# AB-BC N-S Backbone Summer Capability Study

February 22, 2006

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*APEGGA Permit to Practice P-8200*

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# 1 Background

Since the first quarter of 2004, the AESO has initiated several reliability studies to determine the capability of the N-S 240 kV back bone to support southern load and exports. These studies also determined the impact of southern generation on export capability and voltage support to the Calgary area, a large load center in the south.

The initial export limits and Calgary area TMR requirements resulting from these studies were based on conditions with low southern Alberta generation in the base cases. Further stakeholder discussions emphasized the need to review the export TTC limits for scenarios where additional southern generation is on line in real time operation during low load periods. Consequently, the summer and winter limits were reviewed, and it was determined that Calgary Area Generation (CAG) could be used to increase export limits when online at times of light load periods. A new method of calculating export limits was implemented, and calculated export TTC limits by adding the cumulative effect of CAG onto an existing base TTC for each Alberta load block up to the load block that required CAG TMR to support voltage in the Calgary area. Further modifications were implemented for the winter limits to account for the affects of Joffre, Sheerness and Big Horn generation.

It was also observed in real time operation during 2005 that low 240 KV voltages were occurring during light load and high exports periods. Historical real-time data showed that these low voltages occurred during high flow on the North-South (N-S) 240 kV backbone. This investigation suggested that there is a need to monitor N-S backbone flow, determine the N-S flow limit, and study the possibility of a relationship between the N-S flow and export TTC and Calgary Area TMR.

The addition of 514 MVAr of capacitor banks in three locations in the Calgary area by Q1 2006 should eliminate most of the voltage stability concerns that currently limit Alberta Interconnected Electric System (AIES) export capability. It is expected that thermal overloading of the 240 kV backbone circuits post contingency will now become the limiting factor for determining export capability limits. These thermal limitations may be best monitored using metrics other than AIES load for setting export limits, such as North-South (N-S) flow.

# 2 Study Objective

The objectives of this study were to:

- Determine the maximum flow limit of the 240 kV N-S back bone cut plane while meeting the AESO's Operating Criteria.
- Review the current export limits considering the 514 MVAr of capacitor banks (260 MVAr at Janet 240 kV, 200 MVAr at Sarcee 240 kV, and 54 MVAr at East Calgary 5S 138 kV).

- Review the current practice of setting export limits based on Alberta load and southern generation adders. An alternative method may be to set export limits based on the N-S 240 kV Backbone flow, and/or other factors.
- Determine minimum voltage requirements for the summer season given varying load and export scenarios.

# 3 Study Scope

- Steady-state analysis of type B and C contingencies was performed in order to address voltage and thermal overloading concerns.
- Power-voltage (PV) analysis was performed on the AIES to determine the Voltage Stability Load Limit (VSLL) for a base condition.
- The AIES generation stacking order was not used for this study. Instead, southern generation was varied in order to monitor the effect of various generation patterns on N-S flow, thermal overloads, voltage stability, and the required minimum operating voltages to meet the AESO's Operating Criteria.
- Analysis was performed on study cases with summer loads ranging from 6600 MW – 9250 MW; the all time historical summer peak is 8578 MW, which occurred on July 19, 2004. Winter cases have also been analyzed up to approximately 9000 MW. South and north generation dispatches were varied to create a scenario for high N-S flow on the 240 kV back bone to make sure AESO's Operating Criteria expectation were met for B and C type of contingencies.

# 4 Study Assumptions

Constant MVA load models were used. This is in alignment with the WECC paper "Voltage Stability Criteria, Undervoltage Load shedding Strategy, and reactive Power Reserve Monitoring Methodology" dated May 1998

The area loads in PSSE were scaled using a constant power factor.

Only areas of the province that are not largely made up of industrial load were scaled during PV analysis as areas with large industrial loads are generally base loaded and do not vary in the same uniform manner as non-industrial loads. The areas scaled include: 6, 13, 20 to 24, 26, 27, 29 to 32, 34 to 39, 42 to 47, 49, 50, 52 to 57, and 60 (according to the AESO AIES map).

