From: Roger Bryenton
Sent: Wednesday, October 14, 2015 10:48 AM
Subject: Re: BCUC, BC Hydro 2015 RDA, Roger Bryenton & Associates comments on RDA, LRMC factors, COS factors, Revenue Req'ts

Good Morning

Attached is a Review and Comment, and Request for Directions from BCUC to BCH, regarding **long-term** aspects of the RDA, LRMC and COS as they pertain to multi-decade projects and assessments, for project(s) of which are of an unprecedented size and will have considerable impact upon future Revenue Requirements, COS and LRMC.

These aspects do not appear to have been adequately considered or incorporated in the RDA and pose substantial risk.

I trust that you will be able to understand the paradigm shift that can occur as a result of "visionary" Rate Design and planning, and that my concern is for well-being and not provocation. BCH have an enviable reputation in many realms and I wish to acknowledge this and hope that they will be receptive to suggestions offered.

I am also open to offline discussion, revisions, improvements and collaboration as I believe this paradigm shift will be for the benefit of all.

Sincerely

Roger Bryenton, P Eng (retired), MBA
Roger Bryenton & Associates
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<u>Exhibit C11-1 – A "Vision for the Future – Part of the Solution or Part of the Problem?"</u>

Roger Bryenton & Associates – Intervener

RATE DESIGN APPLICATION – BC Hydro - G156-15

<u>1 OBJECTION</u>

The RDA submission is 445 pages long. Relevant appendices are 4457 pages – over four thousand pages! The posted date was October 7th with a response date of October 14th. It is preposterous to attempt to review, understand and make a comprehensive response to such a volume of material within this period. **It can only be concluded that the BCUC has intentionally provided such an impossibly short response time in order to prevent thorough reading and responses to the materials.**

The last rate design by BC Hydro was in 2007, fully eight (8) years ago. Now, in light of BC's largest electricity project which will add <u>50% to BCH's debt yet only 10% to generation capacity</u>, a project that will severely affect the Long Run Marginal Cost of power in BC, possibly for decades, ratepayers and others are expected to respond in just seven days!

If the next RDA is a further 8 years, Site C will be fully and seriously impacting LRMC and revenue requirements . **It will be too late to do anything at that point – the damage will have been done.** Even without Site C, BCH has requested and received price increases of 9% and 6 % with cost of living increases running at 2 to 3%. **Such inflation and pricing disparities constitute a dereliction of duty by BCH management, the Premier of BC, the Minister of Energy, Cabinet and the BCUC. Adding a huge project to BC Hydro's debt, approximately 50% increase in debt, probable interest rate increases, probable unit electricity demand decreases , it is not impossible that even BC Hydro could join myriad other electric utilities in the "downward death spiral" of increasing costs, and rates and decreasing revenue.**

<u>Deadline Extension</u> : It is imperative that this deadline be extended and that all interested <u>and affected</u> parties are made fully aware that this RDA and associated Revenue Requirements and Costs of Service during the next 20 years be fully exposed and studied thoroughly. I suggest that half to full page print ads in the newspapers be used to properly advertise the importance of this RDA process and review, with possibly flyers-inserts into BCH bills and emails sent to on-line account holders.

<u>2 LEADERSHIP – BCUC and BC HYDRO</u> – " **A Vision for the Future – Deep DSM**"

BC Hydro, the Provincial Government, and Ratepayers will continue to benefit long-term, from reduced electricity use, particularly as our society evolves, being aware of climate change and energy use imperatives. **BCUC can play an essential role by <u>directing BC Hydro to take leadership and focus on Conservation – DSM vs new supply</u>, to meet current and long-term electricity needs. This will involve both taking risks and large expenditures as we make a paradigm shift, such as retrofitting "electric baseboard buildings", especially rental units where owners have no incentive to spend money on upgrades because tenants pay for utilities, and tenants have no incentive to upgrade a non-owned unit. We will need Billions of dollars but the benefits far exceed the costs.** BC Hydro will be a "World-Leader".

