

501 NORTHWEST AREA OPERATION

1. Purpose

To define the policies and procedures required to operate the northwestern area of the Alberta Interconnected Electric System (AIES), including transmission must-run (TMR) generation and voltage management.

2. Background

The electric system in the northwest part of Alberta consists of long 144 kV and 240 kV transmission lines. The system is generally radial with a low degree of redundancy of transmission paths. The area generating capacity is substantially less than the area load, which leads to inflows of energy into the area under normal circumstances. Some of the 144 kV lines are heavily loaded.

The outage of a single transmission line or a local generator can result in voltage depressions outside of acceptable limits. This risk can be partially mitigated by ensuring a minimum amount of local generation and VAR capacity in the area, which are deemed to be TMR generation requirements. The provision of TMR reduces the risk of losing firm load due to low voltages, and a voltage collapse for certain critical transmission or generation contingencies. There is also interruptible load in the Grande Prairie area that can be curtailed when required to maintain system reliability.

The following are some of the area operating characteristics:

- The northwest has a number of radially fed customers that are subject to single contingency outages.
- Depending on the amount of generation on line at Rainbow and Ft. Nelson, the loss of the 7L64 transmission line will leave the Rainbow area units islanded with some load. If there is a net energy inflow to the Rainbow area on 7L64, the loss of 7L64 will result in a loss of part, or all, of the load in the Rainbow area island.
- Following the loss of a transmission or generation facility, sudden reductions in voltage at local buses may occur causing voltage sensitive loads to trip off line. The amount of load affected will vary with system conditions.
- There is a possibility that the loss of two or more major transmission or generation elements could lead to an area wide voltage collapse or to a cascading overload leading to an area collapse.

3. Policy

3.1 General

- The northwest area load (NWAL) is the sum of the load and losses in the northwestern part of the Alberta Interconnected Electric System (AIES), calculated as follows:
 - 6L57 line inflows to Kinuso (A727S), plus
 - 9L913, 9L40 and 9L56 line inflows to Mitsue (A732S), plus

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- 9L02, 9L05, 7L56 and 7L90 line inflows to Little Smoky (A813S), plus
- HR Milner (HRM) unit net generation, plus
- Rainbow #1, #2, #3, #4 and #5 (RB2, RL1 and RB5) unit gross generation, plus
- Fort Nelson (FNG) unit gross generation, plus
- Sturgeon #1 and #2 (ST1 and ST2) unit gross generation, plus
- Poplar Hill (PH1) unit gross generation, plus
- Valleyview (VWV1) unit gross generation, plus
- Bear Creek (BRCK) unit gross generation, plus
- Grande Prairie EcoPower (CGE) unit gross generation, plus
- Northstone Power (NPC1) unit gross generation.
- The Rainbow area load (RAL) is the sum of the load and losses in the Rainbow portion of northwestern part of the AIES, calculated as follows:
 - RB1, RB2, RB3, RL1 and RB5 unit gross generation, plus
 - FNG unit gross generation, plus
 - 7L62 and 7L58 line outflows from A788S (Hotchkiss).
- The AESO has contracted for area generators to provide TMR service. These generators are referred to as TMR-contracted generators. Non-TMR contracted generators refer to generators with whom the AESO does not have TMR contracts.
- Of the units available for TMR, two of them (Valleyview and Poplar Hill) can operate in either power generation or synchronous condenser mode (SCM). In SCM they can operate between 0.95 and 1.05 p.u. voltage, provided their reactive output is between 20 MVAR leading and 45 MVAR lagging.
- The AESO will, to the extent possible, meet the area minimum generation requirements through energy dispatches to local generators based on the energy market merit order, before issuing TMR dispatches/directives.

3.2 TMR dispatches

- When the area minimum generation requirements are not met by the generation from local generators through energy market dispatches, TMR dispatches will be issued to TMR-contracted generators to meet the area minimum generation requirements.
- The MW volume of a TMR dispatch is not an incremental amount to the energy market dispatches. It is the minimum MW net output level of the generator that must maintain irrespective of the energy market dispatches.
- When the minimum generation requirements for HRM/Grande Prairie area, as determined in accordance with [Section 3.5](#), cannot be met by the combined generation output of Poplar Hill, Valleyview, Bear Creek gas unit, Bear Creek steam unit, Grande Prairie EcoPower and Northstone Power through energy market dispatches, TMR dispatches will be issued to TMR-contracted generators to ensure that the minimum generation requirements are met as described in [Section 5.1](#).