Area 6 was scaled independently of the other areas; this was done in order to capture that Calgary area load grows faster than Alberta load (for example as AIES goes from 6000 – 7000 MW, the *percentage* of Calgary area load will increase relative to Alberta load). In order to set a study case to a given Alberta load level, first the Calgary area load was scaled to a level that represents a high percentage of Alberta load for the given load level (according to historical data), and then the remainder of the areas mentioned above were scaled in order to reach the desired load level.

Note that while studying the effects of an N-1 loss of 190L or 903L (Keephills to Benalto), the generation limits listed in OPP 517 were applied to the Keephills and Genesee (KEG) generators before analyzing further N-1-1 or N-1-2 contingencies.

# 5 Methodology

Selected single and double transmission contingencies were examined for their effect on thermal overloading and voltage stability. The contingencies selected include the loss of major generation units in southern Alberta, as well as single circuit and double circuit contingencies along the 240 kV backbone. Single contingencies require a 5% load margin for Power-Voltage (PV) analysis, while double contingencies require a 2.5% load margin.

Contingencies were also analyzed to ensure that Transmission Facility Owner (TFO) thermal emergency limits of transmission equipment were not violated in post-contingency situations.

Additional studies to determine the N-S backbone flow limit, export capability of the AIES and need for the south generation during conditions with a major system element (generator, transmission line, or capacitor bank) out of service have been conducted for the summer season.

# 6 Scenarios Studied

Cases were analyzed with summer loads ranging from 6600 MW to 9250 MW, and varying generation patterns. The lowest historical power factor for the summer was used for both the Calgary area and the Alberta Load; this ensured that the reactive demand in the south AIES and the back bone will always be met under worst seasonal power factor.

## 6.1 Pre-Conditions

Table A1 of the appendix list the power factor used in the base case and all subsequent cases. These values correspond to the power factors used in previous studies, and represent the worst historical power factors determined for the summer season.

## 6.2 System Contingencies

The contingencies studied include the loss of select common tower 240 kV lines, select 240 kV lines sharing a common breaker (assuming a breaker failure following a fault on one line in a breaker and half bus configuration, resulting in two lines tripping at the same time), a Calgary area capacitor bank, the Langdon SVC, and major southern Alberta generation units. The complete list of contingencies studied is shown in Table 1. Note that these contingencies were analyzed for both N-0 and N-1 conditions in which another 240 kV backbone line was out of service.

**Table 1: Contingency List**

| Contingencies Studied |
|---|
| 928L & 906L |
| 925L & 929L |
| 922L & 926L |
| 190L & 903L |
| 910L & 914L |
| 927L & 924L 3T Lines |
| 933L & 931L |
| 925L & 901L |
| 918L & 190L |
| 928L & 903L |
| 936L |
| 936L & 937L |
| Janet 74S 240 kV Capacitor Banks |
| Sarcee 240 kV Capacitor Banks |
| Langdon SVC |
| Sheerness 1 |
| Sheerness 1 & 2 |
| Battle River 5 |
| Battle River 5 & Sheerness 1 |

# 7 Summary of Results

The study results indicate that with the new Calgary area capacitor banks in place, the AIES will have increased voltage stability capability on the N-S 240 kV transmission path. Flow on the N-S 240 kV transmission path will now be limited by thermal constraints due to high flow on the N-S cut plane; the worst contingency found was the loss of the double circuit lines running from Benalto 17S to Sarcee 42S (928L and 906L), which results in possible overloading of 900L (Benalto 17S – Red Deer 63S). This change in constraint to a thermal constraint suggests that the current indices used to determine Alberta interchange TTC and Calgary area transmission must run (TMR) considering AIES load and Calgary area load respectively may not be optimal. In fact this dependency on N-S flow suggests that flow on a cut plane should be monitored and used to determine total Alberta export interchange TTC (AB to BC and AB to Sask), and to determine the need for the south generation to support south load and voltage.