3 PREAMBLE

Good rate design requires: transparency, fairness, accuracy for revenue requirements and cost of service, and **long-term planning** (to 20 or more years) to incorporate major projects and the financial and operating impacts. It is essential that the RDA methodology incorporate a **time horizon of at least 20 years, and perhaps 30 years**. Presently this RDA appears to cover 2015 to 2019 only.

3.1 Rate Design – Revenue Requirements: Embedded Costs vs Marginal Cost for Revenue Requirement Allocation and for Rate Structures.

The use of embedded costs for long-term planning and rate structures could create substantial distortions when a single project (or projects) in the order of 25% to 50% of capitalization is undertaken. Such a scenario could occur in the case of Site C, which will add up **to 50% new debt but only 10% new energy and capacity**. Embedded costs will reflect only 2/3 of the total plant value, and if embedded costs are much lower than marginal costs, substantial rate increases must be imposed toward the end of the period, or, incorporated early in the process (anticipatory) to create a "reserve" to cover the large project costs, and avoid "rate shock". A problem with embedded costs is that they are based upon historical information: "with our eyes firmly on the past, it is easy to miss what is coming"

On the other hand, the use of marginal costs to design rate structures and/or allocate revenue requirements, under large capital-outlay conditions, may lead to different distortion and "over-charging". A parallel could be helpful. Think of a small business rapidly expanding. With too rapid expansion, the business can fail since capital requirements become too large, especially if expansion is debt financed and interest rates rise. The demise of WPSS four nuclear plants is a good example where overbuilding and over-commitment created financial problems. We do not want to repeat that.

It would be prudent, and BCUC needs to direct BCH, to forecast 20 or preferably 30 years revenue based on both embedded costs and marginal costs, in order to determine several options for future rates for the 20 and 30 year horizon; to see what the impact of Site C, including transmission and delivery costs to Lower Mainland load centers, will be on rates and revenue requirements, and given increasing interest rates on $8 to $12 Billion in new debt, how financially risky this could be.

3.2 Framework for Rate Design

According to BC Hydro's stated policy, **effective** rate design requires consideration of such factors as: "the underlying drivers, analysis and assumptions that impact BC Hydro's rates for residential, commercial and industrial customers. Government policy, BC Hydro's load resource balance and energy surplus, conservation results and customer experience with the rates will be considered, and may result in amendments or updates to the rates. As **well as changes to BC Hydro's long run marginal cost which is used in rate design**" – (B C Hydro 2015 Annual Report).

3.2.1 LRMC. In the Rate Design Application, page 1-17 Introduction,(pdf page 37) BC Hydro states "The LONG RUN MARGINAL COST represents the price of **the most cost-effective way** of satisfying **incremental customer demand** where existing resources are insufficient to meet that demand, and is used by BC Hydro in rate design applications (BC Hydro- RDA Application – emphasis added).

A key question is "what is incremental"? Is an 1100 MW project "incremental"? The answer is clearly "NO".

A second key question is "what is the most cost-effective way"?
Is an 1100 MW plant the most cost-effective? Again because it is not incremental the answer is also "NO".

Thus in their RDA, BC Hydro should, but fails to, necessarily exclude the proposed major project Site C, from either consideration or inclusion within the LRMC. <u>Site C should not be allowed to proceed as it contravenes BC Hydro's own definitions of both "incremental" and "most cost-effective". BCUC must direct BCH to identify "incremental" and "most cost-effective" alternatives.</u>

3.2.2 Factors Affecting LRMC

The LRMC will be significantly affected by cost of future major projects, interest rates where debt is a substantial portion of "assets", electricity "markets" and prices, cost of competing energy sources, energy and demand growth, commitment to "green futures" where Demand-Side Management/Conservation is a social PRIORITY, demand shift as a result of rate design, economic conditions, social priorities, power market activities and bulk sales and transfers to government – particularly if facilities are built for these purposes or if past activities and facilities are re-dedicated to domestic markets, industrial co-ordination and transfers. Co-operation and co-ordination will affect LRMC. **The use of embedded (average or historical) vs marginal costs will both directly and indirectly affect LRMC as a result of demand impacts.**

3.3 Alternatives with Lower LRMC Than Site C (See **Exhibit C11-1b attached**).

Establishing that the LRMC must meet both the test of "incremental" and "least cost", what alternatives exist?

