AESO Stakeholder Consultation
Long-Term Transmission Planning for Alberta
Stakeholder Questions/Comments and AESO Responses from Nov. 16, 2007 Stakeholder Session
January 22, 2008

The AESO would like to take this opportunity to thank all stakeholders for their participation in the consultation on the Load Forecast 2007-2027 and the Draft Generation Scenarios that will be used by the AESO in the 20-Year Transmission System Outlook and the 10-Year Transmission System Plan.

The November 16, 2007 stakeholder meeting was attended by and/or the AESO received written comments from the following organizations:

ABB Inc
Alberta Wind Energy Corporation
AltaGas Ltd.
AltaLink Management Ltd.
ATCO Electric
ATCO Power
British Columbia Transmission Corporation
C-FAR & Associates
CRD Energy Services
Delaney Management Inc.
Direct Energy Marketing Inc.
Energy Alberta
ENMAX Corporation
EPCOR Utilities Inc.
Golder Associates
Lawson Lundell LLP
MEG Energy Corp
Natural Power
Naturener Canada Inc.
NOVA Chemicals
PowerEN Corporation
Rocky Mountain Power
Shear Wind Inc.
Shell Canada Limited
Siemens Canada Limited
Spirit Pine Energy Corporation
TransAlta Corporation
TransAlta Wind
Utilities Consumer Advocate
Valeo Power

Long-Term Transmission Planning for Alberta
Stakeholder Consultation
Comment and Response Matrix
November 16, 2007- Stakeholder Meeting

TOPIC: Load Forecast 2007-2027

Stakeholder	Stakeholder Question/Comment	AESO Response
1. TransCanada	When using the Conference Board's forecast of GDP do you evaluate their track record against other sources?	The AESO does not evaluate the track record of the Conference Board's GDP forecast. The AESO compares the Conference Board's GDP forecast with those from commercial banking institutions.
2. AltaLink	Do you do a regional load forecast breakdown comparison? Do you consider behind-the-fence load and how do you factor that?	The AESO's long-term load forecast is generated for each metering point. Regional load forecast information is provided to Transmission planners for study purposes. The AESO forecasts behind-the-fence load and this is included as part of the Alberta Internal Load (AIL) forecast. The determination of this load segment is a combination of information from large industrial customers and economic growth projections.
3. Direct Energy	Can you break down the load increases by residential,	No. The three load sectors are: (1) total industrial &

	industrial and commercial by area? (see slide 21). Detailed numbers would help to evaluate our business.	commercial, (2) residential, and (3) farm. The province-wide results are found in Table 1 attached at the end of this document.
4. NOVA Chemicals	Performance metrics under NERC have changed the criteria upon which the existing lines would have been built a) what are your plans to restore line capabilities to original performance b) what are the plans to restore transmission substations to original performance c) have lack of on line tap changers or sub transformers factored into the inflow and outflow capabilities d) what are the plans for installation of lightning arrestors on existing 138kV lines in central Alberta e) have you factored in regulatory changes to restrictions as to when and how to reflect these changes	In Alberta, establishing equipment ratings is the responsibility of the Transmission Facility Owner. The AESO is aware of these ratings and takes them into account in its regional planning studies. Our area planning studies take into account such things as forecast load growth, addition of new generation, age of infrastructure and equipment maintenance requirements. Any mitigative measures proposed as a result of these studies will include changes to equipment if equipment ratings are identified as limitations. The existence of transformer on-line tap changers is more of a consideration for purposes of voltage control as opposed to determining transfer capabilities. The AESO has no specific plans regarding the installation of lightning arrestors on 138 kV lines in central Alberta. This issue is the responsibility of the Transmission Facility Owner (TFO). The AESO is aware of, and stays current on regulatory developments that may have an impact on the planning and operation of the Alberta Interconnected Electric System (AIES). More specific information on future transmission developments will be included in subsequent stakeholder consultation as the process of developing the 20-Year Outlook and 10-Year Plan proceeds in 2008.

5. ENMAX	What is the AIES 10 Year Load Growth Outlook?	Please see Table 2 attached at the end of this document.
6. TransAlta	With the Royalty Review changes and the Canadian dollar doing so well how do they relate to load growth?	The AESO's load forecast was prepared before the results of the Royalty Review were known. Although this seems to have had an immediate effect in the natural gas sector, the ultimate impact on load growth is currently unknown. In general, the appreciation of the Canadian dollar will reduce revenues for industries that export to the United States. This may be off-set by reductions in the cost of imported capital goods. The impact on the short-term load growth is expected to be minimal. The AESO will monitor the impact of the exchange rate on Alberta's economic growth and will update subsequent load forecasts accordingly.