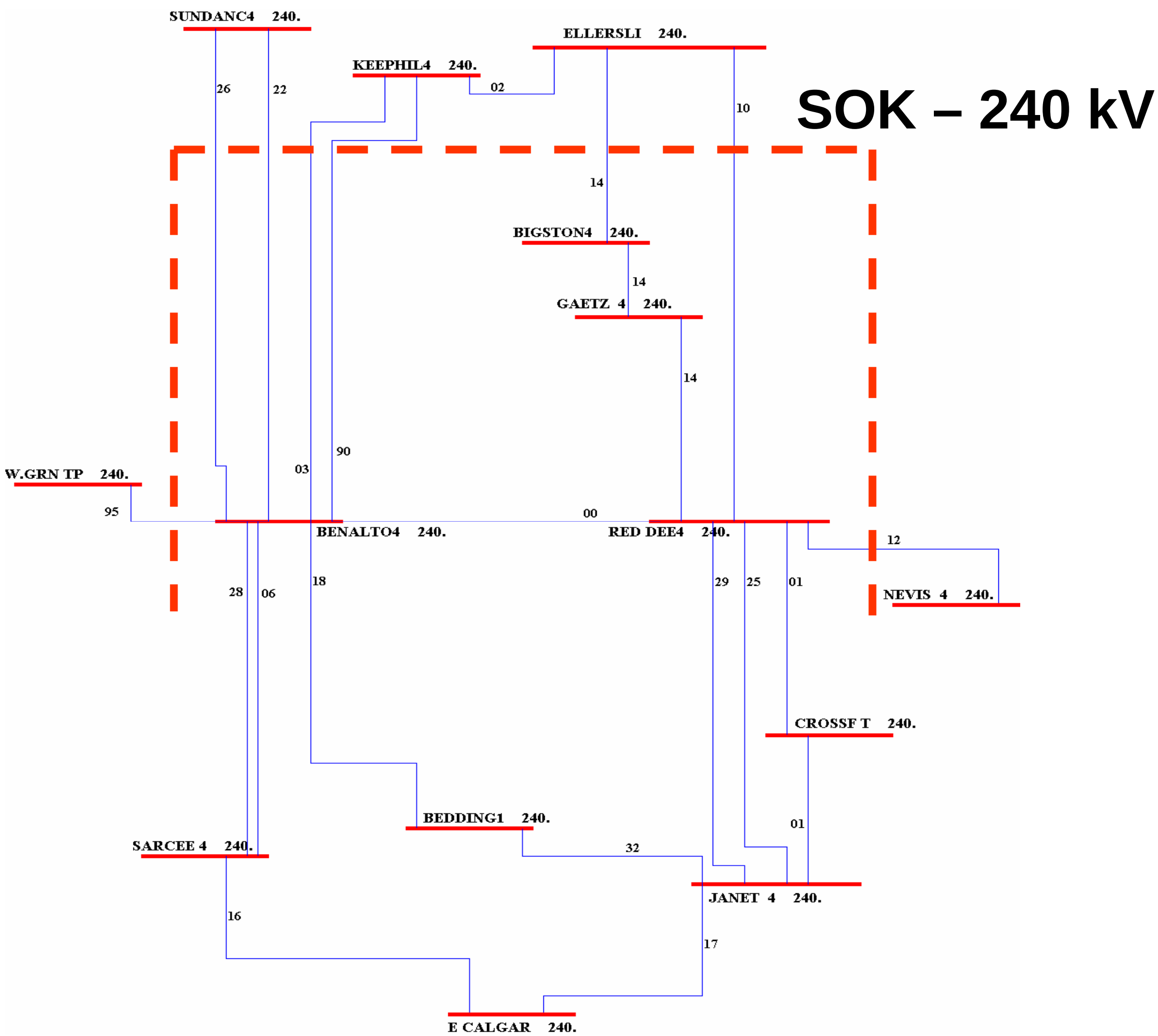
The use of capacitor banks to improve voltage stability does not indicate that static VAR support is all that is needed to support load. The addition of the capacitor banks simply provides additional VAR support during high load or high export conditions, such that the combination of static and dynamic VAR support is sufficient at higher loads than prior to the installation of the capacitor banks. By maintaining N-S cut plane flow below its thermal limit ensures that the amount of dynamic reserve online will increase as load increases in the south because the additional southern generation required to be online at higher load will also provide additional dynamic VAR support.

