DATE/TIME	September 23, 2013 9:00 a.m. – 4:30 p.m.
LOCATION	Executive Room # 470 Wosk Centre for Dialogue, Simon Fraser University 580 W. Hastings Street, Vancouver, B.C.
TYPE OF MEETING	Meeting of the BC Hydro Integrated Resource Plan Technical Advisory Committee (TAC). TAC is a group of knowledgeable participants with significant interest, stake, and experience in BC Hydro's resource planning process assembled to provide detailed, technical input and feedback to BC Hydro during the development of the IRP.
FACILITATOR	Anne Wilson, BC Hydro
PRESENTERS	Doug Little, BC Hydro David Ince, BC Hydro Lindsay Fane, BC Hydro Basil Stumborg, BC Hydro Kathy Lee, BC Hydro Kristin Hanlon, BC Hydro Sanjaya De Zoysa, BC Hydro Randy Reimann, BC Hydro
ATTENDEES TECHNICAL ADVISORY COMMITTEE MEMBERS	Jason Wolfe, FortisBC Loch McJannett, Clean Energy Association of BC Andrew McLaren, First Nations Energy and Mining Council Leigha Worth, Canadian Office & Professional Employees Union Local 378 Doug Chong, BC Utilities Commission Randy Reimann, BC Hydro Bill Andrews, BC Sustainable Energy Association David Craig, Commercial Energy Consumers Association Nat Gosman, Ministry of Energy & Mines Tom-Pierre Frappe-Seneclauze, Pembina Institute Tannis Braithwaite, BC Public Interest Advocacy Centre Richard Stout, Association of Major Power Consumers of BC **REGRETS:** Robert Duncan
MEETING OBSERVERS	Jim Quail, Canadian Office & Professional Employees Union Local 378 Julie Tran, BCUC Nicholas Heap, CANWEA Thomas Hackney, BCSEA Jim Weimer, Weimer Consulting Inc. Paul Kariya, Clean Energy Association of BC
ATTENDEES BC HYDRO	Mike Savidant, BC Hydro Kenna Hoskins, BC Hydro Susan Hancock, BC Hydro Amir Amjadi, BC Hydro Amir Amjadi, BC Hydro

PRE-READING MATERIAL / HANDOUTS / PRESENTATIONS
• Agenda for TAC Meeting #7 • PowerPoint Slides • IRP Recommended Actions

1. WELCOME, REVIEW AGENDA & MEETING OBJECTIVES – Anne Wilson

The facilitator, Anne Wilson, welcomed everyone, reviewed the agenda for the TAC meeting #7 and reviewed the meeting objectives. She explained the purpose of this meeting was to provide an overview of the Integrated Resource Plan submitted to government on August 3, 2013, and to provide attendees the opportunity to ask questions to clarify the plan in order to assist them in preparing written comments.

Participants were reminded that the written comment period closes October 18, 2013.

2. IRP Overview & Recommended Actions – Randy Reimann

(The record notes that, in all cases, the following abbreviations will be used and mean: Q: Question, A: Answer, C: Comment, BCH: Comment from BC Hydro. Further, all questions and comments are from the meeting participants and Answers are from the BC Hydro Team)

Slide #4-21- Overview of Policy Context and Recommended Actions

Randy Reimann provided a high level overview of the IRP submitted to government on August 3, 2013.

Q: What is the mechanism by which Site C costs will be scrutinized?
A: Costs are being considered as part of the Site C's CEA/BCCEA Joint Review. Mike Savidant who is project manager with the Site C Project will be available later this afternoon to answer questions specific to project.

Q: How do you feel about not pressing forward as aggressively with DSM as before?
A: If we do more than required based on the supply-demand balance then rate payer impacts will be incurred without corresponding benefits. BCH will continue to maintain its conservation targets, but timing of DSM program will be important to gauge.

Q: When do you expect government to issue approval of the results of the IRP? What is BC Hydro's DSM Section 44.2 application date?
A: Our hope is that the IRP is approved relatively quickly after the Nov 15 submission to inform the Site C EIS process and the RRA scheduled for the spring. Interveners have been advised by letter of BC Hydro's proposal to file the DSM application as part of, or contemporaneously with, the next RRA or before by March 1, 2014.