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- The dispatch order for HRM/Grande Prairie area generation is shown in Section B of [Appendix A](#).
- When the minimum generation requirements for Rainbow area, as determined in accordance with Section 3.6, cannot be met by the combined generation output of Rainbow #1, #2, #3, #4 and #5 (RB1, RB2, RB3, RL1 and RB5), and Fort Nelson (FNG1) generators through energy market dispatches, TMR dispatch(es) will be issued to meet the minimum generation requirement as described in [Section 5.2](#).
- Generators may provide ancillary services such as supplemental reserves or spinning reserves at the same time as they provide TMR services.
- TMR dispatches will take precedence over reserve dispatches if an overlap occurs. If a conflict or overlap occurs, the participant will restate or withdraw reserve capability.
- If all available TMR-contracted generators in the HRM/Grande Prairie area have been dispatched and the minimum generation requirements as specified in [Table 1](#) or [Table 2](#) are not met, the System Controller (SC) will monitor area voltages and notify the ATCO Electric Transmission Operator of the increased risk to the area loads.

3.3 Load shedding service (LSS)

- LSS Load will be curtailed when all available TMR-contracted generation has been exhausted and the HRM/Grande Prairie area minimum generation requirements as specified in [Table 1](#) or [Table 2](#) are still not met.
- LSS Load will be curtailed to provide system support when all available TMR- contracted generation has been exhausted and the minimum operating limits still cannot be maintained at the Little Smoky 240 kV bus.
- Details about the LSS provider in the Grande Prairie area can be found in Table 2 of [OPP 312](#).
- LSS Load, in an amount specified in a SC directive, will be manually curtailed by the LSS provider within ten minutes of receipt of a SC directive.
- When LSS load is curtailed, the import transfer level and the import schedule will be adjusted to the level corresponding to the required Import Load Remedial Action Scheme (ILRAS) and LSS amount in Table 1 of [OPP 312](#), if required.
- After the curtailment period, the LSS provider will commence load restoration as directed by the SC.

3.4 TMR directives

- For the HRM/Grande Prairie area, when the minimum generation requirements are not met by
 1. energy dispatches to local generators based on the energy market merit order
 2. TMR dispatches to TMR-contracted generator
 3. the LSS load curtailment (see [Section 3.3](#))then directives will be issued for non-TMR contracted generator(s). The non-TMR contracted generators will be directed in the sequence shown in Section C of confidential [Appendix A](#).

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- When the Rainbow area minimum generation requirements as specified in [Table 3](#) are not met by energy market dispatch and TMR dispatch as described in [Section 3.2](#), directive(s) will be issued to non-TMR contracted generator(s) in accordance with the dispatch/directive order up to step 6 as specified in Section A of confidential [Appendix A](#).
- Due to constraining factors, certain non-TMR contracted generators will only be directed in an emergency situation when firm load is anticipated to be curtailed or has already been curtailed, as specified in Section A of confidential [Appendix A](#).
- The MW volume of a directive is not an incremental amount to the energy market dispatches. It is the minimum MW net output level that the generator must maintain irrespective of the energy market dispatches.
- Directive will be issued through the dispatch tool, and sent to participants via ADAMS. Refer to [Section 5.5](#).