## 7.1 South of KEG (SOK) 240 kV Cut Plane

Through study analysis and monitoring of several contingencies, it was determined that flow on the six 240 kV backbone lines from the Keephills-Ellerslie-Genessee (KEG) region to the Red Deer region (910L, 914L, 922L, 906L, 903L and 190L), as well as 995L (Brazeau 62S – Benalto 17S) and 912L (Red Deer 63S – Nevis 766S), must be limited to meet the AESO Operating Criteria for N-1 and N-2 contingencies. These lines are shown in Figure 1 and have been categorized as the "SOK-240" cut plane. Flow on the KEG lines and 995L have a direct impact on the loading of 900L following a double circuit contingency of 906L & 928L. 912L flow must also be included, as the amount and direction of flow on this line also has an effect on the pre-contingency flow of 900L, which determines the thermal limit of the SOK-240 system. Note that the SOK-240 cut plane discussed in the report (also referred to as just the "SOK" in this report) differs from the SOK mentioned in earlier AESO need applications / reports (regarding the Calgary area capacitor banks and 500 kV upgrades). The SOK-240 does not consider flow on 138 kV lines flowing along the N-S cut plane, and it does include the flow of 995L and 912L depending upon the direction of the flow on these two lines.

Flow on 912L must be included as part of the SOK-240 cut plane, as study results indicate that the allowable flow limit on the KEG lines and 995L was reduced in the event of one (or multiple) Battle River or Sheerness units out of service. This is required, as these units usually provide MWs into the Red Deer area through 912L. When a Battle River or Sheerness unit would be out of service, energy may instead flow eastward on 912L line (from Red Deer to Nevis) and also increases pre-contingency flow on 900L from Benalto to Red Deer. This increased flow on 900L during the N-0 condition results in greater loading of 900L following an N-2 contingency. Therefore the SOK-240 limit has to be de-rated when Battle River or Sheerness units are out of service. Instead, positive flow on 912L from Red Deer to Nevis can be included as SOK-240 flow to account for the change in flow direction, allowing the same N-0 SOK-240 limit to be maintained regardless of the generation output of the Sheerness and Battle River units.

**Figure 1. "SOK – 240 kV" Cut Plane**




## 7.2 SOK-240 N- 0 and N-1 Limits

The maximum allowable flow on the SOK-240 cut plane was analyzed for system normal and selected N-1 contingencies (i.e. those deemed to have an effect on maximum allowable N-S flow). SOK-240 flow limits were determined considering both single and double contingencies over and above the first outage for analysis of thermal overloads (i.e. N-0-2, N-1-1 and N-1-2 scenarios), and single contingencies (i.e. N-1) for voltage stability analysis. Table A2 lists the planned (or unplanned) N-1 scenarios analyzed, and the corresponding SOK-240 flow limit for a given load level. Note that initial study findings suggested that one SOK limit could be used for all AIES load levels; further analysis has shown that two load blocks should be used to maximize the maximum allowable SOK-240 flow for scenarios in which AIES load is less than 8000 MW. AESO plans to perform further studies to better identify the transition point of these two load blocks.

It is suggested that two SOK-240 threshold limits be implemented, an "Action" and an "Alarm" limit to manage system reliability based on SOK-240 flow. The Alarm limit should be below the Action limit (a yet to be determined MW reduction from the Action limit, based on SOK flow variation), and its main purpose will be to provide an indication to the system controllers that the hard limit (i.e. the "take action" limit) is being approached. Once the Action limit is reached, SOK-240 flow should be curtailed to below the Alarm limit. This "dead band" between the Alarm and Action limits will allow operators to take action in larger MW increments, rather than having to take action for every small system variation.