C: Given the improvement to the load resource balance where there is now more of a surplus, more time can be taken to consider the IRP. We need to know the costs and rate impacts of making LNG clean. Insufficient scenarios make up the IRP. It would be more useful if the plan demonstrated the actual costs of each project and what customers will have to pay. Also, there is not enough consideration to other scenarios, and it's disturbing to see that BCH is locking into a specific plan.

Q: How does the Industrial Rate Review impact the IRP?
A: Recommendations may fall out of the review that could lead to new policy. To the extent there are such changes and they are applicable to long term planning, it would feed into BC Hydro's next IRP.

3. Managing Resources – Doug Little

Doug Little explained the actions being undertaken to manage BC Hydro's portfolio of resources (IPPs and DSM programs) over the short to medium term to address upward pressure on rates.

Slide #22-31- Managing Resources

Q: Please explain what type of project is being terminated. What are the liquidated damages?
A: Projects in good standing will proceed. Generally projects that are default of their contract terms are being considered for termination. Deferrals have been incorporated through a "not before clause" to extend the delivery of energy to a date closer to need.

Q: How are you making the decision to defer versus terminate?
A: For over a decade, BC Hydro has been committed to getting projects in-service, generating clean energy and minimizing attrition. As a matter of business integrity, we cannot do a 180 on this. A decision to terminate has only occurred after discussions with an IPP determine that the project is not at a stage to continue or be deferred.

Q: Are you paying an incentive to terminate?
A: The terminations and deferrals are forecast to have a net benefit to ratepayers.

Q: Will the names of the projects of the terminated projects be published?
A: Yes, once we get through the process the information will become public.

Q: It looks as though BC Hydro will still be in a surplus when many of these deferred projects will go into in-service. Is this correct?
A: We are expected to still be in a surplus, but there are expected to be substantial savings from pushing out the delivery of energy through the deferral process.

Q: Is it possible to reach an agreement with IPPs rather than terminate their contracts?
A: It should be stressed that most projects that are under default are not under construction.
There are a few that are not under construction and not in default where we have negotiated to delay construction and delivery.

Q: What are the limits?
A: We pushed hard for deferrals. In most cases, these deferrals are within two years of the original in-service date.

Q: Has BCH had discussions with permitting offices to understand if permits could have been extended to facilitate longer deferrals?
A: No.

Q: When reviewing resource options for future demands, how are new technology developments incorporated into the ongoing plans?
A: The IRP is very flexible and allows BCH to keep its options open and allow for new information on future technology developments. For example, Site C is still under review. It will continue to be reviewed against other feasible alternatives on an ongoing basis until approvals are made by the BC Government to proceed with construction.

Q: How is the flexibility of IPP energy that can be acquired in smaller increments captured in the IRP?

A: Flexibility is captured through the portfolio analysis that incorporates a range of different scenarios and gap analyses. In the portfolio analysis, we generally try to time IPP resources with the energy need. This also includes looking at the consequences of alternative scenarios to understand what the future could look like if the outcome is different than expected.

C: BCH should put a clause in their contracts with IPPs to allow BCH the right and flexibility to modify the delivery date for when the energy is needed.
A: In hindsight it would have been better to have the ability to do this. There have been a number of policy changes that have impacted our energy needs after the contracts were established. We now have built in this type of flexibility to some degree with our Standing Offer Program.

Q: With regard to renewals, is there an incentive to keep IPPs on BC Hydro's system?
A: Because these projects typically don't require the significant capital upgrades associated with greenfield projects we expect to get this energy at very cost effective prices that will be stable over a long term.

Q: Before the IRP assumed no biomass EPAs would renew. Now the assumption is 50%. Could you explain how you came to this number?
A: We believe 50% is a better estimate, but it's not based on detailed analysis. These projects often are vital in communities and support economic development in BC and BC Hydro will deal with renewals on a case-by-case basis. If biomass renewals were not in the load resource balance, it would drive us to require more energy sooner.

Q: Is BC Hydro considering removing the Standing Offer Program (SOP)?
A: No, BCH will not cancel the SOP. As per the Clean Energy Act, BC Hydro is required to offer it. However, there have already been some changes made in the rules of the SOP to scale back the volumes acquired and some future changes are expected with respect to cogen.

