YUKON ENERGY CORPORATION (“YEC”) TWO-PART APPLICATION REGARDING ENERGY RECONCILIATION ADJUSTMENT (“ERA”)

YUKON ENERGY

December 6, 2017

PREFACE

Order 2017-08 of the Yukon Utilities Board ("YUB" or "Board") directed Yukon Energy Corporation ("Yukon Energy" or "YEC") to file a separate two-part Energy Reconciliation Adjustment ("ERA") application (the "ERA Application") to comply with the direction of the Yukon Court of Appeal and the further directions of the Board. The Board's directions as to the two parts of the ERA Application are as follows:

> "The first part of the application is to address 2012 Energy Reconciliation Adjustment (ERA) issues. The second part of the application is to address how YEC proposes to address Diesel Contingency Fund (DCF), ERA, wholesale rates, and long-term average hydro generation for the period 2017 forward."

Order 2017-08 also directed that YEC is to provide an alternative forecast revenue requirement for YEC's 2017-18 General Rate Application ("GRA"), using a short-term hydro-electric forecast for the test period and any consequential changes to the thermal generation forecast, and removing any DCF references in that alternative forecast. Order 2017-08 directed that YEC is to continue to treat the DCF as a placeholder to be adjusted upon final determination of the Board in the ERA Application.

The ERA Application provides the following two-part response to Board Order 2017-08:

- **Part 1 – 2012-2016:** Addresses 2012 ERA issues, including an amended Rate Schedule 42 pursuant to the Yukon Court of Appeal direction, the 2012 ERA charge, response to Board Order 2017-08 directions regarding the 2012 ERA amount, and other pre-2017 ERA amounts.
- **Part 2 – Period 2017 Forward:** Addresses how YEC proposes to address long-term average ("LTA") hydro generation forecasts for GRA purposes, the DCF, ERA and wholesale rates for the period 2017 forward, and responds to further directions of the Board relating to these issues. Appendix 2.2 provides the Short-term Hydro Alternative GRA Forecast ("ST Alternative GRA Forecast") as directed in Order 2017-08 so that this alternative can be included in the Part 2 assessments for the period 2017 forward.

Part 1 requests Board approval of the amended Rate Schedule 42, the ERA final amounts for 2012 and 2013, and the ERA interim amounts for 2014 to 2016 (subject to final approvals of the DCF amounts for these years).

Yukon Energy's Part 2 proposals for the period 2017 forward (a) support Yukon Energy's requested approvals in the 2017-18 GRA as filed in June 2017 with regard to the use of LTA hydro generation forecasts for each test year GRA purposes and ongoing use of the DCF, and (b) support use for the period 2017 forward of the amended Rate Schedule 42 as filed under Part 1 of the ERA Application based on the recent direction of the Yukon Court of Appeal.

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PART 1: 2012-2016

1.0 PART 1: 2012-2016

1.1 INTRODUCTION

Part 1 of the ERA Application to comply with the direction from the Yukon Court of Appeal addresses 2012 ERA issues, including an amended Rate Schedule 42 pursuant to the Yukon Court of Appeal direction, the 2012 ERA charge, response to Board Order 2017-08 directions regarding the 2012 ERA amount, and other pre-2017 ERA amounts.

Part 1 includes the following:

1. Context for Part 1 of the ERA Application: Yukon Court of Appeal;
2. 2012 ERA Charge;
3. Response to Board Order 2017-08 Directions regarding 2012 ERA Amount;
4. Other Pre-2017 ERA Amounts: 2013 to 2016; and
5. Amended Rate Schedule 42.

Board approval is requested of the amended Rate Schedule 42, the ERA final amounts for 2012 and 2013, and the ERA interim amounts for 2014 to 2016 (subject to final approvals of the DCF amounts for these years).

1.2 CONTEXT FOR PART 1 OF THE ERA APPLICATION: YUKON COURT OF APPEAL

The Court of Appeal of Yukon direction relates to Yukon Energy's wholesale rate (Rate Schedule 42).

The Court of Appeal of Yukon on September 12, 2017 released its judgment on an appeal by Yukon Energy related to the Board Order 2015-06 and the Wholesale Rate Schedule 42 applicable to The Yukon Electrical Company Limited ("YECL", now ATCO Electric Yukon ["AEY"]). The appeal specifically related to the ERA element of Rate Schedule 42, and the inclusion in ERA determinations of Yukon Energy's diesel generation costs of any net Diesel Contingency Fund ("DCF") payment made by Yukon Energy attributable to YECL's above-forecast wholesale purchases of electricity in 2012.

The Court's findings at paragraphs 63 to 65, as referenced in Appendix A to Board Order 2017-08, included the following:

- The Board accepted for the 2012-13 GRA that the expected diesel costs included in approved rates are based on long-term average ("LTA") hydro generation forecasts provided by the YECSIM model.
- The Board approved the revised DCF in Board Order 2015-01 as a rate stabilization mechanism, and a customer trust fund in which Yukon Energy has no beneficial interest. In approving the revised DCF "...it accepted that Yukon Energy's annual diesel generation costs are its generation costs plus its DCF payments, not just its actual diesel costs."

- "...the ERA is a rate stabilization mechanism intended to ensure that Yukon Electrical receives a full pass-through of all incremental costs or savings of diesel generation attributable to higher or lower than forecast wholesale purchases."

The Court's findings at paragraphs 66 to 70 included the following:

- In 2012, Yukon Energy made an additional and obligatory $439,000 net DCF payment attributable to Yukon Electrical's above-forecast wholesale purchases. [The Court's findings at paragraph 37 reviewed the basis for the $439,000 amount, noting that under DCF rules Yukon Energy was obliged in 2012 to pay into the DCF the expected increase of $1.773 million in diesel generation costs attributable to the excess wholesale demand of 14,264 MW.h higher than forecast, and that additional revenues from the above-forecast purchases were $1.334 million, leaving a shortfall of $439,000].
- The additional net DCF payment of $439,000 in 2012 was real and it was reasonable.
- The Board did not explain why, in these circumstances, it excluded Yukon Energy's net DCF payment attributable to above-forecast wholesale purchases from the definition of its diesel generation costs for ERA purposes.
- "The Board's reference to concerns regarding YECSIM verifiability was unresponsive to the costs definition issue. It had already approved the revised DCF and adopted YECSIM forecasts as the basis for determining Yukon Energy's expected diesel generation costs. The cost Yukon Energy was seeking to recover was the obligatory DCF payment set by the Board based on YECSIM, which, as noted, was previously uncontested and accepted by the Board. There was nothing else to 'verify'."
- "In my view, given the foregoing, the Order contravenes s. 7 of the OIC[1] and the decision was unreasonable....More specifically, the Order fixes a rate that does not enable Yukon Energy to recover from Yukon Electrical its reasonable net DCF payment attributable to above-forecast wholesale purchases, which payment is part of its diesel generation costs."

In paragraph 71 of the Court's judgment, the Court remitted the matter back to the Board with directions "to set a wholesale rate that enables Yukon Energy to recover all of its diesel generation costs, which costs include any net DCF payment made by Yukon Energy attributable to Yukon Electrical's above-forecast wholesale purchases of electricity."

Yukon Energy's proposed amended wholesale rate (Schedule 42) to comply with the Court Order is provided in Appendix 1.1, and reviewed below in Section 1.6. The ERA amounts determined in accordance with this rate are provided in Section 1.3 for 2012, and in Section 1.5 for subsequent pre-2017 years.

[1] Paragraph 17 of the Court judgment reviews Section 7 of Order in Council 1995/90 (the "OIC") which directs the Board to fix rates of Yukon Energy for the wholesale power customer that are "...sufficient to enable Yukon Energy to recover its costs that are not recovered from its other customers."

1.3 2012 ERA CHARGE

Table 1-1 provides the determination of the ERA charge to YECL of $501,000 for the year 2012, based on the amended Rate Schedule 42 in Appendix 1.1. The narrative following the table explains the components of the calculation and the changes from the previous $439,000 amount referenced in Order 2017-08 and the Court of Appeal Order as a result of refinements to the revenue offset.

Table 1-1: ERA Determination for 2012

		2012	
A	**Wholesales Variance for AEY (MW.h)**		
	Actual wholesales	310,264	A1
	GRA approved wholesales assuming Fish Lake LTA generaiton	296,000	A2 [See note 1]
	Fish Lake generation adjustment (expected LTA less actual)	992	A3 [See note 2]
	Change in wholesales for ERA	**13,272**	A4=A1-A2-A3
B	**YEC Cost Impact per kW.h change in Wholesales**		
	Losses (%)	8.80%	B1 [Table 2.2 GRA]
	Total YEC's actual generation net of secondary, LTA wind & FL (MWh)	423,310	B2 [See note 2]
	GRA approved load forecast, net of expected wind (MWh)	405,314	B3 [See note 1]
	YEC incremental generation relative to GRA approved (MW.h)	17,995	B4=B2-B3
	YEC's actual LTA Thermal Generation (MWh)	15,622	B5 [See note 2]
	GRA LTA Thermal Generation (MWh)	7,926	B6 [See note 1]
	YEC Incremenal thermal generation relative to GRA approved (MWh)	7,696	B7=B5-B6
	Incremental thermal generation for incremenal total generation (%)	42.77%	B8=B7/B4
	Thermal Generation cost per GRA ($/kW.h)	0.2871	B9 [See note 1]
	YEC thermal cost change ($/kWh wholesales)	**0.1336**	B10=B9*B8*(1+B1)
C	**YEC Revenue Impact per kW.h change in Wholesales**		
	Rate Schedule 42 Energy Charge ($/kW.h wholesales)	**0.08298**	C1
	Average YEC rider applicable to AEY retails ($/kWh wholesales)	**0.00663**	C2 [See note 3]
D	**Net thermal cost impact on YEC ($000)**		
	Wholesale Change: Cost Impact (YEC thermal generation costs)	**1,773**	D1=A4*B10
	Wholesale Change: Revenue Impact (YEC revenues)	**1,272**	D2=A4*(C1+C2)+A3*C1
	Cost change>revenue change ("Yes"=1, "No"=0)	**1**	D3=is D1>D2 (absolute)
	ERA Charge (rebate) to AEY [Net added cost (cost saving) for YEC]	**501**	D4=D3*(D1-D2)

Notes: 1. Compliance Filing re: Board Order 2013-01, as approved by Board Order 2013-03.
2. Table 1 to DCF Annual Filing for 2016 (which includes records for 2012 to 2016): copy provided in Appendix 3.5 to YEC 2017-2018 GRA.
3. YEC Rider J and R revenues from AEY retail customers, divided by wholesales net of Fish Lake adjustments, each number for last six months of 2012 (when Rider J applicable); applied to 71.8% of change in wholesales (portion in last six months of 2012).

The 2012 ERA determination in Table 1-1 is based on the YUB approved 2012 GRA forecasts and diesel fuel costs per kWh (per Board Orders 2013-01 and 2013-03), actual Yukon Energy sales and generation (net of secondary sales), the final 2012 DCF annual report amounts as approved by Board Order 2015-

06 (Appendix A, page 10), and estimated YEC revenue impacts from changes in wholesale sales (including provision for Rider J and R revenue impacts).

In summary, Table 1-1 indicates the following for 2012:

1. **Part A: Wholesale Variance for AEY (MW.h) –** Actual firm wholesales exceeded the approved GRA forecast by 13,272 MW.h (line A4 of Table 1-1), excluding the impact of Fish Lake hydro generation variances from LTA (which variances are estimated and addressed by the DCF annual report, and accordingly do not affect Yukon Energy thermal generation costs).
2. **Part B: YEC Cost Impact per kW.h Change in Wholesales –** The wholesales increase from the test year forecast increased thermal generation cost for YEC at $0.1336 per kW.h of incremental wholesales, as assessed at long-term average hydro generation conditions for the final DCF determinations and the following factors applicable to Yukon Energy in 2012:
    a. Yukon Energy's thermal generation as assessed for the final DCF determinations accounted for 42.77% of the 17,995 MW.h of incremental Yukon Energy firm generation above approved GRA forecasts (line B8 in Table 1-1);
    b. Yukon Energy's approved 2012 thermal generation cost of $0.2871 per kW.h of thermal generation (line B9 of Table 1-1 - this reflects diesel generation, as no LNG generation was forecast or occurred in 2012); and
    c. Applying the 42.77% to the increased Yukon Energy generation required to supply the incremental wholesales, the increased thermal generation cost equals $0.1336 per kW.h of incremental wholesales [$0.2871 times 42.77% times 1.088 for grid losses].
3. **Part C: YEC Revenue Impact per kW.h Change in Wholesales –** The wholesales increase from the test year forecast increased YEC revenues per kW.h of incremental wholesales:
    a. $0.08298/kW.h of incremental wholesales based on the Energy Charge for Rate Schedule 42 (this revenue change includes incremental wholesales due to Fish Lake hydro generation variances from long-term average); and
    b. $0.00663 per KW.h of incremental wholesales based on Yukon Energy's average Rider J revenues from AEY retail customers of $0.00924 per kW.h of firm wholesales in last six months of 2012 when Rider J was applicable, times 71.8% to reflect the portion of the 2012 wholesale change of 13,272 MW.h that occurred in the last six months of 2012 (this revenue change applies to wholesale changes net of Fish Lake hydro generation variances from long-term average; Rider J charges in 2012 of 6.4% applied from July 1 to December 31).
4. **Part D: Net Thermal Cost Impact on YEC -** Overall, Yukon Energy's 2012 added thermal generation costs of $1,773,000 (line D1 of Table 1-1) were not fully offset by added wholesale revenues of $1,272,000 (line D2 of Table 1-1), i.e., the cost change was greater than the revenue change, assessed as absolute values. The resulting ERA charge to AEY is $501,000.

The ERA charge to AEY of $501,000 (line D4 of Table 1-1) for 2012 recovers Yukon Energy's thermal generation costs, net of recovery from any added Yukon Energy revenues, incurred by Yukon Energy as a direct result of actual wholesale purchases exceeding forecast wholesale purchases in 2012.

Change from Earlier 2015 ERA Filing

The increase of $62,000 from the $439,000 amount estimated in YEC's April 7, 2015 ERA filing, and referenced in the Yukon Court of Appeal Order, is entirely due to refinements in the revenue impact assessments. No changes exist in the thermal cost impact assessments.

The revenue impact assessment for 2012 addresses additional YEC revenues that are reasonably attributable to the wholesales being higher than the forecast. The $62,000 increase in the revenue impact assessment for 2012 relates to (1) the estimate for Rider J revenue amounts per kW.h of wholesales in 2012, and (2) the revenues assessed for wholesales changes due to Fish Lake hydro generation variances from LTA. Each of these is reviewed separately below:

1. **Rider J revenue impacts on incremental wholesales net of Fish Lake hydro generation impacts**: **overall revenue reduction from earlier estimate by $52 thousand for 2012,** as reviewed below:
    a. **Rider J** – Yukon Energy's interim Rider J of 6.40% was charged in 2012, from July 1 to December 31, to base rates of all retail and industrial customers of both YEC and AEY, with all amounts charged to AEY customers being remitted in full to Yukon Energy. Added revenue to YEC occurred in 2012 from Rider J charges on added AEY retail sales attributable to the wholesales being higher than the forecast, i.e., to the 13,272 MW.h increase in wholesales net of Fish Lake adjustments.
    b. **Current and Earlier Rider J revenue estimates** – Table 1.1 shows estimated YEC Rider J revenue of $0.00663/kW.h of wholesales change, based on 2012 actual YEC Rider J revenues from AEY retail customers in the last six months of 2012 when Rider J was applicable.[2] In contrast, the earlier April 2015 estimate assumed $0.01058/kW.h of YEC Rider J revenue which was incorrectly based on the full revenue shortfall of 6.85% for all of 2012 instead of the interim rider of 6.4% for the last half of the year.[3]
    c. **Conclusion** - When assessing Rider J revenues related to added wholesales in 2012, it is necessary to adopt the actual rider charges at that time; Table 1-1 reflects this requirement, and results in approximately $52,000 less revenue than estimated in the April 2015 filing.

[2] The estimate reflects average Rider J revenues from AEY retail customers of $0.00924 per kW.h of firm, wholesales in the last six months of 2012, times 71.8% to reflect the portion of the 2012 wholesale change of 13,272 MW.h that occurred in the last six months of 2012. No Rider J revenues were received from 2012 wholesale change that occurred prior to July 1, 2012.

[3] The 2012 shortfall, plus a 2013 shortfall, was recovered through a temporary 3.62% added Rider R charged from July 1, 2013 to June 30, 2014. Rider R was determined based on GRA approved forecasts, and was not affected by variances in actual 2012 wholesales from the GRA forecast.

2. **Revenue impacts on incremental wholesales resulting from Fish Lake hydro generation impacts: overall revenue reduction from earlier estimate by $10 thousand for 2012,** as reviewed below:
   a. **YEC revenues affected by Fish Lake hydro generation changes** - Changes in Fish Lake hydro generation directly change wholesales to YEC, i.e., lower Fish Lake hydro generation results in higher wholesales (and vice versa with higher Fish Lake hydro generation). YEC revenues are directly affected by the RS 42 Energy Charge, which is applicable to all wholesales.
   b. **Current and Earlier Estimates** - Table 1-1 and the earlier April 2015 estimate both include estimated Energy Charge revenue changes on incremental wholesales resulting from the Fish Lake hydro generation reduction from the approved LTA. The earlier April 2015 estimate also assumed Rider J revenue impact of $0.01058/kW.h of added wholesales resulting from the Fish Lake hydro generation reduction from the approved LTA; however, there is no basis for assuming any change in Rider J revenues due to Fish Lake hydro variances from the approved LTA.
   c. **Conclusion** – Table 1-1 reflects the reality that YEC Rider J revenue does not change due to wholesales changes related only to Fish Lake variances from LTA, and results in approximately $10,000 less revenue than estimated in the April 2015 filing.

1.4 RESPONSE TO BOARD ORDER 2017-08 DIRECTIONS REGARDING 2012 ERA AMOUNT

The Board in Appendix A: Reasons for Decisions to Order 2017-08, noted the following: "As stated in Board Order 2105-01 [sic] and in Board Order 2015-06, the Board accepted the results of the YECSIM model for DCF purposes but expressed several concerns of using results from YECSIM with respect to ERA determinations."

The Board then provided several statements from the record of YEC's 2017-18 GRA (responses to IRs) regarding potential variances of YECSIM model assessments compared to actual YEC operations, and directed Yukon Energy in its application regarding the 2012 ERA amount "...to explain the extent of any adjustments needed to account for the above-noted concerns when it determines the amount payable by AEY to YEC".

Concerns noted in Order 2017-08

In summary, Yukon Energy's response to the above direction is that no adjustments are needed to the ERA amount of $501,000 for 2012 payable by AEY to YEC to account for the concerns noted in Order 2017-08.

The referenced concerns in Order 2017-08 were underlined quotes from statements by YEC on the record of YEC's 2017-18 GRA. The Board's concerns about the applicability of YECSIM results referenced quotes on the following:

- The lack of detailed retrospective verifications or tests of YECSIM;

- Long-term planning models such as YECSIM do not set to replicate actual past short-term operational decisions or to address future short-term operational planning;
- Differences may occur in actual system operation from YECSIM planning model simulations (in response to operator assessments of, or response to, specific conditions);
- YEC assesses added opportunities to enhance winter storage beyond those simulated by YECSIM; and
- The restriction of YECSIM model assessments to specific operation rules.

Yukon Energy provides the following observations regarding the extent that the concerns referenced in Order 2017-08 specifically affect the use of YECSIM results for ERA versus DCF or other determinations of the Board:

1. Yukon Energy's actual diesel generation costs for 2012 were determined based solely on the DCF Term Sheet table as approved by the Board for determining expected diesel generation for the actual grid load in 2012.
    - As noted in the Court of Appeal findings, the issue of "verification" related to YECSIM, or any alternative forecast or planning model, does not affect the fact that YEC's actual diesel generation costs for 2012 were determined based on a DCF Term Sheet table as approved by the Board and as applied to final actual firm grid generation for 2012.
    - YECSIM's accuracy in estimating LTA hydro generation affects the DCF Term Sheet table as well as the test year revenue requirements approved by the Board in the 2012-2013 GRA; however, YEC's final diesel generation costs for 2012 were determined by the DCF Term Sheet table as approved by the Board, and did not involve any new assessments using the YECSIM model.
    - As noted in the Court of Appeal decision, the cost Yukon Energy is seeking to recover was the obligatory DCF payment set by the Board based on YECSIM, which, as noted, was previously uncontested and accepted by the Board.
2. Any variances in actual diesel generation in 2012 from YECSIM forecasts as approved by the Board for the specified 2012 water and load conditions and the DCF Term Sheet table (including all such potential variances noted in the Board's Appendix A: Reasons for Decisions to Order 2017-08) had no impact on the final diesel generation costs incurred by Yukon Energy in 2012.
    - YEC's final diesel generation costs for 2012 at GRA approved fuel prices per kW.h were fully determined according to the expected diesel generation as estimated using the approved DCF Term Sheet.
    - While actual diesel generation affected the payment to the DCF for 2012, it did not affect the total diesel generation cost incurred by YEC as determined by the DCF Term Sheet. In short, the sum of actual diesel generation and the DCF payment always must equal the DCF Term Sheet expected total thermal generation for the actual 2012 grid load.

- Accordingly, YEC final diesel generation costs for 2012 were not affected by actual short-term system operation decisions (where differences can occur from planning model assumptions), or by any decisions on opportunities to enhance hydro storage for wintertime, or by any other specific potential cause for actual hydro operation to vary from YECSIM assumptions for the 2012 water conditions or for any other water year in the multiple years of record included in the 2012/13 GRA YECSIM assessments.

3. The DCF is a trust fund for the benefit of ratepayers. Any efficiencies or inefficiencies related to actual YEC operation of its hydro generation facilities had no impact on Yukon Energy's final thermal generation cost or net income for 2012, even if such factors affect the amounts for YEC's transfers into or out of the DCF. Yukon Energy's final generation cost and net income were based solely on the LTA expected thermal generation determinations made according to the approved DCF Term Sheet.

4. ERA determinations for 2012 are based solely on actual 2012 generation and sales and/or expected diesel generation assessments as previously approved by the Board (i.e., the GRA forecasts for 2012 as approved by the Board based on YECSIM, and the DCF determinations as approved based on the approved DCF Term Sheet derived using YECSIM). These ERA determinations for 2012 do not involve any new YECSIM assessments.

   - ERA determinations in Table 1-1 relating specifically to the actual wholesale variance (line A1 to A4) and YEC revenue impacts (lines C1 and C2) have no relationship to the DCF or YECSIM.
   - The DCF filings, separate from any ERA determinations, resulted in YEC incurring actual 2012 diesel generation costs for an added 7,696 MW.h (line B7 in Table 1-1) of expected or LTA diesel generation related to the actual increase of 17,995 MW.h in YEC firm generation (line B4 in Table 1-1):
     - These factors alone, without any new YECSIM assessments, determined the 42.77% estimate (line B8 in Table 1-1) of incremental YEC LTA thermal generation as a share of the overall YEC incremental total generation in 2012 relative to GRA forecasts.
     - The 42.77% estimate was not affected by YEC operation of its hydro or thermal generation facilities in 2012.
   - The ERA cost amount of $1.773 million for wholesale change impact on YEC thermal generation costs (line D1 in Table 1-1) does not involve any new YECSIM model assessments:
     - This amount is determined by the following factors:[4]

[4] The text provides an alternative way of describing what is shown in Table 1-1. The Table 1-1 presentation combines (at line B10) the impact of the approved diesel generation price per kW.h (line B9), and the share of added grid generation that results in added LTA thermal generation (42.77% per line B8), which results in an average diesel cost per kW.h of added total generation; the system losses factor of 8.8% (line B1) is then applied to convert this cost to a cost of $0.1336 per kW.h of incremental wholesales (line B10).

- Change in wholesales after Fish Lake adjustment [13,272 MW.h per line A4 of Table 1-1];
- The increase in total generation of 14,440 MW.h required to supply this increase in wholesales [includes actual system losses of 8.8%];[5]
- The added YEC LTA diesel generation in 2012 of 6,176 MW.h due to the added wholesales [based on the 42.77% LTA thermal; generation share of increased generation]; and
- The GRA approved average cost of diesel generation ($0.2871 per kW.h, per line B9 of Table 1-1), when applied to the 6,176 MW.h of added LTA diesel generation, results in the added YEC thermal generation cost of $1.773 million related to the added wholesales in 2012.

o As with the determinations of YEC's final diesel generation costs for 2012, the ERA determination is not affected by YEC's actual operation of its hydro or thermal generation, or by any new YECSIM model assessments. Overall, the ERA is determined by the same factors that determine YEC's final thermal generation costs for 2012.

In summary, determination of the 2012 ERA amount of $501,000 does not introduce any new YECSIM issues beyond those noted for use of YECSIM (or any other similar model) to forecast LTA hydro and thermal generation for the GRA, for the DCF Term Sheet table, and the determination of YEC's final diesel generation costs.

Accordingly, no adjustments are needed to the 2012 ERA amount payable by AEY to YEC to account for any variances that may exist with regard to YECSIM model forecasts of actual Yukon Energy operations in any water year for any specific grid load, or any other concerns noted by the Board in Appendix A of Order 2017-08.

Additional Observations

The Board in its earlier Order 2015-01 (page 23) identified the following specific concerns regarding the YECSIM model use for the ERA, in part reflecting comments received from AEY and UCG in that proceeding:

1. "The Board is of the view that the results of the YECSIM model cannot be verified;
2. The YECSIM model is a planning tool and not a billing engine; and
3. Operational decisions of YEC can affect variables such as losses and in turn affect diesel generation requirements."

[5] YEC system losses are affected by actual operation in each year. This factor is required to adjust wholesale changes to overall generation changes.

Yukon Energy has provided additional information on YECSIM in its current GRA filings (in Appendix 3.4 and in response to IRs), including responses referenced by the Board in Order 2017-08 and reviewed above in this section of Part 1 of this ERA Application. In Part 2 of this ERA Application, in order to facilitate additional review of YECSIM beyond that provided to date, YEC provides the YECSIM model User Manual for review by the Board and other parties.

Notwithstanding lack of similar access to the YECSIM model for review in prior proceedings, the results of this model have been used and accepted in previous YEC filings before the Board for the last GRA as well as for the Part 3 proceedings for Mayo B Project and the LNG Project.

Central to the 2012 ERA determination, the YECSIM model results provided the basis for the Board's LTA hydro and thermal generation determinations for the 2012 GRA test year and for YEC's final thermal generation costs determined (in accordance with the approved DCF Term Sheet table) in 2012. These determinations affecting YEC rates and its actual final thermal generation costs for 2012 occurred after recognition of the Board's inability to verify YECSIM results, and after the Board's recognition that such results are linked to various issues applicable to a simulation planning model (including issues related to operational decisions of YEC that can affect variables used to assess diesel generation requirements).

ERA determinations for 2012 do not involve any new YECSIM model assessments. In effect, determination of YEC's final diesel generation costs for 2012 as approved by the Board provides the basis for the ERA determinations, without any further reference even to the approved DCF Term Sheet.

In summary, the YECSIM model is not used separately as a "billing engine" or as the basis to determine the ERA charged to AEY in 2012. The ERA is determined based on the final thermal generation costs actually incurred by YEC in 2012 that can be reasonably assigned to AEY, without any separate reference for ERA purposes to YECSIM or its results.

1.5 OTHER PRE-2017 ERA AMOUNTS: 2013 TO 2016

Table 1-2 provides ERA determinations for 2013 to 2016, based on the amended Rate Schedule 42 in Appendix 1.1 and the same methods and approach used to determine the ERA amount for 2012 in Table 1-1.[6] The Board has approved DCF amounts for 2013, but DCF amounts for 2014 to 2016 are still interim.

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[6] YEC GRA LTA thermal as approved for 2013 assumed AEY connection of the Whitehorse Copper Tailings major industrial load, with an approved modified DCF Term Sheet table to reflect the changed grid load shape. Actual LTA expected thermal generation for 2013 to 2016, however, continued to be determined based on the approved DCF Term Sheet applicable without this new industrial load.
Line B9 thermal generation costs per kW.h are per the DCF annual report, and reflect LNG impacts in 2015 and 2016 resulting in lower average costs per kW.h.
Line C2 estimates of average YEC rider applicable to AEY retails ($ per kW.h wholesales) are per YEC records. The last AEY GRA reported actual or estimated AEY base rate retail revenues and rider payments to YEC for 2013 to 2016 (effective average rider % of base rate AEY retail revenues at 12.02% for 2013, 13.25% for 2014, 11.09% for 2015; assumed at 11.01% for 2016).

Table 1-2: ERA Determinations for 2013 to 2016

	2013	2014	2015	2016	
A Wholesales Variance for AEY (MW.h)					
Actual wholesales	307,927	295,284	297,961	301,207	A1
GRA approved wholesales assuming Fish Lake LTA generaiton	307,147	307,147	307,147	307,147	A2 [See note 1]
Fish Lake generation adjustment (expected LTA less actual)	693	(1,517)	(450)	697	A3 [See note 2]
Change in wholesales for ERA	**87**	**(10,346)**	**(8,737)**	**(6,637)**	A4=A1-A2-A3
B YEC Cost Impact per kW.h change in Wholesales					
Losses (%)	9.04%	7.50%	9.97%	8.34%	B1 [Table 2.2 GRA]
Total YEC's actual generation net of secondary, LTA wind & FL (MWh)	418,242	397,777	410,527	411,841	B2 [See note 2]
GRA approved load forecast, net of expected wind (MWh)	416,148	416,148	416,148	416,148	B3 [See note 1]
YEC incremental generation relative to GRA approved (MW.h)	2,094	(18,371)	(5,621)	(4,307)	B4=B2-B3
YEC's actual LTA Thermal Generation (MWh)	13,291	5,289	10,011	10,536	B5 [See note 2]
GRA LTA Thermal Generation (MWh)	11,006	11,006	11,006	11,006	B6 [See note 1]
YEC Incremenal thermal generation relative to GRA approved (MWh)	2,285	(5,717)	(995)	(470)	B7=B5-B6
Incremental thermal generation for incremenal total generation (%)	109.13%	31.12%	17.70%	10.90%	B8=B7/B4
Thermal Generation cost per GRA ($/kW.h)	0.2871	0.2871	0.2723	0.2046	B9 [See note 1]
YEC thermal cost change ($/kWh wholesales)	**0.3416**	**0.0961**	**0.0530**	**0.0242**	B10=B9*B8*(1+B1)
C YEC Revenue Impact per kW.h change in Wholesales					
Rate Schedule 42 Energy Charge ($/kW.h wholesales)	**0.08298**	**0.08298**	**0.08298**	**0.08298**	C1
Average YEC rider applicable to AEY retails ($/kWh wholesales)	**0.01897**	**0.02109**	**0.01765**	**0.01755**	C2 [See note 3]
D Net thermal cost impact on YEC ($000)					
Wholesale Change: Cost Impact (YEC thermal generation costs)	**30**	**(994)**	**(463)**	**(160)**	D1=A4*B10
Wholesale Change: Revenue Impact (YEC revenues)	**66**	**(1,203)**	**(916)**	**(609)**	D2=A4*(C1+C2)+A3*C1
Cost change>revenue change ("Yes"=1, "No"=0)	**0**	**0**	**0**	**0**	D3=is D1>D2 (absolute)
ERA Charge (rebate) to AEY [Net added cost (cost saving) for YEC]	**0**	**0**	**0**	**0**	D4=D3*(D1-D2)

Notes: 1. Compliance Filing re: Board Order 2013-01, as approved by Board Order 2013-03.
2. Table 1 to DCF Annual Filing for 2016 (which includes records for 2012 to 2016): copy provided in Appendix 3.5 to YEC 2017-2018 GRA.
3. YEC Rider J and R revenues from AEY retail customers divided by wholesales net of Fish Lake adjustments.

In 2013, when wholesales to AEY (after Fish Lake adjustments) were slightly higher than Yukon Energy's approved GRA forecast, Yukon Energy's increased thermal generation cost of $30,000 related to these added sales was fully offset by Yukon Energy's incremental revenues from added wholesales (including added wholesales related to Fish Lake hydro generation being below the approved long-term average, and related to added interim rider recoveries). As a result, there was no net cost for 2013 that YEC needs to recover from AEY, i.e., the ERA is zero.

In each subsequent year from 2014 to 2016, wholesales to AEY (after Fish Lake adjustments) were less than the last GRA approved forecast for 2013. In addition, in each of these years Yukon Energy's reductions in revenues related to these lower wholesales (including any revenue changes related to Fish Lake hydro generation variances from approved long-term average) exceeded its related reductions in thermal generation costs. Accordingly, there was no net cost saving that YEC needs to rebate to AEY in any of these years, i.e., the ERA is zero for each year.

The Table 1-2 ERA assessments highlight the extent to which ERA impacts are focused on YEC thermal cost impacts rather than revenue impacts from wholesale changes, and are dependent on overall grid load and the extent of LTA thermal change for a change in grid load. Compared with earlier ERA estimates provided in YEC's April 7, 2015 ERA filing for 2013 and 2014 (preliminary), changes to YEC thermal generation costs are basically unchanged and changes to YEC revenues are adjusted for the same changes reviewed for the 2012 ERA amount. The key refinement from these earlier ERA estimates is the test in Table 1-2 (line D3) whereby the ERA is zero in years when the revenue change exceeds the cost change.

To highlight the relevance of these factors, Table 1-3 provides a simplified ERA example review, assuming revenue impacts are limited to the RS 42 Energy Charge of $0.08296/kW.h and diesel generation cost of $0.2871/kW.h, for three cases (within each case a wholesales change of (A) +10,000 MW.h and (B) -10,000 MW.h):

- **Case 1 - Faro mine time period** (when diesel accounted for 100% of any load change at LTA hydro):
    - The ERA is clearly relevant for each example.
    - Thermal cost impacts are material and the cost per kW.h wholesale change is much greater than the YEC revenue impact.
- **Case 2 - After Faro mine closure** (when diesel in effect was not affected at all [0% change] of any load change):
    - The ERA is clearly not relevant for each example, as there are no thermal cost impacts.
    - Examples highlight that the ERA is focused on YEC net cost impacts, and does not address wholesale variations from forecast impacts on YEC revenues as such, i.e., YEC <u>revenue impacts</u> [separate from offsets to YEC cost impacts] from changes to wholesales from GRA forecast are not addressed through the ERA or any other mechanism.
- **Case 3 – 2012 and after years** (when thermal accounts for varying % of any load change, the case assumes a low level at only 25%):
    - The ERA ends up not being applied in each example.
    - Examples highlight that the ERA only applies when the YEC cost impacts from wholesale change are greater than the YEC revenue impacts; here the cost impacts are simply below the relevant threshold (as was the case in 2013 through 2016 in Table 1-2).
    - The assessment for this case would change to provide an ERA amount if the % of any load change accounted for by thermal generation was increased to 27% or higher.

Table 1-3: Simplified ERA Examples for Three Cases

	Case 1 - Faro Mine		Case 2 - After Faro Closure		Case 3 - 2012 + Years	
	Case 1A	**Case 1B**	**Case 2A**	**Case 2B**	**Case 3A**	**Case 3B**
Wholesale change (MW.h)	10,000	-10,000	10,000	-10,000	10,000	-10,000
Cost of Thermal ($/kW.h)	0.2871	0.2871	0.2871	0.2871	0.2871	0.2871
Incremental Thermal (%)	100%	100%	0%	0%	25%	25%
Cost ($/kW.h generation)	0.2871	0.2871	0	0	0.0718	0.0718
System Losses (%)	8.80%	8.80%	8.80%	8.80%	8.80%	8.80%
Cost ($/kW.h Wholesales)	0.3124	0.3124	0.0000	0.0000	0.0781	0.0781
YEC ERA Cost $000)	***3,124***	***(3,124)***	***-***	***-***	***781***	***(781)***
YEC ERA Revenue ($/kWh)	0.08298	0.08298	0.08298	0.08298	0.08298	0.08298
YEC ERA Revenue ($000)	***830***	***(830)***	***830***	***(830)***	***830***	***(830)***
YEC Net ERA ($/kW.h)	0.2294	0.2294	(0.0830)	(0.0830)	(0.0049)	(0.0049)
YEC Net ERA ($000)	2,293.85	(2,293.85)	(829.80)	829.80	(48.89)	48.89
Test: cost >revenue change ("Yes"=1, "No"=0)	1	1	0	0	0	0
Corrected ERA ($000)	2,294	(2,294)	0	0	0	0

1.6 AMENDED RATE SCHEDULE 42

Yukon Energy applies for Board approval of Yukon Energy's amended Rate Schedule 42 wholesale rate as provided in Appendix 1.1, effective January 1, 2012.

The amended Rate Schedule 42 includes an ERA that enables Yukon Energy in each calendar year to recover all of its diesel or other thermal generation costs, net of related changes in Yukon Energy wholesale revenues, attributable to YECL's above-forecast wholesale purchases of electricity. The ERA in the amended Rate Schedule 42 also requires Yukon Energy in each calendar year to rebate all of its diesel or other thermal generation cost savings, net of related changes in Yukon Energy wholesale revenues, attributable to YECL's below-forecast wholesale purchases of electricity.

The ERA in the amended Rate Schedule 42 is to be determined for each calendar year based on Yukon Energy's most recent test year forecast wholesale purchases as approved by the Board.

The ERA amount for each year will be provided for Board review and approval, concurrent with the Annual DCF Report filing by Yukon Energy.

APPENDIX 1.1: RATE SCHEDULE 42

APPENDIX 1.1: RATE SCHEDULE 42

RATE SCHEDULE - 42

WHOLESALE PRIMARY (YEC)

AVAILABLE: To The Yukon Electrical Company Limited (YECL)

APPLICABLE: For wholesale primary supply to YECL.

RATE: Energy Charge

All Energy consumed at 8.298¢ per kW.h

Energy Reconciliation Adjustment

YECL’s wholesale primary bill will be adjusted at the end of each calendar year by an amount equal to any increase or reduction in thermal generation costs, net of related changes in wholesale revenues, incurred by Yukon Energy as a direct result of actual wholesale purchases exceeding or falling short of Yukon Energy’s most recent test year forecast wholesale purchases as approved by the Yukon Utilities Board.

TERMS AND CONDITIONS OF SERVICE: The Company's Terms and Conditions of Service approved by the Yukon Utilities Board form part of this rate schedule and apply to the Company and every customer supplied with electric service by the Company in the Yukon and British Columbia. Copies of the Terms and Conditions of Service are available for inspection in the offices of the Company during normal working hours.

PART 2: PERIOD 2017 FORWARD

2.0 PART 2: PERIOD 2017 FORWARD

2.1 INTRODUCTION

Part 2 of the ERA Application addresses how YEC proposes for the period 2017 forward to address long-term average ("LTA") hydro generation forecasts for GRA purposes, the Diesel Contingency Fund (DCF), ERA, wholesale rates, and further directions of the Board relating to these issues, as set out in Order 2017-08.

Appendix A to Board Order 2017-08 directs that Part 2 is to address all of the concerns expressed by the Board in Board Order 2015-01 and Board Order 2015-06, including:

- Board concerns that results of the YECSIM model cannot be verified;
- That it is a planning tool and not a billing engine; and
- That operational decisions of YEC can affect variables such as losses and in turn affect diesel generation.

Appendix A to Board Order 2017-08 also directs that Part 2 is to include information demonstrating the inter-relationship between the LTA hydro-generation, the DCF and the ERA, and detailing the pros and cons from each of those that relate to the other element. Finally, Part 2 should also include any alternatives to the use of the current DCF and ERA approach.

In response to these directions, Part 2 includes the following:

1. Context for Part 2 of the ERA Application;
2. Summary of Board Outcomes & Concerns – Orders 2015-01 and 2015-06;
3. Inter-relationships re: LTA Hydro Generation, DCF and ERA;
4. Issues and Alternatives for the Period 2017 Forward; and
5. Summary Conclusions.

Based on review as directed by the Board, Yukon Energy's Part 2 proposals for the period 2017 forward (a) support Yukon Energy's requested approvals in the 2017-18 General Rate Application (the "GRA") as filed in June 2017 with regard to the use of LTA hydro generation forecasts for each test year GRA purposes and ongoing use of the DCF, and (b) support use for the period 2017 forward of the amended Rate Schedule 42 ("RS 42") as filed under Part 1 of the ERA Application based on the recent direction of the Yukon Court of Appeal.

2.2 CONTEXT FOR PART 2 OF THE ERA APPLICATION

The two-part ERA Application is occurring in the context of past practice and Board decisions pertaining to the Part 2 issues, an ongoing Yukon Energy GRA process for the 2017/2018 test years, and the recent Power Purchase Agreement ("PPA") Application to the Board regarding the Eagle Gold Project.

Past Practice & Board Decisions Re: Part 2 Issues

Yukon Energy and the YUB have been addressing since the early 1990s the key issues related to the use of short-term versus LTA hydro generation forecasts for GRA purposes, along with water-related thermal cost or contingency fund issues and related ERA issues for wholesale rates.

Past practice and Board decisions on these matters are reviewed in Appendix 2.1 in the context of three different time periods:

- 1990s with the Faro Mine operation (when the mine was in operation, any changes in generation were 100% accounted for in diesel generation; when the mine was not operating, changes in generation had no impact on diesel quantities);
- 1998-2011, after the permanent Faro Mine closure, when diesel generation was not responsive to load changes under LTA hydro conditions and DCF operation was generally suspended; and
- 2012-13 GRA and subsequent years when load growth lead to LTA hydro once again being adopted for GRA purposes and the DCF resuming active operation.

Key practice and Board decisions regarding Part 2 issues that emerged during the 1990s with the Faro mine operation include the following core elements:

- **Risk Assignment** - From the outset of Board review of YEC revenue requirements in the late 1980s, it was understood that the risk of low water conditions, as regards added cost for thermal generation, is borne by the customers of the utility.
- **Stabilization Mechanism** - An initial thermal cost or contingency fund account mechanism (i.e., the Low Water Reserve Fund, or "LWRF") to address water-based variances from thermal generation forecasts was established in the early 1990s, when YEC relied upon short-term hydro generation forecasts for GRA purposes. The Board at that time noted concerns about lack of rate stability with use of short-term versus LTA hydro generation forecasts for GRA purposes.

  In 1996/97, after the Faro Mine resumed operations, LTA hydro generation forecasts were adopted for GRA purposes and the DCF was approved by the Board to replace the LWRF as the thermal cost or contingency fund account mechanism to address thermal generation cost variances from GRA approved LTA forecasts and to smooth rate cost fluctuations due to water level divergence from average.
- **ERA Established** - The ERA was established in 1993, when ST hydro generation forecasts were still being adopted for GRA purposes, as a retrospective payment calculation integrated into the wholesale rate (RS 42), designed to ensure that YECL received a full pass-through of all incremental costs or savings of diesel generation attributable to higher or lower than forecast wholesale demand. As with the DCF and its precedent fund (the LWRF), the ERA was only active during the 1990s when the Faro Mine was in operation which resulted in diesel generation accounting for 100% of any generation change due to firm load changes. The basic requirement for the ERA reflected the material variance per kW.h of wholesale in YEC thermal generation costs (fuel plus variable O&M) versus the RS 42 Energy Charge. Given this variance, YEC required (when the Faro

Mine was operating) an ERA mechanism in order to recover a material portion of its incremental diesel generation costs related to an increase in wholesales above GRA forecasts; the ERA mechanism also rebated to YECL the net savings that YEC recovered when wholesales were less than GRA forecasts.

Closure of the Faro Mine in 1998 lead to reduced demand and hydro surplus conditions. Diesel generation was not responsive to load changes under LTA hydro conditions. Under these conditions, LTA hydro generation forecasts were not required for GRA purposes, the DCF was inactive (except for interest income), and the ERA was similarly not active.

Baseload demand increased materially on the Yukon grid in the period leading to 2012. Yukon Energy came to rely once again on diesel generation in response to baseload demands. Yukon Energy accordingly needed to reactivate reliance on LTA hydro generation forecasts for GRA purposes, as well as to reactivate the DCF and the ERA.

As a result of higher loads, Yukon Energy's 2012-13 GRA sought Board approval to set test year revenue requirements based on LTA hydro forecasts, and to reactivate the DCF and the ERA (with proposed revisions to address changes in the Yukon system since the 1990s).

Board Order 2013-1 directed Yukon Energy to reflect 100% long-term average hydro generation in calculating diesel generation requirements for each test year. Board Orders 2015-01 and 2015-06 subsequently reactivated the DCF, with revisions to address current conditions on the Yukon grid, and approved final DCF determinations for 2012 and 2013. The ERA issues, however, lead to the appeal to the Court and reflected concerns of the Board which are separately reviewed in Section 2.3 below.

The LTA hydro forecast for GRA purposes, and the reactivated DCF mechanisms, approved for the 2012-13 GRA differed from similar 1990 provisions in one key aspect - namely, the need in 2012-13 to estimate a changing share of incremental load that is expected to be supplied by LTA hydro generation (rather than the binary situation when the Faro mine was connected to the system, i.e., variations in generation then were either 100% diesel when the mine was operating or 100% hydro when the mine was not operating).

The 2012-13 GRA LTA hydro forecasts, and the DCF Term Sheet table, were developed using YEC's YECSIM planning simulation model. As reviewed in Section 2.3 below, the Board had a range of concerns related to the YECSIM model and its prominence in the reactivated DCF - and these concerns were particularly prominent in the Board's review of the proposed reactivated ERA mechanism.

Current YEC GRA

In the current GRA application process Yukon Energy is seeking the following approvals relevant to the Part 2 ERA Application:

- **Revenue requirements:** Fuel and purchase power costs forecast of $2.381 million and $2.407 million in 2017 and 2018 respectively, including approval to assume that LTA thermal generation requirements (separate from thermal generation maintenance activity requirements) are supplied with a combination of 90% LNG and 10% diesel generation.

- **Update to the DCF and LTA:** Approval of Yukon Energy's Revised DCF Term Sheet provided in Attachment 3.4-1 of Appendix 3.4 of the GRA necessary for determination of annual expected LTA hydro and thermal generation requirements and fuel costs, including proposed updates to the DCF for the following:
    - Updated table for “Expected YEC Thermal; Generation with LTA YEC Hydro Generation” to reflect updated information on LTA wind and hydro generation (YEC and AEY); and
    - Updates for incorporating LNG fuel and generation facilities into DCF cost determinations.