If in real time conditions SOK-240 flow is reduced to well below the Alarm limit, the steps taken to curtail SOK-240 flow can be reversed (if it involved TMR etc.) only to the extent that real-time flow remains below the Alarm limit. Using TMR to reduce SOK-240 flow is a proposal based only on technical merit; the AESO OPP Group, in consultation with Real Time Operations, will firm up these procedures around SOK-240 management.

## 7.3 Reactive Reserve and Dynamic Reactive Reserve Requirements

Reactive demand in the south AIES is dependent on southern load and generation on line, SOK-240 flow, and interchange on the Alberta-BC and Alberta-Sask tie lines. Reactive reserve analysis using VQ voltage stability techniques indicate that there is sufficient reactive reserve during N-0 and N-1 Operating states to sustain the next N-2 double contingency. In order to operate the system in post N-2 state, SOK-240 flow must be reduced and additional capacitor banks and / or generation in south may have to be dispatched on in order to prepare the system for the next contingency.

It has been determined by our studies that the VAR requirements for the system operating in normal (N-0) and operating in post N-1 states on the N-S backbone will be met as long as SOK-240 flow is managed such that it is below the stated limit for each system operating state. Our study results indicate that for an AIES load below 9200 MW in the summer, there will be sufficient dynamic reserve as long as the SVC is operated in the 25 MVAr to -50 MVAr range and operating voltages would be equal to or higher than the minimum operating voltages listed in Tables A3. This is a result of the management of the SOK-240 flow, as higher south load will require additional southern generation on line to keep the SOK-240 flow below its limit. This additional generation will also provide dynamic VARs available in the south to support higher load or higher exports at lower loads. Note that additional northern generation should not affect this, as additional northern generation being brought on line to serve load does not change the amount of southern generation required to support a given amount of southern load (to maintain SOK-240 flow within its limit). However, upgrades to the backbone system, which may increase SOK-240 capability, and raise the allowable flow limit, could result in a shift back to voltage stability being the limiting factor at high loads; this will be examined further as additional studies are conducted.

Further studies are required to assess the dynamic reserve requirements of the Calgary area when the Langdon SVC is out of service. Currently, an SOK-240 derate is recommended, but supplementary dynamic reserve requirements may be recommended once more analysis has been completed.

## 7.4 SVC Operating Range

As stated above, an appropriate level of reactive reserve will be maintained provided that SOK-240 limits are adhered to, and if the Langdon SVC is operated within the range of 25 MVAr to -50 MVAr. However, to provide some additional margin, it is suggested that the Langdon SVC be operated (as much as possible) within the desired range of 0 MVAr to -50 MVAr. This is to ensure that there is at least 250 MVAr of dynamic reserve available on the SVC.

## 7.5 Minimum Operating Voltage Requirements

The minimum operating voltages that must be maintained on the N-S key nodes to meet the AESO's Operating Criteria are listed in Table A3. If all voltage control devices have been exhausted, and pre-contingency voltage falls below the minimum operating voltage at any key node listed in Table A3, curtail export such that SOK-240 flow is reduced until the voltage at all of the buses listed in A3 is restored to at least its minimum operating voltage. In the unlikely event that voltage at one or more buses cannot be maintained at or above the minimum operating voltage and there is no export to curtail, alternative action will be required to restore the bus voltages to the minimum operating voltage; these procedures will be addressed by the new SOK-240 flow management OPP that will be implemented (the procedure for offloading SOK-240 should be similar to the procedures that are listed in the AESO Transmission Constraint Management paper that is currently being reviewed).

Studies also indicate that voltages on the N-S key nodes would be in the desired range of AESO OPP-702 during high southern load or light and high export scenario as long as the system is operated within the SOK-240 flow limits in real time. Additional analysis was also done considering the currently known MVAr constraints placed on some generators units in order to simulate real-time conditions.