Q: Material changes to the SOP will have an impact on projects. Is it a matter for the BCUC?
A: It is within BCH's discretion to make changes to the rules of the SOP. The IRP is approved by government and used by BCUC as a guide for future project approvals.

Q: Does the customer incentives initiative have to go before the BCUC for approval?
A: Yes, I'd expect it would.

Q: Have you looked at the benefit of a deferral of Site C?
A: It's difficult to plan to a knife's edge with projects of this scope. BC Hydro considered two in-service dates for Site C in the IRP analysis. We believe there is a window during which it is viable.

Q: Could you reduce DSM even more than planned over the next few years?
A: If you reduced DSM too much you cannot ramp up again and meet long-term targets. We believe we've found the right balance.

Q: Should the F2021 DSM target be looked at?
A: We still feel the target is the right one. It's ambitious, but DSM is the most cost-effective resource.

BCH: BC Hydro would like to raise the issue of rate differentials between portfolios. In the past our analysis showed that the rate differentials did not provide additional meaningful information to decipher between portfolios. We did not have time run this analysis for the Aug 3 submission but we could for the final submission if there is an interest.

C: We need to see absolute rate forecasts of at least 10 years. There is an underlining pressure on rates that need to be indicated in the scenarios and plans.

A: We are not releasing a rate forecast because of the many variables at play, including the work presently being undertaken with government to manage rates going forward. BC Hydro's rate forecast will come out when we file the RRA.

C: You'll see in our response that AMPC needs to see the rate forecast. It should be part of any plan. You're under a commission order to release it. Agree that present value (PV) is the single most important criteria, but it shouldn't be the only one. It's enshrined in the Clean Energy Act that rates are important to customers.

C: CEC's comments will be the same. It's especially important with Site C where the cash value is very different from the PV. There hasn't been adequate discussion about rate impacts and how to get rid of constraints that limit how they can be managed.

Coffee Break #1

4. Load Forecast – David Ince

Dave Ince provided an overview of the long-term load forecast released in December 2012 and used in the IRP. He noted for comparison purposes that the draft IRP released in May 2012 used the December 2011 Long -Term Load Forecast. The 2012 Long-Term Load Forecast is included in Appendix 2A of the IRP.

Slide #32-40- Load Forecast

Q: Do you provide pulp and paper forecasts over 30 years?
A: Yes, we undertake individual forecasts for each industrial customer that includes market environment changes.

Q: Does the forecast look at new demand from the oil and gas sector upstream from LNG plants?
A: That's included in the oil and gas sector forecast. Demand from Horn River Basin, a portion of the province not connected to the integrated electricity system, isn't included in this integrated system load forecast, rather it's addressed elsewhere in the Plan and does include impacts of LNG.

Q: At the high LNG scenario what projects are included?
A: All known LNG projects have been included in the assessment of the high end.

Q: What are the options available to serve potential load in non-integrated projects?
A: Each project will need to be considered in isolation. These projects are not included in the integrated system forecast as presented today. BC Hydro is currently reviewing how non-integrated projects are supplied. Again, the non-integrated system is addressed elsewhere in the Plan.

Q: Those ancillary LNG loads, are they commercial or industrial? Is there potential for a new rate class for LNG?
A: LNG loads will be served from the transmission system. The BC Government has directed BC Hydro to keep rate payers whole in the servicing of LNG loads. There is potential for a new rate class.

Q: Is the effect of conservation built into the rates?
A: Yes, the forecast assumes that there are load effects caused by traditional block rates. The price elasticity caused by general rate increases is assumed to reduce load in the forecast before DSM. We assume 5% elasticity for all rate classes. The additional load reduction attributed to tiered (conservation) rates is included in the DSM plan.

Q: Is it possible to separate the pure rate impact?
A: It is a challenge to separate out the conservation rate impact from the general rate impact. We have to avoid double counting in accounting for DSM savings. We do quantify and then remove the impact of rate design when undertaking the load forecast.

Q: If a new mine is greenfield you would assume little DSM potential going forward because it be built to a highly efficient standard. Is that right?
A: Yes, our forecast DSM savings for this sector reflects the fact that the savings potential is expected to be lower with this type of new load.

Q: Has there been any revisions/updates to the electrification potential in the IRP?
A: We didn't update the electrification section of the IRP. We would like additional direction from government with regard to Climate Action priorities, and the priority of electrification, before we update this.

