seen that math work
4 with our existing plants. And that applies with and
5 without consideration of the sunk costs.
6 And the Site C portfolio we believe offers
7 the lowest risk going forward, given the advanced
8 state of the project. And Mr. Watson just talked
9 about a few examples of how we've de-risked the
10 project.
11 **Proceeding Time 5:26 p.m. T85**
12 As Mr. Bechard said, through Powerex we do
13 have the capability, probably the leading capability
14 in the west, to manage any surplus that arises, and
15 it's -- there are tremendous opportunities for us to
16 continue to take advantage of those markets and
17 provide any surplus capability into those markets.
18 So, finally, Site C -- it's the cleanest
19 source of firm energy and capacity available to us.
20 It will help us integrate further renewables into our
21 system, and support a broader campaign of
22 electrification and renewal of the B.C. economy,
23 allowing us to meet our long-term climate goals. So
24 we think it is the best project, and we recommend
25 strongly that it carry on.
26 So thank you for the opportunity.

THE CHAIRPERSON: Right. Thank you. Do you have anything further?

Thank you very much, gentlemen. It's been very helpful to us, and we appreciate you sharing your thoughts and your presentation with us. Thank you.

And thank you to everyone else who has presented in the last couple of days. Again, it's very helpful to the panel, and we really appreciate your efforts, so thank you very much.

And I hope you all have a good evening, and what's left of the weekend. Thank you.

(PROCEEDINGS ADJOURNED AT 5:27 P.M.)

I HEREBY CERTIFY THAT THE FORGOING is a true and accurate transcript of the proceedings herein, to the best of my skill and ability.

A.B. Lanigan, Court Reporter

October 16th, 2017