## 7.6 Calgary Area Capacitor Bank Outages

There were no instances found in the summer studies to suggest that a capacitor bank outage in the Calgary area would require de-rating of the SOK-240 flow limit. Along with lower AIES load cases, a summer peak load case was analyzed, and there was found to be adequate margin (using PV analysis) considering the outage of the 260 MVAr capacitor bank at Janet 74S, and the N-2 loss of 928L and 906L. This is a good indication that voltage stability should not be an issue in the summer study, as the analysis was done considering the worst historical power factor found for the summer. This finding is dependent on the management of the SOK-240 flow to below that of its Action Limit. Minimum operating voltage requirements will also be recommended (as per section 7.4) to ensure that if voltage problems do occur in real time due to an unforeseen circumstances, there are guidelines regarding the action to be taken to keep operating voltages as per OPP-702.

## 7.7 Alberta - BC Interchange TTC

It has been determined that voltage stability and/or steady state voltage conditions will not be the limiting factor for determining export limits during the 2006 summer season, except for possibly during high load and high export scenarios, or during select outage conditions. Therefore, AIES export TTC should primarily be based on the available capacity of the SOK-240 cut plane mentioned above, with consideration for the maximum allowable export for the given system conditions (high load and/or element outages). It is expected that for system normal (N-0); the maximum allowable export TTC for all but loads but peak load conditions is expected to be 800 MW; if in real-time, the minimum operating voltages and/or the Langdon SVC cannot be kept within the desired ranges mentioned in Sections 7.4 and 7.5, export should be curtailed until the voltages / SVC can be kept within the desired ranges. The final analysis of maximum export limits for high load conditions and for N-1 conditions is being analyzed, and will documented in the OPPs.

Note that since both Alberta-BC exports, Alberta-SA exports, and demand opportunity load (DOS) load in southeastern Alberta increase N-S flow, all have to be managed such that SOK-240 flow is kept within limits.

## 7.8 Calgary Area Transmission Must Run

Study results indicate that Calgary area TMR will not be required to address voltage stability concerns for the 2006 summer season during system normal conditions (N-0) due to the addition of new 514 MVAR capacitor banks in the Calgary Area. Note that Calgary Area TMR may be required in the event of a Langdon SVC outage; this is being further analyzed, and any requirements found will be documented in OPP 510.

# 8 Recommendations

- It is recommended that the SOK methodology be implemented in real-time system operations to manage flow on the N-S 240 kV backbone.
- Develop an OPP for SOK-240 flow management
- Revise OPP-304 using SOK-240 methodology.
- Revise OPP-510 as its requirements will mainly be determined by the SOK-240 flow management OPP. Some additional Calgary area TMR may be required during a Langdon SVC outage.

The SOK-240 methodology will provide greater insight with regards to the current available TTC export capability of the AIES, as it will better capture the real-time flow on the SOK cut plane, which has been determined to be the best indicator of system capability, and will simplify the procedures used for determining north generation's ability to support southern load or export. It will also help maintain voltages on the N-S key nodes as per OPP-702. The SOK methodology will have a widespread effect on system operations; there will be several OPPs affected by the implementation of this new methodology. Additional OPPs may also have to be created just to address the methodology in general and its effects on system operations, and is discussed below. Two key current OPPs that will be affected by the change in methodology are OPP 304 (AB-BC Interchange Limits) and OPP 510 (Calgary Area TMR); these two OPPs are also discussed below.

## 8.1 Proposed OPP Changes and Additions

SOK-240 Flow Management OPP

It is recommended that a new OPP be implemented to state the SOK-240 flow limits for N-0 and N-1 operating states, and to address the various procedures associated with SOK-240 flow management. This new OPP should detail the procedure for offloading the SOK-240 in the event that the real-time flow limit is exceeded.

The new OPP should not only address the procedures for offloading the SOK in real-time, but also the procedures for managing SOK-240 flow in the event that the hour ahead forecast suggests that SOK-240 flow will exceed the real-time limit based solely on southern load; this scenario would most likely require more action to be taken, as it is firm demand alone causing the limit to be exceeded.