3.5 Determining minimum generation requirements for HRM/Grande Prairie area

- Minimum HRM/Grande Prairie area generation requirements are shown in [Table 1](#) if HR Milner is operating at a minimum generation of 70 MW and [Table 2](#) if HR Milner is off line or operating below 70 MW, respectively. All conditions in the table notes must be met.
- Valleyview must be operating at all times either in synchronous condenser mode (SCM) or power generation mode. When Valleyview is operating in power generation mode, its MW output is counted towards meeting the requirements of minimum generation from Grande Prairie generators (column B) and minimum number of Grande Prairie generators (column C) when the column C is 4 units or above.
- The primary indicator for TMR requirement for the HRM/Grande Prairie area is the NWAL.
- The secondary indicator for TMR requirement is the northwest area voltage level. If after exhausting all voltage control measures, the Little Smoky 240 kV bus voltage cannot be maintained at or above the minimum operating voltage as specified in [OPP 702](#), a higher level of minimum generation requirements than indicated in [Table 1](#) or [Table 2](#) is required. This may require higher generation levels from existing on-line must run units or additional must run units operating in synchronous condenser mode or providing MW (see [Section 3.6](#)).
- Following the loss of 9L11, 9L02 or 9L05, and when HR Milner is operating at or above 70 MW and NWAL is between 701 MW and 750 MW, an additional 10 MW is required to be added to the minimum generation (column B) in [Table 1](#), and Poplar Hill must be operating in power generation mode.
- When 9L11 is out of service and NWAL exceeds 750 MW, a real time assessment is required to determine appropriate mitigation actions that may include additional TMR and/or load shedding to prepare for the next contingency.

3.6 Determining minimum generation requirements for Rainbow area

- Minimum Rainbow area generation requirements are shown in [Table 3](#).
- The primary indicator for TMR requirement for the Rainbow area is the RAL.

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- The secondary indicator for TMR requirement for the Rainbow area is the area voltage level. If, after exhausting all voltage control measures, area voltages cannot be maintained at or above the minimum operating limits as specified in [OPP 702](#), then a higher level of TMR than indicated in [Table 3](#) is required.
- If both the Keg River (A789S) and Sulphur Point (A828S) capacitor banks are switched off, the minimum generation in the Rainbow area are increased by 10 MW (see note 1 to [Table 3](#)).

3.7 Managing voltage levels

- As operating conditions allow, the Sulphur Point (A828S) and/or Keg River (A789S) capacitor bank should be placed in service for voltage support. If possible, other reactive equipment in the area should be switched to allow these capacitors to remain in service.
- The northwest area system voltages will be maintained within the desired ranges as specified in [OPP 702](#), and if possible near the upper ends of the desired ranges.
- When NWAL is greater than 750 MW, all the area available capacitor banks should be put in service, where practical, to keep the area 144 kV system voltage at the higher end of its operating range. The applicable capacitor banks are specified in [Table 4](#).
- When NWAL is greater than 750 MW and if an area capacitor bank is out of service, a real time assessment is required to determine the appropriate mitigation actions to prepare for the next contingency. The applicable capacitor banks are specified in [Table 4](#).
- If HR Milner is off line, and one of Poplar Hill, Bear Creek gas unit, Grande Prairie EcoPower or Valleyview generation plants is unavailable, and the NWAL is over 700 MW, then the following additional actions are to be taken to improve area voltage security:
 1. Dispatch on capacitor banks at Big Mountain, Ksituan, Freidenstal substations and both West Peace River (A793S) capacitor banks, if practical.
 2. Change the Little Smoky (A813S) 240-144 kV tie transformers (813S901T and 813S902T) on-load tap changers (LTC) to manual control mode.
 3. Maintain the Little Smoky (A813S) 144 kV bus voltage at the high end of the desired range of 152 kV by adjusting the 813S901T and 813S902T LTCs.
 4. Reduce the VAR support from the remaining generators in the Grande Prairie area while maintaining voltage within the desired range.
- If after having switched static reactive power compensation devices and adjusted generator terminal voltage, area system voltages are still below the minimum operating limits as specified in [OPP 702](#), the following steps will be taken to maintain area voltage at or above minimum operation limits:
 1. Dispatch additional TMR-contracted generators to level **above** the requirements in [Section 3.4](#), [3.5](#) and [3.6](#).
 2. Shed LSS load.
 3. Direct non-TMR contracted generators.

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- If the Little Smoky (A813S) 240 kV bus voltage cannot be maintained at the minimum voltage limit after exhausting the above steps, then the following criteria will be applied to determine if any further mitigation is required, up to and including load shedding:
 - System voltage response to the above steps is less than normal and/or area voltage decay is observed.
 - Area load is anticipated to increase.
 - Weather conditions in the area pose an increased risk to transmission elements.
 - Current transmission status indicates a much weakened system.
 - Dynamic reactive reserve from area generators is becoming depleted (i.e., a lot of the VAR capability from area generators is already used to support area voltage).
 - Contingency analysis results in very low voltage (i.e., below 0.9 p.u.) or case unsolved upon the next worst contingency.