1. **DSM** – DSM 1 through DSM 5 in the BC Hydro 2013 IRP plan. **"Deep DSM", or DSM 5 can contribute more electricity and capacity than Site C, at half the cost** and twice the number of jobs!
2. **Small, incremental projects**. These are listed, in no particular order, in the Appendices to the IRP. Roger Bryenton & Associates has created a spreadsheet with analysis and a technical note "ranking" the projects listed in BC Hydro's IRP. This is **Exhibit C-2 attached**. This analysis clearly demonstrates that there are in the order of 50 small projects better suited to meeting both incremental demand and lower cost/MWh. In total the small projects can add an equivalent amount of electricity for considerably less cost, and will create more than twice the number of jobs. (**Note**- the cost/MWh for **Site C** in the IRP needs to be updated to the $8.8 Billion presently projected, plus approximately $2 Billion additional transmission cost to deliver the power to the principal load centers in the Lower Mainland and Vancouver Island. The total energy cost then increases to an **estimated $120/MWh (or more)**, not the $85/MWh BC Hydro presently uses).
3. **Purchase of Columbia Treaty Entitlement**. Presently sold for approximately $30 to $40/MWh, this power is a much less costly alternative to Site C.
4. **Repatriation of Columbia Treaty Entitlement** . BC is entitled to approx 1000 MW of capacity and 4000 GWh of electrical energy annually. Again available at a much lower cost than Site C.
5. **Use of "market" power for domestic sales**. In 2014 Powerex sold 23,000 GWh (worth $900 million, which sounds worthwhile until this is identified as 28% of the power creating only 20% of the revenue). **That "market" sale is four times the size of Site C . <u>Clearly this could be sold to domestic customers, and for more money!</u>**

3.4 Detailed Examination of Alternatives by BC Hydro – "Incremental" and "Lowest-Cost"

From the analysis above, it is clear that BC Hydro has not demonstrated transparency or professional integrity when it comes to presenting "incremental" or "least cost" alternatives and chooses to ignore both the incremental and least-cost alternatives of "Deep DSM" and/or smaller projects. **A directive from BCUC to BCH is essential to the RDA. It must clearly specify that <u>all options must be detailed and ranked</u> to develop accurate Revenue Requirements over the next 20 years (at least), not just 3 to 5 years.**

In a Joint Review Panel Report, BC Hydro's lack of competency and scope on renewables and particularly geothermal power were identified. There may well be thousands of GW's and GWh's of geothermal energy available at costs competitive to the $120/MWh cost of Site C. **A directive from BCUC to BCH is needed to address renewable energy and in particular geothermal energy costs and benefits.**

3.5 Accounting Practices To Avoid "Annual Project Expenditures"

The practice of capitalizing interest costs under "project costs" is a highly mis-leading accounting procedure which, for large projects with lengthy time-frames, badly fails to present the "real" annual costs and expenses and hence revenue requirements. Preferably the annual costs of a project like Site C should be shown as expenses and should **be included in each year's revenue requirement. At the very least, this exercise should be performed to examine the effects of long-term projects on cash flow and revenue requirements.**

4. RISKS

BC Hydro has an enormous debt of approximately $20 Billion. Assets are listed as $ 28 Billion. When interest rates rise, interest payments also will rise. Reducing debt allows greater resiliency and less risk. A large or major project in the range of $8 Billion to $12 Billion would substantially increase the financial risk should interest rates rise, other costs increase or should domestic or market revenue decrease. Given the historically low interest rates, it is inevitable that they will rise. Given concerns about global warming, CO_2 emissions, "green lifestyles" "conservation attitudes" it is likely that consumers and businesses will use less electricity by choice. With increasing rates, consumers tend to reduce demand. Thus larger projects will inherently involve greater risk. It is a preferable alternative to implement **smaller scale projects.**

The risk of adding a single project at a cost of $8 to $12 Billion in debt financing to a business with $28 Billion in assets and an existing debt of $20 Billion is extremely risky given that the business has little control over pricing, especially of alternatives, general economic activity and hence demand.