Q: Regarding electrification of the northeast of the province, where is that addressed in the IRP?
A: Section 2.12 provides the load resource balance information, and section 6.6 identifies the resource options for Horn River

5. Load Resource Balance – Lindsay Fane

Lindsay Fane presented the updated Load Resource Balances (LRB), with a focus on changes made since the May 2012 draft IRP.

Slide #40-49- Load Resource Balance

Q: Is the first three years your operating period?
A: Yes it's the modelling period.

Q: The value in Table 4-16 for the SOP states 467 in F2017. Please clarify?
A: The draft IRP had a value of about 520 GWh/year in F2014 and beyond. The -467 GWh value indicates a reduction in the SOP volume from the 520 GWh/year reflecting the changes to the SOP. These reductions decrease over time as SOP volumes are expected to increase at a rate of about 50 GWh/year on a contractual basis which is equivalent to about 25 GWh/year after attrition and reflecting firm expected energy contributions.

Q: Could something be put together to show what's changed between the May 2012 LRB and present one?

Action: Yes, we'll do that. We'll attempt to show the effects of critical water, general forecast changes and LNG forecast changes.

6. Analytical Framework and Uncertainties – Basil Stumborg

Basil Stumborg reviewed the analytical framework and highlighted the key risks and uncertainties that were examined.

Slide #50-56- Analytical Framework and Uncertainties

Q: Does the IRP explain how you arrive at the 5% weighted average cost of capital?
A: Yes, in section 3.2.2.

Q: What do you mean by the uncertainty of DSM Options 4 & 5?
A: From a point of view of comparing portfolios, we won't learn a lot by including resource options that are more uncertain and more expensive.

Q: What is the update on wind resource costs? In the plan, do these assumptions remain constant over time?
A: Since 2010, the cost of turbines has dropped and there have also been efficiency improvements that have affected cost. In this case, we also asked, can this low turbine price be sustained? As we come out of the recession, we don't think so.

C: It's poor planning to eliminate two DSM options because they are too costly. Regarding uncertainty, it's not like a resource like tidal. They are different with different consequences. The assessment of DSM uncertainty continues to be of low quality.

Q: In the portfolio analysis, how does the flexibility of IPPs get incorporated?
A: We've examined the mid-case, then we've asked, what happens if the gap is larger or smaller than expected due to higher/lower forecast and higher/lower DSM savings. As we do this, we're putting all the resources into the scenario so it does capture the incremental benefit and flexibility of IPPs. It shows how Site C compares under all these cases.

C: BC Hydro uses a 10% contingency for Site C cost, yet BC Hydro's record from the pre-construction budget to actual costs is more in the range of 25 to 75%, so you should be modelling more than 10%.

Lunch Break

7. Role of Gas for Non-LNG Load – Kathy Lee

Kathy Lee provided the policy context and background for the recommended action related to the use of gas for loads prior to considering LNG loads.

Slide #58-60- Role of Gas for Non-LNG Load

C: It would be good for the province to re-examine the 93% clean portfolio standard from the perspective of greenhouse gas reductions and jobs.

Q: Does the 93% clean energy requirement prohibit examination of other alternatives?
A: BC Hydro considers this Clean Energy Act objective to be a hard planning constraint in the IRP.

Q: Isn't there an exemption from the 93% clean requirement for LNG load?
A: Yes.

Q: What is the price per megawatt for CCGT and SCGT used in the IRP?
A: Section 6.2, table 6-1, provides the gas pricing scenarios. Chapter 5 describes the market prices. The prices are based on a spring 2013 update. Given the most likely price scenario, a 250 MW CCGT is about $60/MWh. A smaller size would be more costly.

Q: A larger size would be cheaper?
A: Not by much.

Q: Does that make a difference between gas and clean resources about $40/MWh to $50/MWh?
A: With IPP clean resources, yes. But only about $20 difference against Site C's $83/MWh.

Q: I notice different UEC prices are used for Site C in the IRP. Why is this?
A: Different UECs are required for apples-to-apples comparison between resources. For example, in some cases, UECs are presented at the point of interconnection and in others they are adjusted for benefits and costs such as capacity benefits and transmission costs to provide the cost for a comparable product such as energy delivered to the Lower Mainland.