3.8 Curtailing new BC Hydro area load addition in the Northwest Area

- The new BC Hydro load addition (effective March 1, 2008) in the Northwest area will be curtailed under the following system condition:
 - If the Rainbow area minimum generation requirements as specified in [Table 3](#) cannot be met by the combined generation of FNG, RL1, RB5 and RB2Or
 - When it is required to enable any load tripped by the under voltage load shedding (UVLS) scheme in the Rainbow Area
- If the above mentioned system condition occurs, the SC will issue a directive to the British Columbia Transmission Corporation (BCTC) Operator to curtail the required load within 20 minutes as described in [Section 5.2](#).

4. Responsibilities

4.1 ISO

The ISO will:

- Review, on an ongoing basis, the management of the Northwest area generation TMR levels for transmission constraints.
- Adjust and update the area minimum generation requirements as required.
- Perform necessary power flow studies before any planned switching to ensure the post switching system conditions remain within the normal operating limits. If necessary, area minimum generation requirements will be increased before switching to maintain system voltages and transmission loading levels within acceptable limits after switching.

System Controller

The SC will:

- Issue and report all TMR dispatches and directives in the daily AS Dispatch Logs.

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- Notify the ATCO Electric Transmission Operator when all available generation in the HRM/Grande Prairie area cannot meet the minimum generation requirements in [Table 1](#) or [Table 2](#).
- Approve, in real time, all planned or unplanned transmission switching.
- Ensure generators are dispatched or directed for system reliability in accordance this OPP or the System Coordination Plan.
- Manage area voltage as described in this OPP and in [OPP 702](#).

4.2 Transmission Facility Owner – ATCO Electric

The Transmission Facility Owner will:

- Be responsible for transmission apparatus switching in the northwest area.
- During extreme conditions, take immediate actions, including voltage adjustments and shedding of loads, to restore voltages and stabilize the transmission system.
- Notify the SC of immediate actions as soon as possible.

4.3 Ancillary service provider supplying TMR services

A TMR service provider will:

- Be responsible for providing accurate information to the SC on the availability of the generating unit(s) via the ISO's Energy Trading System (ETS).
- Comply with TMR dispatches from the SC.
- Re-state an asset's capability immediately if unable to comply with the TMR dispatches.

4.4 LSS Provider

The LSS provider will:

- With reasonable commercial efforts, inform the SC of unplanned LSS Load unavailability when the unavailability period exceeds one hour, and provide the cause and anticipated duration of the unavailability.
- Provide the SC with real time telemetry of the interruptible load.
- Curtail LSS Load in an amount specified in a SC directive within ten minutes of receipt of a SC directive.
- After the curtailment period, commence load restoration as directed by the SC.

4.5 BCTC

The BCTC operator will:

- Curtail the load as required within 20 minutes upon receiving a directive from the SC.
- Restore the load as permitted by the SC.

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5. System Controller Procedures

5.1 Managing HRM/Grande Prairie area minimum generation requirements

The SC will:

1. Determine the NWAL as displayed on the video wall.
2. Determine the operating status of Valleyview. If Valleyview is off line, issue a TMR dispatch for SCM to Valleyview. (Note: When Valleyview is operating in power generation mode instead of SCM, it can be counted towards meeting the SCM requirement).
3. Determine the operating status of HR Milner.
4. Determine the minimum generation requirements for the HRM/Grande Prairie area by using [Table 1](#) if HR Milner is operating at a minimum of 70 MW. Use [Table 2](#) when HR Milner is off line or operating below 70 MW.
5. When Valleyview is operating in power generation mode and the minimum number of generators required at the Grande Prairie area generators (column B) is 4 units or above, count the MW output of Valleyview towards column B and count Valleyview as one unit towards Column C respectively.
6. Check the status of Poplar Hill, Valleyview, Bear Creek gas unit, Bear Creek steam unit, Grande Prairie EcoPower and Northstone Power, and the amount of their generation output dispatched in the energy market.
7. Determine if Poplar Hill is required on synchronous condenser mode (SCM) by using [Table 1](#) or [Table 2](#), whichever is applicable. If required, issue TMR dispatch for SCM to Poplar Hill. (Note: When Poplar Hill is operating in power generation mode instead of SCM, it can be counted towards meeting the SCM requirement)
8. Verify if the minimum generation requirements specified in [Table 1](#) or [Table 2](#), whichever is applicable, are met by the combined generation output as identified in step 5 and the number of generators currently online to provide MW.
9. If not met, issue TMR dispatches according to the dispatch order in Section B of [Appendix A](#)
10. If the minimum generation requirements still cannot be met and all available TMR-contracted area generation has been used up, issue a directive to curtail the LSS Load.
11. Adjust the import transfer level and import schedule to the level corresponding to the required Import Load Remedial Action Scheme (ILRAS) and LSS amount in Table 1 of [OPP 312](#), if required.
12. If the minimum generation requirements still cannot be met and when all available TMR-contracted area generation and LSS Load have been used up, issue directive(s) for additional generation as described in Section C of [Appendix A](#).
13. If the minimum generation requirements cannot be met, notify the ATCO Electric Transmission Operator of the increased risk to area load. Monitor area voltages and follow the procedures in [Section 5.3](#).
14. If one of 9L11, 9L02 or 9L05 is out of service and under the following conditions:
 - HRM is operating at 70 MW or above, and
 - NWAL exceeds 700 MW and not greater than 750 MW,

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- a. Increase the minimum generation requirement (column B) in [Table 1](#) by 10 MW.
 - b. Check if Poplar Hill is operating in power generation mode. If not, issue a TMR dispatch for 10 MW to Poplar Hill.
15. If 9L11 is out of service and NWAL exceeds 750 MW, perform a real time assessment to determine the appropriate mitigation measures that may include additional TMR and/or load shedding to prepare for the next contingency.

5.2 Managing Rainbow area minimum generation requirements

The SC will:

1. Determine the RAL as displayed on the video wall.
2. Determine the Rainbow area minimum generation requirement by using [Table 3](#) or as required to maintain area voltages.
3. Check the status of Rainbow #1, #2, #3, #4 and #5, and Fort Nelson generators and the amount of their generation output dispatched in the energy market.
4. Verify if the minimum generation requirements specified in [Table 3](#) are met by the combined generation output as identified in step 3 and the number of generators currently online to provide MW.
5. If the requirements are not met, issue TMR dispatches/directives according to the dispatch/directive order **up to step 6** as specified in Section A of confidential [Appendix A](#).
6. If the minimum generation requirements are still not met, direct the BCTC operator to curtail the new BC Hydro area load addition (effective March 1, 2008) to a maximum of 1.5 MW within 20 minutes. Refer to Section D of confidential [Appendix A](#) for details of the new BC Hydro area load addition and the script.
7. Confirm that the BC Hydro area load in the Northwest area is at or below 30 MW.
Note: BC Hydro area load in the Northwest area is calculated as:
 - FNG Gross generation + flow of 7L81 when 7L81 flows from AB to BC , or
 - FNG Gross generation - flow of 7L81 when 7L81 flows from BC to AB
8. After curtailing the new BC Hydro area load addition, if the minimum generation requirements are still not met:
 - a. Notify the ATCO Electric Transmission Operator of the increased risk to area load.
 - b. Monitor area voltages and follow the procedures in [Section 5.4](#).
9. When the system returns to normal and the minimum generation requirements are met, and conditions allow:
 - a. Call the BCTC operator to permit the restoration of the load curtailed in step 6.
 - b. If the ATCO Electric Transmission Operator has been notified per step 8.a, notify the ATCO Electric Transmission Operator that the area risk is back to normal.

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5.3 Northwest area voltage levels

To maintain the northwest area voltage levels, the SC will:

1. Ensure minimum generation levels are met as per [Table 1](#), [Table 2](#) and [Table 3](#).
2. Dispatch capacitors in and/or dispatch reactors out in the northwest area.
3. When NWAL exceeds 750 MW,
 - a. Dispatch all area available capacitors, where practical, to keep the area 144 kV system voltage at the higher end of its operating range as specified in [OPP 702](#).
 - b. If an area capacitor bank is out of service, perform a real time assessment to prepare for the next contingency.
4. Adjust Sundance 240 kV bus voltage within the desired range as specified in [OPP 702](#), if considered necessary.
5. Following the dispatch orders of [Appendix A](#), dispatch additional TMR-contracted area generation as required to maintain area voltages at or above the minimum operating limit as specified in [OPP 702](#) (keying in on the Little Smoky 240 kV bus voltage).
6. Issue a directive to curtail the LSS Load if the minimum operating limit still cannot be maintained.
7. Adjust the import transfer level and import schedule to the level corresponding to the required Import Load Remedial Action Scheme (ILRAS) and LSS amount in Table 1 of [OPP 312](#), if required.
8. If all available TMR-contracted generation and LSS load have been used up, direct non-TMR contracted generation required to maintain area voltages at or above the minimum operating limit as specified in [OPP 702](#) (keying in on the Little Smoky 240 kV bus voltage), as described in Section C in [Appendix A](#). The directives will be issued using the dispatch tool and sent to the participant via ADAMS. Refer to [Section 5.5](#).
9. If HR Milner is off line **and** one of Poplar Hill, Bear Creek gas unit, Grande Prairie EcoPower or Valleyview generation plants is unavailable, and the NWAL is between 701 MW and 750 MW, take the following action:
 - a. Dispatch on capacitor banks at Big Mountain, Ksituan, Freidenstal substations and both West Peace River (A793S) capacitor banks, if practical.
 - b. Request the ATCO Electric Transmission Operator to change the Little Smoky (A813S) 240-144 kV tie transformers (813S901T and 813S902T) on-load tap changers (LTC) to manual control mode.
 - c. Request the ATCO Electric Transmission Operator to maintain the Little Smoky (A813S) 144 kV bus voltage at close to 152 kV by adjusting the 813S901T and 813S902T LTCs.
 - d. Reduce the VAR support from the remaining generator(s) while maintaining voltage with the desired range.
10. If HR Milner is off line **and** one of Poplar Hill, Bear Creek gas unit, Grande Prairie EcoPower or Valleyview generation plants is unavailable, **and** the NWAL exceeds 750 MW, carry out a real time assessment to determine the appropriate mitigation actions.

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11. If the Little Smoky (A813S) 240 kV bus voltage cannot be maintained at the minimum voltage limit, apply the following criteria to determine if any mitigation is required, up to and including load shedding:
 - System voltage response to the above steps is less than normal and/or area voltage decay is observed.
 - Area load is anticipated to be increasing.
 - Weather condition in the area poses an increased risk to transmission elements.
 - Current transmission status indicates a much weakened system.
 - Dynamic reactive reserve from area generators is getting depleted.
 - Contingency analysis results in very low voltage or case unsolved upon the next worst contingency.
12. Coordinate with the ATCO Electric Transmission Operator on any required mitigating measure(s), up to and including load shedding. If load shedding is required, shed area DOS loads first before firm loads.
13. Enter in the Shift Log the details on the security directive including reasons, times and participant names, as described in [OPP 1301](#), if required.

5.4 Rainbow area voltage levels

To manage the Rainbow area voltage levels, the SC will:

1. As operating conditions allow, request the ATCO Electric Transmission Operator to place the Sulphur Point (A828S) and/or Keg River (A789S) capacitor banks in service for voltage support. Other reactive equipment in the area should be switched to allow these capacitors to remain in service, if possible.
2. Following the dispatch/directive order in Section A of [Appendix A](#), dispatch/direct additional area generation to maintain area voltages at or above the minimum operating limits as specified in [OPP 702](#), when required.
3. The directives will be issued using the dispatch tool and sent to the participant via ADAMS. Refer to [Section 5.5](#).
4. Coordinate with the ATCO Electric Transmission Operator to shed area loads to maintain area voltages within the minimum operating limits as described in [OPP 702](#).

5.5 Issuing TMR directives

The SC will:

1. Refer to Sections C and D in [Appendix A](#) for the directive orders for the HRM/Grande Prairie and the Rainbow areas.
2. Using the dispatch tool:
 - a. Open the out of market units list by clicking the appropriate button in the dispatch tool menu bar.
 - b. Select the check box next to the asset to be directed for TMR. This action will populate the ancillary services merit order with the selected unit and designate it an O, for out of market, supply type.