TOPIC: Draft Generation Scenarios

Stakeholder	Stakeholder Question/Comment	AESO Response
1. AltaLink	What is the reasoning behind putting Battle River 6 in the 2017-2027 time frame and not 2007-2017?	The AESO assumes that Battle River Unit 6 will be installed after 2017 following the retirement of Battle River Units 3 & 4.
2. Energy Alberta	The existing effective generation drop in 2025 is less than scheduled retirement amounts. Does the projection of existing generation include some repowering or life extension?	The AESO has included some future retirements for the Battle River, Sheerness, Wabamun, HR Milner, Rainbow, Rossdale and Sturgeon generators; however the specific timing of retirements is speculative at this time. The

		generation scenarios are based on the assumption that repowering will occur for any retirements at the Keephills, Sundance and Genesee coal generation plant sites.
3. Energy Alberta	Do you have preliminary cost estimates for nuclear and how does it compare to the $75 price for supercritical pulverized coal at the low end of the chart?	Preliminary cost estimates from Atomic Energy Canada Limited place the costs of nuclear power close to those of brownfield supercritical pulverized coal. The costs were not included in the presentation since the ACR-1000 unit (Advanced CANDU Reactor) being proposed in Alberta is still in the design phase.
4. Enbridge	How sensitive is the forecast to the assumed GHG offset price?	Scenarios with a higher component of new coal-fired generation are more susceptible to the GHG offset price than those with a high amount of natural gas-fired generation or wind power. In addition, a higher GHG offset price could promote advanced development of new low carbon output/high carbon capture technologies. For transmission planning purposes, the technology type is less of a factor than timing or location.
5. TransCanada	How did you arrive at your calculations for the reserve margin (10, 20, 30%)? Please explain your assumptions.	The effective reserve margin shown in slide 33 excludes intertie capacity and derates the capacity of both wind and hydro generation. Wind is derated to an effective capacity of 20% of installed capacity, legacy hydro is derated to an effective capacity of 67% of installed capacity and irrigation hydro is derated to an effective capacity of 20% of installed capacity. This effective reserve margin is approximately equivalent to a 20% installed reserve margin if all generation is taken at installed capacity. If intertie capacity is included in the calculation, the reserve margin reaches about 30%.

6. TransCanada	Are your cost comparisons levelized costs?	Yes, the comparison is based on the levelized unit electricity cost for each generation type. This represents the price needed to recover all costs over the life of the project, discounted accordingly.
7. TransCanada	Is your capital cost information for combined cycle and simple cycle based on recent or dated information?	The various costs presented on slide 36 were taken from a number of public sources and tested with generation developers. If the numbers are inaccurate we would appreciate your feedback to improve our analysis.
8. TransAlta	With respect to interties, have you incorporated the 20% of load intertie capacity specified in the new draft Transmission Regulation recently released by the Department of Energy, into the creation of your generation scenarios?	We did not incorporate this information as the regulation was still in the draft stage. Note: subsequent to the stakeholder session, changes to the Transmission Regulation were passed; however, a requirement for additional intertie capacity as a percentage of load was not included in the regulation.
9. TransAlta	In the long term if assuming storage capability for wind energy the effective capacity factor of 20% should be increased.	We will investigate this suggestion in more detail.

TOPIC: Other General Questions

Stakeholder	Stakeholder Question/Comment	AESO Response
1. NovaChem	What is the impact of the 500 kV Calgary/Edmonton line on service (curtailment) in central Alberta?	We are currently assessing the full impact of the delay of the Edmonton – Calgary 500 kV line and anticipate being able to provide more information to stakeholders in 2008.
2. TransCanada	TransCanada rejects the AESO assertion that “the past relationship between economic factors and electricity demand is the best predictor, at this time for future demand.” We feel both the relationship between the economic factors and electricity demand and the actual economic factors can be expected to change dramatically over such extended study periods. Overlooking the effects of interchange calls into question the AESO commitment to meeting either the past or new T-Reg requirements. Effects that need to be included in the analysis include: • Peak diversity - Commerce between tightly interconnected systems with different times and seasons of peak load has the effect of reducing the demand for peaking resources, and, in some circumstances, on load following capability. This inter-jurisdictional peak diversity makes planning for a reduced peak a reasonable assumption. • Adjacent system relevance – Renewable standards, existing generation mix, load characteristics and other factors will represent problems or opportunities for Alberta and must be considered. Adjacent systems are aggressively pursuing efficiency and demand side options which can,	At this time there are no quantitative indicators that prompt us to reject the premise that economic growth drives industrial and commercial electricity demand in the province. Each year, as part of the load forecasting process, we undertake an econometric evaluation of the relationship between economic growth and load growth. The current generation scenarios assume neither an increase nor a decrease in the amount of Alberta generation as a result of new intertie capability. We will undertake additional analysis to better quantify how new intertie capability could impact generation additions. Efficiency and demand side options in Alberta are currently market based decisions. Should programs be implemented in the future, their impact will be incorporated in the load forecast.