  Appendix 3.4 of the GRA also provided updates on the following:
    - Potential Thermal Generation Variability (GW.h/yr) Depending on Water Conditions (35 years) – Range of Grid Loads from 380 to 450 GW.h/yr (Attachment 3.4.2);
    - Information on YECSIM Model (Attachment 3.4.3); and
    - DCF Cap Option Assessment (Attachment 3.4.4).

No proposal regarding the Rate Schedule 42 ERA was provided in the 2017-18 GRA application as the ERA was at that time the subject of an appeal to the Court from Board Order 2015-06. Yukon Energy noted that at such time as the Court's decision is provided, it would review the ERA and provide the Board with a filing on this matter. Subsequent to the Court of Appeal judgment in September 2017, and after receiving comments from parties in the GRA proceeding, the Board issued Order 2017-08 on October 18, 2017:

- Part 1 of this ERA Application addresses the outstanding matters with regard to the ERA prior to 2017, including a proposed amended Rate Schedule 42 wholesale rate effective January 1, 2012; and
- Appendix 2.2 of this ERA Application provides the short-term (“ST”) hydro-electric alternative GRA forecast (the “ST Alternative GRA Forecast”) for the test period as directed in Board Order 2017-08 so that this alternative can be included in the Part 2 assessments as directed by this same Board Order.

The oral hearing on the 2017-18 GRA scheduled to begin on November 28, 2017 has been cancelled as a result of Board Order 2017-08 and will be rescheduled in accordance with a revised process schedule that the Board will provide after review of filings as directed in Order 2017-08.

The 2017-18 GRA proceeding has completed the initial interrogatories (IRs) process.

In response to motions from Utilities Consumers Group (“UCG”) and John Maissan seeking a ruling on further IR responses from YEC, Board Order 2017-09 issued November 15, 2017 directed that YEC provide three further IR responses by November 30, 2017. Board Order 2017-09 also stated that the Board will issue a revised process schedule for the GRA “after the alternative proposal, application revisions, and revisions to the first-round of IR responses are received.”

PPA Application regarding Eagle Gold Project

On November 10, 2016 Yukon Energy filed an application with the Board seeking an Order approving specific elements of the PPA between YEC and Victoria Gold Corp. and StrataGold Corp. (Victoria Gold Corp. and StrataGold Corp. collectively known as "VGC Group") (the "PPA Application") regarding the Eagle Gold Project. The PPA Application provides for the sale by YEC to VGC Group of grid electricity required to operate the mine, with commencement of delivery of grid electricity to VGC Group estimated to begin in March 2019.

The PPA Application indicates a potential increase in grid loads over the next decade sufficient to sustain material forecast thermal generation at LTA hydro generation, e.g., prior to any enhanced renewable generation being implemented, incremental YEC LTA thermal generation at 65% to 75% of the incremental generation is needed to supply the VGC mine power requirements. Since the late 1980s, such grid loading magnifies thermal generation cost impacts from load changes which in turn reinforces the requirement for LTA hydro generation forecasts for GRA purposes, LTA DCF-type thermal cost or contingency fund account mechanisms, and the ongoing need for ERA wholesale rate mechanisms.

2.3 SUMMARY OF BOARD OUTCOMES & CONCERNS - ORDERS 2015-01 AND 2015-06

In response to directions in Appendix A of Board Order 2017-08, Part 2 of this ERA Application addresses the concerns expressed by the Board (as well as the outcomes) in Board Orders 2015-01 and 2015-06.

Appendix 2.3 reviews the outcomes and concerns of the Board in these Orders.

In summary, the Board in Order 2015-01 and Order 2015-06 confirmed the need for a mechanism that effectively protects ratepayers from thermal generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions, the use of LTA hydro forecasts for the 2012-13 GRA, the need for and justification of the DCF as currently modified, and the use of the YECSIM model to determine the 2012-13 GRA LTA hydro forecasts and DCF Term Sheet table determinations. YEC's 2017-18 GRA reflected these prior Board decisions with the proposed LTA hydro forecasts and updated DCF mechanisms based on the updated YECSIM model.

The Board also noted in these Orders that continued use in future of any forecast model for GRA, DCF or other forecast processes will require that the model and its results be made available for testing by intervenors and the Board. The Board expressed concerns about YECSIM in this regard, stating that the model and its results must be made available for testing by interveners and the Board if YEC is to continue to use YECSIM for forecasting. The following YEC responses are noted with regard to this concern:

- Yukon Energy in its 2017-18 GRA provided (in Appendix 3.4, including Attachment 3.4.3) considerable additional information and analysis regarding the YECSIM model, and the YECSIM model was also addressed in many of the subsequent IRs from the Board and intervenors.
- In response to Board Order 2017-08, and the Board's re-iterated concerns therein regarding the YECSIM model, Yukon Energy is committed to providing appropriate access to the YECSIM

forecasting model for testing by interveners and the Board so that the Board's concerns can be alleviated. Yukon Energy is providing in Appendix 2.4 of this ERA Application the YECSIM User Manual which will enable the Board and interveners to review fully the constraints, processes and operational rules of this model for testing and assessment. Yukon Energy would then welcome the opportunity to review any further access to the model that would assist the Board and interveners, including potential workshop or other discussion process for review of its specific use (inputs and outputs) for the 2017-18 GRA forecasts and the updated Appendix 3.4, DCF Term Sheet Table 3.4-1.

Finally, the Board noted in these Orders its specific concerns regarding the use of YECSIM as a "billing engine" under YEC's proposed ERA mechanism.

The Board sought to address its concerns regarding use of YECSIM for the ERA by excluding from the ERA any forecast or derived costs from the YECSIM model. As reviewed in Part 1 of this ERA Application, the Court of Appeal has subsequently directed that the wholesale rate must enable Yukon Energy to recover all its thermal generation costs, which costs include any net DCF payment made by Yukon Energy attributable to YECL's above-forecast wholesale purchases of electricity.

Section 1.4 of Part 1 of this ERA Application responds in detail to Board Order 2017-08 specific YECSIM and other concerns regarding the ERA (focusing on the ERA determination for 2012), and notes in summary that the YECSIM model is not used separately in ERA determinations as a "billing engine". The ERA is determined in each year today, as in the 1990s, based on the final thermal generation costs actually incurred by YEC in that year that can be reasonably assigned to AEY, without any separate reference for ERA purpose to YECSIM or its results.

2.4 INTER-RELATIONSHIPS RE: LTA HYDRO GENERATION, DCF AND ERA

In response to directions in Appendix A of Board Order 2017-08, this subsection of Part 2 of the ERA Application provides information demonstrating the inter-relationship between the LTA hydro generation, the DCF and the ERA, and addresses the request that YEC detail the pros and cons from each of those that relate to the other element.

Key Elements in the Inter-Relationships

Overall, when thermal generation is needed to accommodate Yukon hydro grid load increases, past practice and proceedings in Yukon have demonstrated the inter-relationship between:

- LTA hydro generation forecasts for GRA purposes; and
- The DCF or other similar thermal cost or contingency fund account mechanism that is then needed to address water-related variances of actual hydro generation in any year from the latest GRA LTA forecast; and
- The ERA or other similar mechanism separately required to ensure, in accordance with OIC 1995/90 and the direction of the Court of Appeal, that AEY receives a full pass-through of all

incremental YEC costs or savings of thermal generation attributable to higher or lower than forecast wholesale demand.

As reviewed below, these inter-relationships start from the accepted premise that ratepayers bear the risk of low water conditions as regards added costs for added thermal generation, and that material instability in thermal generation costs due to water availability therefore pose direct challenges to the stability of rates that the Board would need to approve.

Linear Nature of the Inter-Relationships

Figure 2-1 highlights the linear nature of the above inter-relationships, with each of the initial two steps below affecting subsequent steps, and the final step (including the ERA) not affecting any of the earlier ones.

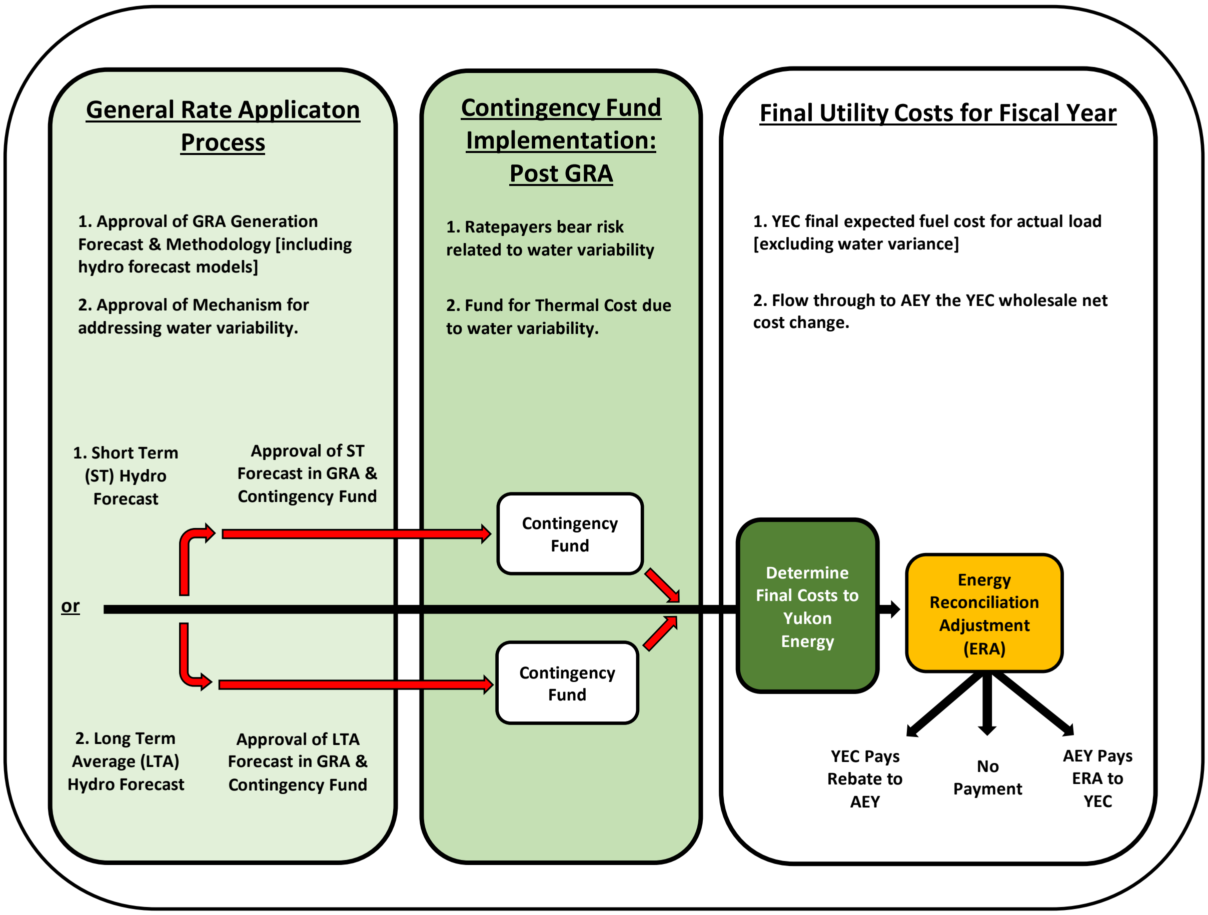
In summary, the following three step description can be provided of the above inter-relationships:

1. **General Rate Application Process -** The relationships start with each Yukon Energy general rate application process, including decisions on the following:
   - GRA generation forecast and methods (including selection of ST or LTA hydro generation forecasts, and review of the selected ST or LTA forecasts planning models); and
   - The contingency fund mechanism to be used, when finalizing YEC post-GRA costs at the end of each fiscal year, for addressing water variability from the approved GRA forecast. The selected contingency fund mechanism may vary depending on whether a ST or LTA hydro generation forecast is selected and approved for the GRA.
2. **Contingency Fund Implementation: Post GRA -** The GRA approvals in the first step determine the mechanism and rules for DCF or other contingency fund implementation post GRA to address (in response to actual load requirements for each fiscal year) the impacts of water variability from the approved GRA forecasts, and the operation of the fund used to address thermal cost variability due to water variability.

   The second step is the implementation of the contingency fund at the end of each fiscal year, including any Board review and approval requirements.
3. **Final Utility Costs for each Fiscal Year -** The final step, following contingency fund implementation, is the determination of the final Yukon Energy thermal generation fuel costs for each fiscal year (i.e., the YEC cost after removing water variability impacts) and the determination of the ERA related to any flow through to AEY of YEC's wholesale net cost changes related to wholesale changes from the GRA forecast.

   The third step, and in particular the ERA determination, cannot proceed until the second step is concluded.

Figure 2-1: Yukon Hydro Grid Inter-relationships re: GRA Hydro Forecasts, Contingency Fund Mechanisms, Final YEC Costs, and ERA Mechanisms



Relevant Historic Experience

Relevant Yukon Energy experience shows that these inter-relationships start from the accepted premise that ratepayers bear the risk of low water conditions as regards added costs for added thermal generation, and that material instability in thermal generation costs due to water availability therefore pose direct challenges to the stability of rates that the Board would need to approve.

Yukon Energy's rate review experience since the late 1980s has included use of both ST and LTA hydro generation forecasts. The current GRA and Appendix 2.2 to this ERA Application provide these two options for review regarding the 2017 and 2018 test years. Regardless of which option is adopted, however, the following are required due to the inter-relationships between GRA forecasts, thermal generation cost or contingency fund account mechanisms, and wholesale rate mechanisms:

- A thermal cost or contingency fund account mechanism similar to the DCF is required to address actual variances of thermal generation costs in any year from the latest GRA forecast due to water variances from GRA forecasts, whether those forecasts are based on ST or LT hydro; and

- A wholesale rate mechanism similar to the ERA is required to ensure, in accordance with OIC 1995/90 and the direction of the Court of Appeal, that AEY receives a full pass-through of all incremental YEC costs or savings of thermal generation attributable to higher or lower than forecast wholesale demand.

The Board to date has consistently accepted and approved the inter-relationships between hydro generation forecasts as used for GRA purposes and the thermal cost or contingency fund account mechanism needed to address actual variances of thermal generation costs in any year from the latest GRA forecast due to water variances from GRA forecasts.

The ERA wholesale rate mechanism has also been a well-established element in YEC rates when variances in YEC thermal generation occur in response to wholesales variances from approved GRA forecasts. The necessary inter-relationship between the ERA and the DCF elements derives from the fact that YEC's final thermal generation costs incurred in any year are directly set by the DCF (or any similar thermal cost or contingency fund account mechanism), and therefore must be referenced when determining any ERA amounts.

Basic Requirements versus "Pros and Cons"

Appendix A to Board Order 2017-08 directed that the pros and cons from each of the above inter-relationships be detailed. Based on the above review, however, the inter-relationships as reviewed appear to be a basic requirement rather than a matter of choice subject to pro and con assessments.

- A fundamental principle of utility rate regulation in Yukon is that ratepayers are to bear the risks related to water variability.
    - Based on the resulting need to identify the impacts of water variability, the inter-relationship between forecast hydro generation for GRA purposes and a **thermal cost or contingency fund account mechanism** is a basic requirement (rather than a matter for choice).
- OIC 1995/90 and the Court of Appeal judgment require that the wholesale rate enable Yukon Energy to recover all its thermal generation costs, including any net payment made to a thermal cost or contingency fund account by Yukon Energy attributable to AEY's above-forecast wholesale purchases of electricity.
    - Based on above directions and requirements, the inter-relationship between the adopted thermal cost or contingency fund account mechanism and **an ERA mechanism** is a basic requirement (rather than a matter of choice).

Current Challenges

Challenges in implementation of the DCF, and therefore the ERA, occur in the current context by the need for a DCF Term Sheet which sets out the LTA thermal share of any change in grid generation depending on the level of the grid load. These challenges focus attention on the current LTA hydro forecast mechanism, i.e., the YECSIM model, as an added and separate element in the defined inter-relationships.

In the past, however, different LTA or ST hydro forecast models were also an important element of the GRA forecast review.

Figure 2-1 indicates that review of YECSIM or any other hydro forecast model is restricted to the decisions needed during the GRA process, and any subsequent process to amend the DCF or other contingency fund mechanism approved during the GRA process.

The current DCF Term Sheet approach as approved in the 2012-13 GRA involves setting out the required directions (regarding the "portion" or percentage for LTA thermal generation at different grid load levels) in a table approved by the Board. Once so approved, the DCF Term Sheet table and other related provisions determine the year end DCF Annual Report amounts presented to the Board for review and approval. Following this Board approval, the resulting final year end thermal generation costs incurred by YEC and the information in the related DCF Annual Report as approved are used to determine any ERA thermal generation costs for that year to be recovered from, or rebated to, AEY.

The key point of continuity today with past practice in the 1990s is that the final DCF determinations each year, and any subsequent related ERA determinations, are based on year end reports reviewed and approved by the Board – and in each case do not involve revisiting or rerunning any forecast model assessments.

2.5 ISSUES AND ALTERNATIVES FOR THE PERIOD 2017 FORWARD

Review Related to Rates & Revenue Requirements

Board jurisdiction with regard to Yukon electricity utilities is tied, in the absence of specific directions from the Minister or by OIC, to the determination of rates and related revenue requirements. Accordingly, Board review of how YEC proposes to address the DCF, ERA, wholesale rates and LTA hydro generation forecasts for GRA purposes for the period 2017 forward is tied to Board determinations on rates and related revenue requirements.

The current Yukon Energy 2017/18 GRA before the Board requires determinations regarding hydro forecasts for GRA purposes and, as reviewed above, concurrent determinations regarding related thermal cost or contingency fund account mechanisms and ERA wholesale rate mechanisms.

Accordingly, the current GRA review provides the opportunity for the Board to address the Part 2 issues for the period 2017 forward that are addressed in this ERA Application.

Consideration of Alternatives to DCF and ERA Approach

Appendix A to Board Order 2017-08 has directed that Yukon Energy include in the Part 2 review for period 2017 forward any alternatives to the use of the current DCF and ERA approach.

Based on the above Section 2.4 and Figure 2-1 review of inter-relationships, Yukon Energy is not aware of any applicable alternative to the requirement for a thermal cost or contingency fund account similar to the DCF to ensure that ratepayers bear the risks related to water variability, and to provide a fund for dealing with thermal cost variability due to water variability. As reviewed in Figure 2-1, implementation of any such contingency fund to address these requirements will determine the extent that Yukon Energy's final thermal generation costs for each fiscal year differ from its costs for actual diesel generation. Options to remove any thermal cost or contingency fund account would require Yukon Energy to bear the risks related to water variability, and would significantly change the utility's overall risk profile.

Yukon Energy is also not aware of any applicable alternative to the requirement for an ERA wholesale rate mechanism that flows through to AEY the YEC wholesale net cost changes related to wholesale changes from the GRA forecast. This requirement arises from the OIC and the Court of Appeal Order. It continues to exist with or without the DCF, or an equivalent thermal cost or contingency fund account mechanism. Based on the above Section 2.4 and Figure 2-1 review of inter-relationships, implementation of any such contingency fund will determine the extent that Yukon Energy's final thermal generation costs for each fiscal year differ from its costs for actual diesel generation, and the ERA will accordingly need to be determined based on YEC final thermal generation costs for each fiscal year.

Within the above framework, the specifics for the DCF or any similar contingency fund mechanism can vary depending on the hydro generation forecast adopted for GRA purposes, e.g., LTA versus ST hydro generation forecasts, or situations similar to the Faro mine time period (when mine operation in effect resulted in diesel generation accounting for 100% of any generation change due to firm load changes) versus the current context (when the LTA thermal generation portion of incremental grid generation increases as grid load increases).

In the current context, it is apparent that LTA hydro generation varies depending on the grid load as well as with any changes to the renewable generation capabilities on the hydro grid. The current DCF Term Sheet includes provisions to address this reality and thereby to facilitate LTA DCF implementation in the current transition period. For the period 2017 forward, it will remain relevant at each GRA to review the DCF Term Sheet to assess the continuing applicability of the existing provisions for the latest forecast period.

LTA versus ST GRA Forecast Alternatives

Within the context of the current GRA, the Board has identified in Order 2017-08 the options of adopting ST versus LTA hydro forecast for GRA purposes. This Part 2 ERA Application provides the following information needed to assess the ST and LTA alternatives, based on the GRA as filed and Appendix 2.2 review of the ST Alternative GRA Forecast:

- **Impacts on revenue requirements, rate increases, and bills -** As expected during a period of favourable water conditions, the ST Alternative GRA Forecast would reduce the test year revenue requirements (by $2.0 and $0.7 million) and cumulative rate increase required by 2018 (reduced by about 11%, from 9.08% to 8.11%).

  This reduction in 2018 rate increase requirements under the ST Alternative GRA Forecast versus the LTA GRA Forecast is misleading to the extent that the DCF cap results in Rider E rebates that reduce actual final bills applicable to ratepayers under the LTA forecast approach:

- In years when the DCF cap applies with LTA forecasts for GRA purposes (as has been the case since 2013), Rider E rebates in effect are expected to return to ratepayers the YEC DCF payments to cover the gap between LTA and actual thermal generation requirements.
- Accordingly, major differences in ratepayer bill impacts with ST versus LTA forecast alternatives for the current GRA for 2017-18 are likely to be limited if the current DCF cap is retained.

Looking beyond the current GRA, impacts on revenue requirements, rate changes, and bills under the ST forecast alternative will vary with each future GRA depending on changes in ST water conditions and forecasts; in contrast, the LTA forecast alternative will tend to provide a more stable basis for forecasts, revenue requirements, rate changes and bills through different future GRAs (as these forecasts will not vary depending on changes in ST water conditions and forecasts).

- **Consistency with past Board Decisions re: Rate Stabilization -** Adoption of the ST Alternative GRA Forecast would constitute a sharp break from past decisions of the Board, when LTA forecasts were approved in the mid-1990s and again in 2012-13 GRA to provide rate stability for ratepayers. Adoption of the ST alternative today would expose ratepayers to considerable rate instability risks.
  - As noted by the Board in the 1990s, adoption of LTA hydro forecasts versus ST hydro forecasts is desired in order to provide greater rate stabilization over time.
  - Adoption of LTA forecasts in the Board's 2012-13 GRA decision has set current rates at a level consistent with LTA forecasts, and well above what was then required with ST hydro forecasts. Changing today from LTA to ST hydro forecasts would therefore introduce rate instability, given the current favourable water conditions that govern the ST hydro forecast for the test years.
  - The PPA Application related to the Eagle Gold Project highlights the near-term prospect of materially higher grid loads and the related increase in LTA thermal generation requirements, providing added confirmation of the material rate instability risk in moving today from LTA to ST hydro forecasts for GRA purposes.
  - The LTA forecast alternative, in combination with the DCF, adjusts to changes in water conditions without the need for new GRAs to adjust rates in response to changes in water conditions; in contrast, the ST forecast alternative presumes that a new GRA is likely to be needed as soon as water condition deterioration is forecast even relative to current favourable water conditions.
  - As reviewed in Appendix 3.4 of the GRA, the Board's 2015 decisions on the current DCF cap identified the need for an adequate DCF cap to facilitate rate stability (by minimizing the need for Rider E adjustments and to ensure adequate funds to stabilize rates during a drought). Adoption of the ST forecast alternative today would reduce the DCF's ability to facilitate rate stability: withdrawals would be needed from the contingency fund whenever water conditions increased thermal generation costs from the highly favourable ST GRA

forecast (i.e., in periods when YEC under the LTA would be making payments to the DCF, YEC would potentially be receiving payments from the fund).

- **Rate Stability Risks re: 2017-18 ST Forecast -** Compared to the LTA GRA forecast, Appendix 2.2 indicates that the ST Alternative GRA Forecast for 2017-18 has considerable risk of major increase in actual thermal generation costs from the ST forecast:
  - Specific risks are related to this ST forecast for reasons not related to water conditions, e.g., experience from 2012-2016 has shown actual annual thermal generation averaging 2.45 GW.h/year, or well above the ST forecast of approximately 1.1 GW.h in 2017 of the current GRA; and
  - Considerable separate risk is related to water conditions, i.e., there is the potential material risk that water conditions will deteriorate, and very little possibility that water conditions could be better than assumed in the ST forecast for the 2017-18 GRA.
- **Contingency Fund Requirements for ST Alternative GRA Forecasts -** Based on the inter-relationships reviewed in Section 2.4 of this Part 2 ERA Application, adoption of the ST Alternative GRA Forecast would require concurrent development, review and approval of appropriate thermal cost or contingency fund account (e.g., ST DCF) mechanisms.
  - While the DCF mechanisms are in place to support LTA forecasts for GRA purposes, no equivalent ST mechanisms are in place today for review by the Board.
  - A ST alternative thermal cost or contingency fund account mechanism would need to specify how changes in actual thermal generation from GRA forecasts can be separated into water-related changes versus changes due to load adjustments, forecast errors or other factors.
  - In summary, a ST hydro forecast version of the current LTA DCF Term Sheet table would need to forecast ST thermal generation at varying loads based on the GRA ST forecast hydro conditions.
- **ERA Requirements for ST Alternative GRA Forecasts -** the ERA mechanism for either ST or LTA forecast options would continue to be required, and to be based on YEC's final thermal generation costs after the applicable DCF or other contingency fund determinations.
  - For both ST and LTA alternatives, Yukon Energy's final thermal fuel costs for each fiscal year will be determined by implementation of the approved DCF or other contingency fund, which in turn will reflect the ST or LTA hydro forecast models adopted for the last approved GRA.
  - Actual ERA determinations in any fiscal year will be based on YEC's final thermal fuel costs for that year, without any new reference to (or running of) the ST or LTA hydro forecast model adopted for the last approved GRA.

In summary, discontinuing for the 2017 period forward a DCF based on forecast LTA water conditions (and instead relying on short-term water condition forecasts and a related ST DCF or contingency fund mechanism) would:

- Increase rate instability for ratepayers;
- Mask rather than display the expected long-term cost of power; and
- Frustrate rather than facilitate intergenerational equity and fair treatment related to the benefits provided by hydro generation over its long-term economic life.

In contrast, retaining LTA forecasts for hydro generation for the 2017 period forward, as provided for in the current GRA, adopts the approach that the Board has previously approved, and what YEC has applied for in the current GRA, in order to address rate stability objectives and appropriate LTA price signals to ratepayers. This approach also facilitates timely completion of the current GRA proceeding.

Aside from the inherent adverse rate stabilization impacts of adopting a ST forecast over a LTA forecast (especially when loads are expected to increase with new mine loads), the option of adopting a short-term forecast alternative for the 2017 period forward would not avoid the need to develop, review and approve appropriate thermal cost or contingency fund account and ERA mechanisms suited to the ST forecasts being used for GRA revenue requirement purposes.

2.6 SUMMARY CONCLUSIONS

The Part 2 filing of the ERA Application supports use for the period 2017 forward of the amended Rate Schedule 42 ("RS 42") as filed under Part 1 of the ERA Application based on the recent direction of the Yukon Court of Appeal. The amended RS 42 provides for ongoing annual ERA determination based on Yukon Energy's thermal generation costs as finalized for the fiscal year, after implementation of any DCF or other contingency fund determinations for that fiscal year.

The Part 2 filing of the ERA Application confirms for the period 2017 forward:

(a) The need for a thermal cost or contingency fund account similar to the DCF to ensure that ratepayers bear the risks related to water variability, and to provide a fund for dealing with thermal cost variability due to water variability;

(b) The important inter-relationships that exist between any such contingency fund mechanism and hydro-electric forecasts adopted for GRA purposes, including inter-relationships today between LTA forecasts and the DCF as last approved by the Board;

(c) The implementation of any such contingency fund mechanism occurs post each GRA, along with the resulting determination of Yukon Energy final expected fuel costs in each fiscal year for the actual grid load in that year; and

(d) The determination of any ERA amounts applicable to the same fiscal year occurs after determination of Yukon Energy final expected fuel costs; the ERA neither affects nor informs the hydrological forecast or the contingency fund mechanism.

In summary, Yukon Energy's Part 2 assessments for the period 2017 forward support Yukon Energy's requested approvals in the 2017-18 General Rate Application as filed in June 2017 with regard to the use of LTA hydro generation forecasts for each test year GRA purposes and ongoing use of the DCF, and highlight the issues and adverse impacts involved with the ST Alternative GRA Forecast. As such, the Part 2 conclusions allow for the current GRA to be concluded in an efficient and timely manner by continuing with LTA hydro generation forecasts rather than introducing a change to the short-term hydro generation alternative forecast as separately filed by Yukon Energy in compliance with Order 2017-08.

APPENDIX 2.1: OVERVIEW OF PAST PRACTICE & BOARD DECISIONS RE: LTA HYDRO, DCF AND ERA

APPENDIX 2.1: OVERVIEW OF PAST PRACTICE & BOARD DECISIONS RE: LTA HYDRO, DCF AND ERA

Yukon Energy and the YUB have been addressing since the early 1990s the key issues related to the use of short-term versus LTA hydro generation forecasts for GRA purposes, along with water-related thermal cost or contingency fund account issues as well as related ERA issues for wholesale rates.[7]

Past practice and Board decisions on these matters can be usefully reviewed in the context of three different time periods:

- 1990s with the Faro Mine operation (a period when mine operation in effect resulted in diesel generation accounting for 100% of any generation change due to firm load changes, and when mine closure in effect resulted in diesel generation remaining unaffected at LTA hydro conditions when firm load changes);
- 1998-2011, after the Faro Mine closure, when diesel generation was not responsive to load changes under LTA hydro conditions and DCF operation was generally suspended;[8] and
- 2012-13 GRA and subsequent years when load growth lead to LTA hydro once again being adopted for GRA purposes and the DCF resuming active operation.

Experience in 1990s leading to establishment of LTA forecasts and the DCF

Short-term hydro forecasts are subject to material change as actual water conditions unfold over any given period (particularly during summer periods). In recognition that such conditions and issues are beyond the reasonable control of the utility, any deviation of actual water conditions from a Board approved short-term hydro generation forecast for a GRA that leads to added thermal generation costs becomes a cost risk that needs to be borne by ratepayers. This in turn leads to establishment of thermal cost or contingency fund account mechanisms similar to the DCF to address variances for thermal generation costs arising from water-related hydro generation variances; such mechanisms are tied to GRA approved hydro and thermal generation forecasts, regardless as to whether such forecasts are based on short-term hydro or LTA hydro conditions.

Reliance on short-term hydro generation forecasts for GRA purposes adds considerable instability to rates over time in response to changing water conditions.

[7] History related to these matters was reviewed in considerable depth in the 2014 proceeding related to the DCF and ERA. Attachments 1 and 2 to UCG-YEC-1-2(a) reviewed Board Orders and OIC directions regarding the DCF and the ERA from 1988 to 2011, including Order 2011-15 (and Appendix A to this Order) finding that there is no interrelationship between the DCF and the Deferred Fuel Price Variance Account (DFPVA). Attachment 2 to YUB-YEC-1-2(a) reviewed the 1996 Settlement that provided for the DCF as well as June 2 and October 7, 1999 DCF filings with the Board.

[8] As reviewed in the October 7, 1999 YEC letter to the Board providing comments on the DCF, during the winter of 1998/99 (when the Faro mine was closed) actual low water conditions did result in baseload diesel being required, and the DCF was used in 1999 to address this variance. This letter emphasized the relevance of "expected diesel generation" determinations when assessing DCF calculations during that earlier time period.

Past history before the Board leading to establishment in 1996 of LTA hydro forecasts for GRA purposes and the DCF, at a time when Faro mine operations had major impacts on grid operation, provides the following guidance in this regard:

- From the outset of Board review of YEC revenue requirements in the late 1980s, it was understood that the risk of low water conditions, as regards added costs for added thermal generation, would need to be borne by the customers of the utility. Material instability in thermal generation costs due to water variability was therefore understood to pose direct challenges to the stability of rates that the Board would need to approve.
- Order 1989-4 describes (page 19) the Reserve for Contingencies for YEC of $2.250 million established at the outset by the owners of YEC (who "are in the end the people") out of retained earnings in 1987. $2 million of this amount was established to cushion the impact of increased costs to produce electricity by diesel generation at time of low water conditions and shutdowns of hydro facilities. This was established on the understanding that, based on NCPC experience and experiences in other jurisdictions, it would be appropriate for the consumers of the utilities to be paying for their own contingencies.
- Prior to the DCF being established, YEC relied upon short-term hydro generation forecasts and the Low Water Reserve Fund (LWRF) thermal cost or contingency fund account mechanism to address variance from such forecasts. At that time, the Board noted (Decision 1992-1, page 52) concern that use of the "level of lake [Aishihik] at the time the [hydro] forecast is prepared" as proposed then by YEC in its October 1991 update, rather than using a hydro generation forecast based upon the long-term average hydro generation, may lead to rate instability.
- In Decision 1992-1, the Board noted its expectation that all matters relating to the LWRF would be re-examined at the next GRA and requested YEC at that time to present evidence relating to the advantages and disadvantages of using current water levels as compared to long-term average hydro generation. This was addressed in the 1993/94 GRA filing in Response to Board Directives, Section 5 of the GRA. The Board addressed the LWRF in Order 1993-8, at pages 68-70, and agreed that under the then present circumstances (i.e., Faro mine not operating, resulting in major rate increase requirements) a reasonable drawdown of the LWRF could be done to reduce revenue requirement in the then current test years without causing undue risk to future customers.
- The 1996/97 GRA as filed jointly by the two Companies (YEC and YECL) highlighted the significant variance in water flows over the three to four prior years, the significant risk that actual Aishihik water flows would continue to be below average in 1996 and 1997, and the conclusion that the potentially large fluctuations in rates caused by variances in available water flows at the system hydro sites warranted a move to long-term average hydro generation for the purpose of determining rates. It was proposed that the LWRF be used as a Rate Stabilization Fund to absorb the annual fluctuations in available water resources without resorting to massive rate fluctuations from year to year.

The DCF was created as a result of the Negotiated Settlement at the 1996/97 GRA and was to operate in the same manner as (but in effect replaced) the earlier LWRF, except for its reliance on LTA hydro forecasts rather than short-term hydro forecasts. Hydro generation forecasts (short-term and LTA) relied on YEC's then-existing forecast models. Overall, however, LTA forecasts used for GRA purposes did not discuss potential variances in LTA hydro generation depending on total grid load levels.

The question as to why a DCF (or similar rate stabilization mechanism) is needed was reviewed in 1999 and summarized in a letter by Yukon Energy to the YUB (based on an excerpt from a report to the YUB in April 1997 prepared by the Accounting firm Stephen Johnson):

> "In certain jurisdictions, electric power is generated at hydro dams or run-of-the-river hydro operations. Low Water Reserves have been established to protect customers against short-term fluctuations in the cost of electricity when more costly sources of generation, such as diesel, are substituted for hydro generation at times of low water conditions behind the dams or in the rivers. Simply, lower than average water level conditions generally result in higher diesel generation costs…"
>
> "Given that the reserve is a vehicle for smoothing the cost fluctuations due to water level divergence from average, it is set up so that it can be drawn down to offset the costs of diesel generation in years of low water levels."

The same letter noted that "the DCF is set up so to replenish in years of high water levels. The result is better rate stability and predictability for both customers and utilities."

Historically, both the DCF and the earlier LWRF were implemented to address variances in the cost of diesel generation related solely to hydro generation variations from GRA approved forecasts that are due to hydro capability variances (e.g., water flows variances).[9] The LWRF and DCF did not address other reasons for diesel generation cost variances (e.g., neither the LWRF nor the earlier DCF addressed diesel generation cost variances from forecasts due to fluctuations in sales or overall generation requirements[10], variances in fuel prices, or variances in diesel plant efficiencies or average O&M costs per kWh).

Table A2.1-1 summarizes traditional diesel-related regulatory risk sharing relationships as established during the 1990s in Yukon.

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[9] Variances in actual diesel generation from forecast diesel generation are not included in Yukon Energy's income under these arrangements, but are accounted for by deposits to or withdrawals from the diesel contingency fund. Where diesel is less that the forecast amount included in the GRA due to higher than LTA hydro generation, the difference is charged to YEC and deposited in the diesel contingency fund (i.e., it is retained for the benefit of ratepayers in future years and is not taken into YEC income).

[10] The LWRF and earlier DCF included provision for "expected diesel" at varying grid loads and thereby ensured that actual diesel generation would be compared against "expected diesel" generation that would apply to actual grid loads. The current DCF in essence retains similar provisions to ensure that, when carrying out the DCF determinations in any year, actual diesel generation is compared with "expected diesel" applicable to the actual grid loads that occur.

Table A2.1-1: Traditional Diesel-Related Regulatory Risk Sharing Relationships in Yukon

Factors that affect diesel generation requirements	Ability to Forecast	Who carries risk for forecast inaccuracy	How is Risk Addressed
1. Fluctuation in diesel price from GRA forecast	Each utility provides a diesel price forecast for the test years; actual fuel prices may vary considerably from forecast due to volatile market conditions that are outside the utility's ability to forecast.	Ratepayers	Rider F and Diesel Fuel Price Variance Account (DFPVA)
2. Availability of water and or/ wind	Each utility provides a forecast of expected LTA hydro generation; actual hydro generation may vary considerably from forecast depending on water availability in a given year.	Ratepayers	Diesel Contingency Fund
3. Volume of interconnected grid sales	Each utility forecasts the volume of sales in GRA test years.	Utilities	Utility forecast risk
4. Location of load (line losses)	Each utility provides forecast of line losses in test years.	Utilities	Utility forecast risk
5. Operation of system	Each utility provides sales and generation forecasts based on its knowledge regarding how the system is expected to operate.	Utilities	Utility forecast risk
6. Unexpected event/ loss	Not forecastable.	Ratepayers	Reserve for injuries and damages (RFID) and insurance.

Experience in the 1990s leading to establishment of the ERA

Whereas the DCF as established in the 1990s addressed YEC diesel generation cost variance related to variable water conditions, the ERA as established during the 1990s addressed YEC diesel generation cost variance related to variances from forecast wholesale purchases.

Established in 1993, the ERA was a retrospective payment calculation integrated into the wholesale rate (RS 42) designed to ensure that YECL received a full pass-through of all incremental costs or savings of diesel generation attributable to higher or lower than forecast wholesale demand.

As with the LWRF and DCF, the ERA was only active during the 1990s when the Faro Mine operation resulted in diesel generation accounting for 100% of any generation change due to firm load changes. ERA assessments estimated wholesale impacts on YEC generation, assuming a simple relationship that did not require any new hydro generation forecast model assessments. In determining the ERA, YEC's net added costs or savings in diesel generation costs were offset by RS 42 Energy Charge revenue changes related to the same wholesale variance from forecast. The basic requirement for the ERA reflected the material variance per kW.h of wholesale in YEC thermal generation costs (fuel plus variable O&M) versus its Energy Charge, such that YEC required (when the Faro Mine was operating) an ERA mechanism in order to recover its incremental diesel generation costs related to an increase in wholesales above GRA forecasts.

Period After Faro Mine Closure: 1998-2011

Closure of the Faro Mine in 1998 lead to reduced demand and hydro surplus conditions. Diesel generation was not responsive to load changes under LTA hydro conditions.

Under these conditions, LTA hydro generation forecasts were not required for GRA purposes, the DCF was inactive (except for interest income), and the ERA was similarly not active.

2012-2013 GRA and Subsequent Years

Baseload demand increased materially on the Yukon grid in the period leading to 2012. Yukon Energy came to rely once again on diesel generation in response to baseload demands. Yukon Energy accordingly came to note a perceived need to reactivate reliance on LTA hydro generation forecasts for GRA purposes, as well as the DCF and the ERA.

As a result of higher loads, Yukon Energy's 2012-13 GRA sought Board approval to set test year revenue requirements based on LTA hydro forecasts, and to reactivate the DCF and the ERA (with proposed revisions to address changes in the Yukon system since the 1990s). Board Order 2013-1 directed Yukon Energy to reflect 100% long-term average hydro generation in calculating test year diesel generation requirements for each test year. However, a revised DCF mechanism or ERA was not approved as part of the 2012/13 GRA and a separate process was initiated in 2014 to review these matters (i.e., the DCF/ERA Proceeding). This proceeding reviewed in detail the history of and rationale for the DCF and the ERA as well as alternative approaches used in other jurisdictions.[11]

Board Orders 2015-01 and 2015-06 [following the DCF/ERA Proceeding] subsequently reactivated the DCF, with revisions to address current conditions on the Yukon grid, and approved final DCF determinations for 2012 and 2013. The ERA issues, however, lead to the appeal to the Court and reflected concerns of the Board which are separately reviewed in Section 2.3 of Part 2 of this ERA Application.

[11] See Yukon Energy Rebuttal Evidence filed on October 15, 2014 to UCG's submission regarding "evidence related to rate stabilization mechanisms approved in other jurisdictions." The UCG submission provided a five page summary of mechanisms in Northwest Territories, Manitoba, Newfoundland and Nova Scotia, and over 600 pages of attached Board Orders from the four noted jurisdictions. The Yukon Energy Rebuttal Evidence provided context for the other rate stabilization mechanisms included in the UCG submission and assessed the relevance, if any, of these other mechanisms to the current proceeding with specific regard to the DCF. The rebuttal evidence concluded that "review of the context for the Orders or filings referenced in four other jurisdictions by the UCG evidence indicates very limited relevance of this information to the current DCF proceeding," and "in the cases where fund operation for rate stabilization is actually related specifically to water variability, the evidence shows that mechanisms are context dependent and vary across jurisdictions and over time within jurisdictions in response to specific changes in, and requirements of, the operating environment."

The LTA hydro forecast for GRA purposes, and the reactivated DCF mechanisms, approved for the 2012-13 GRA differed from similar 1990 provisions in one key aspect - namely, the need in 2012-13 to estimate a changing share of incremental load (rather than an assumed zero percent applicable when the Faro Mine was operating) that is expected to be supplied by LTA hydro generation.

The DCF Term Sheet approved by Order 2015-06 accordingly provided Table 1-1 showing expected YEC diesel generation with LTA YEC hydro generation at YEC grid loads (i.e., YEC generation on the Integrated grid, excluding expected [GRA forecast] YEC wind generation and actual less expected Fish Lake hydro generation) ranging from 390 GW.h/year to 475 GW.h/year. This table showed diesel as a percentage of increased grid load going from 28% at the lowest loads to 78% at the highest loads in the specified range. The DCF Term Sheet also included provisions for Board review and approval of any changes needed in this table in response to material changes in load conditions, i.e., the addition of a major new industrial customer load to this grid.

The 2012-13 GRA LTA hydro forecasts, and the DCF Term Sheet table, were developed using YEC's YECSIM planning simulation model. As reviewed in Section 2.4 of Part 2 of this ERA Application, the Board had a range of concerns related to the YECSIM model and its prominence in the reactivated DCF - and these concerns were particularly prominent in the Board's review of the proposed reactivated ERA mechanism.

APPENDIX 2.2: SHORT-TERM HYDRO ALTERNATIVE GRA FORECAST

APPENDIX 2.2: SHORT-TERM HYDRO ALTERNATIVE GRA FORECAST

Introduction

Part 2 of the ERA Application is directed to assess any alternatives to the current LTA approach, with the related DCF and ERA. Board Order 2017-08 also directs YEC "to provide an alternative GRA forecast, using a short-term hydro-electric forecast for the test period in question and any consequential changes to the thermal generation forecast, removing any DCF references in that alternative forecast and filing the alternative forecast within 60 days of the issuance of this order".

This appendix provides an alternative GRA forecast, using a short-term hydro forecast (the "ST Alternative GRA Forecast"), in order that this alternative to the current LTA approach can be assessed in the ERA Application.

Alternative ST Hydro Forecast for Current GRA

The ST Alternative GRA Forecast for 2017 and 2018 generation assuming ST hydro generation modifies what was provided in Table 2.2 of the original GRA filing. This table provides (under "Existing Forecast") a thermal generation forecast, based on ST forecast hydro, of 1,130.0 MW.h for 2017 and 1,084.4 MW.h for 2018, excluding requirements for maintenance and capital projects (each of which is not affected by selection of ST versus LTA forecasts for hydro generation).

In summary, this ST Alternative GRA Forecast for the test years is based on the following as reviewed in Table 2.2 of the GRA:

- **ST Hydro:** The ST hydro forecast for the ST Alternative GRA Forecasts is based on the following assumptions, using YEC's ST hydro generation forecast model:[12]
  - o 2017 and 2018 forecast started with actual water levels on November 29, 2016 for all three reservoirs (Aishihik, Marsh and Mayo), and thereafter assumed LTA from 35 years of hydrology for water inflows for each month over the following 24 months, and current constrained Mayo Lake outlet and flow restrictions downstream of Mayo B. The final month of 2018 was forecast based on the ST forecast reservoir levels as at the end of November 2018.
  - o The ST Alternative GRA Forecast for 2018 differs from the ST forecast in Table 2.2 of the GRA, which assumed reservoir levels (all three reservoirs) reset as at September 30, 2017 based on latest 5-year average (2012-2016);[13] for GRA revenue requirement forecast

[12] YEC's ST hydro generation forecast model utilizes actual reservoir water levels at a specified date, long-term average assumed water inflows thereafter, current hydro generation capabilities, and forecast grid loads.

[13] This assumption in essence resets reservoirs without reliance on the ST forecast model. ST forecasts apply for up to about 18 months (in terms of reflecting current water conditions). The 5-year average as used for the September 30, 2017 reset for the 2018 ST forecast in Table 2.2 of the GRA reflects a period with water flow conditions higher than LTA. Absent such reservoir reset for the second year, the ST forecast model shows (under current favorable water conditions) materially lower hydro generation for year 2 than for year 1.

purposes it is more reasonable (as was done for the 2012-13 GRA ST forecast filings) to avoid such a reset that relies on recent history.

- **ST Thermal:** As noted in footnote 4 to Table 2.2 in the GRA, forecast ST thermal generation in Table 2.2 of 2,172 MW.h for 2017 and 2,010 MW.h for 2018 reflects ST hydro generation forecasts and the Firm Load Generation forecast at line 6 in this table, and includes forecast capital project requirements at 596 MW.h diesel generation in each test year and forecast maintenance at 446 MW.h in 2017 and 329 MW.h in 2018 (see footnote 3 to Table 2.2).
  - Excluding forecast capital and maintenance (which are unchanged for ST and LTA forecasts), the ST forecast thermal generation in Table 2.2 of the GRA is 1,130.0 MW.h for 2017 and 1,084.4 MW.h for 2018; using the adjusted ST hydro forecast for the ST Alternative GRA Forecast, this ST thermal generation forecast for 2018 is revised to 8,226 MW.h.
  - This ST thermal generation forecast in 2017 is approximately 8% of the “Proposed Forecast” LTA thermal generation (also excluding capital and maintenance) of 14,146 MW.h for 2017, approximately 57% of the “Proposed Forecast” LTA thermal generation of 14,480 MW.h for 2018.