It is relevant to note that **BC Hydro has chosen to reduce DSM support and activity. It is postulated that this is to avoid further demand erosion, and to intentionally create the illusion of growth and thus justify the need for a major project, Site C.**

5. COS – COST OF SERVICE

5.1 Long-Term Sensitivity of Cost to Interest Payments.

Presently interest charges on the approx $20 Billion in BCH debt amount to just under 20% of the total annual cost of $4.4 Billion; which is $600 million short of income and a balanced budget. This interest is at 4.5% on average. Increasing the amount of debt by $8 to $12 Billion for future project(s) will increase interest charges roughly proportionately, unless interest rates rise over the intervening 30 years of amortization, which will put further pressure on the need for increased revenue.

5.2 Residential COS

The present "split" of 50% Energy, 40% Demand, 5% Transmission and 5% Customer apportionment may be a good "general proxy" or average. However, "averages" are poorly suited to guide behavior. Who are the largest "energy users" and who are the largest "demanders", and what structure of incentives or penalties effectively reduces both energy and capacity requirements? Smart meters instantly identify, or can be used to identify demand if a "demand" module is active in the meter.

Peak usage can be shifted using simple control modules – larger electric water heaters, stoves and dryers can be scheduled and peaks reduced significantly during high consumption. Coloured displays can alert users as to green, amber and red (peak) conditions to help educate people on energy use. **Pilot control system programs need to be implemented.**

New Construction
While not in a Rate Structure, "connection fees" for larger services can be included in the effective management and signal the cost of new supply, particularly peak demand costs. Thus 400 amp service for spa's, air conditioning, electric space or floor heating, or other large loads could have a greater "connection fee" than 200 amp service, reflecting the $3000/kW capacity cost borne by BCH. To reduce this fee, BCH could offer a "load management module" that could effectively reduce the 400 amp service to perhaps a 200 amp equivalent, which could be included in the cost of the service and could result in possibly no cost to the customer.

Retrofitting of or fuel substitution (with Fortis Gas probably)for electrically heating buildings, 33% of the present housing stock, especially tenanted structures can achieve **substantial savings** but the problem of split-incentives must be addressed where tenants pay utilities so landlord does not want to retrofit and tenant does not want to spend on non-owned building. (This same problem occurs in most small businesses and must be addressed). **A Pilot program for rental buildings needs to be implemented.**
An aggressive DSM program targeting electrically heated buildings needs immediate implementation. This is particularly important in communities with no or limited access to alternative heating methods – Vancouver Island, Queen Charlotte Islands, and non-natural gas supplied locales.

LED lighting reduces energy by up to 90% with motion sensors, and in commercial buildings also reduces the HVAC load. **A pilot LED program, if not in place, should be implemented.**

In the letter dated Jul 06 2015 the Minister of Energy asked five questions about RIB rates: two are
- What is the potential for existing Demand Side Management programs to mitigate these impacts? And
- Within the current regulatory environment, what options are there for additional Demand Side Management programs, including low income programs?

The Minister also commented, "This request for a BCUC report (on RIB rates) would not preclude either utility from seeking approval to launch or expand Demand Side Management programming prior to the heating season this fall." **A question to BC Hydro, " What options are available and what progress has been accomplished to launch or expand DSM programming?"**

5.3 General Service COS
BCUC needs to direct BCH to fully explore <u>all avenues</u> of energy and peak reduction and to continue, to expand and where not present, to aggressively implement a series of conservation programs and energy management assistance to further dramatically reduce energy use and demand. "Many general service customers were unable to achieve significant electricity savings" (RDA Appendix – Review of GS Savings) despite having an energy manager indicates a clear need for support and co-operation, either through BCH or privately.