	depending on how they are implemented affect interchange. It is also reasonable to expect some of these programs will succeed and that the ones that are successful could be implemented here. It would seem reasonable to sum the targets of these programs and then apply a fractional success factor to show that not all will succeed and occur here.	
3. EPCOR Utilities Inc.	EPCOR continues to have concerns with respect to the lack of explicit price assumptions in the load and generation scenario forecasting and believes that incorporating those assumptions is crucial as generation investors primarily respond to different types of price signals. Electricity, gas and coal price sensitivity analyses should be undertaken in coordinated effort to harmonize load and generation forecasts for the benefit of arriving with a wholesome and comprehensive long-term transmission plan. In particular, the threshold between 2016 and 2017 seems assuming significant changes in the investors' behavior and priorities. The plan is suggesting a fundamental shift from the traditional to more advanced technology with only one explicit reason, the Greenhouse Gases ("GHG") regulation implementation by 2018. This profound hypothesis should be widely discussed during the approaching consultation.	Our analysis of the impact of electricity price on load suggests that there is approximately 300 MW of price responsive load. This responsiveness affects the hourly load shape, which is incorporated into our load forecast. Therefore, although electricity price is not an input variable into our load forecasting process, the price impact is implicit within the long-term load forecast. The generation scenarios were created for the 20-year time period, but then presented in two 10-year intervals. There was no deliberate shift from moderate scenarios for the first 10 years to aggressive scenarios for the 10-20 years. The timing for the adoption of new technologies is uncertain at this time; however, the planning of transmission facilities is more dependent on the location than the technology associated with new generation.

Future Demand and Energy Outlook 2007 - 2027

Table 1: Annual Energy (GWh) by Sector (Industrial & Commercial, Residential, and Farm)

Note: does not include transmission losses or load served by self-generation.

	Industrial & Commercial	Residential	Farm
2000 ACTUAL	40,037	6,964	1,807
2001 A	39,102	6,757	1,769
2002 A	39,319	7,047	1,700
2003 A	38,363	7,369	1,772
2004 A	39,558	7,374	1,730
2005 A	40,585	7,576	1,702
2006 A	41,388	8,044	1,766
2007 FORECAST	42,309	8,272	1,867
2008 F	44,480	8,463	1,931
2009 F	45,779	8,649	1,974
2010 F	47,598	8,828	2,004
2011 F	49,160	9,003	2,026
2012 F	51,236	9,170	2,044
2013 F	53,294	9,342	2,059
2014 F	55,032	9,514	2,073
2015 F	56,936	9,686	2,086
2016 F	59,036	9,862	2,099
2017 F	60,738	10,036	2,111
2018 F	62,180	10,209	2,123
2019 F	63,739	10,384	2,136
2020 F	66,127	10,556	2,148
2021 F	68,308	10,728	2,160
2022 F	70,518	10,900	2,173
2023 F	72,782	11,071	2,185
2024 F	75,119	11,243	2,198
2025 F	77,569	11,411	2,211
2026 F	80,035	11,580	2,224
2027 F	82,605	11,747	2,237

Future Demand and Energy Outlook 2007 - 2027

Table 2: Alberta Interconnected Electric System (AIES) Load

Year	fc2007 (MW)	Growth %
2000/01 Actual	7,666	
2001/02 A	7,527	-1.8
2002/03 A	7,552	0.3
2003/04 A	7,650	1.3
2004/05 A	7,910	3.4
2005/06 A	8,066	2.0
2006/07 A	8,177	1.4
2007/08 Forecast	8,625	5.5
2008/09 F	8,983	4.1
2009/10 F	9,148	1.8
2010/11 F	9,456	3.4
2011/12 F	9,750	3.1
2012/13 F	10,064	3.2
2013/14 F	10,425	3.6
2014/15 F	10,719	2.8
2015/16 F	11,005	2.7
2016/17 F	11,328	2.9
2017/18 F	11,647	2.8
2018/19 F	11,909	2.3
2019/20 F	12,188	2.3
2020/21 F	12,560	3.0
2021/22 F	13,000	3.5
2022/23 F	13,422	3.2
2023/24 F	13,856	3.2
2024/25 F	14,250	2.8
2025/26 F	14,758	3.6
2026/27 F	15,223	3.2
2027/28 F	15,703	3.2

Year	fc2007 (GWh)	fc2007 (Growth %)
2000 A	52,914	
2001 A	52,480	-0.8
2002 A	53,673	2.3
2003 A	53,169	-0.9
2004 A	54,669	2.8
2005 A	55,697	1.9
2006 A	57,315	2.9
2007 F	58,615	2.3
2008 F	61,461	4.9
2009 F	63,054	2.6
2010 F	64,766	2.7
2011 F	66,737	3.0
2012 F	69,271	3.8
2013 F	71,787	3.6
2014 F	73,940	3.0
2015 F	76,278	3.2
2016 F	78,841	3.4
2017 F	80,962	2.7
2018 F	82,784	2.3
2019 F	84,737	2.4
2020 F	87,614	3.4
2021 F	90,264	3.0
2022 F	92,948	3.0
2023 F	95,695	3.0
2024 F	98,517	2.9
2025 F	101,461	3.0
2026 F	104,424	2.9
2027 F	107,501	2.9

AESO Use of Information Provided
In accordance with the AESO's commitment to transparency in its consultation, all comments provided by industry stakeholders will be attributed to the industry stakeholder that provided the comment and will be made publicly available. For further information contact us at: 1-888-866-2959 or email stakeholder.relations@aeso.ca