The ST hydro forecasts were not prepared for the purpose of setting GRA revenue requirement forecasts, and there is considerable risk that actual thermal generation will be materially higher at the forecast total Firm Load Generation. Experience since 2012 has shown actual annual thermal generation (excluding capital, but not maintenance) ranging from 0.6 GW.h in 2014 (LTA thermal was 5.3 GW.h) to 5.1 GW.h in 2016 (when LTA thermal was 10.5 GW.h), and averaging 2.45 GW.h/year or 22% of LTA thermal generation over these last five years.[14] Experience in the first six months of 2017 also revealed actual thermal generation (excluding capital, RFID and maintenance) at 6,352 MW.h, well above the ST forecast in the GRA, with diesel generation at 1,968 MW.h and LNG generation at 4,384 MW.h).[15]

Alternative ST Forecast for Diesel and LNG Thermal Generation

The ST Alternative GRA Forecast as developed above does not address the allocation between diesel and LNG generation. This requirement raises new issues.

As reviewed below, the alternative ST thermal forecast as developed for the ERA Application assumes a 50/50 diesel/LNG allocation of forecast ST generation for each test year. There is a considerable risk, absent any change in the forecast total Firm Load Generation, that the diesel/LNG allocation in each test year could be very different than assumed in this alternative ST thermal forecast.

- The above ST and LTA thermal generation forecasts in Table 2.2 are each assumed in that table to be supplied 90% with LNG and 10% with diesel; however, this assumption is entirely derived

[14] See GRA, Appendix 3.5, DCF 2016 Annual Report, Table 1.
[15] See YEC DCF Quarterly Report for Q2, 2017. Response to YUB-YEC-1-39 provided total diesel and LNG generation for the first six months of 2017, including capital, RFID and maintenance (2,696.8 MW.h diesel and 4,543.8 MW.h LNG).

from the GRA assuming the LTA thermal generation forecasts to be supplied on this basis (for reasons reviewed in Appendix 3.4 of the GRA).

- No useful ST forecast is provided in the GRA of the diesel-LNG allocation for the ST forecast thermal generation. The only prior year with full year LNG generation capability showed 5,087 MW.h thermal (excluding capital and RFID, but not excluding maintenance), with 2,293 MW.h diesel (45%) and 2,794 MW.h LNG (55%)[16]; the first 10 months of 2017 showed 8,317 MW.h thermal (excluding capital, RFID and maintenance), with 3,126 MW.h diesel (38%) and 5,190 MW.h LNG (62%).
- This alternative ST thermal forecast for the ERA Application assumes a 60/40 LNG/diesel allocation of forecast ST generation for each test year. This assumption reflects the tendency for diesel generation to dominate smaller and shorter duration thermal generation, and the lack of any useful additional assessments as to a forecast allocation for each test year.
- It is apparent that there is a considerable risk, absent any change in the forecast total Firm Load Generation, that the diesel/LNG allocation in each test year could be very different than assumed in this alternative ST thermal forecast.

The ST Alternative GRA Forecast compared to the GRA LTA forecast reduces forecast fuel costs (Table 3.2) by $2.022 million in 2017 (new total fuel cost of $0.320 million) and $0.703 million in 2018 (new total fuel cost of $1.665 million), as reviewed below:

- 2017 test year - fuel cost reduction of $2.022 million (adjusted total fuel cost of $0.320 million, including $0.102 million for maintenance):
  - Forecast diesel generation is reduced by 963 MW.h (from 1,415 MW.h to 452 MW.h); at $0.2633/kW.h average diesel price, this reduces fuel cost by $253,600.
  - Forecast LNG generation is reduced by 12,053 MW.h (from 12,731 MW.h to 678 MW.h); at $0.1467/kW.h average LNG price, this reduces fuel cost by $1,768,180.
- 2018 test year - fuel cost reduction of $0.703 million (adjusted total fuel cost of $1.665 million, including $0.075 million for maintenance):
  - Forecast diesel generation is increased by 1,842.4 MW.h (from 1,448 MW.h to 3,290.4 MW.h); at $0.2633/kW.h average diesel price, this increases fuel cost by $485,100.
  - Forecast LNG generation is reduced by 8,096.4 MW.h (from 13,032 MW.h to 4,935.6 MW.h); at $0.1467/kW.h average LNG price, this reduces fuel cost by $1,187,740.

Alternative ST Forecast for Other Costs

The ST forecast thermal generation cost reductions will reduce GRA forecast working capital by approximately $0.140 million in 2017 and $0.049 million in 2018 (assumed working capital impact at approximately 6.93% of operating cost change, based on Schedule 2 of the GRA [Tab 7]).

[16] See GRA, Appendix 3.5, DCF 2016 Annual Report, Table 1.

Assuming the proposed average return on rate base of 4.81% in 2017 and 4.92% in 2018 (per Schedule 4B and 4C of the GRA [Tab 7]), forecast return on rate base would be reduced by $0.007 million in 2017 and by $0.002 million in 2018.

No other forecast revenue requirement costs in the GRA would be changed by the ST hydro alternative forecast.

Alternative ST Forecast Revenue Shortfall and Rate Increase Required

Overall, the ST hydro forecast reductions in fuel costs and return result in the following changes to the forecast revenue requirement and revenue shortfall for the GRA test years (compared to the LTA forecast as filed – Table 4.1):

- 2017:
  - Reduction in revenue requirement and revenue shortfall of $2.029 million (adjusted revenue requirement of $46.515 million).
  - Revenue shortfall reduced by 37.9%, to $3.319 million.
- 2018:
  - Reduction in revenue requirement and revenue shortfall of $0.705 million (adjusted revenue requirement of $49.159 million).
  - Revenue shortfall reduced by 10.7%, to $5.880 million.

The resulting ST hydro forecast rate increase requirements (Table 4.2) are as follows:

- 2017:
  - Overall average rate increase required of **4.58%** (vs. 7.38% with LTA GRA forecast).
  - Rider J increase of **5.61%** (vs. 9.04%).
- 2018:
  - Overall cumulative average rate increase required of **8.11%** (vs. 9.08% cumulative with LTA GRA forecast).
  - Cumulative Rider J increase of **9.92%** (vs. 11.11% cumulative with LTA GRA forecast).

Summary ST Alternative GRA Forecast

The overall ST Alternative GRA Forecast impact compared with the LTA hydro GRA forecast as proposed for 2017 and 2018 is summarized as follows:

- Reduction in test year forecast revenue requirement of $2.029 million in 2017 and $0.705 million in 2018, almost all of which relates to reduced forecast fuel costs related to the lower thermal generation with the current ST hydro generation forecast.
- Reduction of the revenue requirement under the ST hydro forecast results in a reduction of the required cumulative rate increase by 2018 by almost 11% (from 9.08% to 8.11%).

- The related Rider J increase by 2018 is reduced from 11.11% to 9.92%.

The ST Alternative GRA Forecast as reviewed above was not prepared as a proposed forecast for the purpose of setting GRA revenue requirement forecasts.[17] The following are noted in regard to considering the ST hydro forecast as a basis for setting the 2017-18 GRA test year revenue requirements:

1. The Board has previously approved LTA hydro forecasts as the basis for setting revenue requirements in order to provide long-term rate stability for ratepayers. ST hydro forecasts for the current test years reflect current very favourable water conditions, and accordingly would move rates well below the LTA revenue requirement levels required for long-term rate stability for ratepayers. The PPA Application related to the Eagle Gold Project also highlights the prospect of materially higher grid loads and the related increase in LTA thermal generation requirements, providing added confirmation of the material rate instability risk in moving today from LTA to ST hydro forecasts for GRA purposes.
2. There is considerable risk that (a) actual thermal generation will be materially higher at the forecast total Firm Load Generation than the above ST hydro forecast indicates (particularly for 2017), and/or (b) that the allocation of LNG and diesel generation will vary materially from the 60/40 allocation assumed in the ST forecast. For this reason alone, YEC would not propose the above ST hydro forecast as the basis for setting revenue requirements in the GRA test years.
3. Regardless of the hydro forecast adopted (e.g., LTA or ST), there will remain a requirement for some form of fuel cost or contingency fund account (so that variances for actual vs forecast hydro generation due to water conditions are to the account of ratepayers and not to the account of YEC, i.e., ratepayers must continue to bear the risk related to water). As directed in Order 2017-08, the ST Alternative GRA Forecast excludes any DCF references; however, as was the case with the LWRF in the early 1990s when ST hydro forecasts were last used for GRA purposes, a ST version of the DCF would be required. Some key features of a ST DCF vs LTA DCF would include:
    a. For both DCF versions, YEC's GRA rates and revenue requirement would be based on the related ST or LTA hydro forecast adopted for each test year.
    b. Under the ST Alternative GRA Forecast, rates will be lower than the LTA GRA Forecast when water conditions are better than LTA (as is the case today) and higher than the LTA GRA Forecast when water conditions are worse than LTA.
    c. For both DCF versions, YEC's final actual thermal generation costs in any fiscal year would be determined after the DCF mechanism implementation determines actual YEC thermal generation cost changes attributable to water variances from the hydro forecast selected for GRA purposes, i.e., YEC thermal generation cost changes due to such water variances from the GRA forecast would be charged to or refunded from the DCF fund.

[17] The ST hydro forecast as reviewed in this appendix also differs from the "Existing Forecasts" in the GRA as filed. The "Existing Forecast" in the GRA address the situation without a new GRA (where past GRA directions remain including the LTA forecast as last approved and related DCF elements), and as such would not change under the ST hydro forecast alternative.

- Both DCF versions today must address the extent to which forecast thermal generation, based on either LTA or ST hydro condition forecasts, varies depending of grid load levels, i.e., forecast thermal generation today under LTA or ST hydro forecasts will tend to increase, as a percent of incremental generation required, as grid load increases.
- The current DCF based on LTA hydro forecasts is able to provide a DCF Term Sheet table for Board approval during the GRA process, setting out the LTA thermal generation expected at different grid loads based on current overall annual load shape (and a revised table can be provided for Board approval in the event that material changes occur in major industrial customer loads). YEC can then apply this DCF Term Sheet table for annual DCF implementation at the end of each fiscal year.
- A ST hydro forecast version of the DCF would need to provide a similar mechanism to enable DCF implementation at the end of each fiscal year, i.e., in this case the DCF Term Sheet table would need to forecast ST thermal generation at varying loads based on the GRA ST forecast hydro conditions.

d. Overall, as noted above, the ST forecast option will tend to provide much poorer rate stabilization over multiple years than the LTA forecast option – and the DCF under the ST forecast option will not tend to develop funds to help offset adverse cost impacts from poor water conditions to the same extent as would be expected under the LTA forecast option.

4. Regardless of the hydro forecast adopted (e.g., LTA or ST), there will remain a requirement pursuant to the Court Order and OIC 1995/90 for some form of ERA mechanism as part of Rate Schedule 42, as needed to ensure that YEC can recover its actual costs of fuel (including any DCF related payments) related to supplying wholesales to AEY (and thereby deal with any variances linked to wholesales varying from the last GRA approved forecast for YEC).

APPENDIX 2.3: BOARD OUTCOMES & CONCERNS – ORDERS 2015-01 AND 2015-06

APPENDIX 2.3: BOARD OUTCOMES & CONCERNS – ORDERS 2015-01 AND 2015-06

Key relevant outcomes and concerns noted by the Board in Order 2015-01 regarding Yukon Energy's DCF-ERA applications related to the 2012-13 GRA are summarized as follows:

- **Acknowledged need for thermal cost or contingency fund mechanism to protect ratepayers from thermal generation cost changes related to variation in water or wind conditions:** The Board noted in Order 2015-01 that all parties to the proceeding agreed on the need for a mechanism that effectively protects ratepayers from diesel generation cost impacts caused by fluctuation of hydro generation due to water conditions or changes in wind conditions.
- **Determination that Diesel on the Margin was no longer part of criteria for invoking the DCF:** The Board noted that YEC had provided sufficient evidence to convince the Board that based on current loads, expected load growth and LTA hydro generation that there is a reasonable expectation that diesel or thermal generation will form part of the baseload generation. The Board noted that the question of diesel being on the margin or off the margin was effectively moot; and that diesel being on the margin was now not considered to be part of the criteria for invoking the DCF.
- **Determination that Secondary Sales availability was not a hurdle for activation of the DCF:** The Board noted that the availability of secondary sales can represent a situation where water availability diverges from LTA. However, the availability of secondary sales does not determine the application of the DCF. The Board noted that "secondary sales or diesel being on the margin are not hurdles to be overcome before the DCF is applied."
- **Acknowledgement of YECSIM Model Use for determining 2012/13 GRA forecasts and for determining DCF requirements:** The Board noted that it had previously accepted LTA hydro generation based on the YECSIM model as the basis for 2012/13 GRA forecasts; and that the use of the YECSIM model was not contested during the 2012/13 GRA. Further, the Board noted that no evidence was presented in the 2014 DCF and ERA proceeding that the YECSIM model does not operate as intended or that there would be any harm to customers if the model is used in a consistent fashion for DCF purposes.

  The Board noted that it accepts the DCF as proposed by YEC "because it is a fund for customers to smooth rate impacts for those occasions when hydro generation is less than LTA or to build up the fund when hydro generation is greater than LTA." Any application of the DCF outside of this intended use may result in the cessation of the DCF, the dispensation of any balance in the DCF, and the use of short-term forecasts for hydro generation in future GRAs.
- **Concerns regarding need for testing of YECSIM, or any other model, used for forecasting:** The Board noted that if YEC is to continue to use the YECSIM model for forecasting, the model and its results must be made available for testing by intervenors and the Board; and that providing forecasts which can be tested is essential to setting rates. The Board further specified that "Whatever model YEC uses to determine LTA hydro generation, DCF calculations or other forecast process, that model and its results or other forecast process must be made available for testing by the Board and intervenors."

- **Concerns regarding use of YECSIM Model for determining DCF amounts and ERA charges:** The Board in Order 2015-01 noted concerns raised by YECL (now AEY) with respect to the use of the YECSIM model for the DCF and its implications for the ERA, including: the complexity of the Yukon Integrated System (YIS); operational decisions which can impact line losses and consequently diesel requirements; and the complexity of the YIS environment and the ability to isolate a single variable such as water flow appears unrealistic. AEY argued that it was more efficient to test forecast to actual results versus testing the accuracy of a complex model.

  In Order 2015-01, the Board noted that "YECSIM is a planning model and does not lend itself to retrospective verification"; and that for the ERA the "Board interprets costs narrowly" and "the costs are for actual diesel generation costs, not forecast or derived costs from the YECSIM model." The Board noted the following concerns with YECSIM in this regard:

  - The Board is of the view that the results of the YECSIM model cannot be verified;
  - The YECSIM model is a planning tool and not a billing engine; and
  - Operational decisions of YEC can affect variables such as losses and in turn affect diesel generation requirements.

In Order 2015-06, the Board noted concerns regarding the "verifiability of YECSIM" and noted YECL's previously noted concerns that "due to its proprietary nature, YECSIM cannot be independently tested or retrospectively verified". The Board further noted that "concerns expressed that YECSIM has not been fully tested before the Board still stand", and that (a) YEC has not shown that the YECSIM is verifiable for purposes of the ERA; and (b) YECSIM has not been tested in this compliance proceeding.

APPENDIX 2.4: YECSIM MODEL

APPENDIX 2.4: YECSIM MODEL

YECSIM Model and User Manual Overview

YECSIM is a simulation model[18] developed specifically for Yukon Energy by a third-party engineering firm (KGS Group) to evaluate operational alternatives in terms of energy generation (hydro, thermal), environmental flows downstream of lakes, and lake elevations.[19] For 2017-18 GRA purposes, YECSIM has been used to determine LTA or expected hydro and thermal generation (over 35 water years of record) for forecast grid loads and current generation capabilities.

The YECSIM computer program consists of thousands of lines of computer code that are, for all the practical purposes, a translation of the constraints, processes and rules into a language that computers can understand.

The YECSIM model constraints, processes and rules are described in detail in non-computer language in the attached YECSIM Model User Manual. Highlights relevant to YECSIM include:

1) **Constraints -** In the case of YECSIM, constraints are related to the physical state of the system, such as maximum and minimum lake elevations, storage elevation curves of the lakes, and physical characteristics of power generation plants. Constraints are also related to environmental requirements such as, for example, minimum fish flows and meeting the electricity load.
2) **Processes** - In the case of YECSIM, the processes are related to the flow of water and they are defined by continuity equations and equations dealing with capacity of water releases from the lakes.
3) **Rules** - In case of YECSIM, the rules are related to how the water is released to meet constraints.

Access to the Model

In response to Board concerns about the YECSIM model Yukon Energy is committed to providing appropriate access to the YECSIM forecasting model for testing by interveners and the Board so that the Board's concerns can be alleviated. It is providing as part of this appendix the YECSIM user manual which will enable the Board and interveners to review fully the constraints, processes and operational rules of this model for testing and assessment.

[18] Simulation is an approach in a decision-making process that evaluates a large number of alternatives defined by decision-makers and presented to the model for evaluation. Simulation models can be used to measure the performance of alternatives under considerable flexibility and a high degree of realism supplied by decision-makers. This method requires decision-makers to have comprehensive knowledge of the topic to ensure the correct selection of a single option from a potential field of options. It provides an insight into potential outcomes using a variety of predefined conditions.

[19] Appendix 3.4 of the 2017-18 GRA provided updated information on YECSIM assumptions and use for the current GRA, including Attachment 3.4.3 information on the model itself. As reviewed in Attachment 3.4.3 of YEC's 2017-18 GRA, the simulation model develops expected hydro plant capabilities for each load forecast scenario. It reviews, by week, information for available "water years" of record (2017-18 GRA forecasts used 35 water years, 1981-2015) and simulated hydro generation for a specified grid load over the range of all possible sequence combinations (cycles) of the water years. The long-term average thermal energy generation estimates as provided by YECSIM reflect averages of widely varying annual water flow conditions, and the long-term average thermal energy generation estimate varies as YEC grid loads vary. Hydro generation in any one year can vary greatly from the long-term average estimated.

Yukon Energy would then welcome the opportunity to review any further access to the model that would assist the Board and interveners, including potential workshop or other discussion process for review of its specific use (inputs and outputs) for the 2017-18 GRA forecasts and the updated Appendix 3.4, DCF Term Sheet Table 3.4-1.

User Manual for YEC System Simulation Software

November 2017

KGS Group Project: 08-1404-04

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Disclaimer: *This software has been developed methodically and checked as thoroughly as practical. However, KGS Group provides no assurance that every conceivable aspect of the model has been verified under all possible applications.*

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1.0 INTRODUCTION

1.1 HISTORY

Yukon Energy Corporation (YEC) approached KGS Group in 2007 to prepare a plan for preparation of a numerical model that could be used for analysis of the operation and future expansion of the YEC electrical generating system. KGS Group submitted a proposal and approval was granted in June 2008 to proceed. A working model was available by October 2008. It was then used in late 2008 and early 2009 to evaluate various optional expansion scenarios, particularly including the expansion of the Mayo Hydroelectric Generating Station (so-called Mayo B Development).

The model was submitted to YEC in December 2008, but the User's Manual could not be completed until additional funding was approved in 2009.

The current version of the User's Manual contained herein is considered as a ***second draft*** that incorporates refinements required after use of the model. Further refinements are expected as part of the model development.

The software has been called "YECSIM" in this manual.

Any questions or requests regarding this software should be directed to Rick Carson at KGS Group at (204) 478-3237, cell (204) 250-7560, or at email address <rcarson@kgsgroup.com>.

1.2 OBJECTIVES OF YECSIM

The software is intended to be used to assess the potential performance of YEC's energy generating system under a range of conditions, including:

- Seasonal hydrological cycles.
- Varying cycles of runoff from drought to flood.
- Increased system loads, and load distribution throughout the year.
- Variations in license limits of water levels on Marsh Lake, Schwatka Lake, Aishihik Lake, Canyon Lake Mayo Lake, and Wareham Lake.

- Varying configurations of the power system with or without new additions.
- Varying assumptions of the performance of existing plants to suit plans for upgrades.

The software is intended to estimate the generation of hydroelectric energy, diesel, bio-mass, liquefied natural gas (LNG) and wind generated energy for the conditions requested by the user. Tabular and graphical output is produced with the objective of providing the user with a range of understandable results of the simulations requested.

1.3 OVERVIEW OF SOFTWARE

The initial development of the software had the vision of simulating the gradual increase in load demand over a series of decades, with a variety of combinations of hydrological conditions from drought, to normal, to flood. However, it became apparent that due to the unpredictable nature of the future load characteristics with new mines, a methodical comparison of system performance for varying assumptions of plant additions would be impractical.

The software was then modified to address a single load scenario for one load year that is defined by the user. This would form a "snapshot" of a hypothetical future situation, and allow a consistent comparison of the performance of the generating system under differing assumptions of generating capability.

The software is now configured to address this one load scenario, provided in terms of a total annual energy demand. That demand is distributed over an entire year using weekly factors to define weekly energy loads that total to the assumed energy demand.

The software focusses on the deployment of the hydroelectric resources available to YEC, and details on the effective use of the software to simulate that resource are provided in this manual.

The primary alternate source of energy is diesel generation plants. However, the latest version of the software also includes other non-hydro resources, including wind, bio-mass and LNG generation. The latter two non-hydro resources can be defined as non-dispatchable (i.e. base-loaded under the load duration curve), as well as dispatchable, which can be displaced if there is adequate hydroelectric generation to allow that. Details of the user instructions for the nonhydroelectric generation is not yet included in this manual and has been reserved for future refinements after more extensive trials of the latest version have been possible by YEC staff.

The simulation represents a series of the same load "years" (8 in total), and superimposes all the possible combinations of historical flow records over those repeated load years to allow a representation of the hydrological variability that could occur. Eight years are simulated, but only the sixth and seventh years are actually used for the simulation results. The five initial years are needed so that the assumptions of the starting volume of water in the reservoirs will not affect the results. Similarly, the amount of reservoir volume left at the end of a simulation could also influence the comparison of runs. To minimize this effect, the system simulation is extended for one more year after the years used to represent the typical system operation and performance.

The results for the full simulation of the eight load years is available for review by the user, as well as summaries for the sixth and seventh years that can be used for systematic comparisons of one system configuration to another. The primary summary of the results is provided in a graphical output whose general form is demonstrated in Figure 1.1. By default, the program shows these results for the sixth and seventh years. The user can select the load years to be displayed in this graphical output.

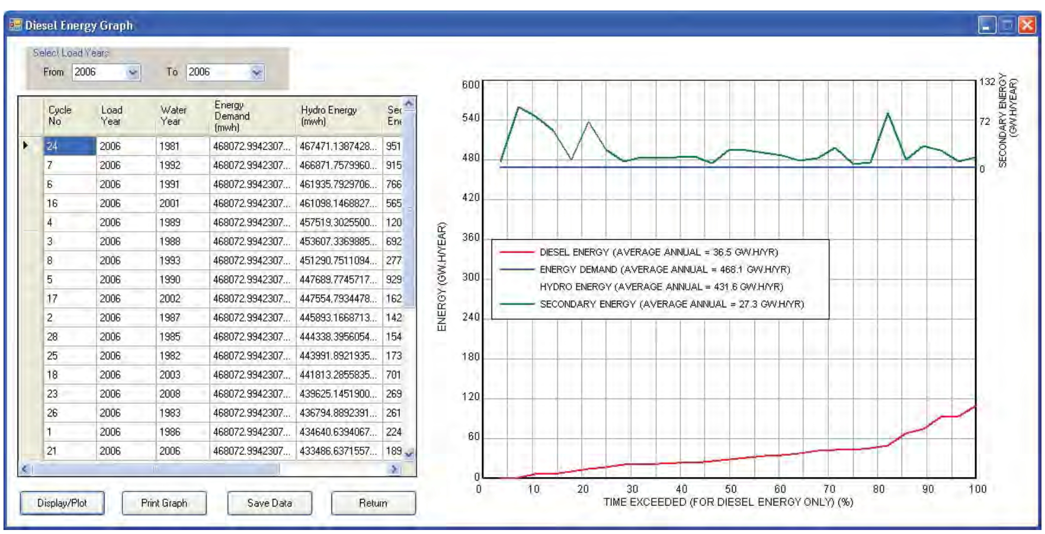


Figure 1.1 – Graph of Diesel Energy Output – Summary of Typical Simulation

A wide variety of other graphical and tabular displays can be requested by the user, as well as tabular output that can be imported conveniently into spreadsheets and analyzed as desired by the user.

The software was originally prepared in the FORTRAN programming language, but was converted to VISUAL BASIC to better suit the needs of the Graphic User Interface (GUI) and database.

2.0 INSTALLING YECSIM

2.1 SYSTEM AND DISPLAY RECOMMENDATIONS

The computer that is used for the system simulation has to meet the following requirements:

- System Requirement – The computer must have the minimum of 1GB of disk space and 512 MB of RAM. If the system configuration of the computer is less than the system requirement, the YECSIM program may not run properly.
- Display Requirement – The computer screen must have the minimum resolution of 1280 x 1024. If the resolution of the computer screen is less than the display requirement, the YECSIM Graphical User Interface will not be properly generated.

YECSIM has been successfully tested in the following platforms:

PLATFORM	CPU/MODEL	TESTED ON	SHOULD ALSO WORK ON
Windows®	x86	Windows XP® Service Pack 2	Windows Server 2003, Other Versions of Windows Vista
Windows	x64	Windows XP® x64 Service Pack 2	Windows Vista 64 Windows Server 2003

2.2 WINDOWS INSTALLATION PROCEDURES

The installation procedures under Windows operating systems are as follows:

1. Insert the YECSIM CD/DVD into the CD/DVD drive of the computer.
2. Create a folder YECSIM on C-Drive of the computer.
3. Navigate to the YECSIM directory of the CD/DVD and copy the whole contents for the CD/DVD to C:\YECSIM. Please make sure the folder name and path are correct, otherwise the software will not work properly after installation.
4. Double–click the setup.exe file in C:\YECSIM and follow the install directions on the screen. Once the installation process is completed, the user interface of YECSIM will appear as shown in Figure 3-1 (see Section 3). If a previous version of YECSIM is on the computer, please uninstall it in advance, following the procedure described in Section 2.3.

2.3 2UNINSTALL PROCEDURES

The YECSIM Setup program automatically registers the software with the Windows operating system. The uninstall procedures are as follows:

1. Select the Control Panel from the Start Menu.
2. Select Add/Remove Programs from the Control Panel.
3. Click the Change or Remove Programs button and select the YECSIM program from the list of installed software, then click the Change/Remove button.
4. Follow the uninstall directions on the screen and the software will be removed from the hard disk.

2.4 TECHNICAL SUPPORT

If any difficulties are encountered during the installation, please contact KGS Group (see Section 1 for contact name and coordinates).

3.0 WORKING WITH THE YECSIM GRAPHICAL USER INTERFACE

3.1 STARTING THE YECSIM GRAPHICAL USER INTERFACE (GUI)

To initiate the program YECSIM from Windows, select **Start -> All Programs** and click **YECSIM->YECSIM**. The main window of the YECSIM GUI will then appear as shown in Figure 3.1. The main menu bar is located on the top of the YECSIM main window, and below the title bar (Figure 3.1). When one of the menus is selected, a group of additional submenus will be displayed. The main menus and submenus are described in Table 3.1.

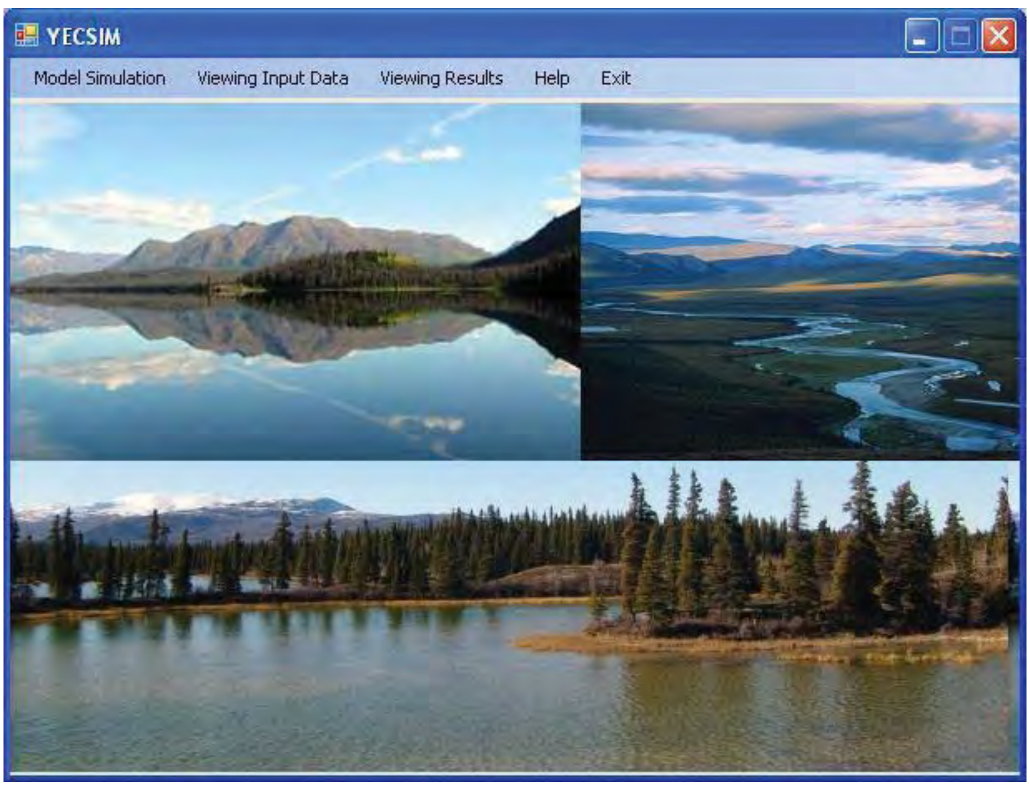


Figure 3.1 – The Main Window

Table 3.1 – Description of the Main Menus and the Submenus

MENU AND SUBMENU NAME	PURPOSE
Model Simulation	
Import Input Data	Imports input data from a file
Modify Input Data	Modifies input data
Lake/Reservoirs	Modifies input data for lakes or reservoirs
Generating Stations	Modifies input data for generating stations
Energy Data	Modifies input data related to energy load, diesel capacity and wind energy
Simulation	Starts a simulation
Viewing Input Data	
IAO Data	Views inflow available for outflow (IAO) data
Rating Curves	Views spillway rating curves (stage-discharge relationships)
Energy Inputs	
Energy Demand	Views energy demand data
Diesel Capacity	Views diesel energy data
Wind Energy	Views wind energy data
Year Load Factors	Views prorating factor for energy load demand of each week
Weekly Duration Curve	Views the energy load duration curve in a week
Powerhouses	
Turbine Maximum Flows	Views the turbine maximum discharges
Winter Effects	Views winter ice effects on the tailwater level
Reservoirs	
Operational Conditions	Views the maximum operation level for Marsh Lake
Riparian Flows	Views riparian flows

MENU NAME	PURPOSE
Viewing Result Data	
Imports Result Data	Imports result data from a file for a previous run
View Result Data at Each Site	Views results at each reservoir/lake/generating station
View Energy Data	Views energy results
Energy Summary	
Total Energy by Plants	Views the energy generated from each plant, energy load and diesel energy required
Hydro Energy by Plants	Views the energy generated to serve load from each plant
Secondary Energy by Plants	Views the potential secondary energy generated from each plant
Diesel Energy Graph	Views the estimated diesel energy generation
Rule Curves	Views rule curves (for explanation of rule curves see Section 6)
Advanced Query	Creates a data query using Microsoft Access Query Language (for users who are familiar with Microsoft Access)
View Warnings	Views the warnings produced from the simulation
Help	
User Manual	Links to the user manual
About YECSIM	Shows the About Window
Compact Database	Minimizes the size of the database used in YECSIM-MTM
Exit	Exits the program

3.2 MODEL SIMULATION

3.2.1 Overview

The ***Model Simulation*** menu (Figure 3.2) is used to set up and run a simulation. The steps to do that are as follows:

1. If there is an input file that has been prepared for the simulation, it can be imported using the ***Import Input Data*** submenu**.** If the input file is not ready, go to Step 2.
2. Edit the input data using the following sub-submenus under the ***Modify Input Data*** submenu:
   - Lakes/Reservoirs
   - Generating Stations

- Energy Data

3. Start a simulation using the ***Simulation*** submenu.

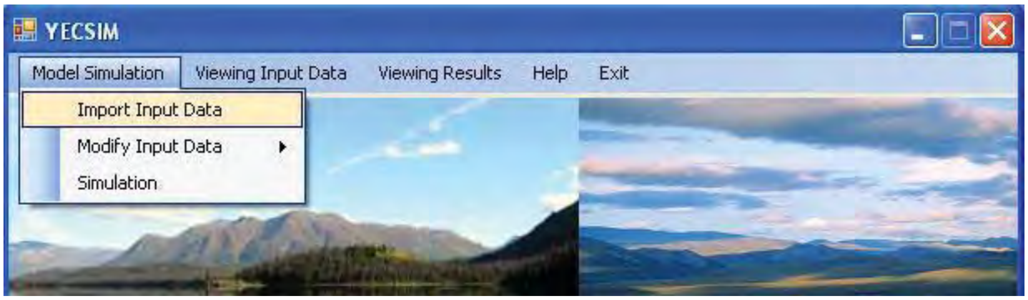


Figure 3-2 - The Menu – Model Simulation

3.2.2 Import Input Data

There is a database included in the YECSIM program. The database was designed using Microsoft Access, and is used to store the input data and the model results for a simulation. When the user starts YECSIM, the input data and model results from the previous run will be automatically loaded from the database to the YECSIM GUI. If the user wants to use different input data, it can be imported from a text file using the Import Input Data submenu. The format of the input file is described in Section 4. The steps to load an input file are as follows:

1. Click the *Import Input Data* submenu (Figure 3.2), and a dialog box will appear as shown in Figure 3.3.
2. Select a file from the dialog box and click the *Open* button to import all input parameters included in the selected file to YECSIM.

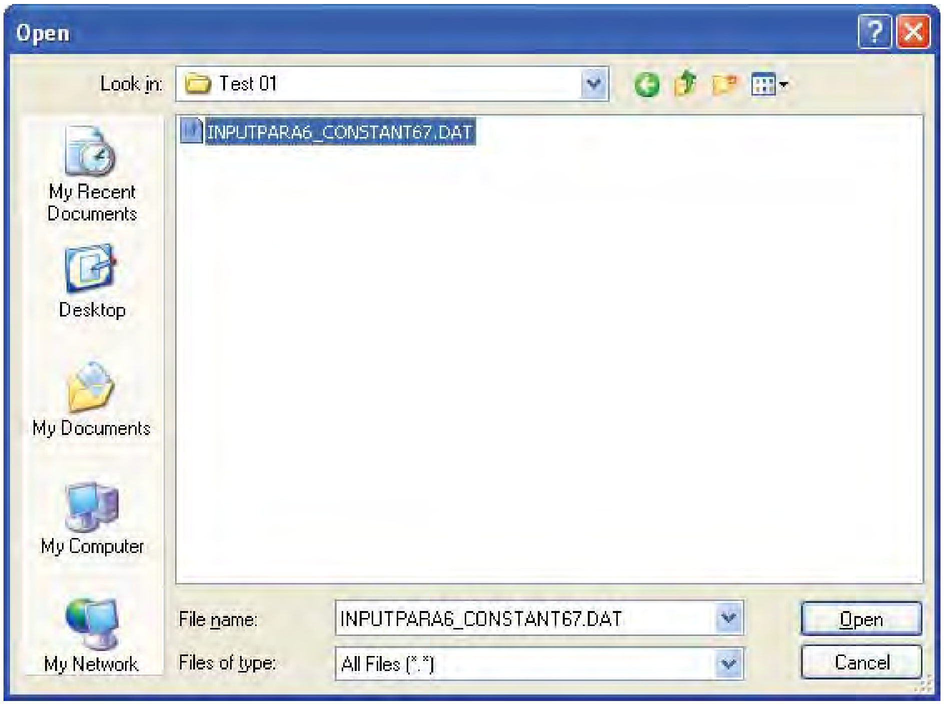


Figure 3.3 – The Dialog Box to Open a File

3.2.3 Modify Input Data

The ***Modify Input Data*** submenu as shown in Figure 3.4 is used to edit input data. Under the ***Modify Input Data*** submenu, there are three sub-submenus:

- Lakes/Reservoirs
- Generating Stations
- Energy Data

Figure 3.4 – The Submenu – Modify Input Data

3.2.3.1 Lakes/Reservoirs

If the user clicks the ***Lakes/Reservoirs*** sub-submenu, a window as shown in Figure 3.5 will appear. This is the ***Edit Input Parameters for Lakes/Reservoirs*** window. The left side of the window is the tab region used for editing reservoir parameters (also see Figure 3.13). The right side of the window consists of a table and 4 buttons.

The table on the right side of the window is used to display and to edit data. The type of data is selected in the left side of the window. The steps to modify data from the table are as follows:

1. Check the check box to indicate the data type (Figure 3.13).
2. Click the ***List*** button (Figure 3.5). The corresponding data will be listed in the table.
3. Double click a cell in the table.
4. Change the data value in the cell. Some columns may be locked and cannot be changed due to requirements of the YECSIM database. In those cases, there are other means to modify the data either directly in the GUI or by importing data files.
5. Click the ***Add/Save*** button to save changes.

The buttons shown under the table, in the right side of the window, are described below:

- **Add/Save Button**

The ***Add/Save*** button is used to add or save the input data in YECSIM:

- **List Button**

The ***List*** button is used to display data in the table. If the user selects a data type by checking a check box and click the ***List*** button, the corresponding data will be listed in the table:

- **Go to G.S. Button**

The ***Go to G.S.*** button is used to exit the current window and open the window as shown in Figure 3.12:

- **Return Button**

The ***Return*** button is used to return to the main window (Figure 3.1).

The tab area in the left side of the window (Figure 3.5) is used for selecting among the available lakes/reservoirs. This tab is designed as a notebook organized into 6 sub-tabs as described in Table 3.2. The user must work through the sub-tabs to set input data for each lake. The corresponding windows have a similar system of displaying data and are shown in Figures 3.5 to 3.12.

Table 3.2 – Descriptions of the Sub-tabs for Lakes/Reservoirs

SUB-TAB TITLE	PURPOSE
Marsh Lake	Edits input data for Marsh Lake (Figure 3.5)
Aishihik Lake	Edits input data for Aishihik Lake (Figure 3.6)
Mayo Lake	Edits input data for Mayo Lake (Figure 3.7)
Schwatka Lake	Edits input data for Schwatka Lake (Figure 3.8)
Canyon Lake	Edits input data for Canyon Lake (Figure 3.9)
Wareham Lake	Edits input data for Wareham Lake (Figure 3.10)
Gladstone Diversion	Edits input data for Gladstone Diversion (Figure 3.11)
Atlin Lake	Edits input data for Atlin Lake (Figure 3.12)