5.4 Industrial and Transmission Service COS
BCUC needs to direct BCH to "partner" with customers, to work with customers to provide the end-use functions needed at the least-cost options. This may require solutions such as BCH using customer-supplied

backup generators during peak periods, and a pilot program to implement; it may involve co-operative agreements with equipment suppliers such as GE or Finning or Cummins and UBC's Westport - Fortis Gas to optimize solutions. Potentially it could involve cross-border agreements with utilities or businesses for co-operative solutions. Within BC it would likely involve both Alcan and Teck, as well as major forestry, chemical, mining and other large corporations. What is required to load-shed or shape or reduce a customer's use? It would be a new era in cooperation, not just supplier and user. BCH and/or private entities could finance and possibly implement such improvements.

Industrial generation and co-generation can be substantially increased, especially during peak demand hours and periods. Co-operative agreements and innovation are key**. A pilot program is needed as directed by BCUC.**

6. CONSERVATION – "DEEP DSM" – An Imperative

Reduced consumption through co-operation between BCH and Customers is in dramatic contrast to BCH's current opinion, "It is not likely that there can be a significant enough difference between on peak and off peak rates to encourage a change in consumption patterns" (BC Hydro RDA Appendices – Voluntary TOU Rate Ch 7 – page 55 (pdf pg 363)).

BCH clearly need direction from BCUC. If "rates" do not facilitate change in consumption, rules, codes, standards and penalties and education are needed, or a greater difference in rates, inclined block, tiered, marginal-cost based rates, etc. The fact that many general service customers were unable to achieve significant electricity savings despite having an energy manager clearly shows the need for support and co-operation.

6.1 BCUC Direction: Conservation vs Construction

BCUC needs to direct BCH to take a "proactive" stance, to make a shift from capital project identification and construction to identifying and implementing the "least-cost, incremental" DSM projects that over the next 12 years can result in an additional 1,100 MW of Capacity and 5,100 GWh of energy annually above present targets.

6.2 BCUC Direction – Long Term Analysis

BCUC needs to direct BCH to perform LONG-TERM COS studies for 2019, 2023, 2027, 2031, 2035 are needed; for 2 scenarios –
a) Incremental and least cost as per definitions above, and Revenue Requirements for the periods, and
b) Assuming a single large project costing b1) $8 Billion , and b2) and Costing $12 Billion to project the effect on long term rates. It is worth noting that already there is an approximate 15% shortfall between costs and revenue and that such conditions have resulted from inaccurate planning: better planning is essential.

7. CONCLUSION

"Deep DSM", or DSM 5 as outlined in the IRP, co-operation and a shift away from construction can create the "Future Vision" for BC Hydro and the Province of BC. BCH will be a world leader and electricity users will have assured and affordable electricity for generations.

Thank you,
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Exhibit C11-1b:

The "Most Cost-Effective Way to Meet Incremental Customer Demand: DSM, not Site C"