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- c. Issue a directive for TMR to the asset specifying the MW amount and expected achieve time. The Participant will receive the message on ADAMS indicating the expected achieve time, the TMR service, the O supply type, the unit and amount (MW) of TMR requested. Although the message will indicate this is a dispatch, it is understood this is an out of market directive because of the O supply type.
3. Follow up all out of market directives with a phone call to the Participant to confirm.
4. Enter in the Shift Log the details on the security directive including reasons, times and participant names, as described in [OPP 1301](#).

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6. Figures and Tables

Table 1⁸

HRM/Grande Prairie area minimum generation requirements with HR Milner on line at a minimum generation of 70 MW¹.

NW Area Load (MW)	Minimum Generation (MW) from Grande Prairie Generation Plants ^{2,3}	Minimum Number of Grande Prairie Generation Plants ² Providing MW	Is Poplar Hill Required to Operate in SCM ⁴ ?	When Valleyview in Power Generation Mode, is its MW Output Counted in Column B and Column C?
Column A	Column B	Column C	Column D	
Below 625	0	0	No	Not counted
625 - 650	0	0	No	Not counted
651 - 675	0	0	Yes ⁵	Not counted
676 - 700	20	1	Yes ⁵	Not counted
701 - 725 ⁶	30	1	No	Not counted
726 - 750 ⁶	50	1	No	Not counted
751 - 775 ⁷	70	2	No	Not counted
776 - 800 ⁷	90	3	No	Not counted
801 - 825 ⁷	120	3	No	Not counted
826 - 850 ⁷	160	4	No	Counted

Note:

1. Valleyview must be either operating in synchronous condenser mode (SCM) or power generation mode at all times. If Valleyview is off line, issue a TMR dispatch for SCM. When Valleyview is operating in power generation mode instead of SCM, it can be counted towards meeting the SCM requirement.
2. Grande Prairie generation plants consist of the following:
 - Poplar Hill
 - Valleyview
 - Bear Creek gas unit
 - Bear Creek steam unit
 - Grande Prairie EcoPower
 - Northstone Power
3. If the minimum generation from Grande Prairie generation plants (column B) cannot be met from energy market dispatches, then issue TMR dispatch(es) and/or direct order(s) as specified in confidential [Appendix A](#).
4. When Poplar Hill is operating in power generation mode instead of SCM, it can be counted towards meeting the SCM requirement as stated in Column D. Its MW output can be counted towards meeting minimum generation (column B) and minimum number of generators (column C).
5. If Poplar Hill is off line, then bring it online by issuing a TMR dispatch for SCM. If Poplar Hill is out of service due to planned or forced outage, then increase the minimum generation requirement by adding the minimum number of Grande Prairie generators providing MW (column C) by one and adding the minimum generation from Grande Prairie generators (column B) by 10 MW.
6. Following the loss of 9L11, 9L02 or 9L05, increase the minimum generation requirement (column B) by 10 MW and Poplar Hill must be operating in power generation mode. If Poplar Hill is offline, issue a TMR dispatch for 10 MW to Poplar Hill.
7. Following the loss of 9L11, perform a real time assessment to determine mitigation measures.
8. A SCC Application has been developed for this table.

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Table 2 ⁶

HRM/Grande Prairie area minimum generation requirements with HR Milner off line or below the minimum generation of 70 MW¹.

NW Area Load (MW)	Minimum Generation from Grande Prairie Generation Plant ^{2, 3} (MW)	Minimum Number of Grande Prairie Generation Plant ² Providing (MW)	Is Poplar Hill Unit required to operate in SCM ⁴ ?	When Valleyview in Power Generation Mode, is its MW Output Counted in Column B and Column C?
Column A	Column B	Column C	Column D	
Below 625	0	0	Yes ⁵	Not counted
625 - 650	20	1	Yes ⁵	Not counted
651 - 675	40	2	No	Not counted
676 - 700	70	2	No	Not counted
701 - 725	95	4	No	Counted
726 – 750	115	4	No	Counted
751 - 775	140	4	No	Counted
776 – 800	160	4	No	Counted
801 – 825	170	5	No	Counted
826 – 850	180	5	No	Counted

Note:

1. Valleyview must be either operating in synchronous condenser mode (SCM) or power generation mode at all times. If Valleyview is off line, issue a TMR dispatch for SCM. When Valleyview is operating in power generation mode instead of SCM, it can be counted towards meeting the SCM requirement. Its MW output can be counted towards meeting minimum generation (column B) and minimum number of generators (column C) when the column B is at 95 MW or above.
2. Grande Prairie generation plants consist of the following:
 - Poplar Hill
 - Valleyview
 - Bear Creek gas unit
 - Bear Creek steam unit
 - Grande Prairie EcoPower
 - Northstone Power
3. If the minimum generation from Grande Prairie generators (column B) cannot be met from energy market dispatches, then issue TMR dispatch(es) and/or direct order(s) as specified in confidential Appendix A.
4. When Poplar Hill is operating in power generation mode instead of SCM, it can be counted towards meeting the SCM requirement as stated in Column D. Its MW output can be counted towards meeting minimum generation (column B) and minimum number of generators (column C).
5. If Poplar Hill is off line, then bring it online by issuing a TMR dispatch for SCM. If Poplar Hill is out of service due to planned or forced outage, then increase the minimum generation requirement by adding the minimum number of Grande Prairie generators providing MW (column C) by one and adding the minimum generation from Grande Prairie generators (column B) by 10 MW.
6. An SCC Application has been developed for this table.

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Table 3 ^{2,3}

Rainbow area minimum generation requirements (for exception see note 1)

Rainbow Area Load (MW)	Minimum Number of Rainbow Area Generators³ Providing MW	Minimum Generation from Rainbow Area Generators³ (MW)
Column A	Column B	Column C
Below 81	3	65
81 - 90	3	75
91 - 100	3	90
101 - 110	3	95
111 - 120	3	110
121 - 130	3	120
131 - 140	4	130
141 - 150	4	150
151 - 160	4	160
161 - 170	4	170

Note:

1. If both the Keg River (A789S) 14.3 MVAR and Sulphur Point (A828S) 10 MVAR capacitor banks are switched off, the Rainbow/Fort Nelson combined area minimum generation requirements are increased 10 MW above the indication in the table.
2. A SCC Application has been developed for this table.
3. Rainbow area generators refer to FNG, RL1, RB5, RB 2, RB3 and RB1.

Table 4

Applicable capacitor banks in the Northwest Area

Substation	Rated Voltage (kV)	MVAR at Base Voltage
Crystal Lake A722S	144	29.6
Ksituan A764S	144	15
High Level A786S	25	4 x 2.5
Keg River A789S	144	14.3
Poplar Hill A790S	144	24.7
West Peace River A 793S	144	2 x 15
Friedenstal A800S	144	15
Louise Creek A809S	144	52.8
Clairmont Lake A811S	144	25
Sulphur Point A828S	25	2 x 5
Big Mountain A845S	144	30

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Appendix A. Northwest Area Transmission Must-Run (TMR) Dispatch and Directive Orders

Confidential

[View confidential Appendix.](#)

7. Revision History

Issued	Description
2008-03-01	Approved for interim implementation effective 2008-03-01, supersedes 2008-01-17
2008-01-17	Approved for interim implementation effective 2008-01-17, supersedes 2007-12-03
2007-12-03	Supersedes 2007-06-27 (confidential Appendix only)
2007-06-27	Supersedes 2006-07-11
2006-07-11	Supersedes 2006-04-27
2006-04-27	Supersedes 2006-01-19
2006-01-19	Approved for interim implementation effective 2006-01-19, supersedes 2006-01-05
2006-01-05	Approved for interim implementation effective 2006-01-05, supersedes 2006-01-01
2006-01-01	Approved for interim implementation effective 2006-01-01, supersedes 2005-03-30
2005-03-30	Supersedes 2004-08-05
2004-08-05	Confidential Appendix A updated
2004-08-04	Supersedes 2004-05-01
2004-05-01	Approved for interim implementation
2004-03-03	Approved for interim implementation
2003-12-10	Supersedes 2003-08-27
2003-08-27	Approved for interim implementation
2003-07-28	Revised to ISO Operating Policies and Procedures

SC Tool Versions

Date	Version	Description
2008-03-01	8.1	Modify Tables 2 and 3; add load curtailment alarms
2008-01-17	8.0	Modify Tables 1, 2 and 3