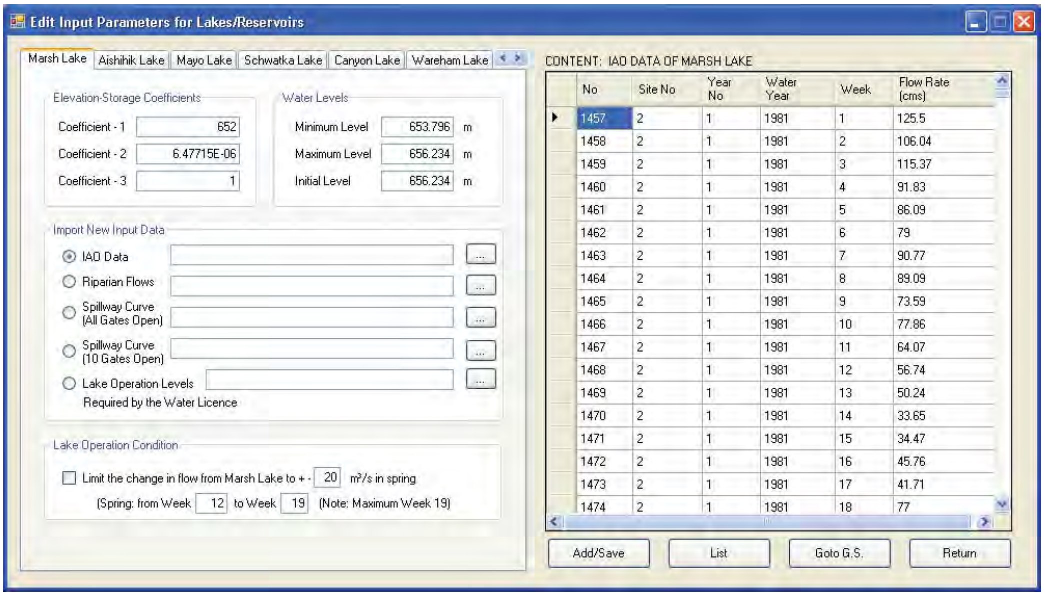


Figure 3.5 – Edit Input Data for Lakes/Reservoirs

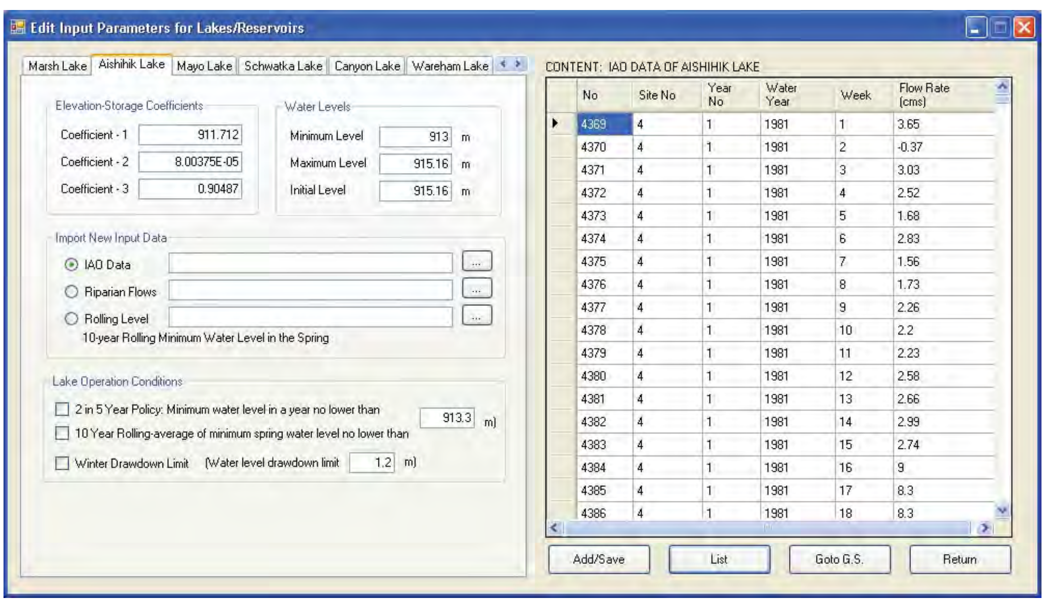


Figure 3.6 – The Active Sub-tab for Aishihik Lake

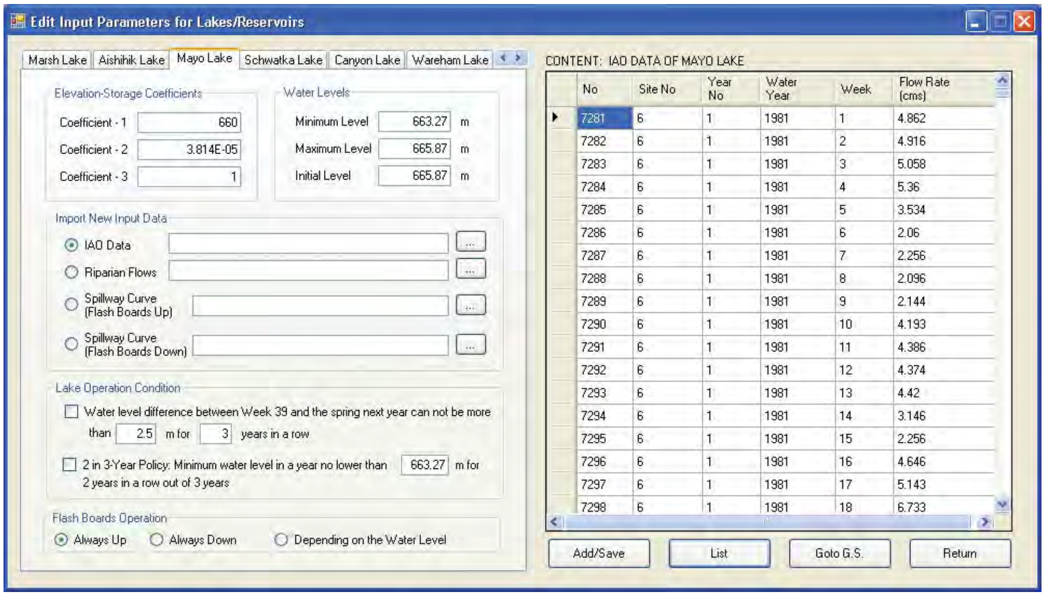


Figure 3.7 – The Active Sub-tab for Mayo Lake

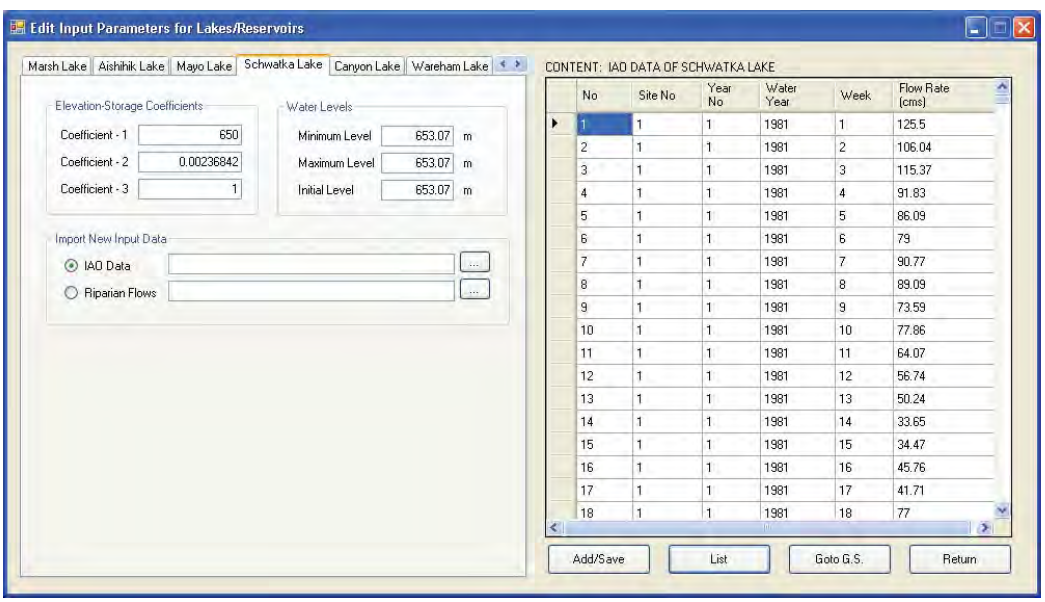


Figure 3.8 – The Active Sub-tab for Schwatka Lake

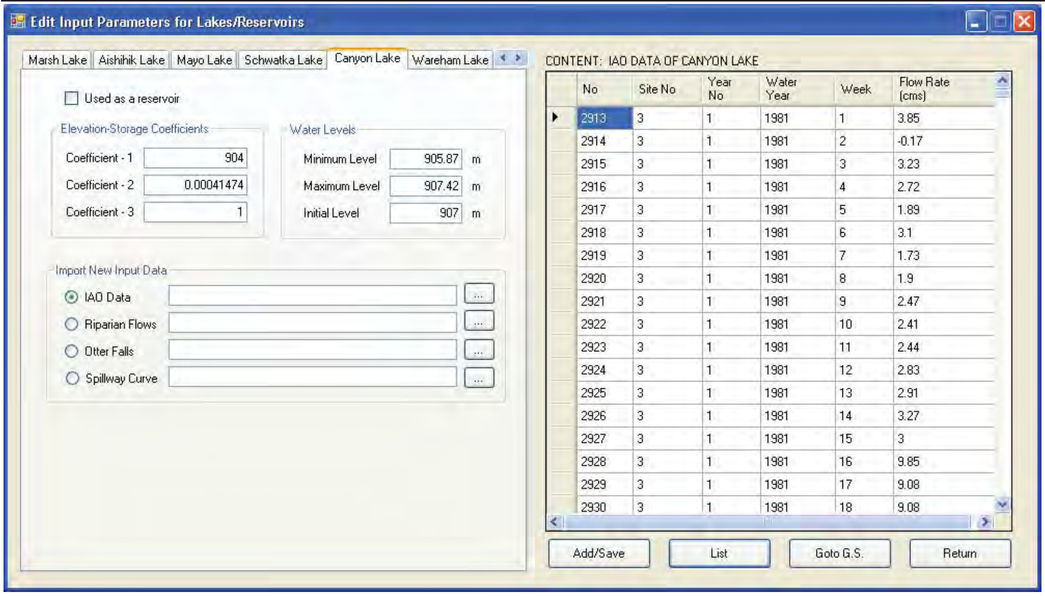


Figure 3.9 – The Active Sub-tab for Canyon Lake

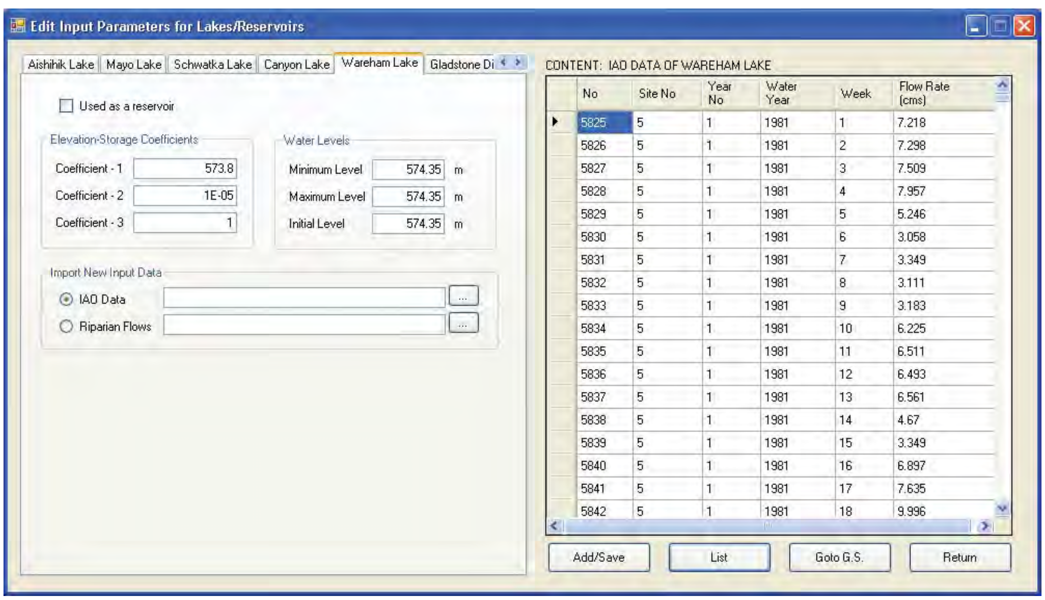


Figure 3.10 – The Active Sub-tab for Wareham Lake

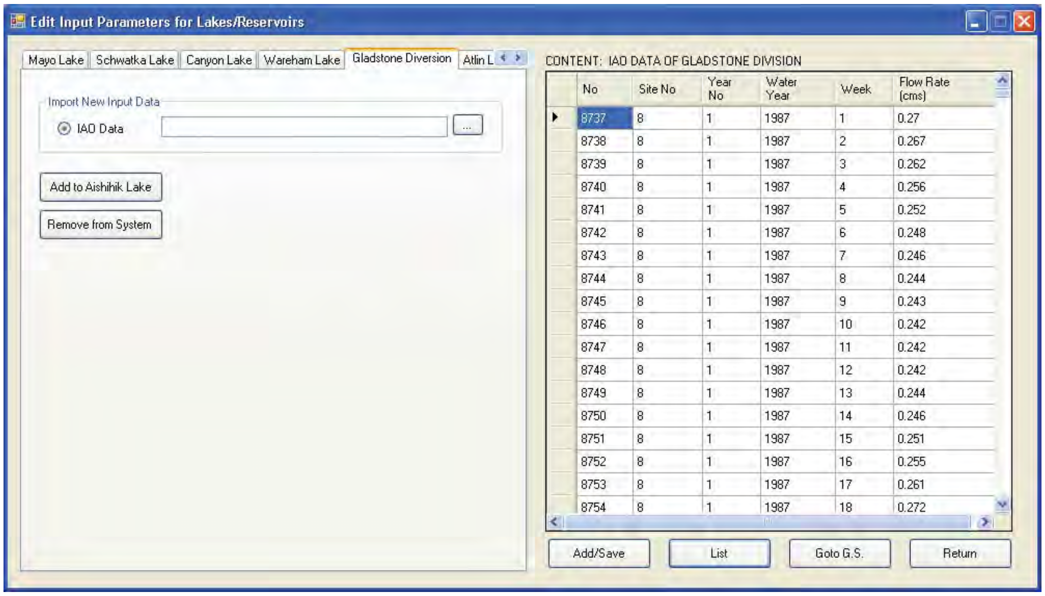


Figure 3.11 – The Active Sub-tab for Gladstone Diversion

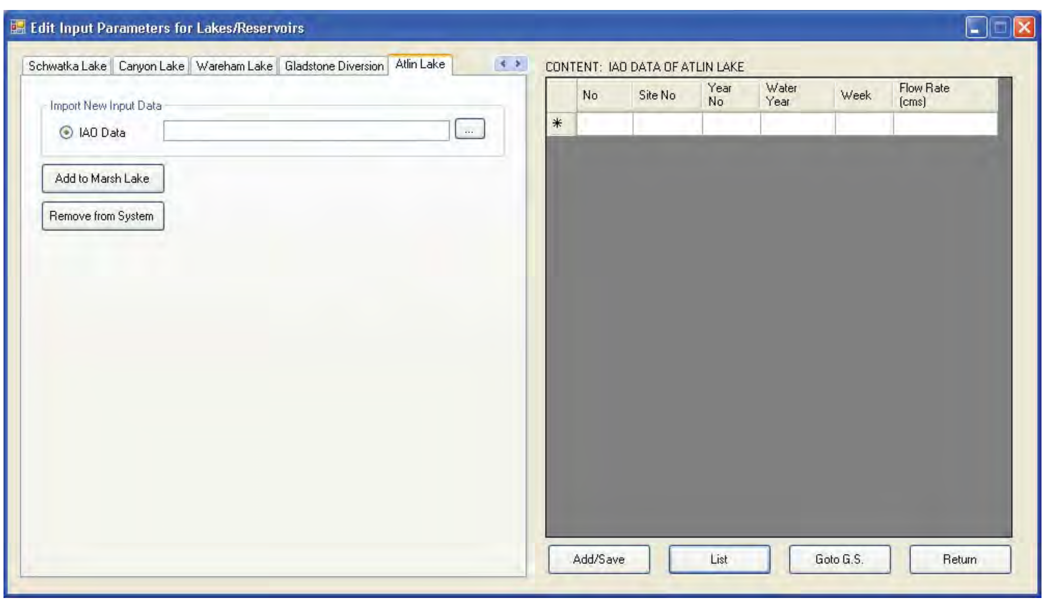


Figure 3.12 – The Active Sub-tab for Atlin Lake

The left side of the ***Edit Input Parameters for Lakes/Reservoirs*** window includes data required to define:

- The reservoir's volume, as an Elevation-Storage curve.
- Its hydrologic input as Inflows Available for Outflow (IAO), defined in Section 6.0 of this manual.
- Its initial water level.
- Its operational conditions in terms of water level and outflow constraints as defined in the corresponding water licenses.
- And in some cases, operational conditions that have been incorporated in the program.

These data are organized in groups and are defined in the following paragraphs.

Elevation-Storage Coefficients

The ***Elevation-Storage Coefficients*** group is used to edit the coefficients for calculating the storage volume for each lake. Generally, the relationship between elevation and storage volume for a lake is as follows:

$$E = C_1 + (C_2 \bullet S^{C_3}) \qquad (3\text{-}1)$$

Where:

E	=	the lake water elevation (m)
S	=	the lake storage corresponding to E (m^3/s-hour)
C_1	=	the equation coefficient 1 (the ***Coefficient-1*** text box in Figure 3.5)
C_2	=	the equation coefficient 2 (the ***Coefficient-2*** text box in Figure 3.5)
C_3	=	the equation coefficient 3 (the ***Coefficient-3*** text box in Figure 3.5)

Water Levels

The ***Water Levels*** group is used to set the water level requirements of a reservoir/lake.

- ***Minimum Level*** text box: the minimum level required by the operation policy.
- ***Maximum Level*** text box: the maximum level required by the operation policy.
- ***Initial Level*** text box: the initial water level at the start of a simulation.

Import New Input Data

The ***Import New Input Data*** group is used to import data of different types from text files. The description of the data files for all sub-tabs (Figures 3.5 to 3.12) is listed in Table 3.3 and their format is shown in Appendix A. The steps to import new input data from a text file are:

1. Check a check box to indicate the data type (Figure 3.13).
2. Click the corresponding ***Browse*** button [...] to find a file using the open file dialog box as shown in Figure 3.3.
3. After finding and selecting a file, click the Open button on the dialog box. The file path and name should appear in the text box between the check box and the Browse button. The user can also type the file path and name in the text box.
4. Click the ***Add/Save button***. The input data will be imported into YECSIM and listed in the table (Figure 3.5).

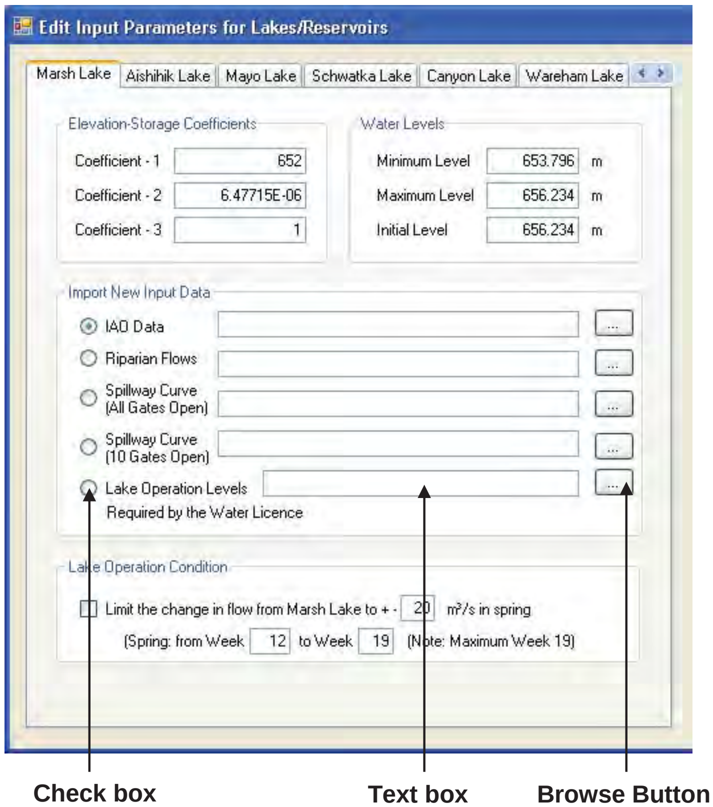


Figure 3.13 – The Left Side of Figure 3.5

Table 3.3 – Description of Input Data Files

DATA FILE TYPE	DESCRIPTION	FORMAT INDEX
IAO Data	Inflow-available-for-outflow data in all water years	Appendix A-1
Riparian Flows	Riparian flow data in a year	Appendix A-2
Spillway Rating Curves	Spillway rating curve data	Appendix A-3
Lake Operation	Water levels required by the operation policy	Appendix A-4
Rolling Level	Spring water levels in the latest 10 years	Appendix A-5
Otter Falls	Minimum flow rates past Otter Falls in a year	Appendix A-2
Turbine Maximum Flow	Turbine maximum allowable discharges	Appendix A-2
Mayo B G.S. Minimum Flow	The minimum flow required at Mayo B G.S.	Appendix A-2
Winter Effects to Tailwater Level	The increase in tailwater level due to winter ice effects	Appendix A-6
Energy Load	System energy demand per load year	Appendix A-7
Diesel Energy	Diesel energy generator capacity per load year	Appendix A-8
Weekly Load Duration	Factors of weekly energy load distribution in each year	Appendix A-9
Load Duration Curve	Energy load duration curve in a week	Appendix A-10
Wind Energy	Weekly Wind Energy in each Year	Appendix A-11

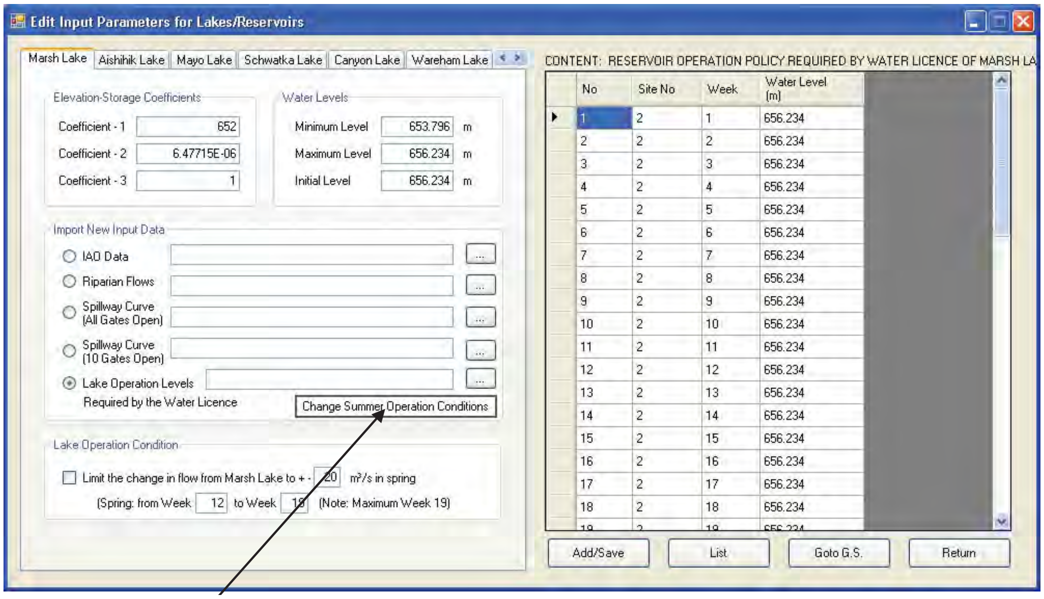
Operation Conditions for Marsh Lake

The sub-tab ***Marsh Lake*** (Figure 3.5) allows modifying the operation conditions for Marsh Lake that are used during the simulation. Summer and spring conditions can be applied, as follows:

- **Summer Operation Conditions**

The license constraints for Marsh Lake require full or partial opening of the gates at the Lewes Dam, during the summer. This depends on the time (week) and the water level in the lake. The default values for these conditions correspond to the current water license (Appendix E); but can be modified for simulation purposes, following these steps:

1. Select the Tab for Marsh Lake (Figure 3.5)
2. Check the check box for ***Lake Operation Levels*** in the ***Import New Input Data*** frame group. The ***Change Summer Operation Conditions*** button will appear as shown in Figure 3.14.



Change Summer Operation Conditions Button

Figure 3.14 – Button for Setting the Summer Operation Policy at Marsh Lake

3. Click the ***Change Summer Operation Conditions*** button and a new window, as shown in Figure 3.15, will appear.

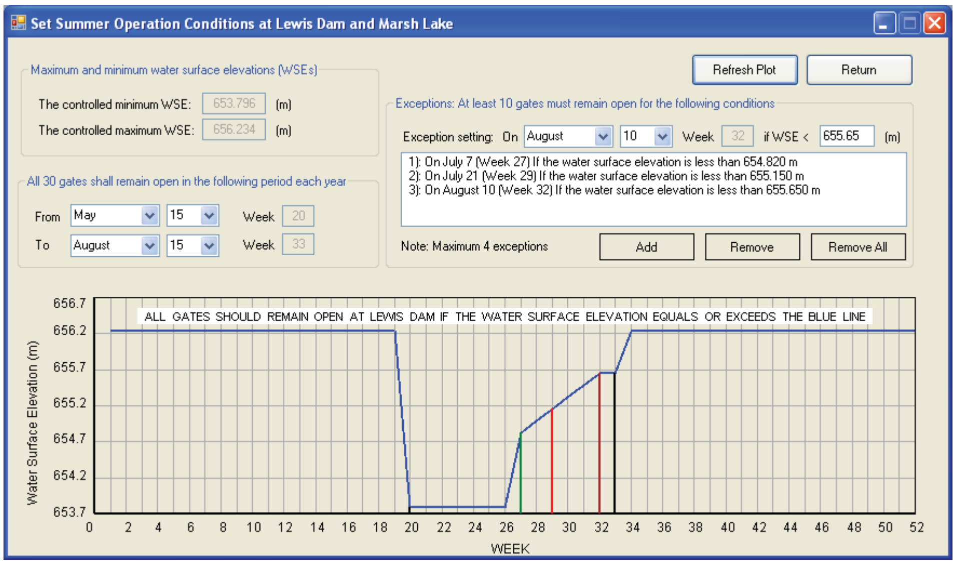


Figure 3.15 – Define the Summer Operation Policy at Lewes Dam and Marsh Lake

4. Click the ***Refresh Plot*** Button to see the graph on the window for the existing summer operation conditions at Lewis Dam and Marsh Lake (Figure 3.15).

The upper left portion of the window is the group frame "***Maximum and minimum water surface elevations (WSEs)***" (Figure 3.15). It shows, for reference, the values selected in the ***Edit Input Parameters for Lakes/Reservoirs*** window for minimum and maximum water levels on Marsh Lake. The group frame "***All gates shall remain open in the following period each year***" allows setting the period in which all the 30 gates in Lewes Dam are required to be open.

5. Select the month and day for the application of the summer operation conditions. By selecting the corresponding month and day, the weeks for the start and end of this period will be calculated automatically.

It is important to note that during the period defined in this group frame, the model simulates the Lewes Dam with either 30 gates open or 10 gates open, depending on the conditions set in Step 6. No intermediate values of gate opening can be simulated.

The upper right part of the window is the group frame "Exceptions: At least 10 gates must remain open for the following conditions" (Figure 3.15).

6. Select the exceptions to the requirement of maintaining 30 gate opens during the summer in the group frame "***Exceptions: At least 10 gates must remain open for the following conditions***". These are conditions (dates and lake levels) for which only 10 gates would remain open at the Lewes Dam. This group frame is used as follows:
   - By selecting the exception month, day and the critical water surface elevation and clicking the Add button, an exception should be added and shown in the list box.
   - By selecting an exception in the list box and clicking the Remove button, the selected exception can be removed.
   - The ***Remove All*** button allows deleting all exceptions.

7. Click the ***Return*** Button to return to the window "***Edit Input Data for Lakes/Reservoirs***" (Figure 3.14).

   - **Spring Operation Conditions (Outflow Limit from Marsh Lake in the Spring)**

The lower portion of the "*Edit Input Data for Lakes/Reservoirs*" window is the *Lake Operation Conditions* group frame. It allows limiting the week-to-week variation of the flows released from Marsh Lake to a specified value, for a given period in the spring. By default, the week-to-week flow variation limit is 20 m^3/s, the starting week is Week 12 and the final week is Week 19. The final week is hard wired in the program not to be later than Week 19.

To activate this condition, the user should check in the check box and enter the flow limit, the start week and the end week in the text boxes located in the group frame.

To remove this condition, the user needs to check out the check box.

<u>**Lake Operation Conditions for Aishihik Lake**</u>

On the sub-tab ***Aishihik Lake*** (Figure 3.6), there is a group frame for setting Aishihik Lake operation policies. The following 3 conditions can be applied on Aishihik Lake during a simulation:

- **2-in-5-year Minimum Lake Level Policy:**

The minimum water level in a year cannot be lower than the defined water level more than 2 years in a 5-year period.

To activate this policy, the user should check in the check box and enter the minimum water level in the text box.

To remove this condition, the user should check out the check box.

- **10-Year Rolling Average of Minimum Levels**

  The 10-year rolling average of minimum water levels (average of the minimum values for the last ten years, including the current year) cannot be less that a given value.

  To activate this policy, the user should check in the check box and enter the minimum water level in the text box.

  To remove this condition, the user should check out the check box.

  Note that the 2-in-5-year and the 10-year rolling average rules are not to be used simultaneously. The same box is used for the water level used to define either policy.

- **Winter Drawdown Limit**

  The difference between the maximum lake level in weeks 40 to 44 of a year and the minimum level in the period from week 45 of that year and week 17 of the following year shouldn't be less than the value entered in the text box.

  To activate this policy, the user should check in the check box and enter the winter drawdown limit in the text box.

  To remove this condition, the user should check out the check box.

Lake Operation Conditions on Mayo Lake

On the sub-tab ***Mayo Lake*** (Figure 3.7), there is a group frame for setting Mayo Lake operation policies. The following 2 conditions can be applied on Mayo Lake during a simulation.

- **Winter Drawdown Limit**

  The water level difference between Week 39 in a year and Week 17 in the following year cannot be more than the specified value for a number of years in a row. For example, the rule can be that the winter drawdown cannot exceed 2.5m for 3 years in a row.

  To activate this policy, the user should check in the check box, and enter the water level limit and the number of years in the text boxes located in the group frame.

  To remove this condition, the user should check out the check box.

- **2-in-3-year Minimum Lake Level Policy:**

  The minimum water level in a year cannot be lower than the defined water level for more than 2 years in a 3-year period.

  To activate this policy, the user should check in the check box and enter the minimum water level in the text box.

  To remove this condition, the user should check out the check box.

Flashboard Operation on Mayo Lake

On the sub-tab ***Mayo Lake*** (Figure 3.7), there is also a group frame for setting the operation policy for the flashboards in the Mayo Lake control structure. There are 3 options:

- **Always Up:** The flashboards are always up during a simulation.
- **Always Down:** The flashboards are always down during a simulation.
- **Depending on the Water Level:** The flashboards are automatically adjusted (up or down) depending the water level changes during a simulation.

The latter option corresponds to maintaining the flashboards up unless later in the simulation, this operation would result in the water overtopping the flashboards. It implies for the program that there is perfect foresight of future inflows, and tries to mimic what YEC operators could do based on experience at the site. The default option, in the program, for flashboard operation policy is ***Always up***.
To activate one option, the user should check the corresponding option box.

Canyon Lake

The default simulation setting is that the water levels in Canyon Lake are constant during the simulation. The sub-tab ***Canyon Lake*** (Figure 3.9) includes the check box "***Used as Reservoir***", which allows simulating the operation of Canyon Lake as a reservoir, in which case its water level fluctuates as a function of volume, inflows and outflows.

Wareham Lake

The default simulation setting is that the water levels in Canyon Lake are constant during the simulation. The sub-tab ***Wareham Lake*** (Figure 3.10) includes the check box "***Used as***

Reservoir", which allows simulating the operation of Canyon Lake as a reservoir, in which case its water level fluctuates as a function of volume, inflows and outflows.

Gladstone Diversion

In the window corresponding to the sub-tab ***Gladstone Diversion*** (Figure 3.11), there are two buttons. These are:

- **Add to Aishihik Lake**

  By clicking this button, the inflow available for outflows (IAOs) at Gladstone Diversion will be added to the IAOs at Aishihik Lake.
- **Remove from System**

  By clicking this button, the IAOs at Gladstone Diversion will be removed from the IAOs at Aishihik Lake if the IAOs at Gladstone Diversion have been be added to the IAOs at Aishihik Lake.

Atlin Lake

On the sub-tab ***Atlin Lake*** (Figure 3.12), there are two buttons described below:

- **Add to Marsh Lake**

  By clicking this button, the inflow available for outflows (IAOs) at Atlin Lake will be added to the IAOs at Marsh Lake.

- **Remove from the System**

- **Remove from System**

  By clicking this button, the IAOs at Atlin Lake will be removed from the IAOs at Marsh Lake if the IAOs at Atlin Lake have been be added to the IAOs at Marsh Lake.

3.2.3.2 Generating Stations

If the user clicks the ***Generating Stations*** option under the ***Modify Input Data*** submenu (Figure 3.4), the ***Edit Input Parameters for Powerhouses*** window as shown in Figure 3.16 will appear. The left side of the window is the tab region used to edit input data for each generating station. The right side of the window consists of a table and 4 buttons.

The right side of the ***Edit Input Parameters for Powerhouses*** window is similar to that of the ***Edit Input Parameters for Lakes/Reservoirs.*** The table can be used to display or edit data. The buttons are described below for completeness:

- Add/Save

The ***Add/Save*** button is used to add or save the input data in YECSIM.

- List

The ***List*** button is used to display the data information in the table. If the user selects a data type by checking a check box and clicks the ***List*** button, the corresponding data will be listed in the table.

- Go to Lakes

The ***Go to Lakes*** button is used to exit the current window and open the window shown in Figure 3.5 to input reservoir data.

- Return

The ***Return*** button is used to return to the main window (Figure 3.1).

The tab area shown in Figure 3.16 is used to select among the generating stations, and it is designed as a notebook, organized into 4 sub-tabs that are described in Table 3.4. The user must navigate through the sub-tabs to input or edit data for each generating station.

The left side of the ***Edit Input Parameters for Powerhouses*** window includes data required to define:

- active/inactive switch for the simulation,
- plant efficiency defined by a 3-tier relationship, described in Section 6.0 of this manual,
- coefficients to define energy loss,
- tailwater conditions,
- head loss coefficients,
- plant flow capacity,

- in some cases, operation conditions incorporated into the program.

These data are organized in groups and are defined in the following paragraphs.

3.2.3.3 3-tier System of Turbine-Generator Efficiencies

The ***3-tier System for Turbine / Generator Efficiency*** group is used for defining the overall efficiency of each plant (see Section 6 for a more detailed description of the 3-tier concept). For each tier, a set of discharge and efficiency values is given.

Table 3.4 – Descriptions of the Sub-tabs for Generating Stations

SUB-TAB TITLE	PURPOSE
Whitehorse Rapids G.S.	Edits input data for Whitehorse Rapids Generating Station (Figure 3.16)
Aishihik G.S.	Edits input data for Aishihik Generating Station (Figure 3.17)
Mayo A G.S.	Edits input data for the Mayo A Generating Station (Figure 3.18)
Mayo B G.S.	Edits input data for Mayo B Generating Station (Figure 3.19)

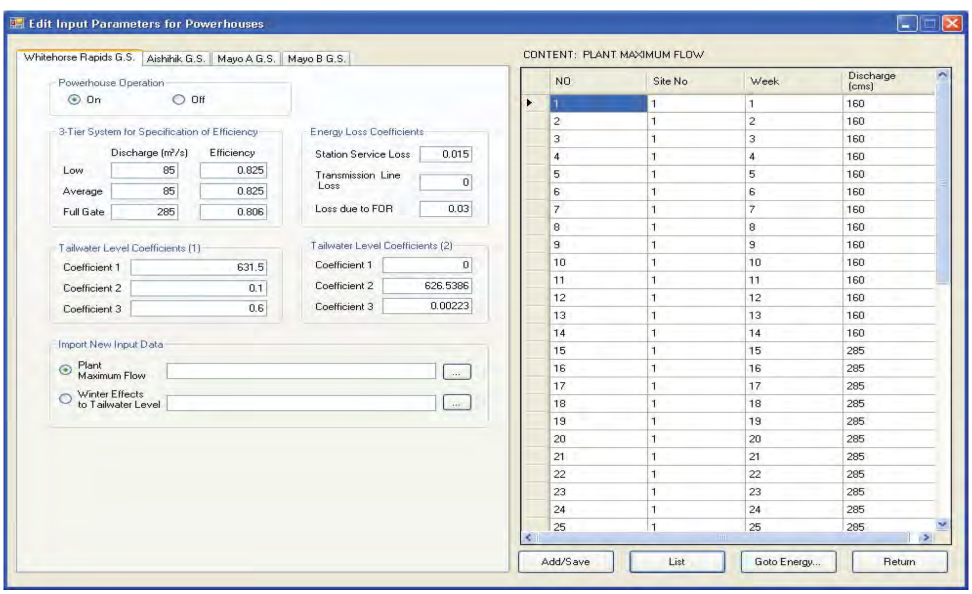


Figure 3.16 – Edit Input Data for Generating Stations

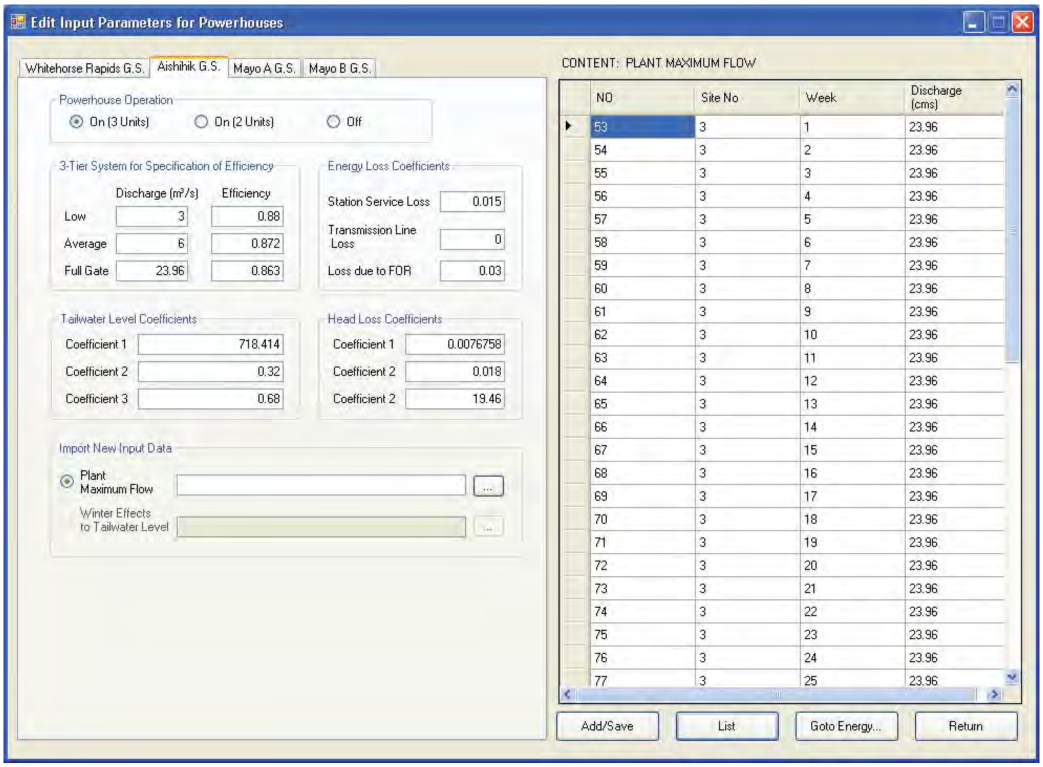


Figure 3.17 – The Active Sub-tab for Aishihik GS

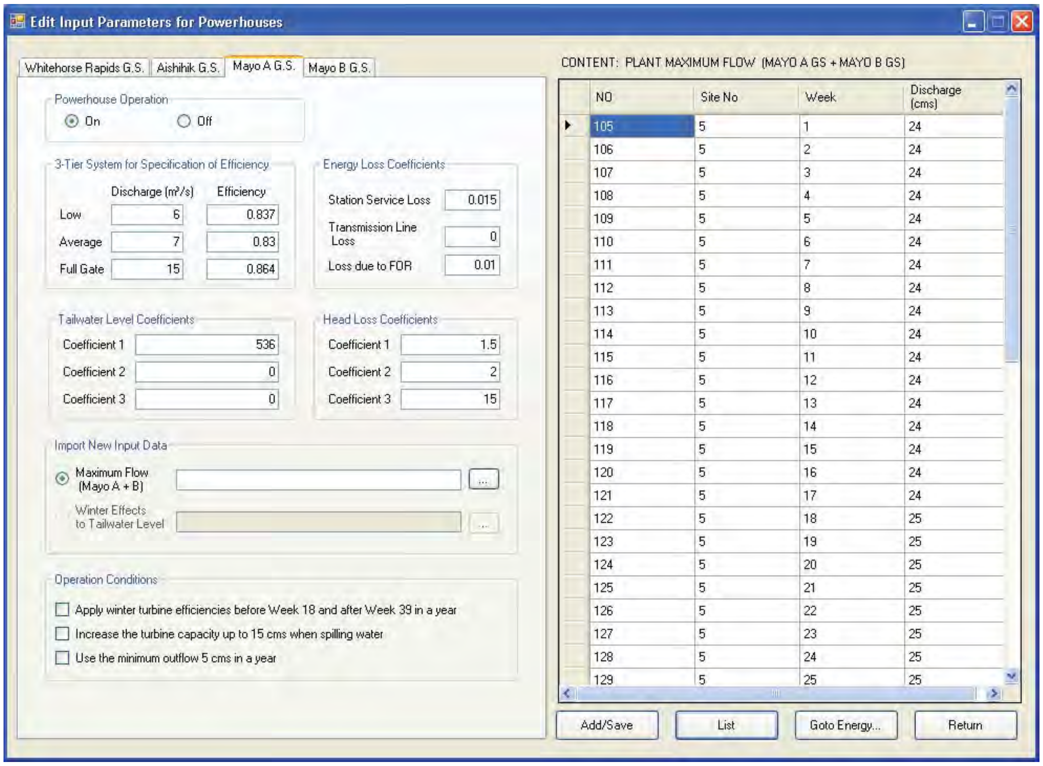


Figure 3.18 – The Active Sub-tab for the Mayo A GS

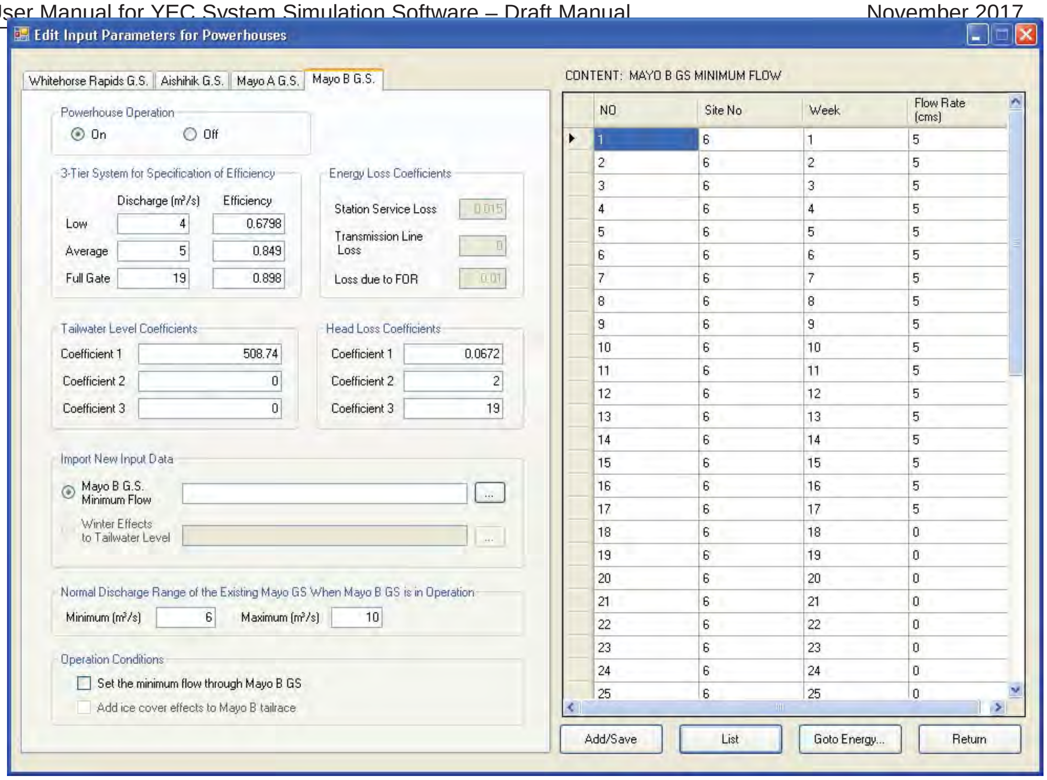


Figure 3.19 – The Active Sub-tab for Mayo B GS

3.2.3.4 Powerhouse Operation

The ***Powerhouse Operation*** group is used to turn the plant on or off for a given simulation (Figures 3.16, 3.18 and 3.19). There are two options:

- **On:** The plant is turned on.
- **Off:** The plant is turned off during the simulation.

To activate an option, the user should check in the option box and then click the ***Add/Save*** button.

The ***Powerhouse Operation*** group for Aishihik Generating station shown in Figure 3.17 features three options:

- **On (3 Units):** The plant is turned on with 3 units.

- **On (2 Units):** The plant is turned on with 2 units.
- **Off:** The plant is turned off during the simulation.

To activate an option, the user should check in the option box and then click the ***Add/Save*** button.

<u>Energy Loss Coefficients</u>

The ***Energy Loss Coefficients*** group is used for editing the energy loss coefficients for each plant (Figures 3.16 to 3.19). These are the following three coefficients, which are described in more detail in Section 6 of the manual:

- Station service loss: the energy used for local purposes in the Powerhouse.
- Transmission line loss: the energy losses due to the transmission line. It is customary for YEC that these losses are included in the projected load demand, so normally this value is set as zero in YECSIM. The program provides the ability to include these losses separately in case is needed in the future.
- Loss due to forced outages: the energy reduction in turbine efficiency at full gate flow, used to represent forced outages.

<u>Tailwater Level Coefficients</u>

The ***Tailwater Level Coefficients*** group is used for editing the coefficients for tailwater level calculation (Figures 3.16 to 3.19). Generally the tailwater level of a generating station is estimated in the YECSIM program using the following generic equation:

$$TWL = C_1 + (C_2 \bullet Q^{C_3}) \qquad (3\text{-}2)$$

Where:

TWL = tailwater level of a generating station (m)

Q = total discharge from the generating station (m^3/s)

C_1 = coefficient 1 (the ***Coefficient-1*** text box in the Group)

C_2 = coefficient 2 (the ***Coefficient-2*** text box in the Group)

C_3 = coefficient 3 (the ***Coefficient-3*** text box in the Group)

For the Whitehorse Rapids Generating station, the program allows the use of separate tailwater rating curves for Unit 4 (***Tailwater Level Coefficients (1)***) and for Units 1 to 3 (***Tailwater Level***

Coefficients (2)). If zero values are input for the three coefficients in ***Tailwater Level Coefficients (2)*** the model automatically uses the rating curve defined by the coefficients in ***Tailwater Level Coefficients (1)*** for the entire plant.

Head Loss Coefficients

The ***Head Loss Coefficients*** Group is used for editing the coefficients for head loss calculation (Figures 3.16 to 3.19). Generally, the head loss of a generating station is estimated in YECSIM using the following equation:

$$h = C_1 Q^2 + (C_2 \bullet \left(\frac{Q}{C_3}\right)^2) \quad (3\text{-}3)$$

Where:

h	=	head loss in the water conveyance system (m)
Q	=	discharge through all turbines (m^3/s)
C_1	=	head loss coefficient of the water conveyance system (the ***Coefficient-1*** text box in the Group)
C_2	=	head loss coefficient of the branch pipe for one unit, if applicable (the ***Coefficient-2*** text box in the Group)
C_3	=	maximum turbine capacity (the ***Coefficient-3*** text box in the Group)

Normally the second and third head loss coefficients are used for the Aishihik Generating Station only, to better define head losses for the flow of two or three units. For other plants the default value of these two coefficients is zero.

<u>Import New Input Data</u>

The ***Import New Input Data*** group is used to import new input data from text files (Figures 3.16 to 3.19). The description of these data files is provided in Table 3.3 and their format in Appendix A. The steps to import new input data from a file are as follows:

1. Check a check box to indicate the data type.

2. Click the ***Browse*** button  to find a file, using the open file dialog box as shown in Figure 3.3. The file format is referenced in Table 3.3.

3. After finding and selecting a file, click the ***Open*** button on the dialog box. The file path and name should appear in the text box between the check box and the Browse button. The user can also type the file path and name in the text box.

4. Click the ***Add/Save*** button. The input data will be imported into YECSIM and listed in the table.

Changes to the default values for maximum discharge capacity of the generating stations are generally input to the model via the ***Import New Input Data*** group. Alternatively, if the changes are minimal these can be edited directly on the table in the right side of the ***Edit Input Parameters for Powerhouses*** window.

The ***Edit Input Parameters for Powerhouses*** window includes a number of settings that are specific to each of the generating stations in the YEC system. For instance, the ***Import New Input Data*** group for the Whitehorse Rapids G.S. includes the option for applying winter effects on the tailwater level. These can be done by importing from a text file or by editing the values after listing them in the table to the right of the window.

A number of options are included to determine how the generating stations at Mayo are to operate during a given simulation. These settings are either in the ***Mayo A G.S.*** tab or in the ***Mayo B G.S.*** tab. Notwithstanding, in which tab these settings are located, they often affect both generating stations at Mayo. For instance, the maximum flows defined in the ***Import New Input Data*** group for the existing Mayo A Generating Station apply to the total discharge at the two Mayo stations, i.e. the values correspond to the summation of flows for Mayo A and Mayo B. The ***Import New Input Data*** group for the Mayo B G.S. does not include the definition of maximum flows through the plant. The option for defining minimum flows through Mayo B is included instead. The following descriptions are provided for the options located in each tab.

<u>The Mayo A Generating Station Tab</u>

In the window corresponding to the ***Mayo A G.S.*** tab (Figure 3.18), there is a group frame for setting conditions at the existing Mayo Generating Station. The following 3 conditions can be applied:

- **Use Winter Turbine Efficiencies before Week 18 and after Week 39 in a Year**

  This option allows adjusting the plant efficiency of the existing Mayo Generating Station to the winter flows for the plant. The winter is defined as the period from Week 39 to Week 18 of the following year.

  To activate this condition, the user should check in the check box.

  To remove this condition, the user should check out the check box.

- **Increase the turbine capacity up to 15 m^3/s when spilling water**

  This option allows simulating a condition in which at times when water is being spilled at Wareham Lake due to excess inflows, the generating capacity at the existing Mayo Generating Station can be increased from minimum flows to a maximum of 15 m^3/s, as long as there is a demand for that energy in the system.

  To activate this policy, the user should check in the check box.

  To remove this condition, the user should check out the check box.

- **Use the minimum outflow 5 m^3/s in a year**

  This option allows setting a constant minimum flow of 5 m^3/s for the Mayo A Generating Station, instead of the default minimum outflow requirements of 5 m^3/s in the winter and 6 m^3/s in the summer.

  To activate this policy, the user should check in the check box.

  To remove this condition, the user should check out the check box.

The Mayo B Generating Station Tab

In the window corresponding to the ***Mayo B G.S.*** tab (Figure 3.19), there is a group frame for setting discharge limits to the existing Mayo A Generating Station and a group frame for setting the operation condition for the Mayo B Generating Station:

- Normal Discharge Rate for the Existing Mayo G.S. when the Mayo B G.S. is in Operation.

The **Normal Discharge Rate for the Existing Mayo G.S. when the Mayo B G.S. is in Operation** group is used for setting discharge limits for the existing Mayo A plant to be applied when Mayo B is included in the simulation.

The ***Minimum (m^3/s)*** text box allows setting the minimum discharge required to pass through the turbines at the existing Mayo A Generating Station.

The ***Maximum (m^3/s)*** text box defines a maximum flow to be discharged before starting the Mayo B units. If the total flow through the Mayo complex (Mayo A + Mayo B) is more than this value, then Mayo A would pass the flow specified in the **Minimum** textbox, with excess flows conveyed through Mayo B.

- **Operation Conditions.**

The ***Operation Conditions*** group includes the ***Set the minimum flow through Mayo B*** check box. This check box works in conjunction with the values input to the model via the ***Import New Input Data*** group frame for Mayo B. When the check box is checked, these minimum plant flows are used in the simulation. Otherwise, these minimum flows are ignored.