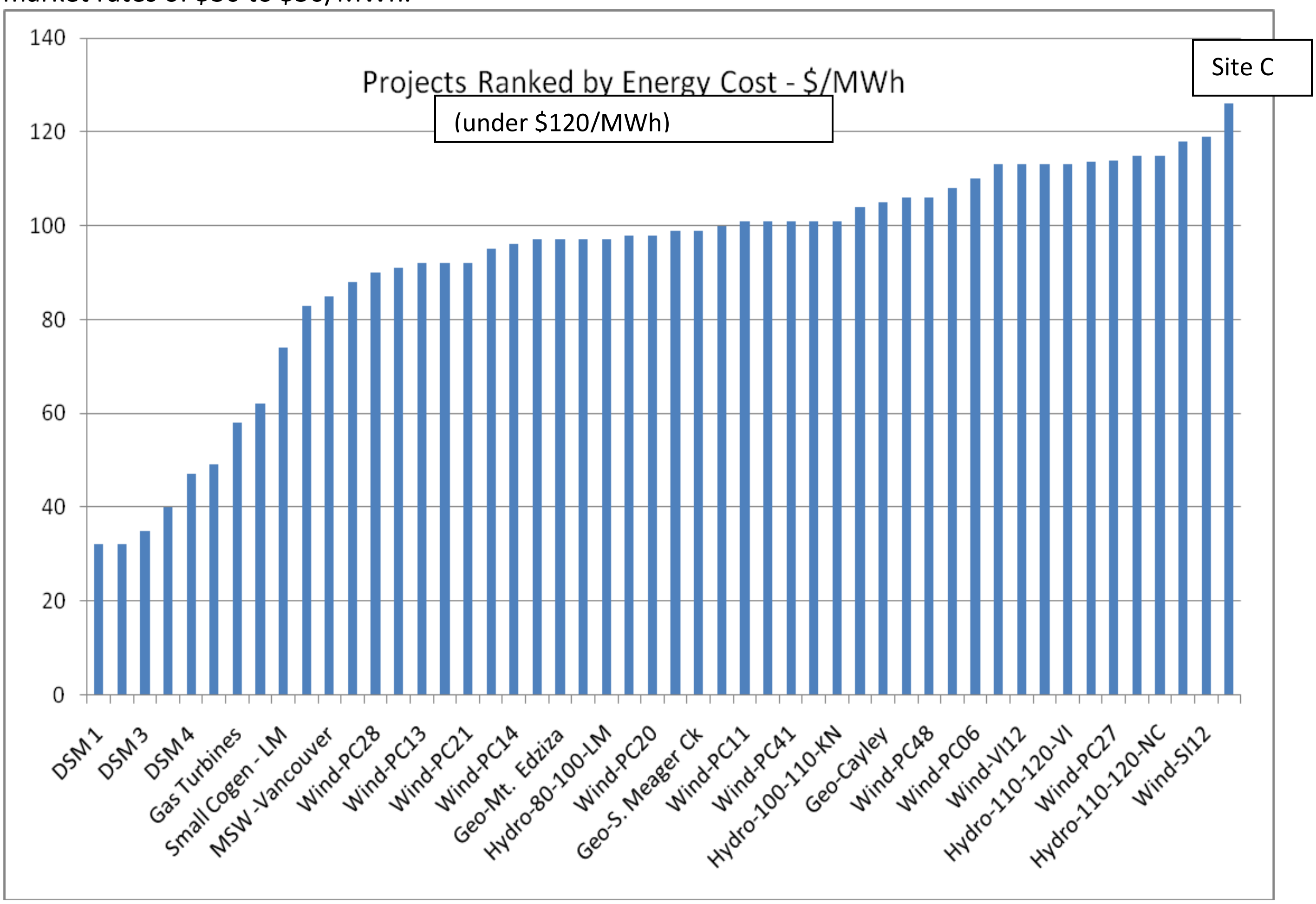
Roger Bryenton & Associates – Intervener BCHydro RDA

"Electricity Conservation and Small Projects vs Site C: Less Cost - More Jobs"