The procedures implemented for both real-time and hour-ahead SOK-240 flow management should be similar to the procedures outlined in the Constraint Management Protocol.

OPP 304

OPP 304 should be revised to reflect a new method of setting export limits based on SOK-240 flow. The day-ahead export limits should be set by estimating the remaining capacity on the N-S 240 kV backbone after southern AIES load and base generation is considered. So for day-ahead forecasts the TTC limit should be:

= (SOK Limit[1] – South AIES load forecast + Estimated South Generation) * TTC Conversion factor[2]

[1] SOK scheduling limit may be Alarm Limit or Action Limit.

[2] The algorithm to convert remaining SOK capacity to export TTC has not been determined; the TTC Conversion factor would account for losses corresponding to utilizing remaining capacity and export (estimated to be between 0.9 and 0.95).

The estimated level of each southern generator to be used on a day-ahead basis is shown in Table A4. Note that the generation output levels listed will only affect the day-ahead forecast (they will not be used in the hour-ahead, or real-time operation), and will be adjusted after further analysis of generation patterns, to better represent actual operating conditions.

The same formula should be used on a same-day basis, but the assumed generation on-line shown in Table A4 should be replaced with an estimate of total southern generation based on the merit order at T-2 and the AIES load forecast (in order to determine units on line). Without the market changes that lock the merit order 2 hours before the delivery hour, the SOK methodology may still be used, but alternative methods will have to be developed to estimate the generation online during the upcoming delivery hour.

Although the assumptions used to forecast TTC on a day-ahead basis may result in export limits similar to those currently in place (because the generation assumed to be online for day ahead forecasts may be very similar to the base assumptions in previous export studies), any additional southern area generation will be significantly more effective at supporting higher TTC in real time (i.e. within 60-90 minutes of the delivery hour) as 1 MW from any southern generation offloads the NS backbone by approximately 0.90 to 0.98 MW (i.e. approximately 0.90 to 0.98 MW export/1 MW southern generation). Furthermore, the SOK-240 approach allows variations in load patterns in the AIES to be better captured, so that lower than expected southern load for a given AIES load will result in lower SOK flow than what would be found in engineering studies (meaning more SOK-240 capacity available). Studies have confirmed that this new method is appropriate, as the constraint on N-S flow will shift from a voltage stability constraint to thermal constraints caused by an N-2 contingency on the 240 kV N-S backbone.

This change to monitoring SOK flow will simplify the real-time management of export TTC as no export adders will be required. In effect, every surplus MW on line in the south will now be considered approximately 0.90 to 0.98 MW of additional export capability as seen at Cranbrook end of the 500 kV line, which is the interchange metering point, regardless of AIES load. The derate of 0.9 -0.98 is only meant to account for increased losses based on the additional power flow, and is being further analyzed to determine the most appropriate value. This is now possible as the new capacitor banks will be able to provide the additional VAR support voltage in the south and 1201L flow as per OPP-304 TTC limits.

Also, the change in operating strategy will remove the loss of a generator as an N-1 or N-2 system condition (i.e. the AIES would be in “system normal” before and after the loss of one or both Sheerness units). This will mean that the N-S flow limit would not change if a unit was out; however in real-time the allowable export TTC limit would reduced due to increased N-S flow due to the loss of the unit in the south.

Note that maximum limits on AB-BC or AB-SA export will still be required such that maximum flow across the tie line is never exceeded for a given system condition (i.e. export limits will be lower for elements that directly limit export, such as 1201L). AESO will determine these limits and issue an update to this report.

OPP 510

The current Calgary area TMR requirements are based on voltage stability limitations; this will no longer be the reliability constraint following the commissioning of the new Calgary Area capacitor banks. Therefore, the current TMR requirements could be replaced with requirements based on SOK-240 kV flow. Also generation in the Calgary area may be required during Langdon SVC outage to support voltage and provide dynamic reserves. AESO is currently performing system studies to determine these requirements under different operating conditions. Once studies are complete, AESO will issue an update to this report.