- **Add ice cover effects to Mayo B tailrace**

  This option is not currently available.

3.2.3.5 Energy Data

If the user selects the ***Energy Data*** submenu under the ***Modify Input Data*** menu (Figure 3.4), the ***Edit Energy Information*** window appears, as shown in Figure 3.20. The left side of the window is the tab region used to navigate through the three options described in Table 3.5.

The right side of the window consists of a table for displaying and editing data and three buttons. These buttons are similar to those described in previous sections for other data editing windows in YECSIM. As in the previous cases, these allow the following actions:

- adding or saving changes,
- listing data, and
- navigating out of the window.

Table 3.5 – Descriptions of the Sub-tabs for Energy Data

SUB-TAB TITLE	PURPOSE
Energy Load	Edits input data for energy load required in each year (Figure 3.20)
Diesel Capacity	Edits input data for Diesel Capacity (Figure 3.21)
Wind Energy	Edits input data for possible wind energy (Figure 3.22)

The following descriptions are for each tab of the ***Edit Energy Information*** window.

Energy Load

In the window for the tab ***Energy Load*** (Figure 3.20), through the combo box ***Start Year*** and the combo box ***End Year***, the user can input the load years defining the start and the end of the simulation period. The number of load years allowed in YECSIM is limited to a maximum of 60.

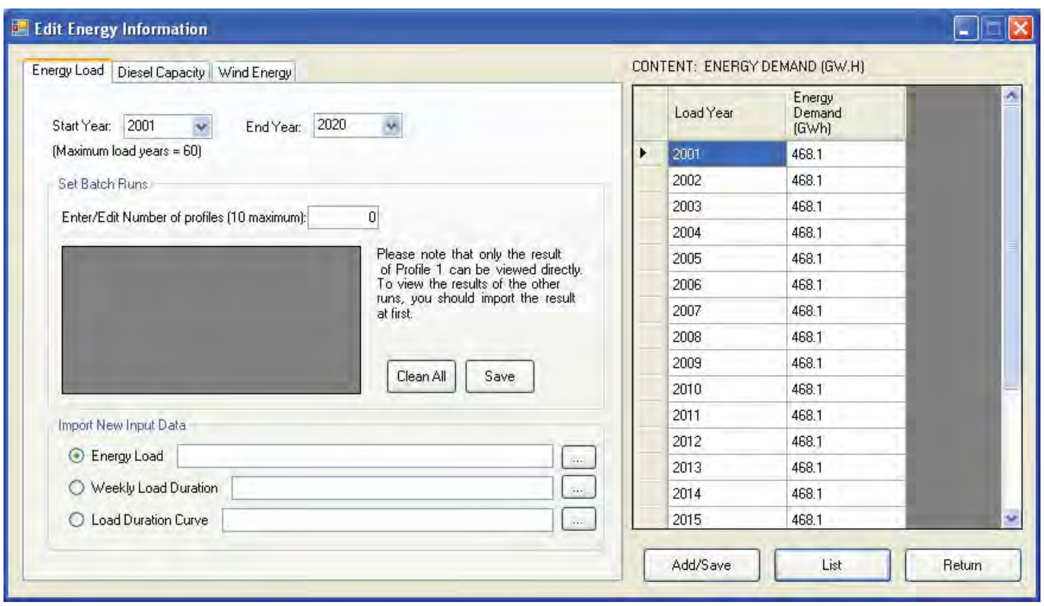


Figure 3.20 – Energy Load Information

Set Batch Runs group frame

YECSIM supports batch runs, allowing the user to set up 10 runs to be simulated in sequence. Some conditions are required, as follows:

- all batch runs are carried out for the same load years, which are those defined in the ***Start Year*** and ***End Year*** combo boxes,
- the annual energy load for each run should be constant, and
- all other input parameters, except the annual load, are kept equal.

To perform batch runs with YECSIM the user must do the following:

- Enter the number of batch runs (or profiles) in the text box in the group frame ***Set Batch Runs***.
- click any other button or textbox in the user interface, and a table will appear in the group frame ***Set Batch Runs***. Column 1 in the table lists the number of the run and Column 2, the corresponding energy load.
- Double-click a cell in Column 2 of the table, and enter the annual energy demand for the run number shown in Column 1.
- Click the ***Save*** button to save the batch runs in YECSIM. Or click the ***Clean All*** button to clear the table.

Import New Input Data

The ***Import New Input Data*** group is used to import energy input data from a text file. The description of the input files is listed in Table 3.3. Sample formats are provided in Appendix A. The steps to import new input data from a file are as follows:

1. Check the check box to indicate the Data Type.
2. Click the Browse button [...] to find a file using the open file dialog box as shown in Figure 3.3. The file format is referenced in Table 3.3.

3. Click the Open button on the dialog box. The file path and name should appear in the text box between the check box and the Browse button. The user can also type the file path and name in the text box.
4. Click the Add/Save button. The input data will be imported into YECSIM and listed in the table.

The data in the YECSIM database can be listed in the table in the right side of the ***Energy Edit Information*** window. The data displayed in the table can be modified following these steps:

1. Check the check box to indicate the data type.
2. Click the ***List*** button. The corresponding data will be listed in the table.
3. Double click a cell in the table.
4. Change the data value in the cell. Some columns may be locked and cannot be changed because of the requirements of the YECSIM database.
5. Click the ***Add/Save*** button to save.

Diesel Capacity

The window corresponding to the ***Diesel Capacity*** tab (Figure 3.21) allows the user to define the capacity for diesel energy generation for each year in the simulated period. If a constant value is to be used for all load years, this can be input in the ***Diesel Capacity (if constant, MW)*** box. Alternatively, the diesel capacity for each year can be imported from a text file, using the frame group ***Import New Input Data***.

As with other data types, the data can be edited directly in the table located in the right side of the window.

The diesel capacity values are only used in the program to provide warning messages in the event that these are not sufficient to supply the load. Notwithstanding the values input in the ***Edit Energy Information***, ***Diesel Capacity*** tab, during a simulation the program would account for as much energy from diesel as required to supply the load, in excess of the energy available from other sources (i.e. hydro and wind). To activate these warning messages the user should check the check box ***Have a warning if the diesel capacity is less than the required***.

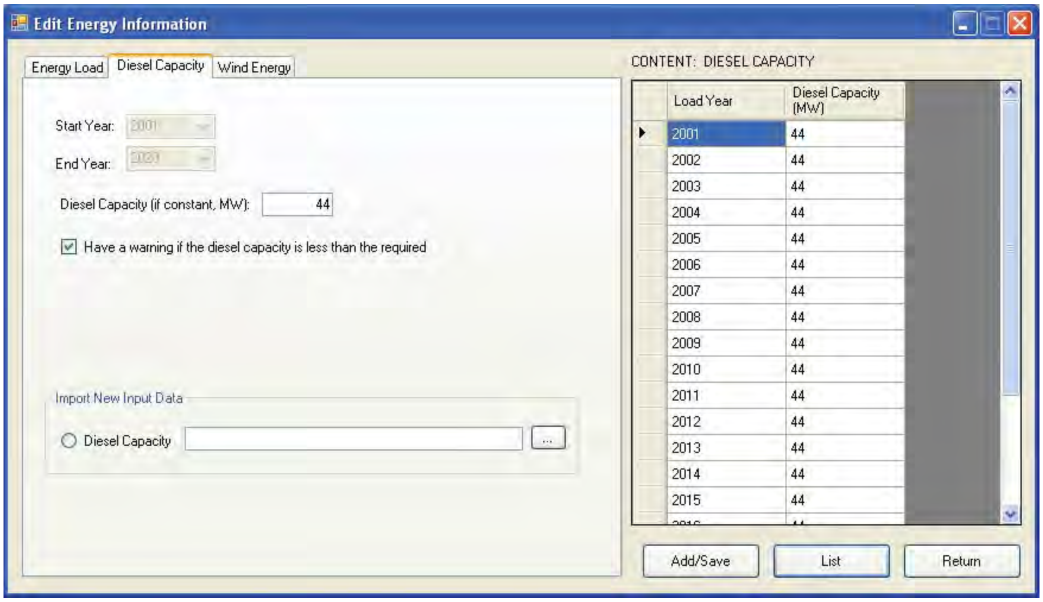


Figure 3.21 – Diesel Capacity

Wind Energy

In the window for the ***Wind Energy*** tab (Figure 3.22), the user can input weekly values for wind energy available. The weekly wind energy values are constant during the simulation; but are only applied for the period selected by the user through the ***Start Year*** and ***End Year*** combo boxes in the ***Edit Energy Information*** window for the ***Wind Energy*** tab.

The user can import the weekly values for wind energy available from text files using the group frame ***Import New Input Data***. The user can also modify the data values of wind energy in the table at the right side of the window.

By default, wind energy is not included in a simulation. If intended, the user should check in the check box ***Add wind energy in the simulation***.

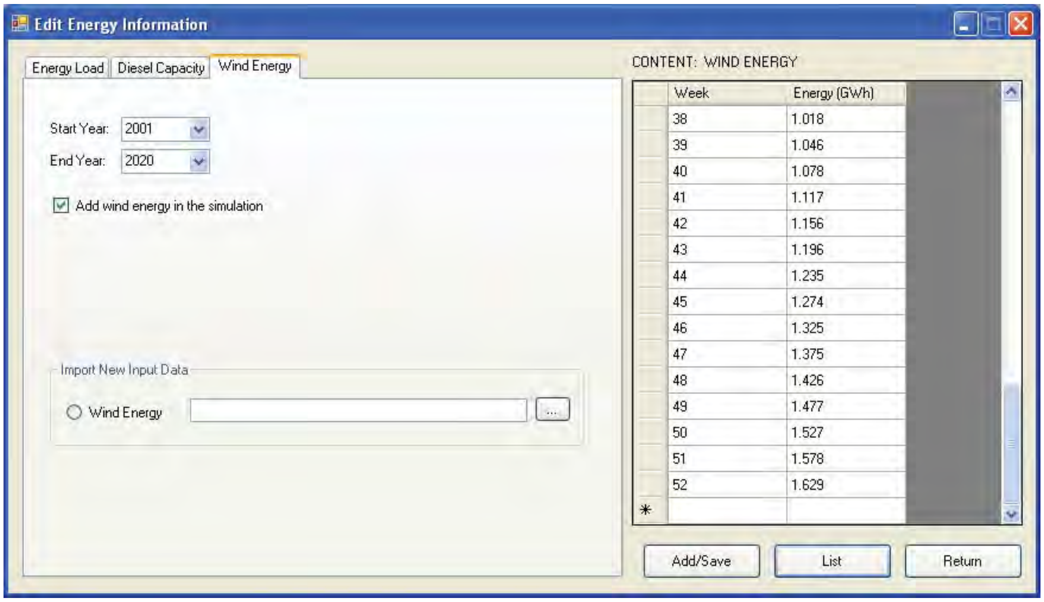


Figure 3.22 – Wind Energy

3.3 PERFORMING A SIMULATION

The steps to perform a simulation are as follows:

1. Select the ***Simulation*** submenu (Figure 3.2), to display the ***Simulation*** window, as shown in (Figure 3.23).

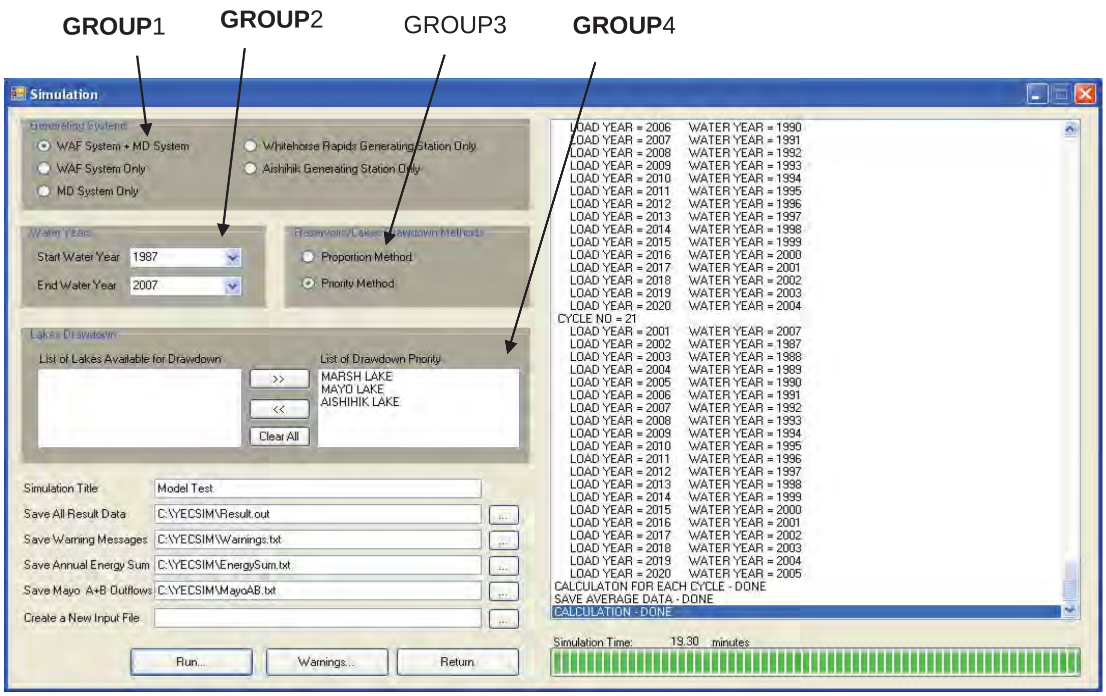


Figure 3.23 – Simulation

2 Select an option in the ***Reservoirs/Lakes Drawdown Methods*** frame group (Group 3 in Figure 3.23). See further explanation of this concept in Section 6.

3 If the selected option in Step 4 is ***Priority Method***, set the drawdown priority of lakes/reservoirs in the ***Lakes Drawdown*** frame group (Group 4 in Figure 3.23), as follows:

a. Select a lake/reservoir name from the ***List of Lakes Available for Drawdown*** box (List Box 1 in Figure 3.24).

b. Click the Add button  to move the lake/reservoir name to the ***List of Drawdown Priority*** box (from List Box 1 to List Box 2 in Figure 3.24).

c. Repeat the 2 steps above until all reservoirs are assigned a draft priority in the ***List of Drawdown Priority*** box (List Box 2 in Figure 3.24).

d. To change the selected order for one lake, click the Remove button [<<] to move a single lake/reservoir back to the ***List of Lakes Available for Drawdown*** box (from List Box 2 to List Box 1 in Figure 3.24)

e. To clear all contents in the selected list, Click the ***Clear All*** button

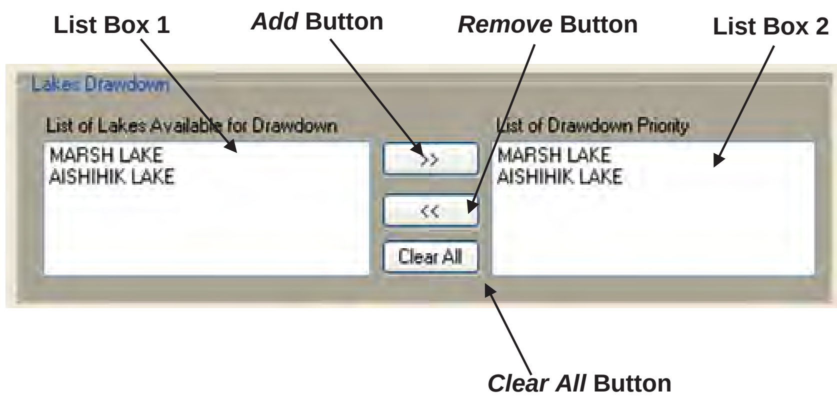


Figure 3.24 – Group 4 on the Window – Simulation (zoom in)

5. Enter a title for the simulation in the box in front of the ***Simulation Title*** text.

6. Select a result file name to save all results data (required), using the Browse button [...] in front of the ***Save All Results Data*** Text. Or create a new result file by browsing to the desired folder and writing a new filename (required).

7. Select a file to save warning messages or create a new one, using the Browse button [...] in front of the ***Save Warning Messages*** Text (required).

8. Select a file to save all energy data or create a new one, using the Browse button [...] in front of the ***Save Annual Energy Sum*** Text (optional).

9. Select a file to save the result data for flows at the existing Mayo A Generating Station and the Mayo B Generating Station or create a new one, using the Browse button [...] in front of the ***Save Mayo A+B Outflows*** Text (optional).

10. Select a file to save the input conditions or create a new input file, using the Browse button  in front of the ***Create a New Input File*** Text (optional). It is important to note that not all settings are saved in the input file thus generated. To reproduce a simulation from a previously saved input file, the user needs to verify parameters in all input windows.

11. Click the ***Run*** button to start the simulation. The GUI will display the following information:

    a. Some key information such as cycle numbers in a simulation will be listed in the text box in the right side of the ***Simulation*** window (Figure 3.23).

    b. The progress bar (in the bottom-right side of the ***Simulation*** window) will show the progress of the simulation run as it proceeds.

    c. A message box will appear with the message "Calculation Done" when the simulation is completed. Click the ***Ok*** button in the message box.

12. Click the ***Return*** button to return to the main window (Figure 3.1).

3.4 VIEWING INPUT DATA

The data present in the YECSIM database, either from a previous simulation or imported into YECSIM following the instructions in Section 3.2.2, is available for review in graphical and tabular formats. The ***Viewing Input Data*** menu as shown in Figure 3.25 is used to view the input data. The general description of each option in the menu is listed in Table 3.1. The following instructions allow using these options.

Figure 3.25 – The Menu – Viewing Input Data

IAO Data

Click the ***IAO Data*** submenu, to display the ***Inflow Available for Outflow*** window as shown in Figure 3.26. More detailed explanation of IAOs (Inflows-Available-for-Outflow) can be found in Section 6. The steps to view the IAO data are as follows:

1. Select a lake name from the ***Site No*** combo box.
2. To select a specific period:
   - Check the ***Water Year*** check box.
   - Select the start water year from the ***From*** combo box.
   - Select the end water year from the ***To*** combo box.

If a period is not selected, all water years in the database will be displayed

3. Click the ***Display*** button to display data in the table. The table in the left side of the ***Inflow Available for Outflow*** window will be updated to show the data for the selected site and years. The data will also be displayed graphically in the graph area in the right side of the window.
4. To print the graph, click the ***Print Graph*** button.
5. To save the tabular data into a text file, click the ***Save*** button.
6. Click the ***Return*** button to return to the main menu.

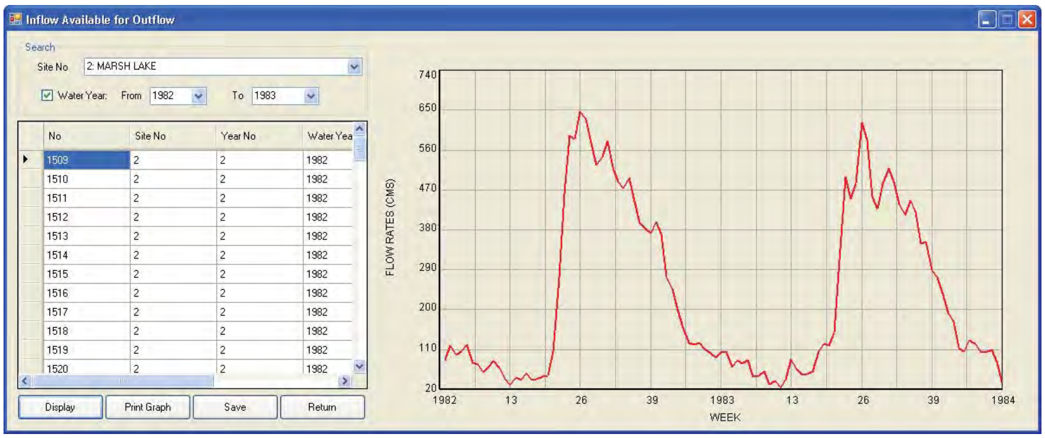


Figure 3.26 – Inflow Available for Outflow Window

Rating Curves

Click the ***Rating Curves*** submenu to display the ***Spillway Rating Curve*** window, as shown in Figure 3.27. The steps to view the rating curve data are as follows:

1. Select a lake/reservoir name from the ***Site No*** combo box.
2. Check the ***Gate No.*** check box and select one option from the ***Gate No*** combo box.
   - For Marsh Lake, there are two options that correspond to 10 or 30 gates fully open at the Lewes Dam control structure.
   - For Mayo Lake, there are two options that correspond to the position of the flashboards (up or down) at the Mayo Lake control structure. Both curves correspond to fully open conduits at the structure
   - For both sites, select "*All*" from the ***Gate No*** combo box to display a graph of both options.
3. Click the ***Display*** button to display data in the table. The table in the left side of the ***Spillway Rating Curve*** window will be updated to show the selected data. The data will also be displayed graphically in the graph area in the right side of the window.
4. To print the graph, click the ***Print Graph*** button.
5. To save the tabular data into a text file, click the ***Save*** button.

6. Click the ***Return*** button to return to the main menu.

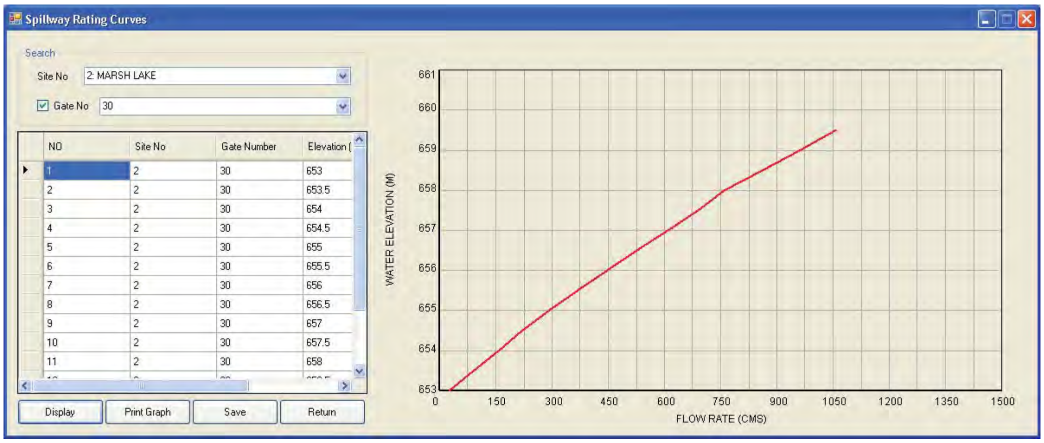


Figure 3.27 – Spillway Rating Curve

<u>Energy</u>

The ***Energy Input*** menu has five submenus (Figure 3.28):

- Diesel Capacity
- Energy Demand
- Wind Energy
- Year Load Factors
- Weekly Duration Curve

The latter two options correspond to the factors input to the program to distribute the yearly energy load values. A single value is given for each load year, which the program distributes among the 52 weeks of the year using the “Year Load Factors”. The resulting weekly loads are then assumed to be distributed among the 168 hours of a week following the “Weekly Duration Curve”. The program works in weekly time steps but uses the duration curve to calculate peak loads within a week. See Section 6 for details.

The steps to view energy data are as follows:

1. Click on one of the submenus in the ***Energy Input*** menu. For instance, click on the ***Year Load Factors*** submenu. A window will appear, in this case the ***Prorating Factors for Energy Load in Each Week of a Load Year*** window, as shown in Figure 3.29. The corresponding data will be listed in the table.
2. Click the ***Plot*** button to create a graph in the graph area.
3. Click the ***Print Graph*** button to print the graph.
4. Click the ***Save*** button to save the tabular data into a text file.
5. Click the ***Return*** button to return to the main menu.

The same format and the same instructions apply for all five options in the ***Energy Input*** menu.

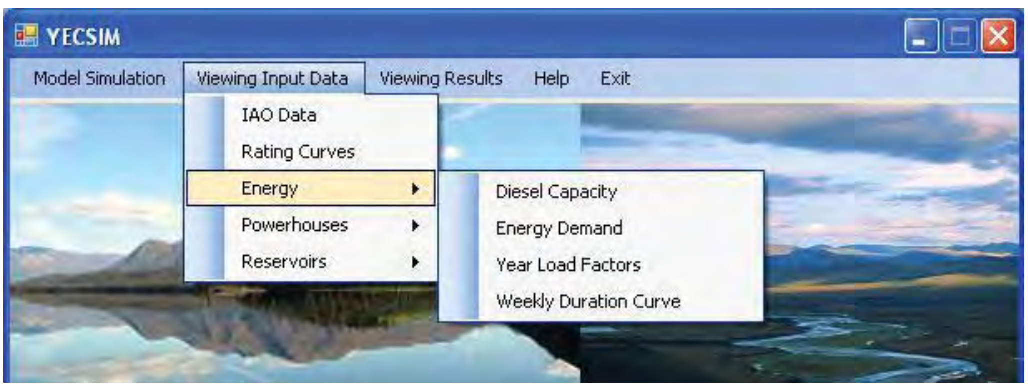


Figure 3.28 – The Submenu - Energy

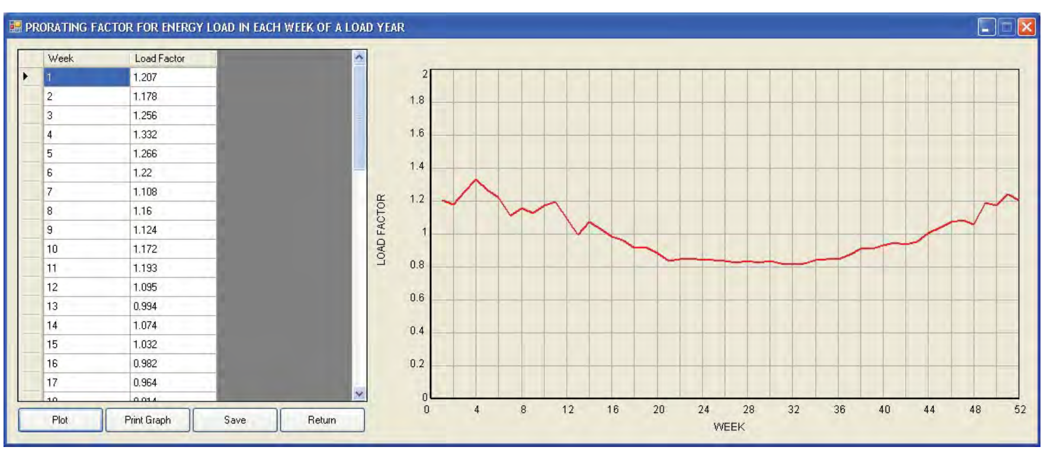


Figure 3.29 – Year Load Factors

Powerhouses

The ***Powerhouses*** menu has 2 submenus (see Figure 3.30):

- Turbine Maximum Flows
- Winter Effects

The latter corresponds to increases in tailwater level due to ice cover formation, as described in Section 6 of this manual.

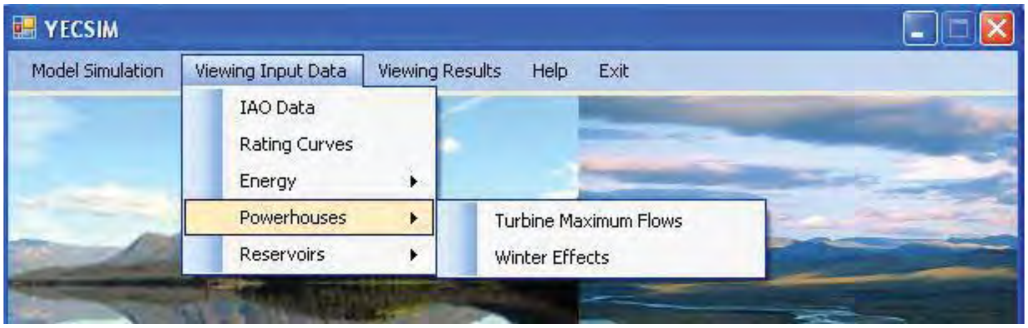


Figure 3.30 – The Submenu - Powerhouses

The steps to view the input data related to powerhouses are as follows:

1. Click on one of the submenus in the ***Powerhouses*** menu. For instance, click on the ***Turbine Maximum Flows*** submenu. A window will appear, in this case the ***Turbine Capacity*** window, as shown in Figure 3.31.
2. Select a generating station name from the ***Site No.*** combo box.
3. Click the ***Display*** button to display data in the table. A graph will be created in the graph area.
4. Click the ***Print Graph*** button to print the graph.
5. Click the ***Save*** button to save the tabular data into a text file.
6. Click the ***Return*** button to return to the main menu.

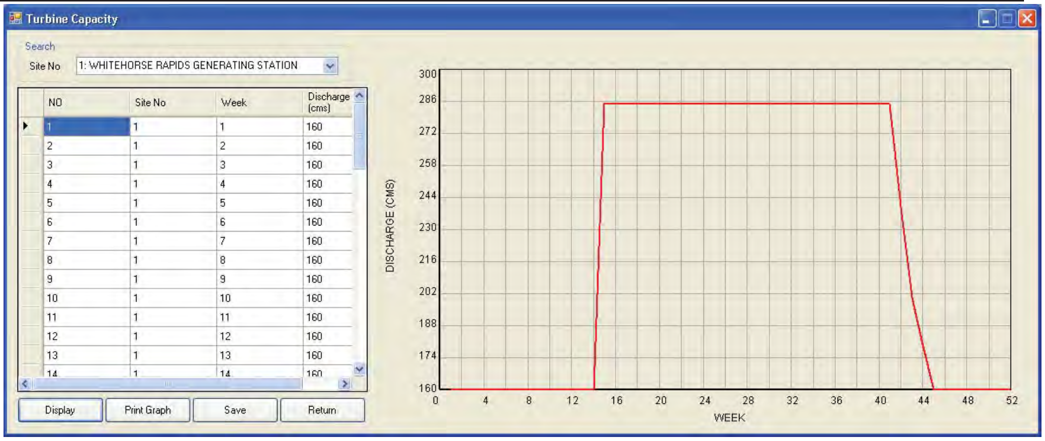


Figure 3.31 – Turbine Maximum Flows

The same format and steps are used to view the ***Winter Effects*** input data.

Reservoirs

The ***Reservoirs*** menu has 2 submenus (see Figure 3.32):

- Operational Conditions
- Riparian Flows

Figure 3.32 – The Submenu - Reservoirs

The steps to view the input data related to lakes/reservoirs are as follows:

1. Click on the submenu for one of the above options. For instance click on the ***Operational Conditions*** submenu. In this case, the ***Reservoir Operation Levels Required by Licence Policy*** window will appear, as shown in Figure 3.33.
2. Select a site name from the ***Site No*** combo box
3. Click the ***Display*** button to display data in the table. A graph will be created in the graph area.
4. Click the ***Print Graph*** button to print the graph.
5. Click the ***Save*** button to save the tabular data into a text file.
6. Click the ***Return*** button to return to the main menu.

The same format and steps are used to view the ***Riparian Flows*** input data.

Figure 3.33 – Lake Level Operation on Marsh Lake

3.3 VIEWING RESULT DATA

When a simulation is completed, the results are saved automatically into the YECSIM database. These results are then available for viewing in graphical and tabular format using the ***Viewing Result Data*** menu (Figure 3.34). Only the current results in the database are available for review. However, the results from previous simulation runs can be imported into the YECSIM database from the corresponding output files.

The description of each option in the ***Viewing Result Data*** menu is listed in Table 3.1. The following instructions allow using these options.

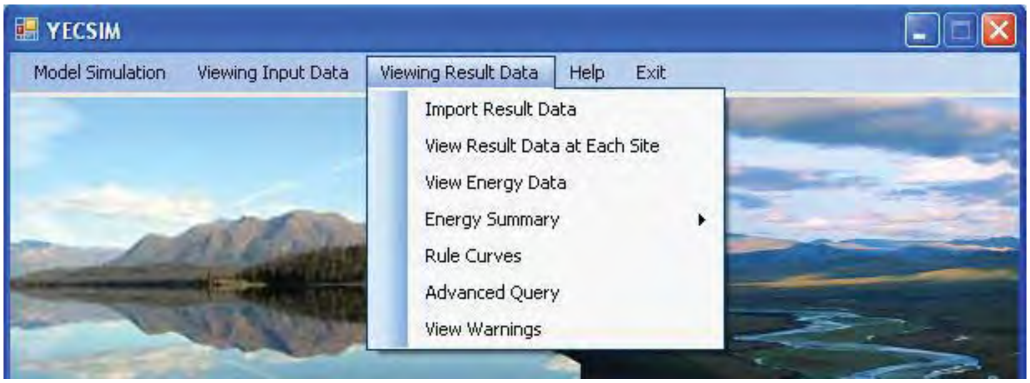


Figure 3.34 – The Menu – Viewing Result Data

Importing Result Data

The ***Import Result Data*** submenu is used to import results from a previous run and load them to the YECSIM database. Click this submenu, and the ***Importing Result Data*** window will appear as shown in Figure 3.29. The steps to load results from a file are as follows:

1. Select an option in the ***Options to Import Results*** group from:

   - ***Import All Data***: imports the result data and the input data from the result file.
   - ***Import Results Only***: imports the result data only from the result file.
   - ***Import Input Data Only***: imports the input data only from the result file.
   - ***Import Mayo A and Mayo B Result Details***: imports the data from a file where flow and energy results at Mayo A GS and Mayo B GS were saved during a simulation.

2. Click the ***Browse*** button  to find a file using the open file dialog box as shown in Figure 3.3.

3. Click the ***Open*** button on the dialog box. The file path and name should appear in the text box between the check box and the browse button. The user can also type the file path and name in the text box.

4. Click the ***Read*** button to import the result data.

- Some key information, such as cycle numbers in the result file, will be listed in the text box at the bottom of the window (Figure 3.35) as the operation proceeds.
- The progress bar will show the estimated progress of the run as it executes.
- A message box appears once the importing has been completed. Click the ***Ok*** button in the message box.

5. Click the ***Return*** button to return to the main menu.

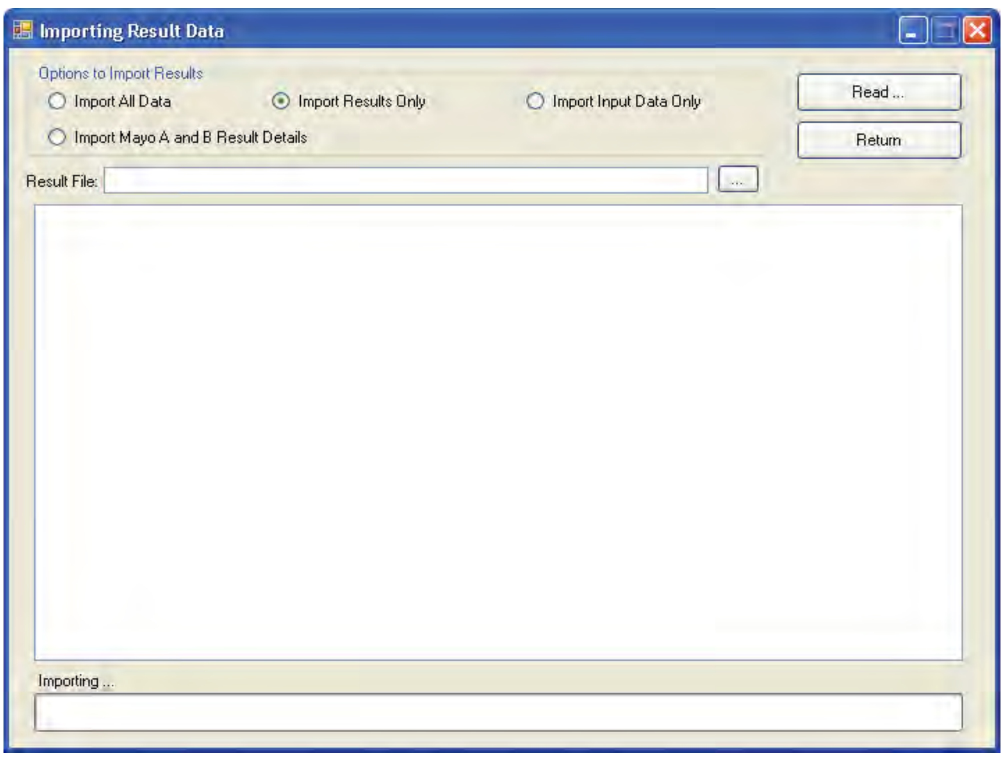


Figure 3.35 – Importing Result Data

<u>View Site Data</u>

Click the ***View Results at Each Site*** submenu, and the ***Viewing Results at Each Site*** window will appear, as shown in Figure 3.36. This window is used for viewing the results for each lake or generating station. The ***Viewing Results at Each Site*** window has five distinct areas as follows:

- On the upper left part of the window there is the ***Search*** group, which allows selecting the data to be displayed,
- To the right of the ***Search*** group there are four buttons that allow use of the window,
- Below the ***Search*** group is the ***Data Information*** group, which displays more detailed data,
- On the upper right part of the window, to the right of the buttons, there is a display table,
- On the lower part of the window there is a graph area for graphical display of data.

The steps to select and view result data are as follows:

1. Select a site name from the ***Site No.*** combo box.
2. Select a cycle number from the ***Cycle No.*** combo box. To view the average data of all cycles select cycle number "-1".

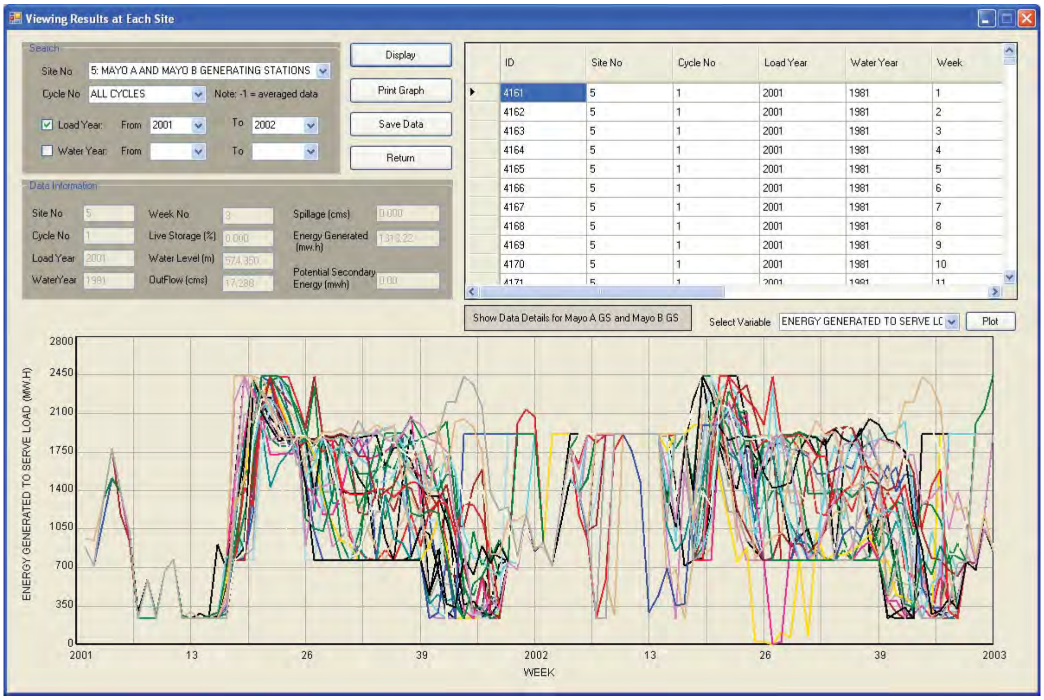


Figure 3.36 – Viewing Results at Each Site

3. Check the ***Load Year*** check box and select the load year period.

- Select the start load year from the ***From*** combo box.
- Select the end load year from the ***To*** combo box on the same line.

By default, the result data for all load years will be listed.

4. Check the ***Water Year*** check box and select the water year period.

- Select the start water year from the ***From*** combo box.
- Select the end water year from the ***To*** combo box on the same line.

By default, the result data for all water years will be listed.

5. Click the ***Display*** button. The table and the graphs in the window will be updated. If the selected site in the ***Site No.*** combo box is "Mayo A and B Generating Stations" and the simulation included the Mayo B generating station, a new button will appear under the table. The details will be described later in this manual.

6. Select the variable to be displayed from the ***Select Variable*** combo box and click the ***Plot*** button. The available options in the combo box are:

   - Live storage,
   - Water level,
   - Outflow,
   - Spillage,
   - Energy generated to serve load, and
   - Secondary energy

The table on the right side of the ***Viewing Results at Each Site*** window shows the data that has been selected for display. The table has scroll bars to move in the vertical direction, showing results for different weeks, and in the horizontal direction, showing the different variables that are available. The cells in the first row of the table indicate the variable names, and can be selected for sorting the data. The first column in the table has blank cells that can be selected to highlight the results for a given week.

7. Double click in any cell in the first row of the table, and the detailed data for the corresponding week will be shown in the ***Data Information*** group (Figure 3.36).

8. Click the ***Print Graph*** button to print the graph. The following steps are required:

- Click the ***Print Graph*** button and the ***Print*** window, as shown in Figure 3.37, appears.
- Select a printer from the ***Print*** window.
- Click the ***Preference*** button to adjust the settings. Figure 3.38 shows an example of the setting selection. This widow can vary depending on the available printer(s).
- Select landscape orientation for the plot.
- Select letter paper size. Figure 3.39 shows an example of the setting selection. This widow can vary depending on the available printer(s).
- After choosing the plot settings, click the ***Print*** button in the ***Print*** window (Figure 3.37). A window will appear to allow selecting a title for the chart, as shown in Figure 3.40.
- Enter the desired title of the graph and click the ***OK*** button.

9. Click the ***Save Data*** button to save the tabular data in a text file. A standard window will appear to allow selection of the location and name of the file.

10. Click the ***Return*** button to return to the main menu.

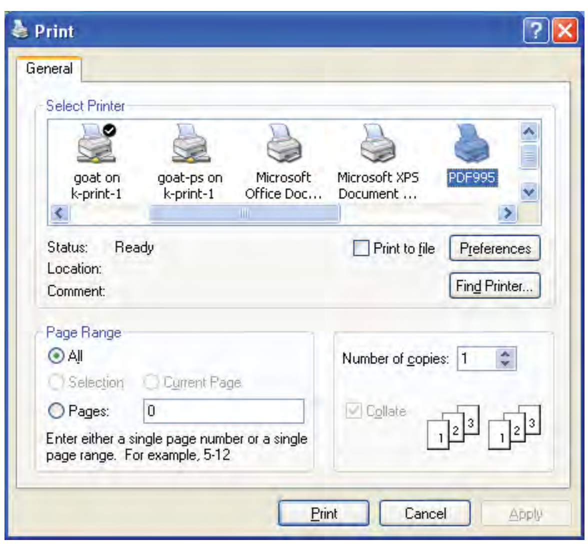


Figure 3.37 – Selecting a Printer

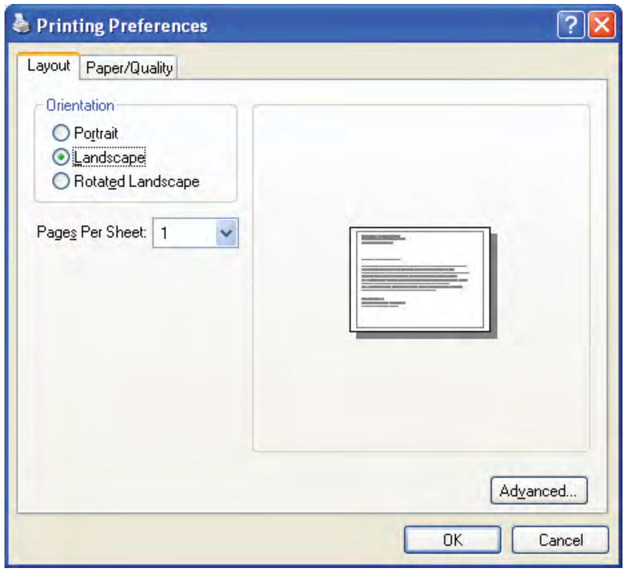


Figure 3.38 – Printing Preferences

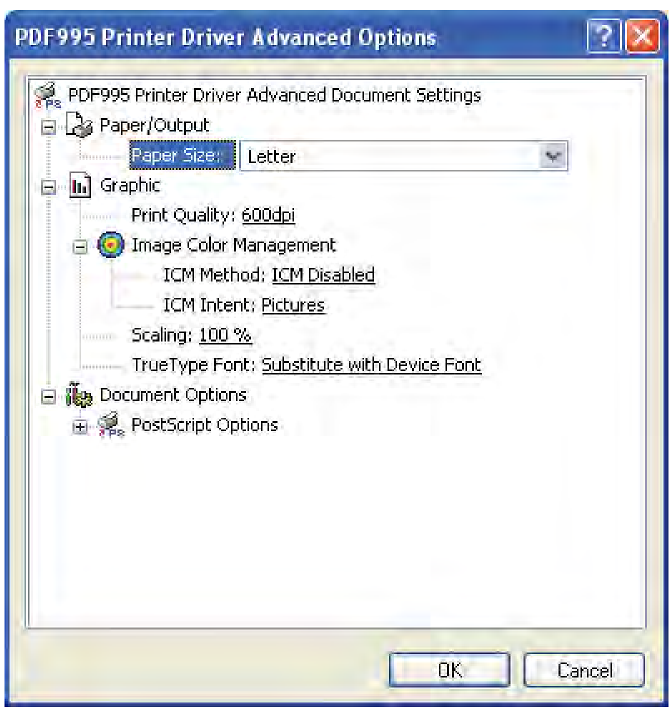


Figure 3.39 – Printer Advanced Option

Figure 3.40 – Input New Chart Title

As indicated previously, in Step 5, if the site "Mayo A and B Generating Stations" is selected in the ***Site No.*** combo box and the simulation includes the Mayo B Generating Station, the ***Show Data Details for Mayo A GS and Mayo B GS*** button will appear, between the table and the graph area, when the ***Display*** button is selected (see Figure 3.36). The ***Show Data Details for Mayo A GS and Mayo B GS*** button is used to view the plant flows and hydro energy generated from Mayo A GS and Mayo B GS individually.

Click the ***Show Data Details for Mayo A GS and Mayo B GS*** button and the ***Flow and Energy Distribution Between Mayo A and Mayo B GS*** window, as shown in Figure 3.41, will appear. The steps to view the selected result data are as follows:

1. Select a cycle number from the ***Cycle No.*** combo box. To view the average data of all cycles select cycle number "-1".