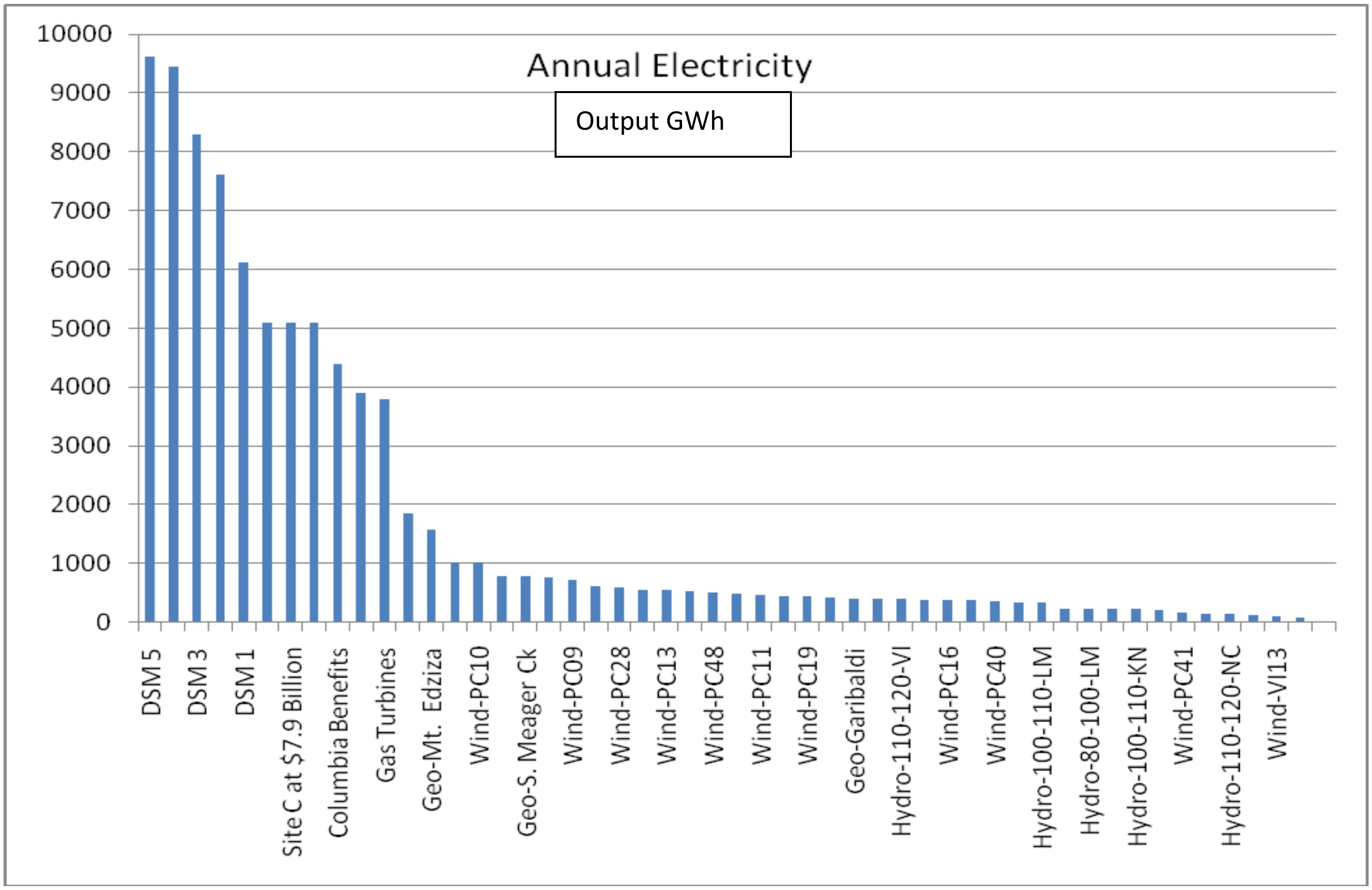
Roger Bryenton & Associates, 2015

Conservation is Cheaper than Site C - Using BC Hydro's own numbers, the Cost of Site C, is now estimated to be $8.8 Billion. This is $126/MWh or 12.6 cents/kWh. Electricity conservation, or Demand Side Management (DSM) can provide the equivalent electricity at less than half this cost, as low at $32/MWh; up to $49/MWh for DSM 5.

New Supply from Small Projects is Cheaper than Site C - If and when new supply is needed, there are many projects available under $126/MWh, including repatriation of the Columbia River Entitlement at market rates of $30 to $50/MWh.