Action: BC Hydro to provide breakdown of UECs for natural gas, Site C and IPP resources.

C: It's useful to know that CCGT and hydro systems are a match from a planning perspective. For example, you might pick a different amount of market reliance if you had CCGTs as back up.

8. Conserving First – Kristin Hanlon

Kristin Hanlon reviewed the three DSM recommended actions and discussed the rationale for near term adjustments to spending when compared to the May 2012 draft IRP.

Slide #61-67- Conserving First

Q: Regarding recommended action #1, it seems like an expenditure cut will not "maintain" targets.
A: The word "moderate" is intended to compare to previously proposed spending levels. In fact we are still on target to achieve 7800 GWh/year of DSM by F2021.

Q: Regarding DSM recommendation #2, what utility comparisons exist for this type of load?
A: There is quite a lot of experience that can be drawn from markets, particularly from amongst the industrial sector; one notable difference is that residential and commercial peaking load in places like California tends to be driven by cooling which may be more sensitive to price than jurisdictions where load is driven by heating.

C: There is a lot of experience in other jurisdictions with long-term load curtailment contracts.

Q: What is the difference between Options 2 &3 on the May 2012 draft IRP and the current IRP?
A: The potential for both of these options is lower.

Q: How have you incorporated the impact of rate forecast on conservation?
A: Natural conservation is embedded in the load forecast.

Q: Are the potential savings from load curtailment included in the load forecast?
A: No, they are not yet being counted on as the actions in the IRP are intended to explore the amount of saving s we can rely on going forward.

Q: What is the long run marginal cost (LRMC) for energy used in the IRP?
A: It's $85/MWh to $100/MWh. The LRMC in part is based on the price signal of DSM on the margin—the amount of investment needed to drive the level of DSM recommended by the IRP. Overall, the DSM-driven portion of the LRMC is not as bright a line as when IPP energy is on the margin. For capacity, our point of comparison is Revelstoke Unit 6.

C: If I look at option 2, then switch to option 3 in 2022, I can get 1000 GWh/year of savings at a lower marginal cost. Deferral of Site C with more DSM can have a huge financial benefit.

Q: In section 6.3, it shows DSM options converging at the end of 20 years. Why is that?
A: The conservation potential starts to tap out at this point for industrial customers. Because of this and the general uncertainty 20 years out in the future, we made the assumption to flat-line savings at the end of the planning time frame.

Q: Is there a difference between DSM options 2 and 3 in terms of the customers you're targeting?
A: In general, not over the 20 year plan, but there may be some difference in the next three years because we're focusing on avoiding lost opportunities—that is opportunities to capture efficiencies that if not undertaken now would be lost for many years to come.

Q: If the resource cost of DSM is so low, is there not a rationale for doing more of it if you can sell excess energy on the market?
A: That doesn't work because the incremental cost of DSM is much more than the average resource cost for DSM.

C: We see the total resource cost, and we need to see the marginal cost of DSM.

Q: With near term adjustments, is BC Hydro capturing all cost-effective DSM savings? At any point is there a change in criteria?
A: The DSM target hasn't changed, but the criteria regarding how we built it up have changed. Over the near term, there may be a trade-off between cost-effectiveness and rate impact, which was considered in developing the DSM plan.

C: Have you made any uncertainty assessments related to these options?
A: We did undertake a full uncertainty assessment that can be found in appendix 4B. Numbers in the IRP are adjusted and incorporate uncertainty.

Q: Is there an advantage to delay DSM savings until the technology has improved, especially when there are rate pressures?
A: There may be and over the next three years, some DSM savings will be deferred because they do not represent lost opportunities. Our conservation potential review is a benchmark in that regard, though it is becoming somewhat dated given it was released in 2007.

Q: How do you evaluate the quantitative success / savings of the annual DSM plan?
A: We have a rigorous process to measure the savings that examines results, program-by-program, and we report out on it annually.

Q: What does the split look like in terms of savings by customer class?
A: It depends on the metric, but roughly it's divided equally amongst the three major classes. There is information on this in chapter 8.

9. Meeting LNG and the North Coast Supply Needs –Sanjaya DeZoysa

Sanjaya De Zoysa provided information on the analysis and recommended actions associated with meeting the LNG and North Coast supply needs.