2. Check the ***Load Year*** *c*heck box and select the load year period.
   - Select the start load year from the ***From*** combo box.
   - Select the end load year from the ***To*** combo box on the same line.

By default, the result data for all load years will be listed.

3. Click the ***Display*** button. The table and the graphs will be updated.
4. Click the Y-Axis in the graph area to modify the settings of the Y-Axis.
5. Select the variable to be displayed from the ***Select Variable*** combo box and click the ***Plot*** button. The available options in the combo box are:

6. Click the ***Print Graph*** button to print the graph.

7. Click the ***Save Data*** button to save the tabular data in a text file.

8. Click the ***Return*** button to return to the main menu.

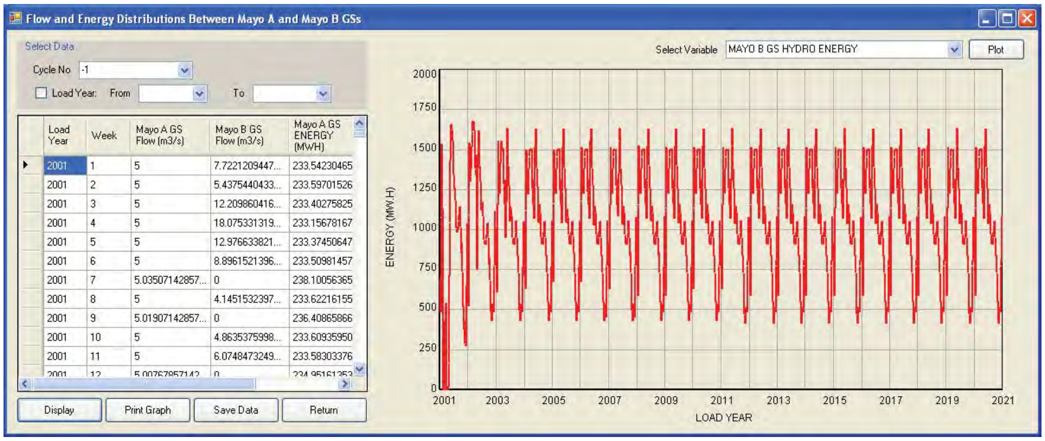


Figure 3.41 – Flow and Energy Distribution Details Between Mayo A GS and Mayo B GS

Viewing Energy Data

Click the ***View Energy Data*** submenu, the ***Viewing Energy Data*** window will appear as shown in Figure 3.42. This window is used for viewing the following energy results:

- Energy demand
- Hydro energy to serve load
- Potential secondary energy
- Diesel energy required

The layout of the window is similar to that of other result visualization options, and includes five distinct areas as follows:

- On the upper left part of the window there is the ***Search*** group, which allows selecting the data to be displayed,
- To the right of the ***Search*** group there are four buttons,
- Below the ***Search*** group is the ***Data Information*** group,

- On the upper right part of the window there is a display table,
- On the lower part of the window there is a graph area for graphical display of data.

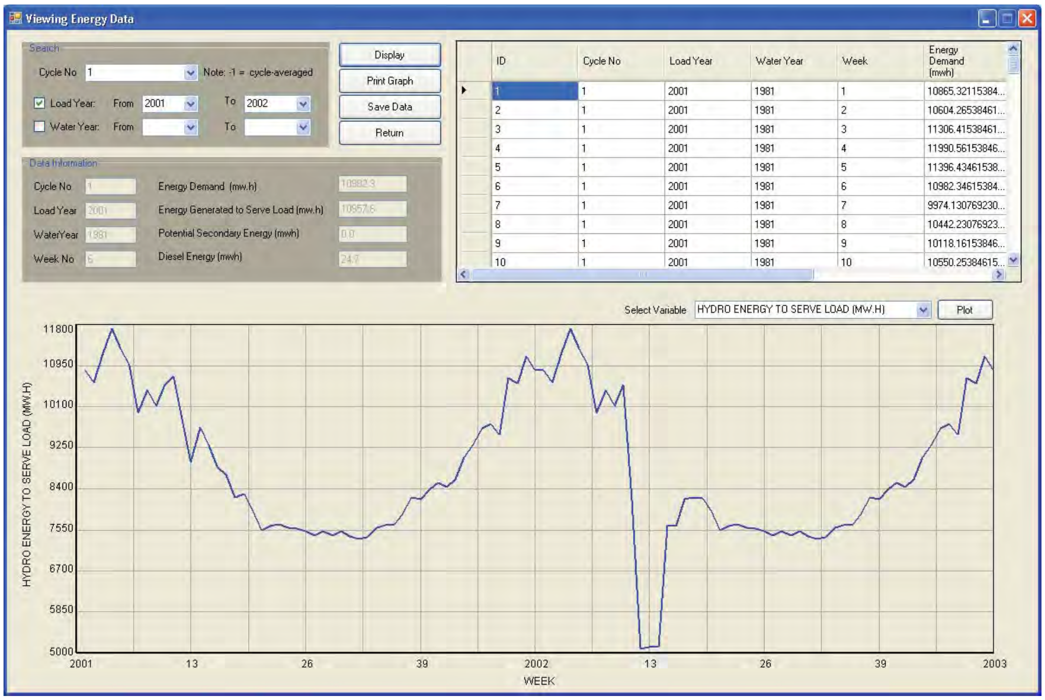


Figure 3.42 – Viewing Energy Results

The steps to select and view result data are as follows:

1. Select a cycle number from the ***Cycle No.*** combo box. To view the average data of all cycles select cycle number “-1”.
2. Check the ***Load Year*** check box and select the load year period.
   - Select the start load year from the ***From*** combo box.
   - Select the end load year from the ***To*** combo box on the same line.

By default, the result data for all load years will be listed.

3. Check the ***Water Year*** check box and select the load year period.
   - Select the start load year from the ***From*** combo box.
   - Select the end load year from the ***To*** combo box on the same line.

By default, the result data for all water years will be listed.

4. Click the ***Display*** button. The table and the graphs will be updated.
5. Select the appropriate variables from the ***Select Variable*** combo box and click the ***Plot*** button to display the curves.
6. Click the ***Print Graph*** button to print the graph.

The table on the right side of the ***Viewing Energy Data*** window shows the data that has been selected for display. The table has scroll bars to move in the vertical direction, to see results for different weeks, and in the horizontal direction, to see the different variables that are available. The cells in the first row of the table indicate the variable names, and can be selected for sorting the data. The first column in the table has blank cells that can be selected to highlight the results for a given week.

7. Double click in any cell in the first row of the table, and the detailed data for the corresponding week will be shown in the ***Data Information*** group.
8. Click the ***Save Data*** button to save the tabular data in a text file.
9. Click the ***Return*** button to return to the main menu.

Energy Summary

The ***Energy Summary*** menu includes the following options as shown in Figure 3.43,

- Total Energy by Plant
- Hydro Energy by Plant
- Secondary Energy by Plant
- Diesel Energy Graph

These options allow displaying energy results for the overall system and for the individual plants.

Figure 3.43 – Submenu – Energy Summary

Total Energy by Plant

Click the ***Total Energy by Plant*** option, in the ***Energy Summary*** menu, to display the ***Total Energy*** window, as shown in Figure 3.44. This window is used to show the following results:

- Hydro energy generated to serve load at Whitehorse Rapids Generation Station (WRGS).
- Hydro energy generated to serve load in the Whitehorse-Aishihik-Faro (WAF) system, including the WRGS and the Aishihik Generation Station (AGS).
- Hydro energy generated to serve load in the entire system, including the WAF and the Mayo-Dawson (MD) systems. The MD system includes the existing Mayo A Generating Station and the Mayo B Generating Station.
- Potential secondary energy generated at WRGS.
- Potential secondary energy generated in the WAF system.
- Potential secondary energy generated in the entire system.
- Diesel energy required in the entire system.

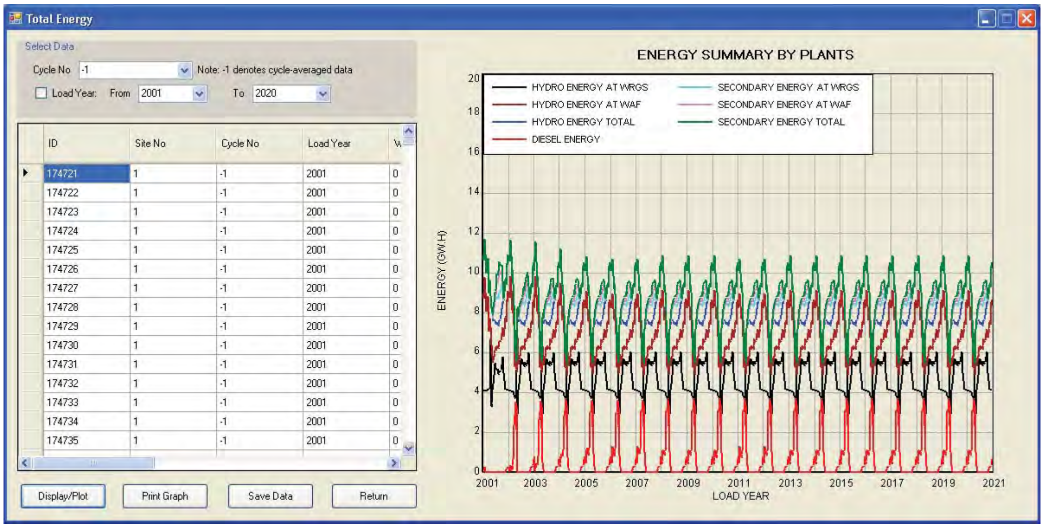


Figure 3.44 – Energy Summary by Plants

The steps to view the selected result data are as follows:

1. Select a cycle number from the ***Cycle No*** combo box. To display average data of all cycles, select cycle number “-1”.

2. Check the ***Load Year*** check box and select the load year period in the ***From*** and ***To*** combo boxes. By default, the results for all load years will be listed.

3. Click the ***Display/Plot*** button. The table and the graphs will be updated.

4. Click the ***Print Graph*** button to print the graph.

5. Click the ***Save Data*** button to save the data in a text file.

6. Click the ***Return*** button to return to the main menu.

Hydro Energy by Plant

Click the ***Hydro Energy by Plant*** option, in the ***Energy Summary*** menu, to show the ***Hydro Energy to Serve Load*** window, as in Figure 3.45. This window is used for displaying the following results:

- Hydro energy generated to serve load at the WRGS
- Hydro energy generated to serve load at the AGS
- Hydro energy generated to serve load at the Mayo A Generating Station and Mayo B Generating Station
- Total hydro energy generated to serve load from all plants

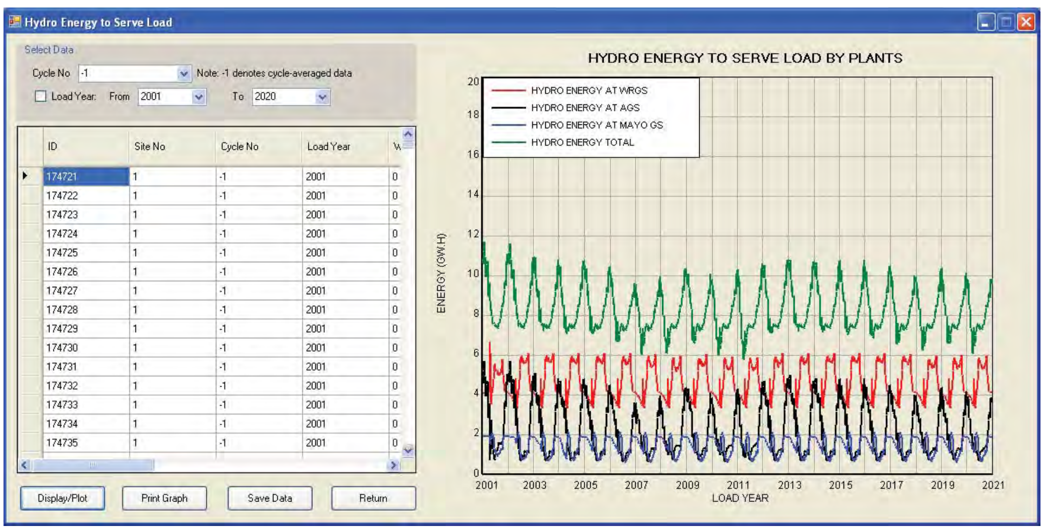


Figure 3.45 – Hydro Energy Generated to Serve Load by Plants

The steps to view the result data are as follows:

1. Select a cycle number from the ***Cycle No*** combo box. To display average data of all cycles, select cycle number "-1".

KGS GROUP

2. Check the ***Load Year*** check box and select the load year period in the ***From*** and ***To*** combo boxes. By default, the results for all load years will be listed.
3. Click the ***Display/Plot*** button to update the table and the graphs.
4. Click the ***Print Graph*** button.
5. Click the ***Save Data*** button to save the data in a text file.
6. Click the ***Return*** button to return to the main menu.

Secondary Energy by Plant

Click the ***Secondary Energy by Plant*** option, in the ***Energy Summary*** menu, to show the ***Secondary Energy Graph*** window as in Figure 3.46. This window is used for displaying the following results:

- Potential secondary energy generated at the WRGS
- Potential secondary energy generated at the AGS
- Potential secondary energy generated at the Mayo A Generating Station and Mayo B Generating Station
- Total potential secondary energy from all plants

The steps to view the selected result data are as follows:

1. Select a cycle number from the ***Cycle No*** combo box. To display average data of all cycles, select cycle number "-1".
2. Check the ***Load Year*** check box and select the load year period in the ***From*** and ***To*** combo boxes. By default, the results for all load years will be listed.
3. Click the ***Display/Plot*** button to update the table and the graphs.
4. Click the ***Print Graph*** button.
5. Click the ***Save Data*** button to save the data in a text file.
6. Click the ***Return*** button to return to the main menu.

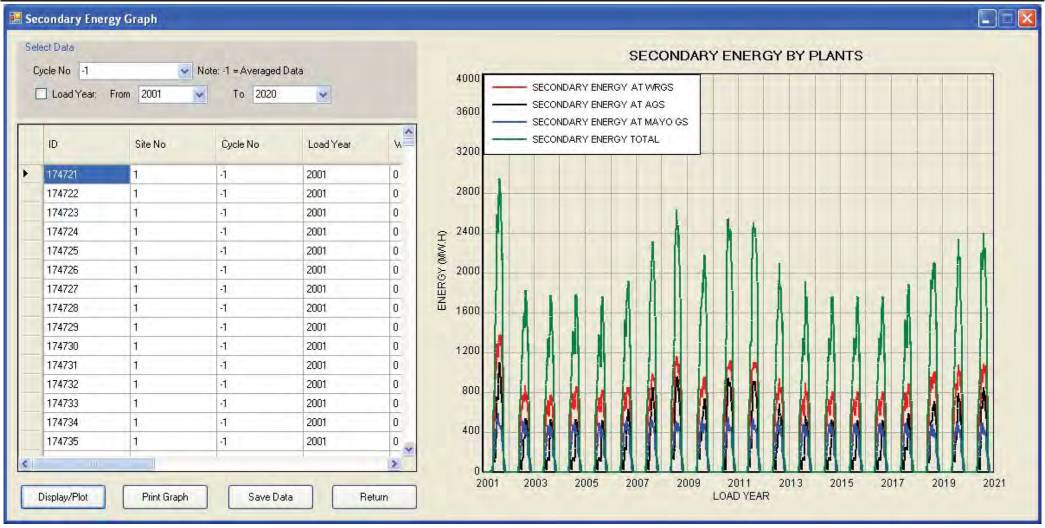


Figure 3.46 – Secondary Energy by Plants

Diesel Energy Graph

Click the ***Diesel Energy Graph*** option in the ***Energy Summary*** menu to display the ***Diesel Energy Graph*** window, as shown in Figure 3.47. This window is used for creating a graph that summarizes the results for diesel energy. The graph is based on average results for all cycles, which are sorted to provide an estimate of the frequency and amount of diesel energy requirements. Further details on this concept are provided in Section 6 of this manual. The steps to view the result data are as follows:

1. Select the load year period in the ***From*** and ***To*** combo boxes. By default, the results for all load years will be listed.
2. Click the ***Display/Plot*** button to update the table and the graphs.
3. Click the ***Print Graph*** button.
4. Click the ***Save Data*** button to save the data in a text file.
5. Click the ***Return*** button to return to the main menu.

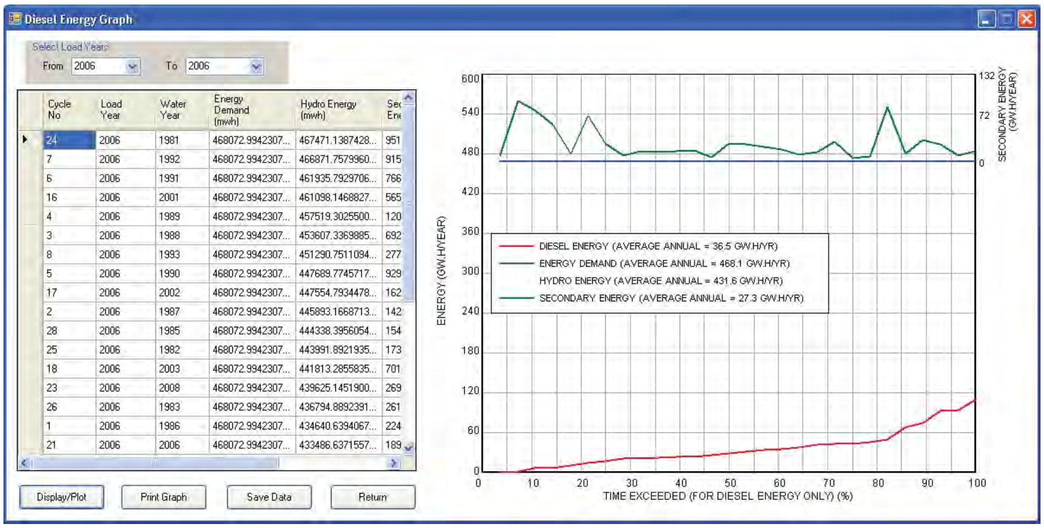


Figure 3.47 – Diesel Energy Graph

Viewing Rule Curves

Click the ***Rule Curves*** option in the ***Viewing Result Data*** menu to display the ***Rule Curves*** window as shown in Figure 3.48. This window is used to view the rule curves used in the simulation. Further details of the concept of rule curves are provided in Section 6 of this manual. The rule curve data refers to the amount of storage in the reservoirs that is required to guarantee compliance with minimum flow requirements. It is available in the following two formats:

- Live storage volume (%)
- Water Level (m)

The steps to view the rule curve data are as follows:

1. Select a site name from the ***Site No*** combo box.
2. Check the ***Load Year*** check box and select the load year period in the ***From*** and ***To*** combo boxes. By default, the results for all load years will be listed.

3. Click the ***Display*** button to update the table and the graphs.

4. Select one option from the ***Select Variable*** combo box and click the ***Plot*** button to display the curves.

5. Click the ***Print Graph*** button.

6. Click the ***Save Data*** button to save the data in a text file.

7. Click the ***Return*** button to return to the main menu.

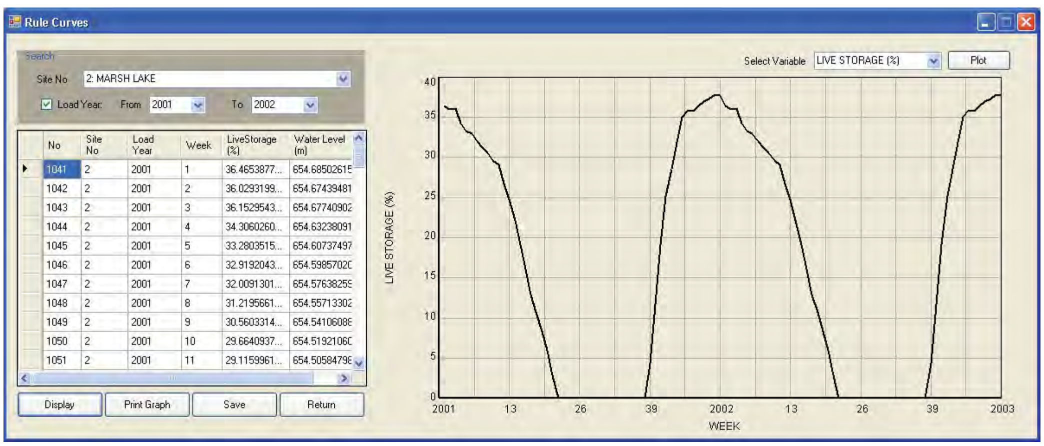


Figure 3.48 – Viewing Rule Curves

<u>Advanced Query</u>

Click the ***Advanced Query*** option in the ***Viewing Result Data*** menu to display the ***Advanced Data Query*** window as shown in Figure 3.49. This window can be used to create a query from the results using SQL language compatible with Microsoft Access. The steps to carry out data queries are as follows:

1. Enter the full description of the data query in the ***Query*** text box.
   - The ***Table Name*** list box lists the names of the tables in YECSIM database.
   - The ***Components in Table*** list box lists the variables available in each table.

2. Click the ***Display*** button to update the table with the query results.

3. Click the ***Save Data*** button to save the data in a text file.

4. Click the ***Return*** button to return to the main menu.

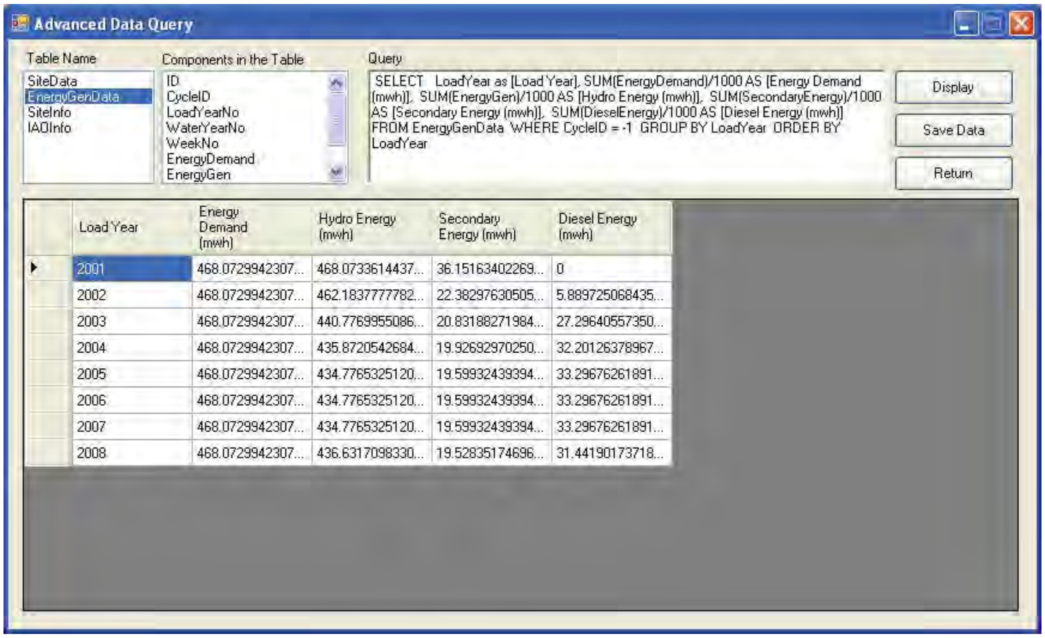


Figure 3.49 – Advance Data Query

The following instructions are useful for saving results in a text file, using the options in this window:

1. Enter the text "Save All" in the ***Query*** text box and click the ***Save Data*** button. Then the result data for all sites in all cycles will be saved in a text file.

2. Enter the text "Save Cycle " and a cycle number in the ***Query*** text box and click the ***Save Data*** button. For instance, enter "Save Cycle 1" to save the result data for all sites and for cycle number 1 in a text file.

View Warnings

Click the ***View Warnings*** submenu to display the ***Warning Message*** window as shown in Figure 3.50. This window can be used to view the warnings generated during a simulation. These may be related to instances in which:

- the water level at a given site falls below the minimum license level,
- the diesel capacity input to the program is exceeded,
- the generating capacity in the system is not sufficient to satisfy peak loads and as a result diesel energy is required. These warning messages are referred to as “Plant Stacking”.

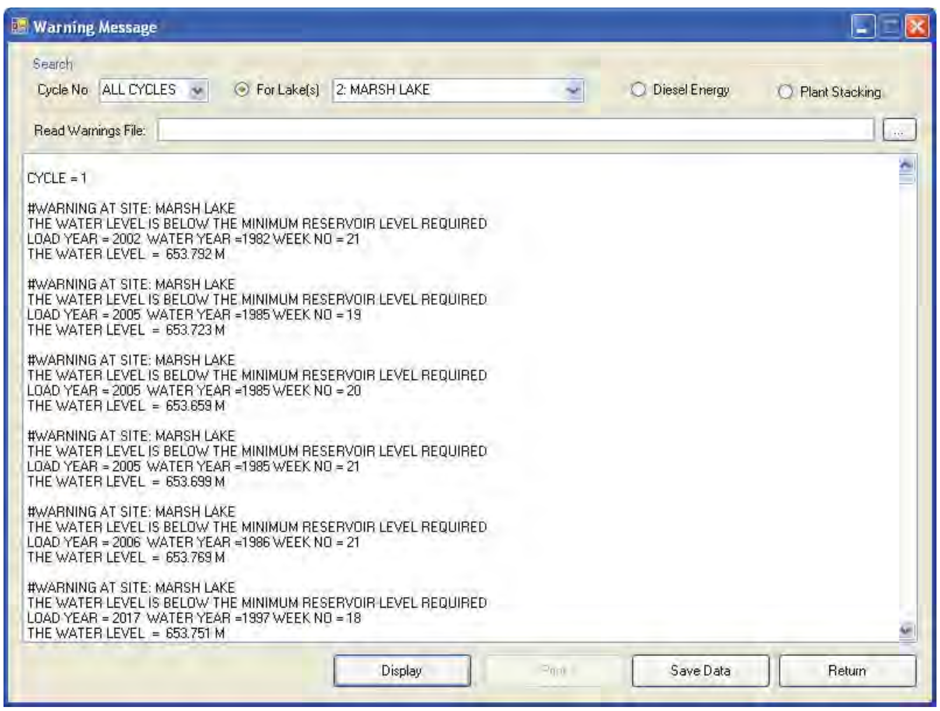


Figure 3.50 – Warnings

The steps to view the warnings are the following:

1. Select a cycle number or “All Cycles” from the ***Cycle No*** combo box.

2. Select one of the following check boxes, according to the type of warnings to be displayed:

- ***For Lake(s)***

This option is selected along with the option "All Sites" or the name of a lake from the combo box besides the check box.

- ***Diesel Energy***

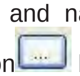
- ***Plant Stacking***

3. Click the ***Display*** button to show the warnings in the text pad on the screen.

4. The ***Print*** button is not available for now.

5. Click the ***Save Data*** button to save the listed warnings in a file.

6. Click the ***Return*** button to return to the main menu.

This window also allows importing the warnings file from a previous simulation. For this, the path and name of the file should be entered in the ***Read Warning File:*** text box. The button  besides the text box allows navigating to and selecting a warning file.

3.4 HELP

Under the ***Help*** menu (Figure 3.51), there are 3 options, which are described in Table 3.1.

Figure 3.51 – The Menu – Help

3.5 USER MANUAL

The ***User Manual*** option, shown in Figure 3.51, is used to open the user manual file. The user manual is only provided in PDF format. The steps to open the user manual are as follows:

1. Click the ***User Manual*** option in the ***Help*** menu and a window will appear as shown in Figure 3.52.
2. Click the hyperlink for the user manual in PDF format to open the manual in PDF format. The software Adobe Reader versions 8.0 and up must be installed in advance.

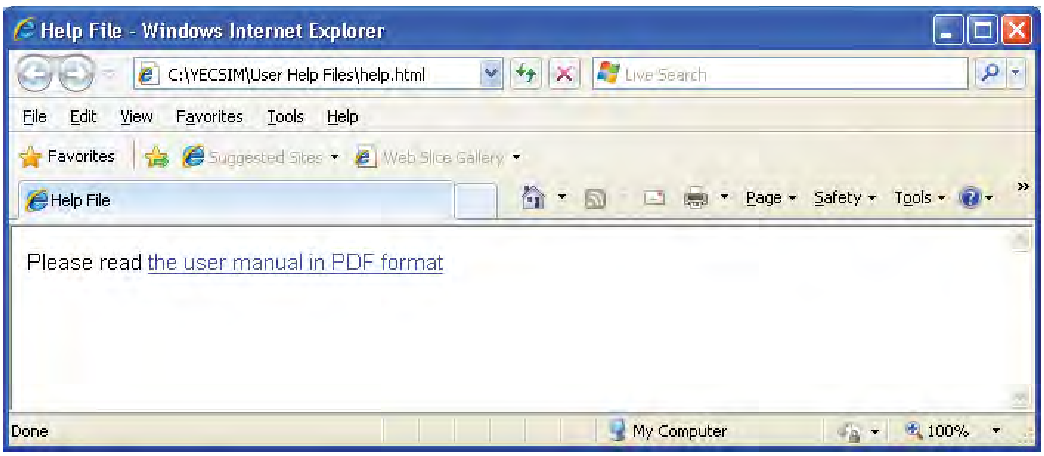


Figure 3.52 – The Link Window to Open the User Manual

3.6 ABOUT YECSIM

The ***About YECSIM*** option, shown in Figure 3.51, provides some information related to the software YECSIM. Click this option and the ***About YECSIM*** window will appear as shown in Figure 3.53.

Click the ***OK*** button to return to the main menu.

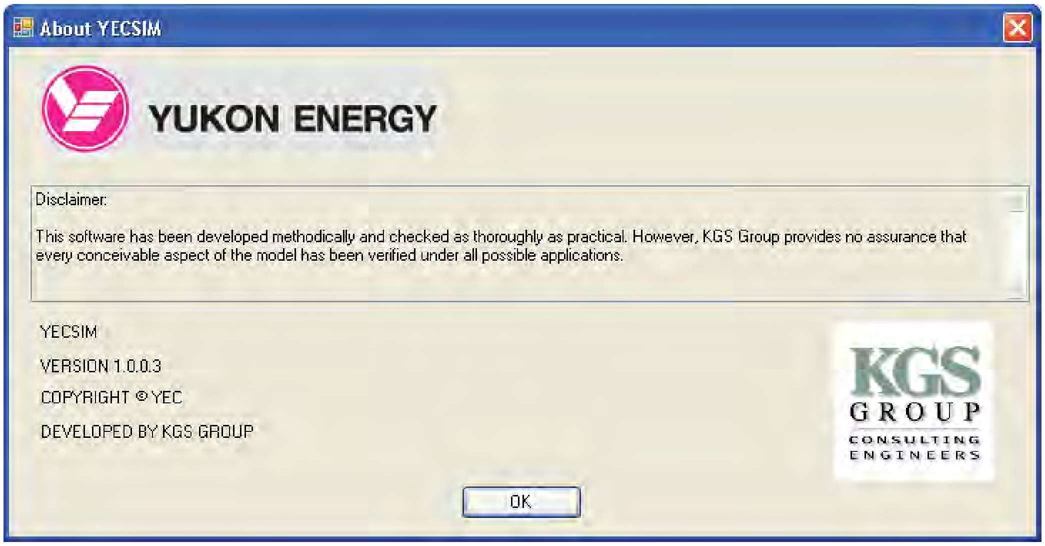


Figure 3.53 – The About Window

3.7 COMPACT DATABASE

When YECSIM is used frequently, the size of the current database tends to increase. This resulted in errors in early versions of the program. The ***Compact Database*** option in the ***Help*** menu (Figure 3.51) is used to compact the YECSIM database to prevent it from becoming too large.

It is recommended to compact the database after completing every 10 simulations using YECSIM.

Click the ***Compact Database*** option in the ***Help*** menu. A warning window from MS Access, shown in Figure 3.54, will appear.

Figure 3.54 – Warning for Compacting Database

The buttons shown on the window (Figure 3.54) are described below:

- **OK**

Click the ***OK*** button to compact the database included in YECSIM, and then return to the main window (Figure 3.1). Normally, users will not lose any data in the database due to database compaction.

- **Cancel**

Click ***Cancel*** button to return to the main window (Figure 3.1) without compacting the database.

3.8 EXIT

Click the ***Exit*** menu (Figure 3.1) to exit YECSIM.

4.0 INPUT

4.1 OVERVIEW

The input file includes most of the information required for a simulation. Normally, the data types included in an input file are as follows:

For Lakes/Reservoirs:

- Inflows-available-for-outflow for all available water years.
- Riparian discharges.
- Lake operation policies (required minimum water levels at various times of the year).
- Water level operation requirements (minimum / maximum).
- Spillway rating curves (stage-discharge relationships).
- Elevation-storage volume relationships.

For Generating Stations

- Active turbine units.
- Turbine maximum discharges.
- Transmission and station service loss coefficients.
- Tailwater level coefficients.
- Head loss coefficients.
- 3-tier system for specification of turbine / generator efficiencies.
- Winter ice effects on tailwater levels for Whitehorse Generating Station.
- Discharge limits to the existing Mayo Generating Station if the Mayo B Generating Station is available.

For Energy Data

- System energy demand per load year.
- Diesel energy generator capacity per load year.
- Weekly energy distribution factors in each year.
- Energy load duration curve in a week.

The detailed input requirements are described in next section.

4.2 DESCRIPTION OF INPUT FILE

There are 29 data types in a typical YECSIM input file. Each data type has a description line and a number of input data lines. The number of input data lines depends on the number of items of data. All the data types described in this section should be included in the input file, unless specified otherwise. There is a maximum of 10 pieces of data in each input line. The detailed description for each data type is as follows:

DATA TYPE 0

Set a simulation title. There is one input line only.

For Example:
WAF SYSTEM

DATA TYPE 1

Set the number of sites (lakes/reservoirs and generating stations). There is one line only.

For Example:
6

Other pointers:

- The number of sites is equal to 4 if only the WAF system is to be simulated in this run. In this case, the user should only set all parameters related to the WAF system, and should not add any parameters related to the MD system (i.e. Mayo Lake, Wareham Lake, the existing Mayo Generating Station, and Mayo B Generating Station).
- The number of sites is equal to 6 if the integrated WAF / MD system is required to be simulated.

1 - Whitehorse Rapids Generating Station / Schwatka Lake
2 - Marsh Lake
3 - Canyon Lake / Aishihik Generating Station
4 - Aishihik Lake
5 - Wareham Lake / the Existing Mayo Generating Station & Mayo B Generating Station
6 - Mayo Lake

DATA TYPE 2

Set water year periods of IAO data. The number of the input lines in this section depends on the number of lakes/reservoirs defined in DATA TYPE 1. There are 4 columns in each line:

Column 1: the site number
Column 2: the start water year
Column 3: the end water year
Column 4: the site name

For Example:

1	1987	2007	: Whitehorse Rapid Generating Station/Schwatka Lake
2	1987	2007	: Marsh Lake
3	1987	2007	: Aishihik K Generating Station/Canyon Lake
4	1987	2007	: Aishihik Lake
5	1987	2007	: Existing Mayo Generating Station/Wareham Lake
6	1987	2007	: Mayo Lake

DATA TYPE 3

Set load year period. There are two columns in the input line:
Column 1: the start load year
Column 2: the end load year

For Example:
2001 2008

DATA TYPE 4

Set water year period used in the simulation. There are two columns in the input line:

Column 1: the start water year
Column 2: the end water year

For Example:
1987 2007

DATA TYPE 5

Set drawdown priority of lakes/reservoirs. The number of the input lines depends on the number of lakes/reservoirs defined in DATA TYPE 1. There are 2 columns in each line, including the priority and the corresponding site name. When a lake/reservoir must keep a constant water level in a simulation, the priority has to be set to 0.

For Example:

0 : Schwatka Lake
1 : Marsh Lake
0 : Canyon Lake
3 : Aishihik Lake
0 : Wareham Lake
2 : Mayo Lake

For this case, the priority values of Schwatka Lake, Canyon Lake and Wareham Lake are "0", which means that these three lakes must maintain a constant water level during a simulation. The priority is use of storage from Marsh Lake at first, then Mayo Lake, and then Aishihik Lake, as required to supply water to generate energy to supply the energy demand.

DATA TYPE 6

Set the minimum operation level for each lake/reservoir. There is one line only. The number of columns of this line depends on the number of sites stated in DATA TYPE 1.

For Example:

653.07 653.796 905.870 913.0 573.90 663.27

In this example,

Column 1: 653.07, the minimum operation level of Schwatka Lake
Column 2: 653.796, the minimum operation level of Marsh Lake
Column 3: 905.870, the minimum operation level of Canyon Lake
Column 4: 913.0, the minimum operation level of Aishihik Lake
Column 5: 573.90, the minimum operation level of Wareham Lake
Column 6: 663.27, the minimum operation level of Mayo Lake

DATA TYPE 7

Set the maximum operation level for each reservoir. The input requirements are the same as DATA TYPE 6.

For Example:

653.07 656.234 907.42 915.16 573.9 665.87

DATA TYPE 8

Set the initial water level for each reservoir. The input requirements are the same as DATA TYPE 6.

For Example:

653.07 656.234 907.42 915.16 573.9 665.87

DATA TYPE 9

Set the number of points on the spillway/outlet rating curve for each lake/reservoir. The requirement is the same as DATA TYPE 6.

For Example:

0 14 0 0 0 17

DATA TYPE 9A

Set the discharge capacity (m3/s) from Marsh Lake, for the lake levels given in DATA TYPE 9B. This is for all gates fully open at the Lewes Control Dam. The number of the input lines depend on the number of points specified in DATA TYPE 9 for Marsh Lake, and correspond directly to them.

For Example:

25.0 90.0 158.0 220.0 294.0 370.0 448.0 526.0 610.0 690.0
760.0 860.0 960.0 1060.0

DATA TYPE 9B

Set the water levels (m) on Marsh Lake for the corresponding discharge capacities stated in DATA TYPE 9A.

For Example:

653.0 653.5 654.0 654.5 655.0 655.5 656.0 656.5 657.0 657.5
658.0 658.5 659.0 659.5

DATA TYPE 9C

Set the spillway discharge capacity (m^3/s) for the Mayo Lake outlet. The number of the input lines depends on the number of points specified in DATA TYPE 9 for Mayo Lake.

For Example:

0.000 0.180 2.360 5.800 10.300 16.100 21.000 25.000 28.600 31.500
35.420 50.000 60.000 70.000 80.000 95.000 110.000

DATA TYPE 9D

Set the water levels (m) for Mayo Lake that correspond to the discharge capacities stated in DATA TYPE 9C.

For Example:

660.800 661.000 661.500 662.000 662.500 663.000 663.500 664.000 664.500 665.00
665.730 666.000 666.100 666.200 666.300 666.400 666.500

DATA TYPE 10

Set coefficients for the elevation-storage relationship for each lake/reservoir. The number of the input lines depends on the number of sites defined in DATA TYPE 1. There are 3 columns in each line:

Column 1: coefficient C_1 (see Equation 3.1 in Section 3)
Column 2: coefficient C_2 (see Equation 3.1 in Section 3)
Column 3: coefficient C_3 (see Equation 3.1 in Section 3)

For Example:

650.0000 0.00236842000 1.00000
652.0000 0.00000647715 1.00000
904.0000 0.00041474000 1.00000
911.7120 0.00008003750 0.90487
573.8000 0.00001000000 1.00000
660.0000 0.00003814000 1.00000

DATA TYPE 11

Set the number of the available turbine-generator units at the Mayo B Generating Station. There is one input line only. If the Mayo B Generating Station is not available, please set to 0 in the input line.

For Example:

1

Please note the DATA TYPE 11 should not appear in the input data file if the number of sites is equal to 4 (specified in DATA TYPE 1), which states only the WAF system is to be simulated in this run.

DATA TYPE 12

Set available numbers of turbine-generator units at each generating station except Mayo B (which is stated in DATA TYPE 11). The input requirement is the same as DATA TYPE 6. Add zeroes for the sites that don't have a generating station.

For Example:

4	0	3	0	2	0

DATA TYPE 13A

Set the maximum turbine flows (m^3/s) weekly for the Whitehorse Rapids Generating Station. There are totally 52 points, which represent 52 weeks in a year.

For Example:

160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0	160.0
160.0	160.0	160.0	160.0	285.0	285.0	285.0	285.0	285.0	285.0
285.0	285.0	285.0	285.0	285.0	285.0	285.0	285.0	285.0	285.0
285.0	285.0	285.0	285.0	285.0	285.0	285.0	285.0	285.0	285.0
285.0	240.0	200.0	180.0	160.0	160.0	160.0	160.0	160.0	160.0
160.0	160.0								

DATA TYPE 13B

Set the maximum turbine flows (m^3/s) for the Aishihik Generating Station. There are totally 52 points, which represent 52 weeks in a year.

For Example:

23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96
23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96
23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96
23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96
23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96	23.96
23.96	23.96								

DATA TYPE 13C

Set the maximum turbine discharge capacity (m^3/s) for the Mayo complex, including the existing Mayo Generating Station and the Mayo B Generating Station. There are totally 52 points, which represent 52 weeks in a year.

For Example:

25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
25.00	25.00								

DATA TYPE 14A

Set the minimum allowable releases (m^3/s) from Schwatka Lake. There are totally 52 points, which represent 52 weeks in a year.

For Example:

85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0

DATA TYPE 14B

Set the minimum allowable releases (m^3/s) from Marsh Lake. There are totally 52 points, which represent 52 weeks in a year.

For Example:

85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0 85.0
85.0 85.0

DATA TYPE 14C

Set the minimum allowable releases (m^3/s) from Canyon Lake. There are totally 52 points, which represent 52 weeks in a year.

For Example:

2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832
2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832
2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832
2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832
2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832 2.832
2.832 2.832

DATA TYPE 14D

Set the minimum allowable releases (m^3/s) from Aishihik Lake. There are totally 52 points, which represent 52 weeks in a year.

For Example:

1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416
1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416
1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416
1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416
1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416 1.416
1.416 1.416

DATA TYPE 14E

Set the minimum allowable releases (m^3/s) from Wareham Lake. There are totally 52 points, which represent 52 weeks in a year.

For Example:

2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8

DATA TYPE 14F

Set the minimum allowable releases (m^3/s) from Mayo Lake. There are totally 52 points, which represent 52 weeks in a year.

For Example:

2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8 2.8
2.8 2.8

DATA TYPE 14G

Set the minimum allowable releases (m^3/s) through Otter Falls. There are totally 52 points, which represent 52 weeks in a year.

For Example:

0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142
0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.425	0.567	0.708
0.708	0.708	0.708	0.708	0.708	0.708	0.708	0.708	0.708	0.708
0.708	0.708	0.708	0.708	0.708	0.708	0.425	0.425	0.142	0.142
0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142	0.142
0.142	0.142								

DATA TYPE 15A

Set discharges for the 3-tier system of defining the turbine-generator efficiency for Whitehorse Rapids Generating Station. There are 3 columns in the input line:

Column 1: discharge (m^3/s) below which the first tier efficiency prevails
Column 2: discharge (m^3/s) below which the second tier efficiency prevails (and above the first tier range)
Column 3: discharge (m^3/s) at full gate opening at which the third tier efficiency prevails

For Example:

85.00 85.00 285.0

(JQ this does not make sense there should be three levels of flow to suit the definition we have laid out)

DATA TYPE 15B

Set 3-tier of efficiency for Whitehorse Rapids Generating Station. There are 3 columns in the input line:

Column 1: the first tier efficiency
Column 2: the second tier efficiency
Column 3: the third tier efficiency

For Example:

0.825 0.825 0.806

DATA TYPE 15C

Set discharges for the 3-tier system of defining the turbine-generator efficiency for Aishihik Generating Station. There are 3 columns in the input line:

Column 1:	discharge (m^3/s) below which the first tier efficiency prevails
Column 2:	discharge (m^3/s) below which the second tier efficiency prevails (and above the first tier range)
Column 3:	discharge (m^3/s) at full gate opening at which the third tier efficiency prevails

For Example:

3.000	6.000	23.96

DATA TYPE 15D

Set 3-tier of efficiency for Aishihik Generating Station. There are 3 columns in the input line:

Column 1:	the first tier efficiency
Column 2:	the second tier efficiency
Column 3:	the third tier efficiency

For Example:

0.880	0.872	0.863

DATA TYPE 15E

Set discharges for the 3-tier system of defining the turbine-generator efficiency for the existing Mayo Generating Station. There are 3 columns in the input line:

Column 1:	discharge (m^3/s) below which the first tier efficiency prevails
Column 2:	discharge (m^3/s) below which the second tier efficiency prevails (and above the first tier range)
Column 3:	discharge (m^3/s) at full gate opening at which the third tier efficiency prevails

For Example:

2.000	3.000	15.000

DATA TYPE 15F

Set 3-tier of efficiency for the existing Mayo Generating Station. There are 3 columns in the input line:

Column 1: the first tier efficiency prevails
Column 2: the second tier efficiency prevails
Column 3: the third tier efficiency prevails

For Example:

0.863	0.863	0.863

DATA TYPE 15G

Set discharges for the 3-tier system of defining the turbine-generator efficiency for Mayo B Generating Station. There are 3 columns in the input line:

Column 1: discharge (m^3/s) below which the first tier efficiency prevails
Column 2: discharge (m^3/s) below which the second tier efficiency prevails (and above the first tier range)
Column 3: discharge (m^3/s) at full gate opening at which the third tier efficiency prevails

For Example:

2.500	5.000	22.20

DATA TYPE 15H

Set 3-tier of efficiency for Mayo B Generating Station. There are 3 columns in the input line:

Column 1: the first tier efficiency
Column 2: the second tier efficiency
Column 3: the third tier efficiency

For Example:

0.689	0.863	0.873

DATA TYPE 16A

Set the coefficients for computation of the tailwater levels at the Whitehorse Rapids Generation Station. There are 3 columns in the input line:

Column 1: coefficient C_1 (see Equation 3.2 in Section 3 for detailed description)
Column 2: coefficient C_2 (see Equation 3.2 in Section 3 for detailed description)
Column 3: coefficient C_3 (see Equation 3.2 in Section 3 for detailed description)

For Example:
631.500 0.100 0.600

DATA TYPE 16B

Set the coefficients for computation of the tailwater levels at Aishihik Generation Station. There are 3 columns in the input line:

Column 1: coefficient C_1 (see Equation 3.2 in Section 3 for detailed description)
Column 2: coefficient C_2 (see Equation 3.2 in Section 3 for detailed description)
Column 3: coefficient C^3 (see Equation 3.2 in Section 3 for detailed description)

For Example:
718.414 0.320 0.680

DATA TYPE 16C

Set the coefficients for computation of the tailwater levels at the existing Mayo Generation Station. There are 3 columns in the input line:

Column 1: coefficient C_1 (see Equation 3.2 in Section 3 for detailed description)
Column 2: coefficient C_2 (see Equation 3.2 in Section 3 for detailed description)
Column 3: coefficient C^3 (see Equation 3.2 in Section 3 for detailed description)

For Example:
536.00 0.00 0.000

DATA TYPE 16D

Set the coefficients for computation of the tailwater levels at Mayo B Generation Station. There are 3 columns in the input line:

Column 1: coefficient C_1 (see Equation 3.2 in Section 3 for detailed description)
Column 2: coefficient C_2 (see Equation 3.2 in Section 3 for detailed description)
Column 3: coefficient C^3 (see Equation 3.2 in Section 3 for detailed description)

For Example:
510.00 0.00 0.000

DATA TYPE 17A

Set coefficients for computing head losses in the water conveyance system at Whitehorse Rapids Generation Station. There are 3 columns in the input line:

Column 1:	coefficient C_1 (see Equation 3.3 in Section 3 for detailed description)
Column 2:	coefficient C_2 (see Equation 3.3 in Section 3 for detailed description)
Column 3:	coefficient C_3 (see Equation 3.3 in Section 3 for detailed description)

For Example:

0.00000	626.5386	0.00223

DATA TYPE 17B

Set coefficients for computing head losses in the water conveyance system at Aishihik Generation Station. There are 3 columns in the input line:

Column 1:	coefficient C_1 (see Equation 3.3 in Section 3 for detailed description)
Column 2:	coefficient C_2 (see Equation 3.3 in Section 3 for detailed description)
Column 3:	coefficient C_3 (see Equation 3.3 in Section 3 for detailed description)

For Example:

0.0076758	0.018	19.46

DATA TYPE 17C

Set coefficients for computing head losses in the water conveyance system at the existing Mayo Generation Station. There are 3 columns in the input line:

Column 1:	coefficient C_1 (see Equation 3.3 in Section 3 for detailed description)
Column 2:	coefficient C_2 (see Equation 3.3 in Section 3 for detailed description)
Column 3:	coefficient C_3 (see Equation 3.3 in Section 3 for detailed description)

For Example:

1.500	2.00	15.000

DATA TYPE 17D

Set coefficients for computing head losses in the water conveyance system at Mayo B Generation Station. There are 3 columns in the input line:

Column 1:	coefficient C_1 (see Equation 3.3 in Section 3 for detailed description)
Column 2:	coefficient C_2 (see Equation 3.3 in Section 3 for detailed description)
Column 3:	coefficient C_3 (see Equation 3.3 in Section 3 for detailed description)

For Example:

0.050	2.00	22.20

DATA TYPE 18

Set the increase in tailwater level (m) due to winter ice effects at the Whitehorse Rapids Generation Station over the open water level that would occur. The increases are stated for each week of the year (52 data values).