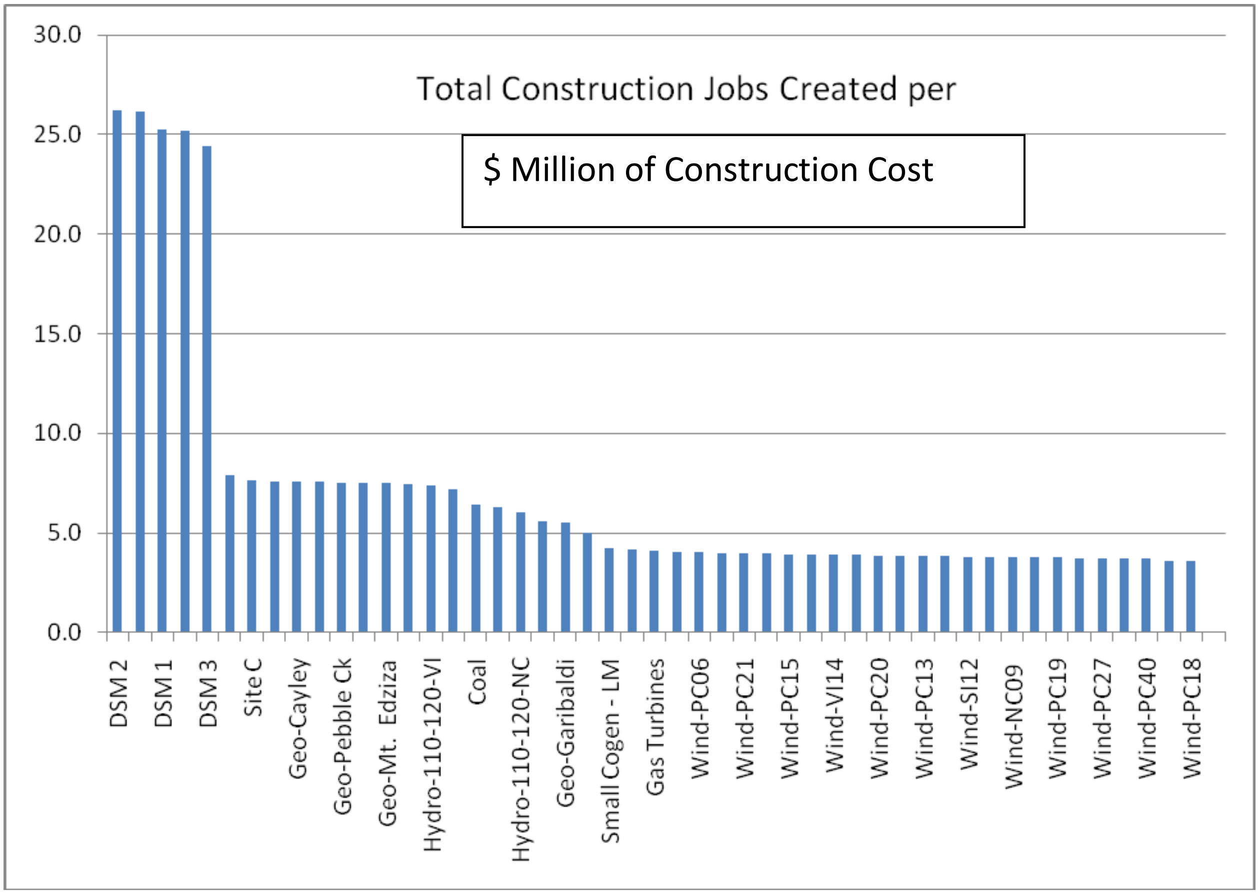


Almost Twice the Power of Site C at Half the Cost– The chart below shows that Electricity Conservation, DSM, can provide more power than Site C. DSM 1, BC Hydro's base case conservation, provides 20% more power than Site C at less than half the cost. DSM 5, BC Hydro's greatest conservation scenario provides **almost twice** the electricty of Site C annually at less than half the cost. DSM also provides as much capacity as Site C, to meet peak demands when needed; a few hours each year.



<u>Jobs Creation from Conservation more than Double Site C</u> – (Below) BC Hydro's employment numbers, there are roughly twice the number of total construction jobs from Conservation compared with Site C.

<u>Electricity Conservation – More Jobs and at Less Cost</u>. The chart below shows that up to <u>four times the jobs are created from Conservation when compared with Site C</u> for the same expense; more than 26 jobs per million dollars for DSM and 7 jobs per million dollars for Site C.



Site C is an expensive solution to a problem that does not exist. Conservation will reduce the demand, small projects can add electricity supply if and when needed, all at much lower cost than Site C.

We do not need to flood the Peace Valley. We need a “Change in Thinking”

Roger Bryenton 2015