Slide #74-82- Meeting LNG and the North Coast Supply Needs

Q: With regard to the expected 3000 GWh/year of LNG load, what is the breakdown of megawatt per plant?
A: Of the 12 facilities proposed, we're assuming ancillary load from three large plants or ancillary load from one or two big plants and full load from one small plant.

Q: What is the cost of the reinforcement of the line to the North Coast?
A: About $150 million. It involves building three capacitor stations and adding adequate voltage support and transformation capacity to maintain a reliable transfer capability along this lengthy line.

Q: Have you looked at a scenario where the North Coast region becomes an exporter of power to other parts of the province?
A. No

Q: Where do GHG considerations come into this? The transmission capacity option to the North Coast reduces operation of gas.
A: There should be a net GHG benefit from transmission. We're working closely with government and LNG proponents on this. The starting point for discussions is whether LNG proponents want electricity service from BC Hydro. Then, if we're going to supply them, how should we do so? Another significant focus for us is the reliability of the region. Gas in the North Coast can be beneficial when the transmission line is down.

Q: What are the GHG assumptions associated to the North Coast?
A: We're basing it on carbon tax adder of $30 per tonne.

Q: What type of load is the LNG going to be—will it be "peaky"?
A: No, it's essentially a base load with an annual load factor of around 94%.

Q: I gather the curtailment opportunity with LNG is very limited.
A: Yes.

Q: Am I right that a key principle in the approach to serving LNG load is keeping existing ratepayers whole?
A: Direction from government includes two key principles: first, the notion of keeping ratepayers whole so that other ratepayers don't subsidize the LNG industry, and second, that LNG proponents get to decide whether to receive service from BC Hydro.

Coffee Break #2

10. Planning for the Unexpected – Lindsay Fane

Lindsay Fane provided background on the contingency resource plans.

Slide #83-88- Planning for the Unexpected

Q: Do the contingency plans include pumped storage?
A: No, the CRPs are developed to test and preserve transmission requirements and because pumped storage is largely located in the Lower Mainland, these resources were excluded.

Q: What is the probability of high-gap situation?
A: That is where you have high load and low DSM response. We assume there is about a 10% probability of occurring.

Q: The Horn River Basin is off grid at the moment. If the LNG sector is successful, has the gas supply from that region been assessed? Have you looked at a scenario where that region is electrified?

A: We considered electricity supply strategies for gas production and processing in the Ft. Nelson and Horn River Basin (HRB) regions, including interconnection with BC Hydro's integrated system in the Peace region and local gas-fired generation options. Our analysis suggests that preference for a particular supply strategy would vary with the expected pace of development in the area, particularly the size of gas processing developments as well as commodity pricing, GHG policies and carbon capture and sequestration (CCS) assumptions.

Generally speaking, scenarios contemplating smaller electrical loads, lend more preference to local gas-fired generation options supported by local transmission in the Ft. Nelson/HRB area. Scenarios contemplating larger electrical loads combined with higher commodity pricing and impetus for either offsetting of GHG's or carbon capture and sequestration, lend more preference to a supply strategy based on clean energy from the BC Hydro integrated system.

Q: Has BC Hydro looked into how rate increases with Site C and LNG could cause other industrial customers to switch to self-generation with gas?

A: Good question. No data on that scenario. BC Hydro has given some thought on the cost of gas for smaller customers with inefficient load shapes and our initial assessment was that we are a long way off from that cross-over point.

C: There will eventually be a cross-over. We need a contingency plan for this. In the future, Site C may not be as suitable as gas generation.

11. Meeting Future Electricity Needs-Kathy Lee

Kathy Lee provided background to the recommended actions aimed at adding demand-side management and supply-side resources to meet long-term growth in capacity and energy demand. Mike Savidant was on hand to address questions related to Site C.

Slide #68-77- Meeting Future Electricity Needs

Q: What is the asset life of Site C, 90 years?

A: The economic planning life for Site C is actually 70 years. For small hydro it's 40 years and for wind it's 15 to 20 years.

Q: On Slide 72, if you look at the cost of a clean + thermal portfolio with DSM option 3 and no Site C ($7,204 M) and compare that to the cost of a clean portfolio with DSM option 2 and including Site C ($7,215) it's almost the same. So isn't that saying that it would be better to do DSM 3, thermal and no Site C?