**The following points apply to both OPP 304 and 510:**

- Note that the loss of a N-S 240 kV line or the SVC will most likely result in a derate of the maximum allowable SOK-240 flow. The allowable SOK limit for each N-1 condition is shown in Table A2.
- Winter N-1 SOK-240 limits have not been fully determined. It is assumed though, that the process used for determining winter export limits will be similar to those mentioned above for the summer case.

## 8.2 SOK-240 Flow Management and Utilizing the Constraint Management Protocol

Management of the SOK-240 will become a major focus within real-time operations. Management of the SOK-240 must be in alignment with proposed AIES Transmission Constraint Management protocol that is currently being reviewed and will be implemented in the near future.

## 8.3 SOK Flow Forecasting

Monitoring SOK-240 flow to determine both export capability and reliability needs to serve south load will require that southern area load be forecast on a week-ahead and day-ahead basis (and possibly further out). This will allow for SOK-240 flow to be estimated using the load forecast and the assumed southern generation on line. The Operations Planning and Analysis (OP & A) group is currently working with Operations Forecasting to develop a southern AIES load forecast tool, and to use this forecast to estimate SOK flow.

## 8.4 Future Considerations

Although the addition of the capacitor banks in the Calgary area mitigates some contingencies that limit export TTC due to voltage stability concerns, thermal overloads are not mitigated and they become the most constraining factor with regards to export capability. The use of Generator shed Remedial Action Scheme (GRAS), which trips a generator within the AIES in order to mitigate overloads in the event of an N-2 contingency, should be investigated to determine the potential gain in export capacity if such a system is implemented. The initial stages of this analysis have begun.

# Appendix A
# Summer Study Results

**Table A1: Base Case Power Factors**

| Area | Summer |
|---|---|
| AIES | 0.927 |
| Calgary area | 0.919 |

**Table A2: Summer SOK N-S Flow and Export Limits**

| AIES Load Range | | System Normal | 1201L Out of Service | SVC Out of Service | 937L Or 936L | 918L | 900L | 190L Or 903L | 922L Or 926L | 910L | 914L | 906L Or 928L | 929L Or 925L Or 901L |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| < 8000 MW | Allowable Scheduled N-S Flow (Alarm Limit) | | | | | | | | | | | | |
| | N-S Flow where Action Required | 1640 | 1640 | 1400 | 1640 | 1150 | 1050 | 1600 | 1550 | 1420 | 1365 | 1575 | 1640 |
| > 8000 MW | Allowable Scheduled N-S Flow (Alarm Limit) | | | | | | | | | | | | |
| | N-S Flow where Action Required | 1600 | 1600 | 1360 | 1600 | 1110 | 1010 | 1560 | 1510 | 1380 | 1325 | 1535 | 1600 |

**Table A3: Summer Minimum Voltage Requirements**

| Bus | Minimum Voltage (kV) |
|---|---|
| Sundance 310P 240 kV | 252 |
| Keephills 320S 240 kV | 247 |
| Genesee E330P 240 kV | 247 |
| Ellerslie T89S 240 kV | 242 |
| Benalto T17S 240 kV | 242 |
| Gaetz T87S 240 kV | 240 |
| Sarcee T42S 240 kV | 245 |
| Janet T74S 240 kV | 246 |

**Table A4. Base-Loaded Generation**

| Generation Plant | Output |
|---|---|
| Sheerness net-to-grid (NTG) | 600 MW |
| Battle River NTG | 600 MW |
| South Hydro (Irrigation) | 0 MW |
| South Wind | 0 MW |
| Med Hat Total Generation | 75 MW |
| Joffre | 0 MW |
| Balzac | 0 MW |
| Bow Hydro | 0 MW |
| Calpine | 0 MW |
| Carseland | 64 MW |
| Cavalier | 0 MW |