For Example:

0.30 0.30 0.30 0.30 0.30 0.30 0.30 0.15 0.15 0.15
0.15 0.15 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00
0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00
0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00
0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.00 0.15 0.15
0.15 0.15

DATA TYPE 19A

Set the licensed minimum reservoir water level (m) for Marsh Lake for each week of the year. There are totally 52 points, which represent 52 weeks in a year. For the summer weeks, the values in this data group indicate the level at or above which all the gates at the Lewes Dam should be fully open. The example values correspond to the current license (weeks 20 to 33).

For Example:

656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234
656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234
656.234 656.234 656.234 656.234 656.234 656.234 654.820 654.985 655.150 655.317
655.483 655.650 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234
656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234 656.234
656.234 656.234

DATA TYPE 19B

Set the discharge capacity (m^3/s) from Marsh Lake outlet, for the lake levels given in DATA TYPE 9B. This is for 10 gates fully open at the Lewes Control Dam.

For Example:

20.0 53.0 85.0 119.0 157.0 200.0 245.0 292.0 347.0 403.0
510.0 600.0 670.0 714.0

DATA TYPE 20A

Provide the previous 10-year water level records (m) on Aishihik Lake (mean annual) required to apply the 10-year rolling average policy. There are 10 columns in the input line.

For Example:

913.00 913.74 914.48 914.41 914.40 914.16 914.12 914.20 913.86 914.260

DATA TYPE 20B

Set the minimum water level (m) required by the 2 in 5-year policy for Aishihik Lake.

For Example:
913.70

DATA TYPE 21

Set the minimum and the maximum discharges (m^3/s) through the existing Mayo Generating Station if new Mayo B station is active. There are 2 columns in the input line:

Column 1: the minimum allowable discharge (m^3/s)
Column 2: the maximum allowable discharge (m^3/s)

For Example:
6.00 10.00

DATA TYPE 22

Set the total diesel generator capacity in the YEC Generating System per load year (MW). The number of the input lines depends on the number of load years being simulated (normally 8).

For Example:
44.0 44.0 44.0 44.0 44.0 44.0 44.0 44.0

DATA TYPE 23

Set the total energy demand per load year (GW.H). The number of the input lines depends on the number of load years (normally 8).

For Example:
468.1 468.1 468.1 468.1 468.1 468.1 468.1 468.1

DATA TYPE 24

Set the energy loss coefficients that represent the station service loads at the generating stations, in the form of a factor that is applied to the gross energy generation at the site. The input format is similar to DATA TYPE 6.

For Example:
0.015 0.000 0.015 0.000 0.015 0.00

DATA TYPE 25

Set coefficients that represent energy losses from the transmission lines, in the form of a factor that is applied to the gross hydroelectric energy generated (no losses are applied to diesel generation). The input format is very similar to DATA TYPE 6.

For Example:

0.000 0.000 0.000 0.000 0.000

Note that it has been the custom of YEC to incorporate the transmission losses into the system load forecasts, so if that is the case for the simulation, then the transmission loss coefficients should be zero.

DATA TYPE 26

Set the coefficient that is used to represent the loss due to force outages at the generating stations (this is further explained in Section 6). The input format is very similar to DATA TYPE 6.

For Example:

0.030 0.000 0.030 0.000 0.030 0.000

DATA TYPE 27

Set the factors that define the weekly distribution of the energy demand throughout the year as a proportion of the total load for the year (i.e. from DATA TYPE 23). By definition, the overall average of the 52 weekly factors must equal 1.0.

For Example:

1.207	1.178	1.256	1.332	1.266	1.220	1.108	1.160	1.124	1.172
1.193	1.095	0.994	1.074	1.032	0.982	0.964	0.914	0.922	0.882
0.838	0.848	0.852	0.844	0.842	0.835	0.825	0.836	0.825	0.835
0.823	0.818	0.822	0.844	0.850	0.850	0.876	0.913	0.909	0.932
0.947	0.937	0.955	1.004	1.036	1.073	1.083	1.057	1.189	1.175
1.243	1.206								

DATA TYPE 28

Set the number of points on the generic system load duration curve.

For Example:

168

Note that the load duration curve (and all parts of DATA TYPE 28) is not used in the program at this juncture in the program development (see further explanation in Section 6).

DATA TYPE 28A

Set load values for each of the points on the load duration curve. The number of the input lines depends on the number of points specified in DATA TYPE 28.

For Example:

1.28	1.26	1.25	1.25	1.24	1.23	1.23	1.23	1.22	1.22
1.21	1.21	1.21	1.20	1.20	1.20	1.20	1.19	1.19	1.19
1.18	1.18	1.18	1.18	1.18	1.17	1.17	1.17	1.17	1.16

DATA TYPE 28B

Set percent of time exceeded for each of the loads. The number of the input lines depends on the number of points specified in DATA TYPE 28.

For Example:

1.00	2.00	3.00	4.00	5.00	6.00	7.00	8.00	9.00	10.00
11.00	12.00	13.00	14.00	15.00	16.00	17.00	18.00	19.00	20.00
21.00	22.00	23.00	24.00	25.00	26.00	27.00	28.00	29.00	30.00

DATA TYPE 29A

Set the site number of Schwatka Lake.

For Example:

1

DATA TYPE 29B

Set local IAO data for the site specified in DATA TYPE 29A. The water year period for the local IAO data is defined in DATA TYPE 2. There are 52 points in each water year, which represent 52 weeks in a year.

For Example:

0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

DATA TYPE 29C

Set the site number of Marsh Lake.

For Example:

2

DATA TYPE 29D

Set IAO data for the site specified in DATA TYPE 29C. The water year period for IAO data is defined in DATA TYPE 2. There are 52 points in each water year, which represent 52 weeks in a year.

For Example:

100.85	84.29	91.93	75.67	80.66	78.04	86.81	55.46	33.87	67.27
86.45	67.01	60.62	24.39	54.39	28.60	-8.94	41.39	94.03	89.90
135.34	282.03	331.79	312.28	370.99	525.32	723.78	597.52	503.58	620.79

DATA TYPE 29E

Set the site number of Canyon Lake.

For Example:

3

DATA TYPE 29F

Set the local IAO data for the site specified in DATA TYPE 29E. The water year period for the local IAO data is defined in DATA TYPE 2. There are 52 points in each water year, which represent 52 weeks in a year.

For Example:

0.16	0.16	0.15	0.15	0.13	0.12	0.10	0.08	0.06	0.04
4.65	3.85	1.62	1.12	1.03	1.66	1.23	1.21	0.97	0.65
0.61	0.84	1.12	1.24	0.66	1.00	1.56	0.93	0.91	1.29

DATA TYPE 29G

Set the site number of Aishihik Lake.

For Example:

4

DATA TYPE 29H

Set the IAO data for the site specified in DATA TYPE 29G. The water year period for IAO data is defined in DATA TYPE 2. There are 52 points in each water year, which represent 52 weeks in a year.

For Example:

3.09	4.20	5.51	3.67	2.32	3.63	2.05	4.81	3.82	3.12
2.35	3.10	0.97	0.06	3.72	1.91	2.94	4.15	9.12	10.35
6.47	8.67	18.06	19.04	13.59	10.57	16.60	9.89	9.68	9.72

DATA TYPE 29I

Set the site number of Wareham Lake.

For Example:
5

DATA TYPE 29J

Set the local IAO data for the site specified in DATA TYPE 29I. The water year period for the local IAO data is defined in DATA TYPE 2. There are 52 points in each water year, which represent 52 weeks in a year.

For Example:

1.85	1.87	1.93	2.41	2.11	1.26	1.01	0.32	1.09	1.15
30.13	47.08	27.75	11.29	11.26	11.31	9.03	14.07	8.83	4.31
3.38	4.62	6.58	7.20	5.17	6.85	10.39	8.77	9.25	9.44

DATA TYPE 29K

Set the site number of Mayo Lake.

For Example:
6

DATA TYPE 29L

Set the IAO data for the site specified in DATA TYPE 29K. The water year period for IAO data is defined in DATA TYPE 2. There are 52 points in each water year, which represent 52 weeks in a year.

For Example:

3.83	3.85	3.98	4.97	4.36	2.60	2.09	0.67	2.26	2.38
62.18	97.17	57.28	23.30	23.25	23.34	18.63	29.03	18.22	8.89
6.98	9.54	13.57	14.87	10.66	14.13	21.44	18.10	19.09	19.48

4.3 LIMITS OF THE INPUT FILE

The following input data that is not included in the input file has to be imported using the graphical user interface if the user needs:

- The spillway rating curve for Mayo Lake for the flash boards down.
- The minimum plant flow in each week for Mayo B Generation Station.
- The weekly wind energy in a year.

5.0 OUTPUT

5.1 OVERVIEW

YECSIM creates 4 output files in a text format:

- Result File: Stores all model results.
- Warning File: Stores warning messages.
- Energy File: Stores energy data.
- Mayo A + B Data: Stores flow data and energy data for Mayo A GS and Mayo B GS separately.

The description of these output files is in the following sections.

5.2 RESULT FILE

5.2.1 Overview of the Result File

YECSIM exports model results to a text file, which consists of the following sections:

1. Simulation options.
2. Input data.
3. Rule curve data for all sites (for explanation of reservoir rule curves see Section 6).
    - Rule curve data in live storage format for each site.
    - Rule curve data in water level format for each site.
    - Rule curve in water level format for Aishihik Lake at the minimum operational level = 913.7 m.
4. Energy demands.
5. Model results for all cycles. See Section 6 for further explanation of cycles.
   In each cycle, the following parameters are included:
    - Live storage for each site.
    - Water levels of each site.
    - Outflows of each site.
    - Spillages of each generating station.
    - Energy generated to serve load at each generating station.
    - Potential secondary energy generated at each generating station.
    - Energy generated to serve load at all generating stations.
    - Potential secondary energy generated at all generating stations.
    - Energy required from diesel.

6. Averaged data of all cycles.
   - Live storage of each site.
   - Water levels of each site.
   - Outflows of each site.
   - Spillages from each generating station.
   - Energy generated to serve load at each generating station.
   - Potential secondary energy generated at each generating station.
   - Energy demands.
   - Energy generated to serve load at all generating stations.
   - Potential secondary energy generated at all generating stations.
   - Energy required from diesel.

5.2.1 Simulation Options

This section is used to indicate:

- Lake drawdown method.
- Lake operation conditions.
- Generating station operating conditions.

5.2.2 Input Data

This section is used to export input parameters. The section is bounded by the description lines "INPUT DATA INFORMATION BEGIN" and "INPUT DATA END". Compared to the input file (see Chapter 4), many blank lines are added to this section for better view. The output structure of IAO data is as follows (Format 1):

- Two blank lines.
- One line for the result data description.
- One line for the site name and site number.
- One line for the water years listing.

There are many columns in this line. The first column states the line description *Water Year*. The remaining columns list the water years.

- One blank line.
- Data output.

Each column contains 52 rows, which indicates 52 weeks. The first column lists the week number. The other columns list the data value in the corresponding week and year.

- One blank line.
- One line for the minimum value in each year.
- One line for the maximum value in each year.
- One line for the average value in each year.
- One line for the average value of all years.

For Example:

```
       INFLOW AVAILABLE FOR OUTFLOW
       WHITEHORSE RAPIDS GENERATING STATION    - SITE NO =   1
       WATER YEAR    1987       1988       1989       1990       1991      …

              1   100.850     83.770     94.010    116.950     82.180      …
              2    84.290     78.280    101.930    115.560     93.330      …
              3    91.930    100.030     86.550     97.410     91.980      …
              …         …          …          …          …          …      …
             52    78.330    116.860    111.790     95.860    124.280      …

      MINIMUM      -8.940     37.800     17.670     -3.230     36.710      …
      MAXIMUM     723.780    769.210    705.540    726.150    755.990      …
      AVERAGE     240.075    261.709    289.634    282.602    263.924      …
      ANNUAL AVERAGE:          251.262
```

5.2.3 Rule Curves

In this section, the rule curve data includes the following:

- Rule curve data in live storage (%) format for each site.
- Rule curve data in water level (m) format for each site.
- Rule curve data in water level (m) format for Aishihik Lake at the minimum operational level = 913.7 m.

The output structure of rule curve data for each site is as follows (Format 2):

- Two blank lines.
- One line for the result data description.
- One line for the site name and site number.
- One line for the load years listing.

There are many columns in this line. The first column states the line description Load Year. The remaining columns list the load years.

- One blank line.
- Data output.

Each column contains 52 rows, which indicates 52 weeks. The first column lists the week number. The other columns list the data value in the corresponding week and year.

- One blank line.
- One line for the minimum value in each year.
- One line for the maximum value in each year.
- One line for the average value in each year.
- One line for the average value of all years.

For Example:

```
       RULE CURVE - LIVE STORAGE (million m3)
       MARSH LAKE                              - SITE NO =   2
       LOAD YEAR     2001       2002       2003       2004       2005        …

              1   494.121   494.121   494.121   494.121   494.121        …
              2   488.212   488.212   488.212   488.212   488.212        …
              3   489.887   489.887   489.887   489.887   489.887        …
              …         …         …         …         …         …        …
             52   511.624   511.624   511.624   511.624   511.624        …

      MINIMUM       0.000     0.000     0.000     0.000     0.000        …
      MAXIMUM     513.372   513.372   513.372   513.372   513.372        …
      AVERAGE     240.980   240.980   240.980   240.980   240.980        …
      ANNUAL AVERAGE:         235.814
```

5.2.4 Energy Demands

This section exports the weekly energy demand for all load years. The output structure of energy demand data is as follows (Format 3):

- Two blank lines.
- One line for the result data description.
- One line for the load years listing.

There are many columns in this line. The first column states the line description *Load Year*. The remaining columns list the load years.

- One blank line.
- Data output.

Each column contains 52 rows, which indicates 52 weeks. The first column lists the week number. The other columns list the data value in the corresponding week and year.

- One blank line.
- One line for the minimum value in each year.
- One line for the maximum value in each year.
- One line for the average value in each year.
- One line for the average value of all years.

For Example:

```
 ENERGY DEMAND FOR ALL LOAD YEARS (MW.H)
LOAD YEAR     2001      2002      2003      2004      2005      …

        1 13348.956 13348.956 13348.956 13348.956 13348.956      …
        2 13028.227 13028.227 13028.227 13028.227 13028.227      …
        3 13890.877 13890.877 13890.877 13890.877 13890.877      …
        …       …         …          …         …          …      …
       52   511.624   511.624   511.624   511.624   511.624      …

MINIMUM  9046.765  9046.765  9046.765  9046.765  9046.765       …
MAXIMUM 14731.408 14731.408 14731.408 14731.408 14731.408       …
AVERAGE 11058.977 11058.977 11058.977 11058.977 11058.977       …
ANNUAL TOTAL AVERAGE:      575066.821
```

5.2.5 Model Results for All Cycles

This section exports the model results for all cycles. The section is bounded by the description lines "RESULT DATA FOR EACH CYCLE" and "RESULT DATA FOR EACH CYCLE - DONE". The results for each cycle include the following:

1. Result data related to each lake:
    - Live storage volume (%).
    - Water level (m).
    - Outflow (m^3/s).

2. Result data related to each generation station:
    - Spillage (m^3/s).
    - Energy generated to serve load (MW.h).
    - Potential secondary energy generated (MW.h).

3. Energy data for all generating stations:
    - Energy generated to serve load (MW.h).
    - Potential secondary energy generated (MW.h).
    - Energy required from diesel (MW.h).

The output structure of the result data for each lake or generation station is as follows (Format 4):

- Two blank lines.
- One line for the result data description.
- One line for the site name and site number.
- One line for the load years listing.

There are many columns in this line. The first column states the line description *Load Year*. The remaining columns list the load years.

- One line for the water years listing.

There are many columns in this line. The first column states the line description Water Year. The remaining columns list the water years.

- One blank line.
- Data output.

Each column contains 52 rows, which indicates 52 weeks. The first column lists the week number. The other columns list the data value in the corresponding week and year.

- One blank line.
- One line for the minimum value in each year.
- One line for the maximum value in each year.
- One line for the average value in each year.
- One line for the average value of all years.

For Example:

```
      WATER LEVEL (M)
      AISHIHIK LAKE                            - SITE NO =   4
      LOAD YEAR     2001      2002      2003      2004      2005      …
      WATER YEAR    1993      1994      1995      1996      1997      …

            1   915.085   914.144   913.132   913.177   913.515      …
            2   915.033   914.069   913.122   913.148   913.518      …
            3   914.952   913.986   913.106   913.156   913.508      …
            …         …         …         …         …         …      …
           52   914.230   913.141   913.176   913.498   914.315      …

     MINIMUM    913.990   913.031   913.000   913.000   913.365      …
     MAXIMUM    915.085   914.144   913.459   913.659   914.506      …
     AVERAGE    914.516   913.303   913.205   913.325   913.907     …
     ANNUAL TOTAL AVERAGE:        914.103
```

The output structure of the energy result data for all generating stations is as follows (Format 5):

- Two blank lines.
- One line for the result data description.
- One line for the load years listing.

There are many columns in this line. The first column states the line description *Load Year*. The remaining columns list the load years.

- One line for the water years listing.

There are many columns in this line. The first column states the line description water Year. The remaining columns list the water years.

- One blank line.
- Data output.

Each column contains 52 rows, which indicates 52 weeks. The first column lists the week number. The other columns list the data value in the corresponding week and year.

- One blank line.
- One line for the minimum value in each year.
- One line for the maximum value in each year.
- One line for the average value in each year.
- One line for the average value of all years.

For Example:

```
      ENERGY FROM ALL PLANTS (MW.H)
      LOAD YEAR     2001      2002      2003      2004      2005      …
      WATER YEAR    1993      1994      1995      1996      1997      …

             1 11809.059 12081.652  5130.320  5130.320  5669.178     …
             2 11809.059 12081.652  5130.320  5130.320  3790.168     …
             3 11809.059 11809.059  5130.320  5130.320  4866.837     …
             …        …         …         …         …         …     …
            52 11841.201  5162.463  5456.073  5216.513  7911.864     …

      MINIMUM   9046.766  5162.463  4212.907  3384.613  3314.036     …
      MAXIMUM  12113.795 12081.652 11103.854 10473.831 10621.260     …
      AVERAGE  10646.445  8595.315  7466.246  7034.479  7341.923     …
ANNUAL TOTAL AVERAGE:        438778.648
```

5.2.6 Averaged data of all cycles

This section exports the average results for all cycles. The section is marked at the beginning by a description line "AVERAGED DATA FOR ALL CYCLES". The result outputs in this section include the following data information:

1. Averaged data for each lake/reservoir:
    - Live storage (%).
    - Water level (m).
    - Outflow (m^3/s).

2. Averaged data related to each generation station:
   - Spillage (m^3/s).
   - Energy generated to serve load (MW.h).
   - Potential secondary energy generated (MW.h).

3. Averaged energy data for all generating stations:
   - Energy demand (MW.h).
   - Energy generated to serve load (MW.h).
   - Potential secondary energy generated (MW.h).
   - Energy required from diesel (MW.h).

The output structure of the result data for each lake or generation station is the same as the output Format 2 described above. The output structure of the energy result data for all generating stations is the same as the output Format 3 described above.

5.3 WARNING FILE

The warning file is used to save all warning messages during a simulation. For example, a warning message will be provided in the simulation when the water level of a lake is less than the minimum allowable water level of the lake. In those cases, the lake name, the load year, the week and the corresponding water year in a cycle will be reported in the file.

5.4 ENERGY DATA FILE

The energy data file is used to save the annual energy data accumulated for all generating stations. In an energy file, the first line is the simulation title, and then the output data titles following. There are 8 columns in the energy data file:

- Column 1: cycle number
- Column 2: order number of a load year
- Column 3: load year
- Column 4: water year
- Column 5: total of the diesel energy required in a year (MW.h)
- Column 6: total of the potential secondary energy in a year (MW.h)
- Column 7: total of the energy generated to serve load in a year (MW.h)
- Column 8: total of the energy demands in a year (MW.h)

5.5 MAYO A+B DATA FILE

The Mayo A+B data file is used to save the flow and energy distribution between Mayo A GS and Mayo B GS. In a Mayo A+B data file, the first line is the simulation title, and then the output data titles following. There are 12 columns in the Mayo A+B data file:

- Column 1: cycle number
- Column 2: load year
- Column 3: water year
- Column 4: week
- Column 5: total outflow (m^3/s)
- Column 6: spillage (m^3/s)
- Column 7: Mayo A GS flow (m^3/s)
- Column 8: Mayo B GS flow (m^3/s)
- Column 9: energy generated to serve load at Mayo A GS (MW.h)
- Column 10: energy generated to serve load at Mayo B GS (MW.h)
- Column 11: total of the energy generated to serve load at Mayo A GS + Mayo B GS (MW.h)
- Column 12: secondary energy (MW.h)

6.0 PROGRAM THEORY

6.1 MODELLING STRAGTEGY AND ASSUMPTIONS

The YEC simulation model is a composite of a variety of sub-models that represent hydraulic conditions of water levels, reservoir volumes/water levels, generation of energy from hydroelectric generating station, etc. The following descriptions address the primary issues that affect modeling of the YEC system, and how the model has been configured to resolve them.

6.1.1 Time Steps

The model has been configured to represent the operation of the YEC system in weekly time steps. This duration was selected to balance a variety of factors:

- Short enough to represent the variations in the licensed water levels on the various reservoirs.
- Long enough that time of travel of flow between the reservoirs (such as between Marsh lake and Schwatka Lake, for example) does not affect the accuracy of the calculation of reservoir releases and does not require complex representations of travel times and attenuation of flow fluctuations.
- Long enough that the complex hourly load dispatching that occurs in the real world can be simplified to a general calculation based on averages over a weekly period.
- Short enough so that the variations in load over the seasons can be captured in the simulation process.

The model uses 52 weeks per year (364 days), and ignores leap years. River flow records have been adjusted to eliminate one (Dec. 31) or two days (Dec.31 and Feb. 29) each year (depending on leap year) so that weekly averages will comply with exactly 52 periods.

6.1.2 Rotation/Superimposition of "Water Years" on "Load Years"

A common procedure in power simulation models of this type is to superimpose a recorded sequence of river flows (called "water years") over the future years that are being analyzed (called "load years"). This provides one hypothetical scenario of energy generation capability that would occur if the recorded series of water years would repeat itself. The terminology used in this manual to refer to this single combination of water years over load years as a "cycle". The water years are then shifted by one year and superimposed on the load years again. This generates a second scenario, or cycle. This process is repeated until all possible combinations of recorded water years have been superimposed on each load year. If the end of the recorded water years is reached before the end of the load years, the first water year then is "wrapped around" to form a continuation of flow data. In this way, there are as many cycles as there are years of recorded flow data. The results become a basis for judging the range of possible energy generation and distribution between hydroelectric and diesel generated energy sources.

6.1.3 Inflows-Available-for-Outflow (IAO)

This data is the primary basis for the calculation of the hydroelectric energy generation. This data represents the "naturalized river flow" that would have occurred if the water released from, or stored in, the lakes/reservoirs is taken out. IAO is computed using the following fundamental equation:

Outflow=Inflow – Change in Storage

No special calculations of influences such as evaporation, precipitation, and volumes of storage occupied by reservoir ice cover in winter, are required with this approach. It is based on the assumption that the area of the lake is similar (preferably identical) to what it was when the recorded river flows were measured.

In the computation of these values for the reservoirs, numerous negative IAOs were revealed, particularly for Aishihik Lake. Negative IAOs are not necessarily incorrect, and can in some circumstances represent a realistic physical phenomenon. For example, in late summer, when evaporation from a large reservoir is at its peak in the annual cycle, the magnitude of water lost from evaporation could exceed the amount gained by precipitation and inflow of the river that flows into the reservoir. In winter, however, the negative inflows that consistently appear in the record for Aishihik Lake cannot be caused by evaporation, because the reservoir is ice-covered at that time and evaporation is obviously zero. Two plausible causes were identified:

- An error in the stage-area relationship from which the available storage was derived.
- Drawdown of the water level in the winter could cause some reservoir ice to hang up on the shallow zone near the shoreline and, as a result, prevent the water that has been calculated as available storage from being released.

Whatever the reasons are for the negative inflows, it was rationalized that they appear to be the result of some systemic error or physical phenomenon. Since the anomaly apparently affects the calculation of the IAOs and also the availability of storage in a more or less equal way, it was also rationalized that no major net error should arise in using the IAO record that contains numerous negative values.

Nevertheless, it is recommended that further consideration of the negative inflows be addressed in future studies to confirm this conclusion.

6.1.4 Length of Simulation Period

The first configuration of the model was developed with a vision to analyze a series of several decades of load growth, and how a possible range of hydrological conditions can affect the supply of the projected loads. However, it became clear that the future load projections are varied and diverse and are driven largely by the expectations of new mines that may start and the timing of their needs. It was decided that a model configuration that would be capable of addressing a single load year with a variety of possible hydrological conditions would be more useful and effective.

As a result of that revelation, the model was reconfigured to simulate a series of 8 years with a constant load demand in each year (however, with weekly distribution of that load over each week of the year). Eight years were needed so that the effects of the following "edge effects" could be eliminated:

- The effects of starting the reservoirs at a full stage on Jan 1 of the first load year. This is unrealistic. Although it could be resolved by choosing a lower starting water level that could be representative for comparative purposes between simulations, it was considered more effective for the initial effects to be eliminated by several years of operation. The end of the fifth year, was found for all cases addressed, to have reservoir levels that were identical. So the first five years are now considered as a "start-up phase" that leads to the sixth and seventh years, which can be used to generate system operation statistics that are not arbitrarily affected by the start-up conditions in the first year.

- The effects of the computation of the reservoir rule curves that protect against the drawdown of water levels under existing licensed limits. The rule curves are described in more detail below, but the point is that they allow the reservoir to draw down to the lowest limit on Dec.31 of the last load year. The backwards calculation from that point in time determines the rule curve. This arbitrary assignment of the lowest reservoir level would affect the simulations in an unrealistic way if not corrected. The means to eliminate such effects were selected to consist of allowing one additional years after the sixth and seventh years (i.e. Year 8) so that the last year would not unrealistically influence the statistics in the two previous years. This is a similar, but inverted, correction described in the bullet above.

In summary, all simulations consist of 8 load years with a constant load, with cycling of all combinations of hydrological records past each of the 8 years. The year that is used for statistical information that represents the results of the run are taken ***ONLY*** from Years 6 and 7.

6.1.5 System Load

YECSIM accepts two parameters to represent the load that must be served. First the user must specify the annual energy demand in Gwh. In addition, the user must supply weekly distribution factors that distribute that energy demand across each of the weeks in each load year. If the transmission line losses have been included in the load estimation, then the user should specify that the transmission line loss coefficient is zero.

Within a week, the program uses a load duration curve to estimate peak loads. The curve consists of 168 values, one for each hour in a week, each value corresponding to the ratio of hourly peak load over the average load of all hours. The duration curve, in conjunction with the weekly load, indicates the number of hours in a week for which a given load value would be equal or greater. The load duration curve is provided as input to the program. Use of the weekly load duration curve allows consideration of peak loads while simulating weekly time steps.

6.1.6 Hydroelectric Plant Models

Within the system simulation software there are internal "models" of each hydroelectric plant. The primary means of calculation the energy generated from a hydroelectric generating station is based on the following algorithm:

$E=9.8 * (HWL-(TWL+Ice)-H_l) * Q * e * 168$

Where:

E = Energy generated during a one week period (Kwh)
HWL=Reservoir water level (m)
TWL=Tailwater level for open water conditions (m)
Ice = The increase in tailwater level due to winter ice effects (m)
H_l = Head loss in the water conveyance system (m)
Q = Total discharge through the Powerhouse (m^3/s)

e = Turbine efficiency

168 Number of hours in one week

6.1.7 Turbine / Generator Efficiency

The algorithm for energy generation stated in Section 6.1.6 includes a value for efficiency of the turbine / generator unit. The efficiency of a turbine / generator unit is a function of the discharge released through the units, and the net head that is available. It varies often on an hourly basis depending on the characteristics of the operation needed to meet the varying loads. There is a temptation to supply a model like YECSIM a relationship between head, discharge and efficiency and to select the efficiency from that information, based on the discharge through the units. Although that would appear to apply precision in defining the efficiency, it is not accurate for a weekly simulation. In reality the discharge through a unit will vary substantially over the week. In reality, the discharge through the units will vary substantially over the week, and an attempt to precisely capture the swings in efficiency that would occur is beyond the scope of a planning model like YECSIM.

To provide a reasonable representation of the range of efficiencies that may occur, a "three tier" system has been used.

The first tier refers to a low range of total plant outflow, where it is clear that if the plant outflow were to average within that range, the efficiency would be relatively low. The user should select a representative value of the turbine/generator efficiency to reflect this.

The second tier represents the majority of operation wherein the plant outflow is less than maximum, but clearly above Tier 1. Again, the User must review the existing efficiency curves for the plant and select a value that would best represent the turbine/generator efficiency for this range.

The third tier is restricted to the case where the software has requested a continuous outflow for a week that represents the full gate discharge of the units in the plant. In this case, it is clear that the efficiency achieved in the generation of energy can be represented by the efficiency of the units at full gate discharge. Again the User must select the best values to represent the plant. It will normally (but not necessarily always) be less than the efficiency defined for Tier 1.

A summary of the values for efficiency that have been selected for the development of the software is provided in Appendix D-3. These have been taken from detailed information developed by Acres International some years ago and provided to KGS Group for this software development effort. The values selected by KGS Group are based solely on the data supplied by Acres, and no additional effort has been expended to check or refine these values. Such work was clearly out of scope and would have significantly added to the budget requirements of the software development.

6.1.8 Transmission Line Losses

Transmission of electricity through transmission lines invariably results in losses of energy. YEC has generally incorporated such losses in the estimation of system loads, so that no additional losses at the generating source must be recognized. However, the software has been developed to include separate transmission line losses, if desired by the user. This is in the form of a factor that is applied to the energy generation at each site, and the factored amount of energy deducted from the gross energy available. For example, if a transmission line loss is defined with a factor of 0.07, that means that the gross energy available at the hydroelectric station (refer to Section 6.1.6) will be reduced by 7% to acknowledge losses in the transmission lines.

One factor is used for the entire YEC hydroelectric system (i.e. no separate transmission loss factors for each site).

If transmission losses are included in the system load (see Section 6.1.5), the transmission loss factor must be set to zero.

6.1.9 Forced Outages

YEC normally schedules routine maintenance for periods when the load is low (summer and/or off-peak times during each day or on weekends). However, there are outages that occur unpredictably, or result from maintenance activities that exceed the length of time available in low-load periods. The software has been equipped with a factor that represents such "forced outages". It is applied in a way similar to transmission line losses, in that the factor is applied to at-site generation to represent an amount of energy that is not available from the plant due to the forced outage. However, the forced outage factor differs in that it is only applied at a particular site if the energy generation that is requested by the model is equivalent to that available from all the units at "full gate". If the energy is less than that amount, it is implicit that the potential loss due to the forced outage could be compensated over the weekly time steps by extra generation from the operable units. This algorithm for forced outage should be recognized by the user in defining the appropriate reduction factor.

6.1.10 Winter Tailwater Effects

At some hydroelectric generating stations, ice on the river downstream of the dam can cause tailwater levels in winter that are higher than would occur during open water conditions at a comparable discharge. This reality of stations in a cold climate has been recognized in the software by the capability of defining a rise in tailwater level that would typically occur. Separate values of this rise are allowed to be defined by the user for each week (in metres) of the year.

The values that are input must be selected by the user from analyses that are carried out independently from the software. For the YEC system, the only plant that is known to be vulnerable to such ice effects is the Whitehorse Rapids Generating Station. Data Type 18 in Section 4.2 shows the distribution of the ice effects over the weeks of each year that have been routinely used for the Whitehorse site (all other values for other sites, such as Aishihik, have been defined as zero in the calculations). These values for Whitehorse are recognized to be approximate only and have been based on estimates from recent SCADA data from that site.

6.1.11 Stacking of Generating Units under Load Duration Curve

The concept of stacking of generating stations under a load duration curve has long been recognized as a pre-requisite to meaningful simulations of system operation. Appendix B contains a description of the concept of stacking and has been extracted from the textbook "Water Resources Engineering" by E. Kuiper (1968, Butterworth).
The input allows for a load duration curve to be defined (Input Type 28). The model addresses the stacking of generating stations by performing a check of energy and generation capacity at each weekly time step. The check is directed to confirm that the energy calculated can be fit within the load duration curve for that week. It ensures that not only the total energy load but also the peak power demand are satisfied.

6.1.12 Lag Times

The principal feature of the model that permits it to realistically represent the efficient use of reservoir storage is the reservoir drawdown / refill models. The model represents releases of water from storage, or storage of excess inflows to suit what is required for satisfying the system load demand. This has been represented mathematically in the model without recognition of the travel times of water released from storage in reservoir. It is implicit in this-simple approach that the travel time is much less than the computational time steps of one week. This is a common assumption in planning models of this type. In fact, this assumption is appropriate for all reservoirs / stations that currently exist or are being actively planned for future expansion of the YEC system.

6.1.13 Reservoir Routing

Simulation of the response of major reservoirs like Marsh Lake must acknowledge the potential for uncontrolled rises in water level when flood inflows exceed the maximum outlet capacity. YECSIM is equipped with logic that addresses this phenomenon in periods when inflows are high. Standard level pool routing calculations are embodied in the logic and use the reservoir stage-storage relationships and outflow discharge capacities to estimate the fluctuations in water levels during flood events. Similar logic has been included for Aishihik and Mayo Lakes.

6.1.14 Reservoir Rule Curves

Reservoir "rule curves" are routinely used in hydroelectric system to provide guidelines for operation of hydro-thermal stations. They are used in particular in systems that have relatively small non-hydro sources of generation. The principles of rule curves are clearly described in Appendix B, which is an excerpt from the textbook "Water Resources Engineering" by E. Kuiper (1968, Butterworth).

Rule curves provide a decision basis for base-loading thermal generating stations, and conserving water in drought conditions.

Early in the development of the software, it was recognized that the thermal component of the YEC system (i.e. diesel generators) is so large that rule curves are not needed for decisions of base loading diesel generators. The primary goal in the YEC system for the foreseeable future is simply to utilize the most hydroelectric energy possible in any particular week, and thereby minimize the generation of energy from diesel generators.

However, it became obvious in the software development that the compliance with license limits on reservoir water levels requires the use of reservoir rule curves, at least in a mathematical sense in the model execution.

For example, without some strategic form of conserving water, drawdown of Marsh Lake over a typical winter could lead to water levels in the spring that would be lower than defined by the water license granted by the Yukon Government to YEC. This principle of conservation is intuitively applied in the real-world operation of the YEC system. The releases from Marsh Lake are set at moderate levels in winter so that the risk of violating the lower licensed limit for the lake is acceptably low. These moderate releases are selected by YEC staff based on a variety of complex factors such as antecedent autumn inflows to Marsh Lake, snow pack, expected loads, weather, etc.

This selection of Marsh lake releases is a process that involves a great deal of judgement and skill that is impossible to reliably represent numerically. The process has been approximated in the model by the application of reservoir rule curves. These curves are computed with the same principles described in Appendix B. They define water levels (and corresponding live storage volumes) below which reservoir releases must be restricted to the minimum riparian river flow. Use of more than the minimum amount could result in reservoir levels dropping below the licensed limit if streamflows are low.

The principle of reservoir rule curves has been used for all reservoirs. However, it was discovered that strict adherence to the principle for Marsh Lake resulted in end-of-winter water levels that were consistently greater than what has actually occurred in recent years. It appears that YEC has intuitively selected a mode of operation that has a small degree of risk of resulting in violation of the lower licensed limit for Marsh Lake (i.e. El. 653.796 m).

To mimic this strategy by YEC, the model operation of Marsh Lake was adjusted so that the lake level would be gradually drawn down to reach within about 5 to 15 cm of the minimum supply level (El 653.796 m). This end-of-winter level has been achieved quite consistently in the real-time management of the lake and has been the guide for the model.

For all other reservoirs, operation in the model has been strictly based on the conventional rule curves that prevent drawdown of the reservoir level below the licensed range for all hydrological conditions comparable to the recorded period of inflows.

6.1.15 Reservoir Drawdown Priorities

The software is equipped with two modes of operation:

- Proportional draft mode whereby all reservoirs are attempted to be drawn down in unison or filled in unison to suit the load demands. The unison operation is defined in terms of percent of the live storage available. This is simple method that can be achieved with the minimum complexity of programming logic and was developed to allow the first testing of the model.
- Priority drawdown/refill whereby a specific priority list is followed and must be supplied by the user. The sequence that best represents the operation used by YEC and the optimum means of generating energy is:
  - 1 – Marsh Lake.
  - 2 – Mayo Lake.
  - 3 – Aishihik Lake.
    - This sequence dictates that if water must be drawn from storage to supply the system load demand it is first attempted at Marsh Lake, up to the point that additional releases would result in spillage at Schwatka Lake.
    - Then if there is still a shortfall of energy, releases from Mayo Lake will be made, and then Aishihik Lake.
    - On the other hand, if the natural flow can exceed the energy demand, water is stored first in A lake, and then in the other two in reverse sequence.

Tests to compare the two modes indicated that the priority drawdown method would supply about 3% more energy from the hydroelectric system than the proportional draft method. As a result, all further efforts were focused on developing and using the priority system. However, the two options remain in the model. The selection of drawdown method is made in the **Simulation** window of the GUI.).

6.1.16 License Limitations for Reservoir Levels

There is a variety of limitations imposed on the operation of YEC's reservoirs. All are listed in the licenses that have been granted to YEC, which are reproduced in Appendix E. YECSIM has been configured to comply with these restraints.

6.1.17 Other Energy Sources and Model Capabilities

The model calculates diesel generation as the energy required to supply the load after the energy from hydro and other sources have been calculated. Diesel is included to the weekly generation if there is a deficit in either the total energy load or the power to supply the peak of the load duration curve.

Wind generating capacity is included in the program input as energy available for each week, and it is placed at the base of the weekly load duration curve.

LNG and biomass energy sources are included in the program input as generating capacity. The user has the option to indicate if some of that capacity is non-dispatchable. The non-dispatchable capacity from LNG and biomass is placed at the base of the load duration curve, along with the energy generated from wind. The dispatchable portion is included in the weekly generation after the energy from hydro sources and before the energy from diesel.

During the development of the model, YEC was interested in investigating the merits of additional sources of hydrologic inputs to the reservoirs in its current system. Two such options were added to the model, to assist their assessment: the Gladstone Diversion, which would potentially add inflows to Aishihik, and Atlin Lake, which would provide inflows to Marsh Lake. The model, in its current version, provides means for the user to add these hydrologic inflows, which are required to be computed outside of the model.

6.2 PROGRAM CODE AND FLOWCHARTS

Appendix C contains flowcharts that demonstrate the global logic that is incorporated in the YECSIM software. The program code is located on the CD that has been transmitted to YEC with this User's Manual. Changes to the code would best be undertaken by the developers of the model. If modifications are desired by YEC, the most efficient means of implementing them would be by the staff of KGS Group.

7.0 EXAMPLE SIMULATIONS

This section illustrates the use of the YECSIM model for a number of system configurations. It is intended to present the user with simple examples that can be easily followed and, to provide a means to familiarize the user with the program.

The examples included in this section are for the following system configurations:

- Whitehorse-Aishihik-Faro (WAF) System with existing plants.
- WAF System with existing plants plus a third unit at the Aishihik Generating Station.
- WAF-Mayo-Dawson (MD) interconnected system with existing plants and a third unit at the Aishihik Generating Station.
- WAF-MD interconnected system with existing plants plus third unit at Aishihik plus the Mayo B plant.

7.1 WAF SYSTEM WITH EXISTING PLANTS

This example is a simulation of the WAF System for a load of 380 GWh-year on average. The input to YEC-SIM is comprised of the following components:

- Hydrologic data. These are the inflows available for outflows (IAO's) for all sites.
- Site-specific data. These include the characteristics of the reservoirs, generating stations, operation rules.
- Energy demand data. These correspond to the loads expected along the simulated period distribution of load along the year.
- System data. These include the system configurations, the mode of operation and some additional details for the case under consideration.

The input to YEC-SIM is described in detail in Section 4 and Appendix A of this User's Manual. The simplest way to start a simulation with YEC-SIM is to load an existing input file and to apply the necessary changes to the data that correspond to the scenario under consideration. This strategy simplifies the input process, since a large part of the data will typically remain unchanged. In general, for example, the hydrologic data does not need to be modified for each new simulation.

The steps to complete this run are the following:

Step 1 – To open and load an existing input file, select "Import Input Data' in the Model Simulation menu (Figure 7.1).

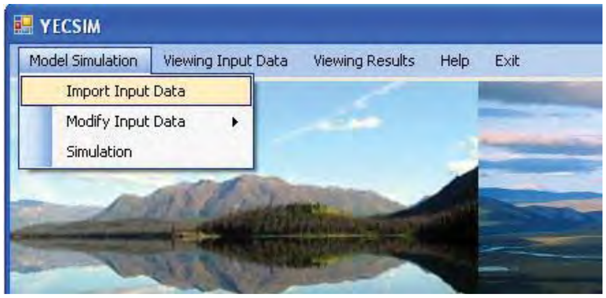


Figure 7.1 – Loading an existing input data file

A standard Windows screen will allow the user to navigate to the appropriate folder and select the appropriate input file (Figure 7.2).

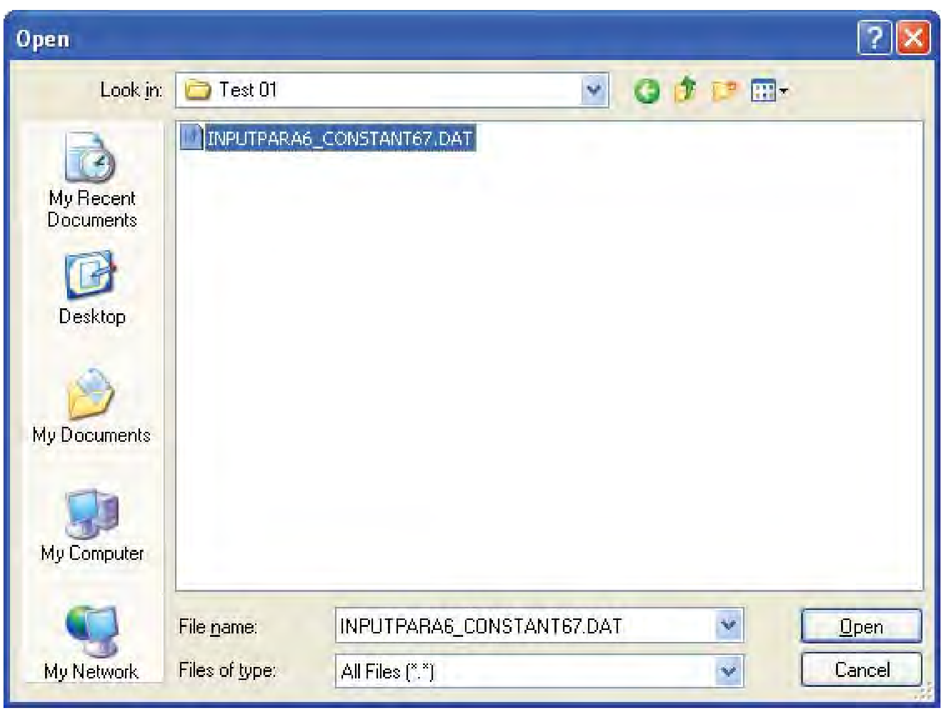


Figure 7.2 – Searching for and selecting an input file to be loaded to YECSIM

Go to the appropriate folder and select the file: YECSIM-EXAMPLE.DAT, provided in the installation package. Click the Open button (Figure 6.2). Click OK to the ensuing message.