A: No, one should compare the costs of portfolios assuming that BC Hydro has made the decision to pursue either a clean portfolio or a clean + thermal portfolio. That is if BC Hydro is willing to forgo the loss of using gas as a contingency option then we should compare the cost of two alternatives under that assumption. For example the cost of a clean + thermal portfolio with DSM option 3 and no Site C ($7,204 M) should be compared to a clean + thermal portfolio with DSM option 2 and Site C ($6,888 M). This shows that pursuing Site C is more cost-effective than DSM Option 3 in a world where BC Hydro decides to use the 7% gas headroom. The same is true in an all clean world ($7,955M – No Site C/DSM 3 vs. $7,215M for Site C/DSM 2).

Q: Are IPP resources more cost-effective because they can be applied in smaller, incremental chunks that match load growth?

A: No. In these portfolios, for analysis purposes, we have Site C coming on line at two different time (2024 and 2026) while the IPP resources come on line as needed. The analysis showed Site C is more cost-effective, even with the timing advantage of IPPs.

Q: Does Site C make up the majority of your portfolio cost? 7.9 B out of your roughly 7 B portfolio cost?
A: The 7.9 B for Site C project costs is in nominal $/as spent $ and includes sunk costs, whereas the roughly 7B portfolio PV is portfolio costs discounted to F2013 and represented in real dollars. They are not comparable.
Q: I want to understand the present value number for Site C compared to your portfolio PV number.

Q: Have you done cost over-run sensitivity analysis?
A: We show a +10% cost sensitivity. (See section 6.4.4.3)

Q: What is the wind integration cost?
A: It's $10/MWh in the expected scenarios and we do a sensitivity of $5/MWh and $15/MWh (See section 6.4.4.4).

C: The table on slide 73 is very difficult to understand.
C: Agree. It's coming across as information to justify Site C.

Q: Am I right that if you defer Site C by two years from 2024 to 2026, the benefit is ~$200 million in savings?
A: Table only reflects change in timing of generation and shows Site C is cost-effective at both F2024 and F2026. Decision on in-service date requires consideration of several other factors such as the regulatory schedule and the potential cost of delay. There will be a government decision regarding whether to initiate construction of Site C.

C: What I take away from this is there added value in delaying Site C.

Q: Can you give us a rough time frame for an EA decision and government decision?
A: Via the environmental assessment process, it's a permitting decision by both the federal and provincial governments. The Joint Review Panel will conduct public hearings late this year; they then have 90 days to make a recommendation to their respective governments (March/April), with final permit decisions in October. We can't speak for government regarding the timing of their direction.

Q: I was told earlier today that Site C has small window of time within which it's viable. Please explain further. It relates to the question of whether BC Hydro should calculate the benefits of delaying Site C.
A: The assessment in the IRP was based on the current cost estimate and regulatory schedule. If the in-service date is delayed too long, then current cost estimates and current permits may need to be reviewed. If we stopped work on Site C and had to start again, we'd potentially need to restart engineering and environmental studies and restart the environmental assessment process. The consequences of delay could include substantial cost related to updating studies.

C: So the concern seems to be more around process than need.
A: It's both. If Site C is an option beyond this time frame, we don't have the analysis.

C: You cannot say for sure if it would be more expensive to delay Site C. You have not looked at a later date.

Q: Do you know how long the environmental approval process would be good for?
A: Roughly five years, but depends on the regulators.

Q: What other significant permitting processes are involved with Site C project?

A: Not aware of other permitting requirements, except for the environmental assessment that contains a number of permitting requirements.

Q: If you get the environmental assessment permits, then you're ready to go out to bid, correct?
A: Yes, subject to government direction to proceed to construction. The estimate for construction of Site C is a good one (Class 3).

Q: What is your percentage on contingency in the Site C cost estimate?
A: 18 % on the direct project costs.

Q: How does First Nations fit into Site C plans? How do you deal with opposition from FN?
A: BCH has an extensive consultation process.

C: I'm surprised that the lead time for natural gas is 4 to 5 years. In Alberta, it only takes 2- 3 years.
A: In the BC context, we keep hearing that 4 to 5 years to permit and build natural gas may be too short an estimate.

Q: At the moment, the downstream benefits go out of province, but presumably the value is affected by the market too. So the province could receive higher value by keeping the downstream benefits.
A: The IRP is recommending to lean on downstream benefits more to bridge our capacity needs to Site C. However, such ability to lean on the market and downstream benefits is constrained by transmission capacity.

Q: What procurement models has BCH looked at for Site C.?
A: The procurement model is contained in the business case for Site C available online. The contract sizes range between small and large depending on the type of work. Most are in the design-bid-build to design-build spectrum. The worker accommodation is expected to use a P3 structure.

Q: Have you looked at risks associated with the availability of labour and labour rates, given the other development taking place in the north?
A: Site C considered risk to labour rates and availability when developing the project contingency. We've been very mindful of other projects and hear your point.

12. Roundtable /Close – Anne Wilson / All

The facilitator asked the TAC members for any closing remarks:

Remarks:

- My organization is concerned about the near-term DSM levels and about the treatment of Site C and the sensitivity of cost estimates to the alternatives. We are also concerned about the treatment of the LRMC that is creeping into the DSM analysis, it is more like a mid-term costs rather than long term.

- We can appreciate the complexity of the IRP and are always impressed by the expertise available at BC Hydro to help analyze and explain all the material. There is a need to better understand DSM potential and its forecasting. We would like a more proactive, aggressive approach to encouraging the development of clean resources through marketing their benefits.

- We're going to be in an energy surplus position for a long period of time then we build Site C to create another many years of surplus. There is a cost associated to this surplus. Suggest using Downstream Benefits in BC. Examine and update Electric Vehicle assumptions in the last part of the load forecast. We would like to see more planning information to hold a more informed discussion on how to deal with this surplus. I'm looking for targeted discussion on scenarios to help resolve issues. We also have significant rate impacts, as well as significant infrastructure development in place. These factors will impact our forecasts as we see people leave BC Hydro service for a more competitive product. I'm also concerned about the cut backs on the DSM, and the set of assumptions are too low a quality for the size of the impact they are tied to. I continue to enjoy the technical dialogue with your team.

- Presentation was very well done.

- BCH is following direction from government on 93% clean energy policy. Could we do more electrification? Another option is to create more public dialogue to see what citizens would like. BC Hydro could have the ability to provide more information on both sides of the argument to the public. Also, BC Hydro offers 10% contingency scenarios, but it would be useful to see other ranges related to Site C. Nowhere in the IRP is impact of it on overall GHG targets addressed. We need additional information regarding the GHG impacts of the plan in the northeast. It would also be good to understand the land impacts of Site C and know where it's compared. Other than that, I want to thank BC Hydro on their presentation.

- It struck me how much has changed since the last version of the IRP. I will find it extremely helpful to receive the load resource balance comparison information to better understand the changes. It's difficult to comment on specific items because of the complexity of each component of the IRP. On Site C, as we've stated before, the FNEMC cannot take a position.

- Commend BCH on their presentation today.

- My key message is that the size of the impending rate increases will have a large impact on stakeholders. Assumptions about elasticity are only applicable to smaller incremental increases—there will be step change in customer response. I anticipate by 2015 BC Hydro will no longer be competitive. We're no longer in a world where we can take a long term, inflexible risk like Site C.

- My organization too is concerned about rate impacts and over-supply position. What also struck me, what is the variability of BC Hydro's forecast? Has BC Hydro looked at its control over both sides of the supply-demand equation to manage the surplus? In the longer term, we need to look at the social implications of communicating an over-supply as we have worked so long to communicate a shortage to incent conservation.

- My clients are concerned about the inflexibility of government policy—for example, over-priced IPP contracts. I'd like to see BC Hydro working with government to advocate for the types of issues that we have heard around the table. We are interested in having a strong utility. Additionally, I would like to see BC Hydro working harder to analyse the elasticity. More context, particularly with respect to rates, behind the analysis would be helpful.

- Randy Reimann thanked participants on behalf of BC Hydro. He told participants that BC Hydro aim has been to construct a prudent, flexible plan with expenditures over the next few years focused on maintaining adequate on- and off-ramps should circumstances change or new information becomes available.

Facilitator Anne Wilson thanked everyone for their engaged participation and reminded them of the deadline to submit written comments (October 18).

The meeting ended at 4:28 p.m.