Once the input file has been loaded in the YEC-SIM database, changes can be made to the database, according to the intended simulation.

Step 2 – In the Model Simulation menu select "Modify Input Data". Three choices are available.

Select "Lakes/Reservoirs" (Figure 7.3). The Edit Reservoir Parameters window will appear on the screen (Figure 6.4) displaying the data for all reservoirs in the system.

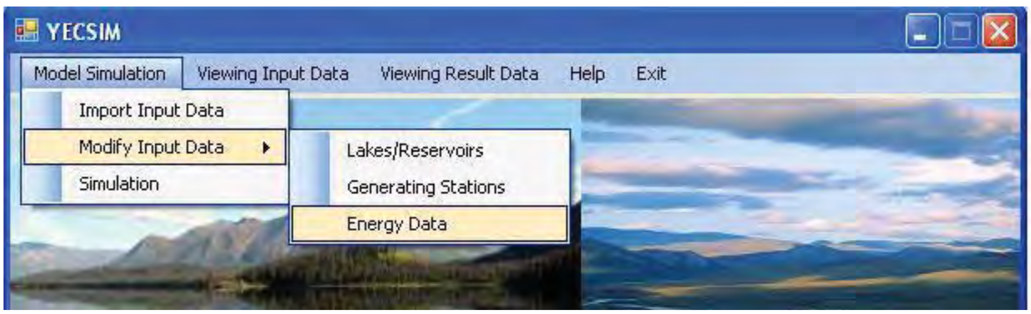


Figure 7.3 – Modifying the input data

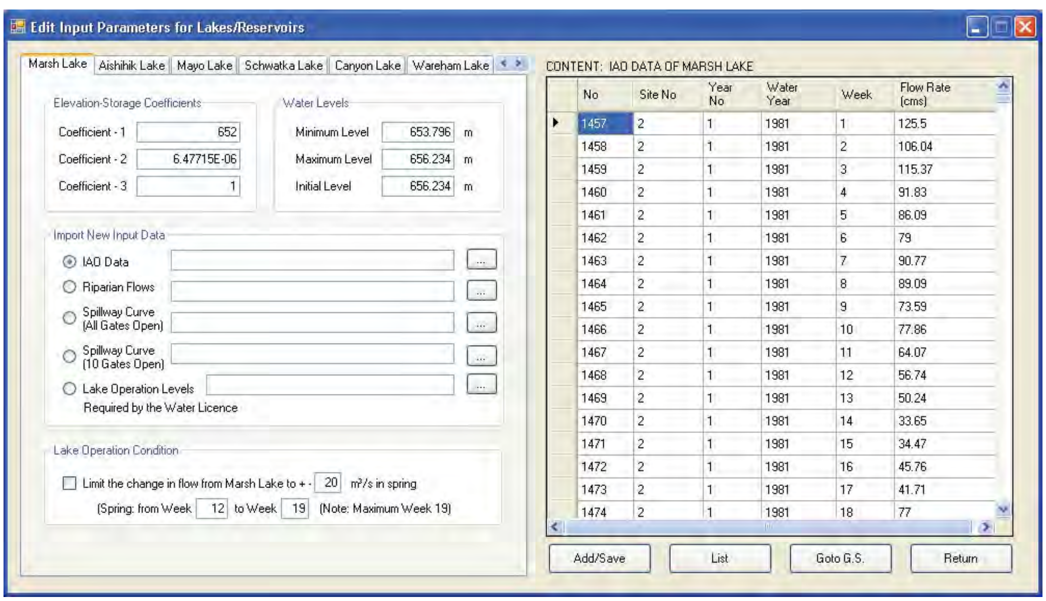


Figure 7.4 – Edit Reservoir Parameters window

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The different options in the Edit Reservoir Parameters window have been described in Section 3.0. These include:

- Information about the storage capacity of each reservoir.
- Water levels for operation, maximum and minimum.
- Inflows-available-for-outflow (IAO Flows).
- Spilling rating curves.
- Minimum riparian flows.
- Specific conditions specified in the operation licence.

If necessary, the data described above can be loaded from individual text files, using the checkbox list, text boxes and browse buttons located at the bottom-left area of the Edit Reservoir Parameters window. The user would have these files previously prepared, according to the format described in Appendix A.

The Content section, at the right side of the window, displays the data selected in the bottom-left area. To review this data, click on the appropriate checkbox (bottom-left) and press the List button (bottom-right) to update the Content section. At this point, it is possible to verify that the information in the input file corresponds to the scenario under consideration. Changes can be made by directly editing the table in the Content section and pressing the Add/Save button.

The Add/Save button allows saving changes to the database in stock for the simulation, with no changes to the original input file. A new input file can be saved as described in Step 5.

For this example, no changes to the Lake/Reservoir data are necessary.

Click the Return button.

Step 3 – Other options in the Modify Input Data menu (Figure 7.3) allow changes to the input data in the Generating Stations menu and the Energy menu. Descriptions of all options in these two menus are provided in Section 3.

Select Generating Stations in the Modify Input Data menu and then select the Aishihik G.S. tab (Figure 7.5).

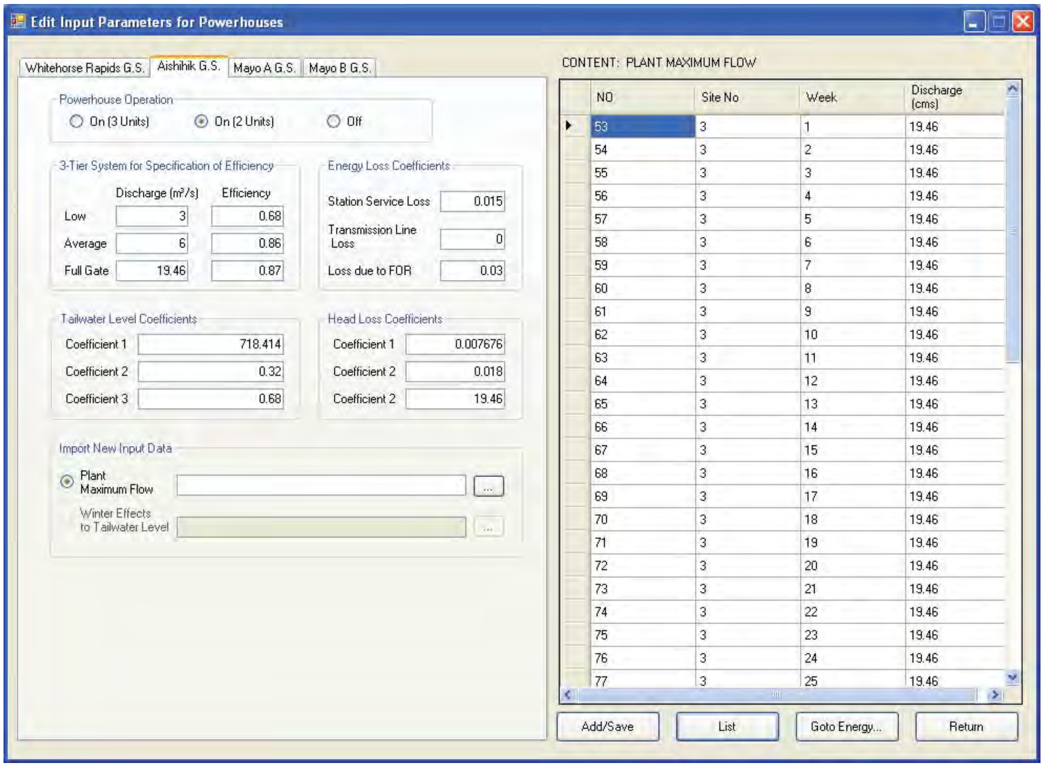


Figure 7.5 – Modifying generating station data

Check in the On (2 Units) option box in the Powerhouse Operation group.

Click the Add/Save button.

No additional changes are required to the generating station data

Click the Return button.

Step 4 – Select Energy Data in the Modify Input Data menu (Figure 7.3). The program will display the Energy Load Information Window, shown in Figure 7.6.

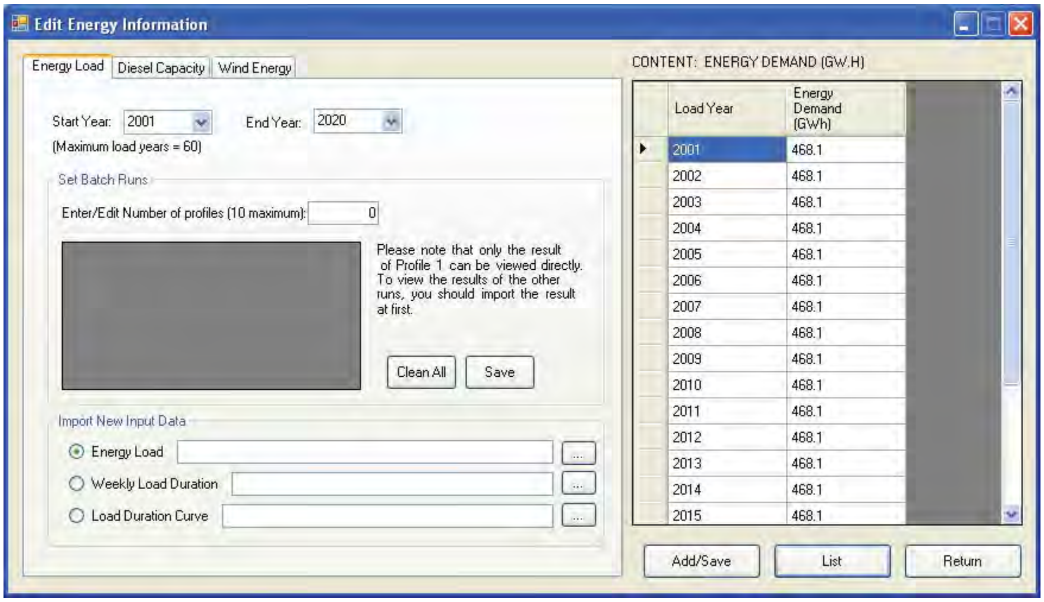


Figure 7.6 – Energy Load Information Window

Click in the Energy Load option box and then click the List button.

The right side of the Energy Load Information window, should change to display the average annual energy demand for the system (Figure 7.7).

Change the values in the third column of the resulting table, Energy Load, to 380, which is the average energy demand, in GWh-year, intended for this simulation.
The user can add or remove load years, by typing new data in the table or by selecting and deleting rows. This table determines the number of load years to be simulated. A minimum of 8 years is recommended. Example 1 was carried out with 8 load years.

Click the Add/Save button, to save changes to the database.

Other options in the Energy Load Information window are explained in Section 3. For this example no more changes are required to the data in this window.

Click the Return button.

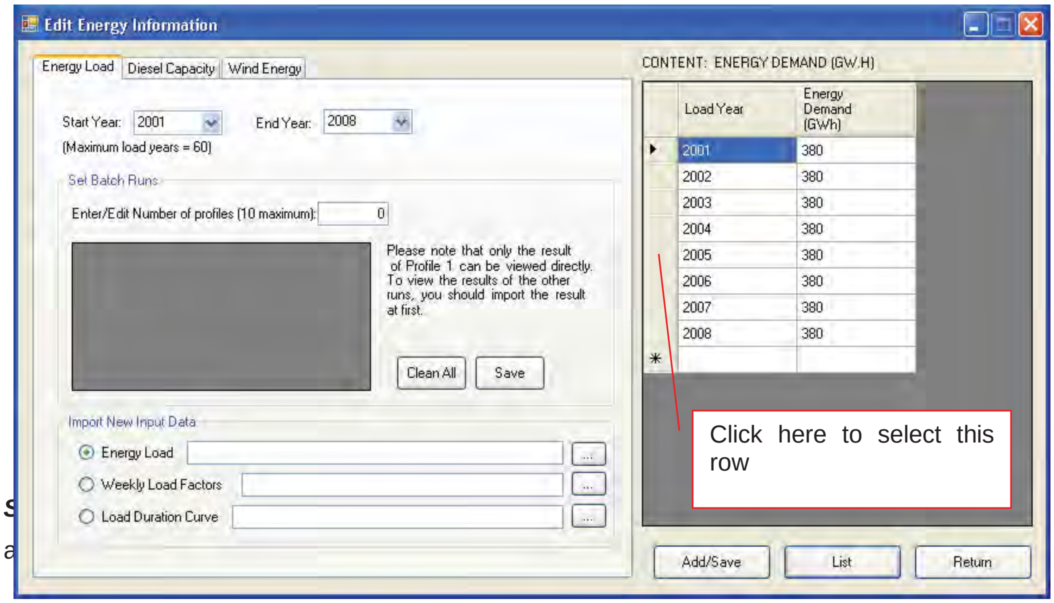


Figure 7.7 – Load data in the YECSIM-EXAMPLE.DAT input file

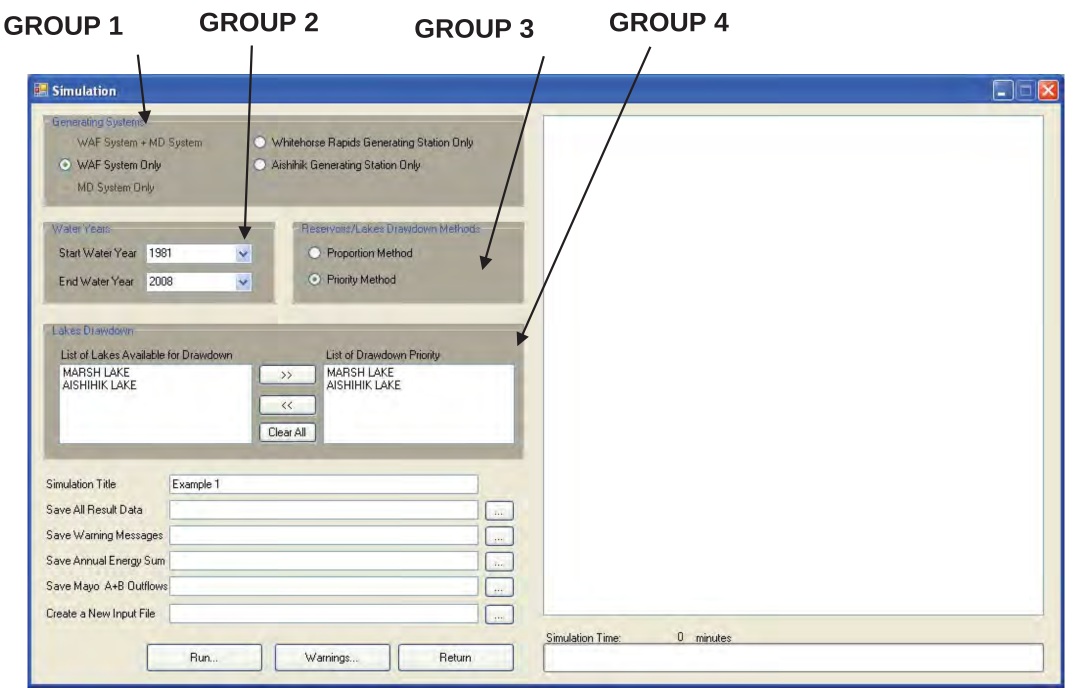


Figure 6.8 – Simulation Window

Click the option box with the label “WAF System Only” in Group 1 (Generating System)

Group 2 shows the water years to be used in the simulation. For this example, the years 1981 to 2008 are used. No changes are required.

Verify that Priority Method is selected in Group 3 (Drawdown Priority).

Use the Add button and the Remove button in the Reservoirs/Lakes Draft Option list boxes (Group 4) to select the drawdown order to be used in the simulation. The selection for this example is shown in Figure 7.9.

Figure 7.9 – List box with the priorities for reservoir drawdown for Example 1

Note that Canyon Lake is not included in the list box at the right side, since it will not be operated as long-term storage in this simulation. Also the priority shown in Figure 7.9 prescribes that the system will use as much water as possible from Marsh Lake before using Aishihik Lake. Mayo Lake is not included in this simulation of the WAF system.

The minimum riparian flows, license constrictions and the conveyance capacity for the outlet structures in Marsh Lake (Lewes Dam) are all taken into consideration by the model. Modifications to these are possible, using the options in the Modify Input Data submenu, but are not included in this example. Section 3 provides more information for these options.
Enter the following information in the Simulation window:

- Simulation title.
- File name to save all result data.
- File name to save warnings that the program provides (See Section 3). This is optional.
- File name to save energy results.
- File name to save the changes to the input in a new input file. This is not required but is recommended.

Click the Run button. The Simulation window will provide a status of the simulation during run time (Figure 7.10).

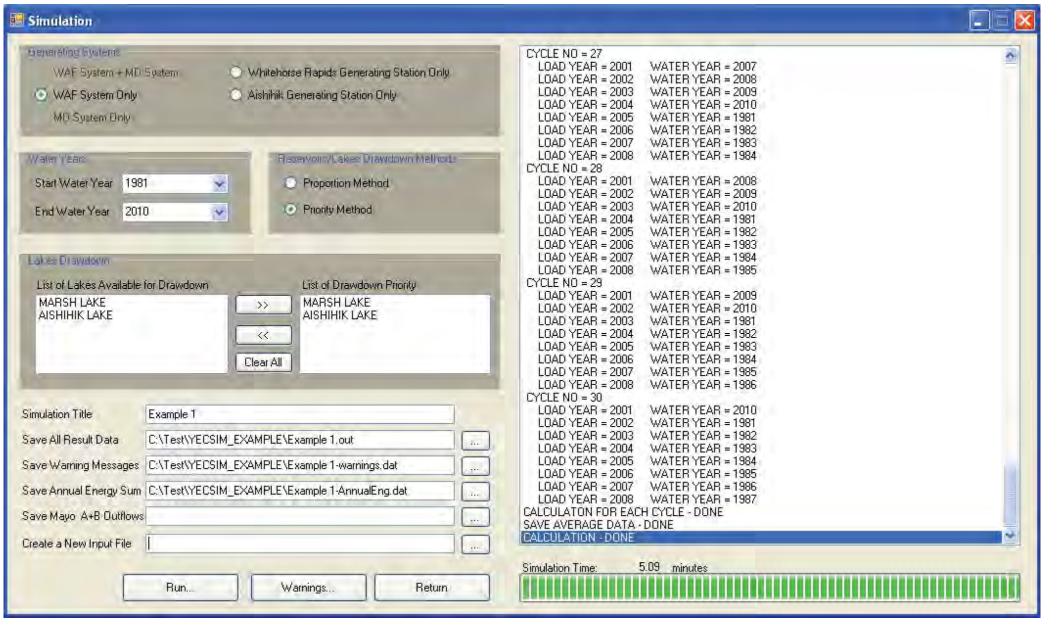


Figure 7.10 – Simulation Window at the End of the Run

When the simulation ends, a message will appear on the screen to notify the user. Click OK, to return to the Simulation window.

Click the Return button in the Simulation window.

Step 6 – To display results, in the main menu, select Viewing Result Data and in the subsequent menu select Energy Summary -> Diesel Energy Graph (Figure 7.11)

This analysis shows a summary of the diesel energy required to supply the load, and provides a means to summarize the overall results of the simulation in one figure.

In the Select Load Years section of the Diesel Energy Graph, select the years from 2006 to 2007.

Click the Display/Plot button to display the summary figure as presented in Figure 7.12.

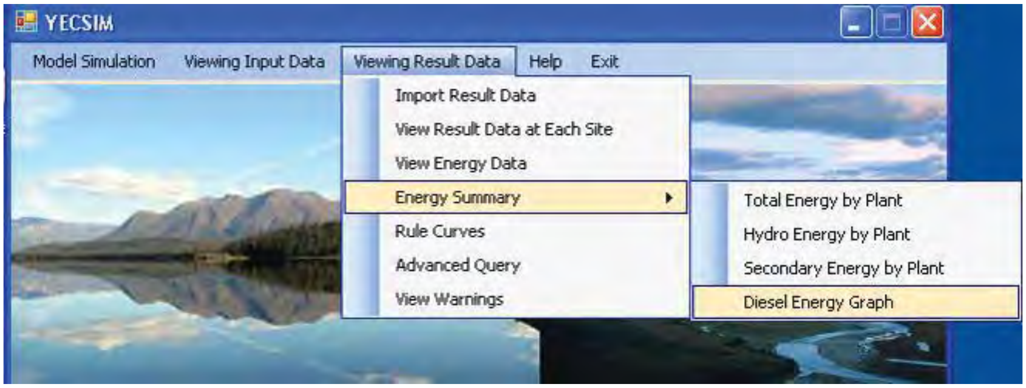


Figure 7.11 – Reviewing results for energy analysis

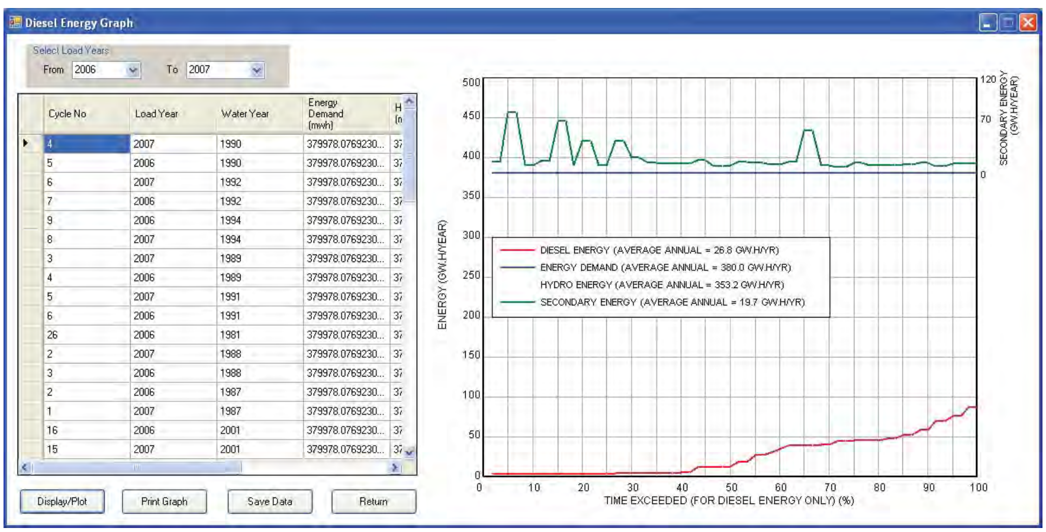


Figure 6.12 – Diesel Energy Graph

The results indicate that, for a load of 380.0 GWh/year, constant in this example, the hydroelectric plants would provide 353.2 GWh/year, while the diesel plants would be required to supply the remaining 26.8 GWh/year. Additional secondary energy in the amount of 19.7 GWh/year would be available. These are averaged results from all the water years used in the simulation.

The Viewing Result Data menu provides access to all the information obtained in the simulation. For instance, to display average levels in Marsh Lake, select View Results at Each Site. In the ensuing window, select:

- Site 2-Marsh Lake.
- Cycle number –1 (default for average).
- load year 2007 in both the from and to boxes.

Click the Display button, to show the type of display in Figure 7.13.

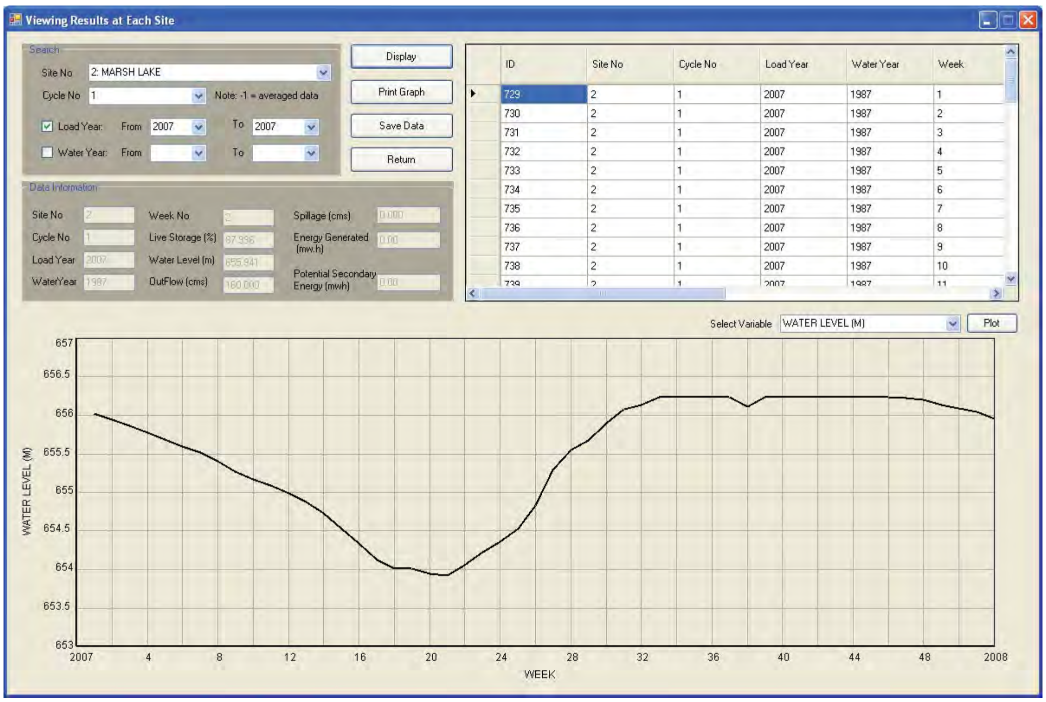


Figure 6.13 – Results for Marsh Lake average levels

Following the same procedure, the average levels at Aishihik Lake can be obtained, as shown in Figure 7.14.

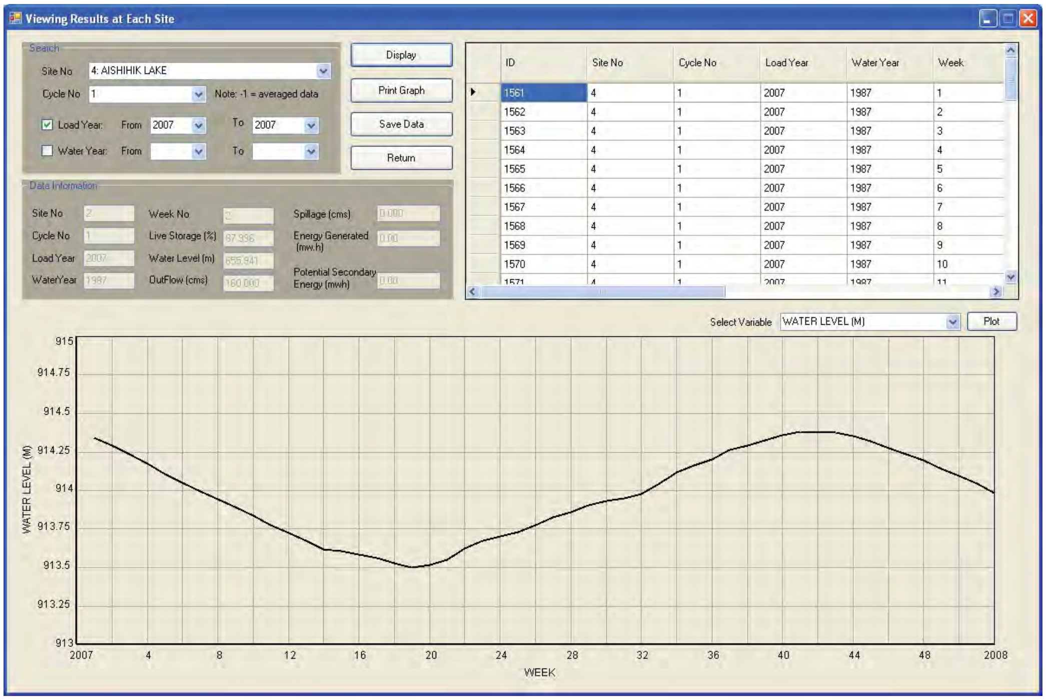


Figure 7.14 – Results for Aishihik Lake average levels

All result display windows include a Save Data button, to export the output table into a text file.

7.2 WAF SYSTEM WITH EXISTING PLANTS PLUS THIRD UNIT AT AISHIHIK

To simulate the effect of the proposed third unit at Aishihik, the necessary adjustments to Example 1 are described in this section.

Step 1 – Open the new input file created in Step 5 of Example 1, following the same procedure as explained in Step 1 of Section 6.1.

Step 2 – Under the Model Simulation menu (Figure 7.3) select Modify Input Data and then select Generating Stations

Select the Aishihik G.S. (Figure 7.5). Click the On (3 Units) option box to set the number of turbines to 3. Click the Add/Save button.

Step 3 – In the Model Simulation menu (Figure 7.1), select Simulation.

In the Simulation window (Figure 67.8) select “WAF System Only” by clicking in the corresponding option box.

Verify the options in the Reservoirs/Lakes Draft Option and Water Years sections as well as in the Draft Option list box. These should be as in Example 1.

Assign new names to the simulation title, Result Data file, Warning Messages file, Energy Data file and the new Input File (recommended).

Click the Run button to carry out the simulation.

Click the Return button.

Step 4 – Following the same steps described in Step 6 of Section 6.1, display the Diesel Energy Graph window with the results for load years 2006 to 2007. The results are shown in Figure 7.15.

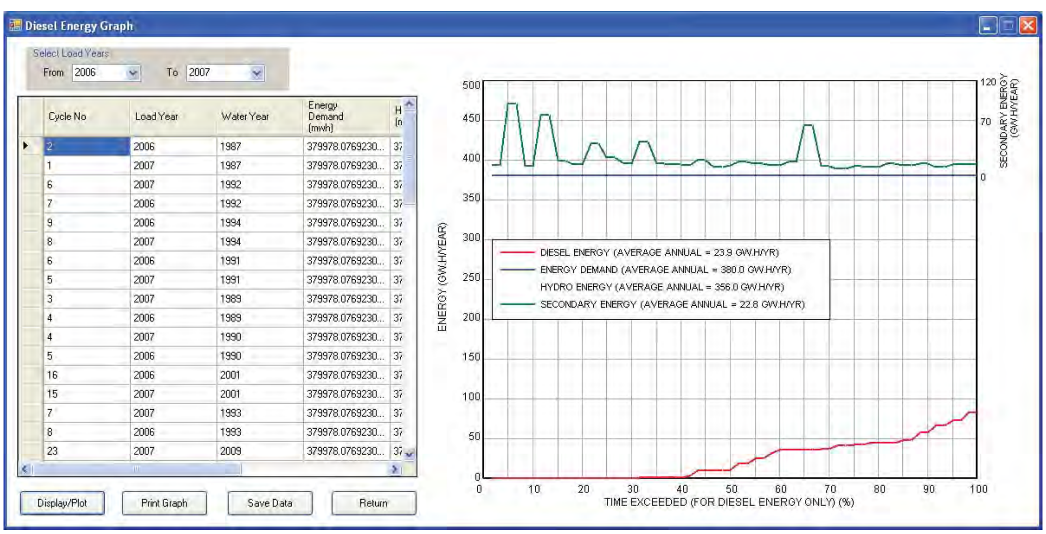


Figure 6.15 – Diesel analysis results for Example 2

7.3 WAF-MAYO DAWSON SYSTEM – EXISTING PLANTS PLUS THIRD UNIT AT AISHIHIK

This example is for the WAF-MD interconnected system including the third unit at Aishihik Generating Station. Mayo B is not included. A load of 500 GWh/year will be used for this system.

Step 1 – Following the same method as in Step 1 of Section 6.1 load the original YECSIM-EXAMPLE.DAT input file.

Step 2 – Verify the data in the input file using the Modify Input Data options in the Model Simulation menu.

Most of the data in the YECSIM-EXAMPLE.DAT file is appropriate for this simulation. The following changes are required:

- Verify that the minimum level at Mayo Lake is 663.27 m, reflecting the current licence conditions.
- Click the Off option box in the Powerhouse Operation group in the sub-tab for Mayo B Generating Station. This will allow simulation of the system without Mayo B.
- Change the energy load to 500 GWh/year as stipulated for this example.

These changes can be done, following the corresponding steps, as described in Sections 6.1 and 6.2. After each change is made, the Add/Save button must be pressed to save the changes to the database.

To reduce the number of load years the user must delete the extra rows, if any, in the Energy Load information table. Figure 6.16 illustrates this process. For this example, the number of load years is 8 and do not need to be changed. The energy load, however, must be changed to 500 GWh/year. Check he Add/Save button after the changes.

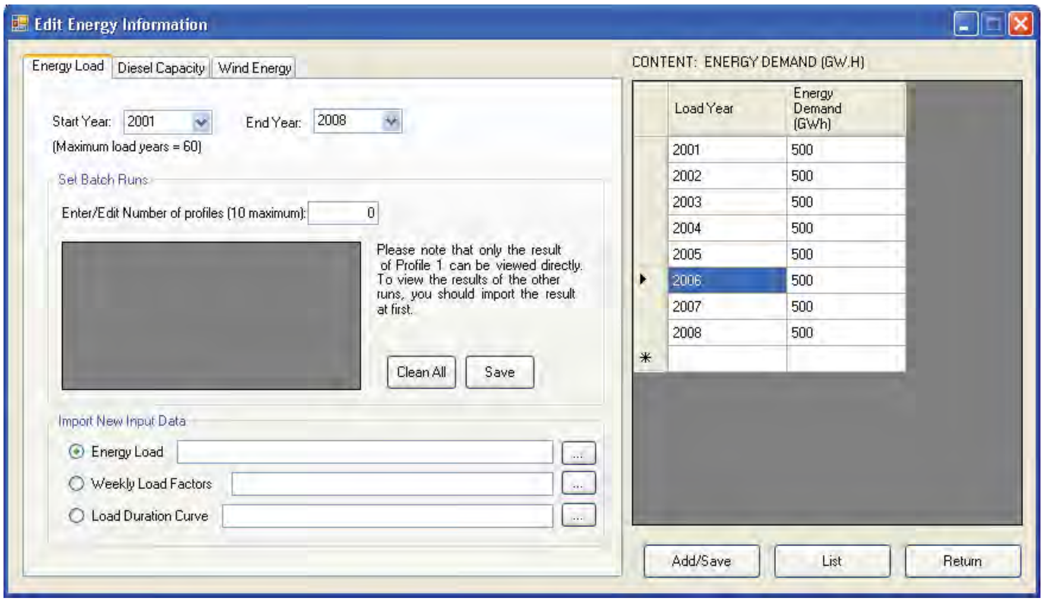


Figure 7.16 – Reducing the number of load years

Step 3 – Open the Simulation window (from the Model Simulation menu) and set a simulation for:

- WAF-MD system.
- Water years from 1981 to 2010.
- Priority drawdown method.
- Drawdown sequence:
  - o Marsh Lake.
  - o Mayo Lake.
  - o Aishihik Lake.

The resulting Simulation window should be as shown in Figure 7.17

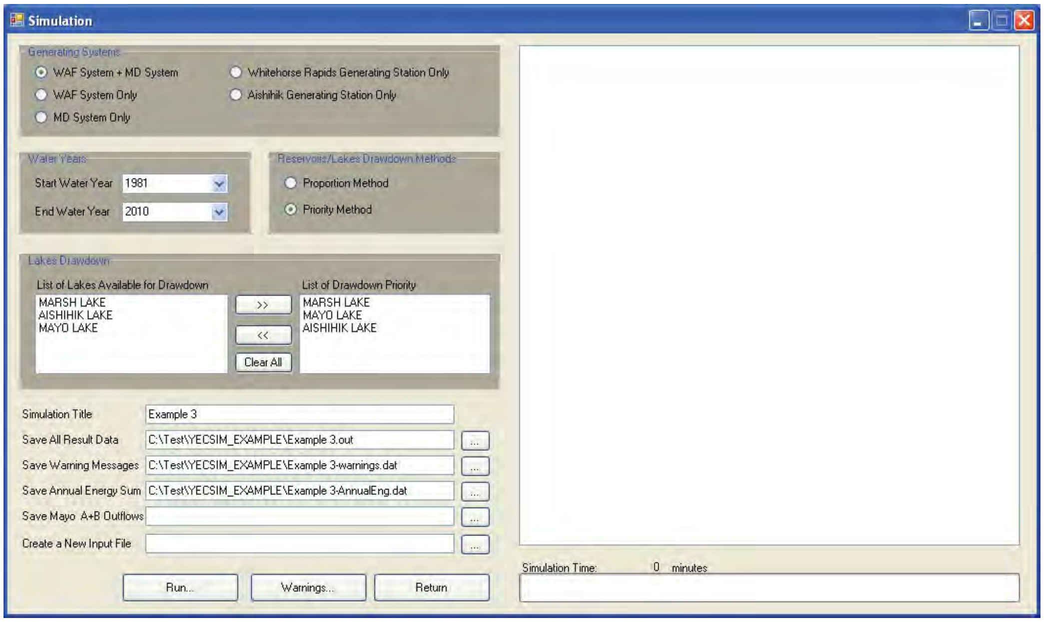


Figure 7.17 – Simulation window for Example 3

Step 4 – Results can be reviewed using the options in the Reviewing Results menu (Figure 7.11).

The Diesel Energy Graph window for this simulation is shown in Figure 7.18.

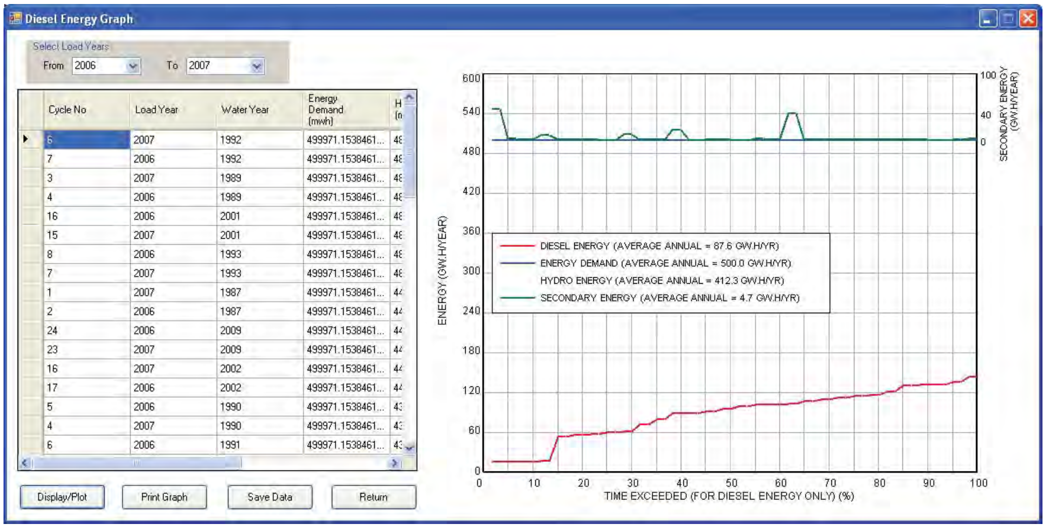


Figure 7.18 – Diesel Energy Graph window for Example 3

7.4 WAF-MAYO DAWSON SYSTEM – EXISTING PLANTS PLUS THIRD UNIT AT AISHIHIK AND MAYO B

For this example, Mayo B is included.

Step 1 – Open YECSIM-EXAMPLE.DAT file.

Step 2 – Modify the load data to 500 GWh/y as in previous examples.

Step 3 – Verify other data, go to the simulation window and start a new run.

Step 4 – Verify the results.

The Diesel Energy Graph window for this simulation is shown in Figure 7.19.

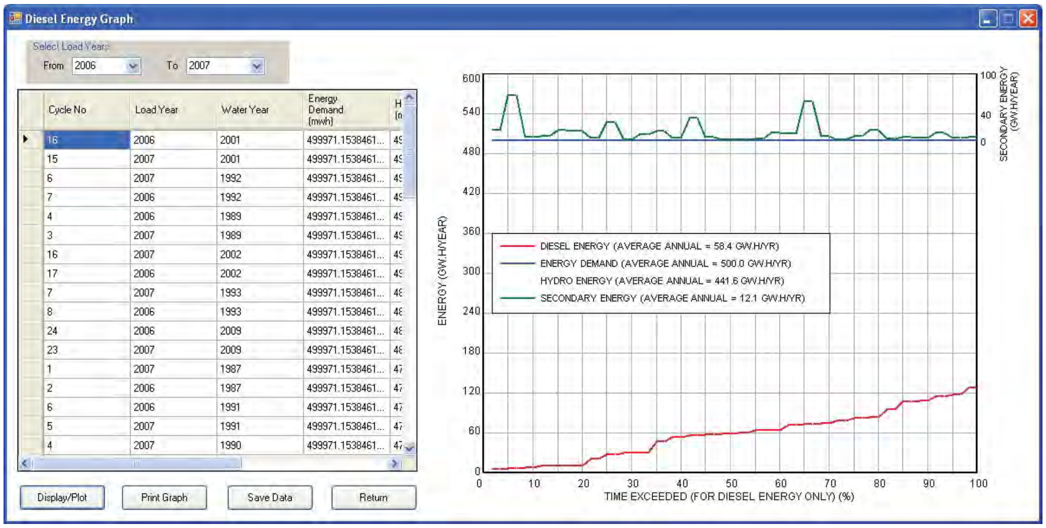


Figure 7.19 – Diesel Energy Graph window for Example 4

To review data from previous simulations without repeating the run, select "Import Result Data" from the Viewing Results menu (Figure 7.20).

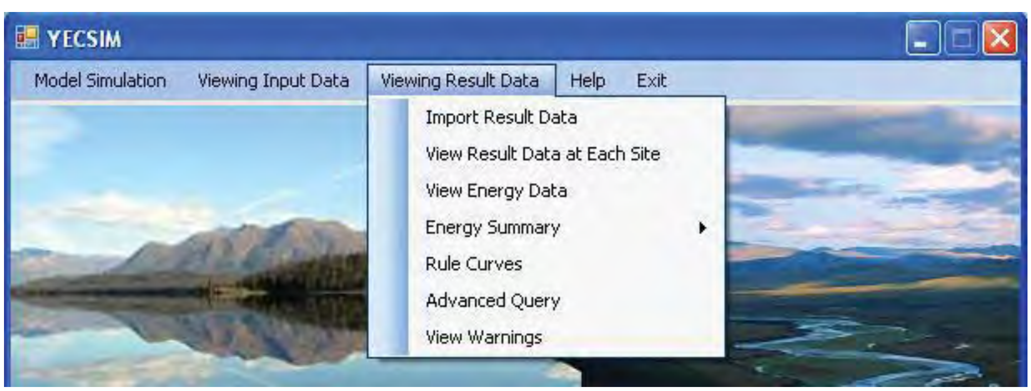


Figure 7.20 – Reviewing an existing output file

The resulting window allows finding a previously saved output file to be loaded to the program.

Input data in the current database can be reviewed by using the options in the Viewing Input Data menu (Figure 7.21).

Figure 7.21 – Reviewing Input Data Loaded to the Database

The display options for input and output data provide tabular and graphical displays of all the data and results. The tables can be exported to text files using the Save button.

8.0 TIPS ON PROGRAM APPLICATION AND PROBLEM AVOIDANCE

1. If the YECSIM Graphical User Interface is not displayed properly, please check the resolution of the computer screen. The computer screen must have the minimum resolution of 1280 x 1024 (see Section 2).

2. When the user starts YECSIM, the input data and model results from the previous run will be automatically loaded from the database to the YECSIM GUI. The user can directly start a run without importing or editing any input data.

3. Input data can be entered through text files or direct typing into the YECSIM GUI.

4. The formats for the input data files indicated in this manual are strictly required (see Section 4) for YECSIM to load the input data properly.

5. If the number of sites (specified in DATA TYPE 1 in of input file) is equal to 4, then only the WAF system is to be simulated. To avoid errors, the user should not add any parameters related to the MD system (i.e. Mayo Lake, Wareham Lake, the existing Mayo Generating Station, and Mayo B Generating Station) in the input file.

6. It is suggested to run only one simulation at a time. If a second run is required, it is recommended to exit the program and open it again. Continuously running many simulations in YECSIM could increase the size of the database and cause the program to crash. To solve this problem, if it occurs, the user would have to reinstall the program. Multiple simulations can be done as batch runs, with some restrictions.

7. ***Other tips will be added to this list after the training sessions, and after KGS Group receives feedback from users.***

APPENDICES

APPENDIX A

FORMAT OF INPUT FILES

APPENDIX A – FORMAT OF INPUT FILES

All input files must be in ASCII (text) format. The first line in the input file must be a title line, which states the variables included in the file. The actual input data starts from the second line. A space is required between two data values in the same line. The detailed description of the data format starting from the second line file is listed for different types of input.

Appendix A-1. IAO Data:

Data format: 3 columns starting from the second line.

Column 1: Water Year Number
Column 2: Week Number
Column 3: Flow Rate (m³/s)

Example: *IAO-Marsh.txt*

Water Year	Week	Flow Rate (m³/s)
1987	1	100.85
1987	2	84.29
1987	3	91.93
.	.	.
.	.	.
.	.	.
2007	52	101.30

Appendix A-2. Riparian Flows:

Data format: 2 columns starting from the second line.

Column 1: Week Number
Column 2: Flow Rate (m³/s)

Example: *Riparian-Marsh.txt*

Week	Flow Rate (m³/s)
1	85.00
2	85.00
3	85.00
.	.
.	.
.	.
52	85.00

Appendix A-3. Spillway Rating Curves:

Data format: 4 columns starting from the second line.
Column 1: Data Number
Column 2: Number of Gates Open
Column 3: Water Level (m)
Column 4: Flow Rate (m^3/s)

Example: *SpillwayCurve-Marsh.txt*

No.	Gates Open	Water Level (m)	Flow Rate (m^3/s)
1	30	653.0	25.00
2	30	653.5	90.00
3	30	654.0	158.00
4	30	659.5	1060.00
.	.	.	.
.	.	.	.
.	.	.	.
15	10	653.0	20.00
16	10	653.5	53.00
.	.	.	.
.	.	.	.
.	.	.	.
28	10	659.5	714.00

Appendix A-4. The Minimum Water Levels of Marsh Lake for License Constraint for All Gates Open:

Data format: 2 columns starting from the second line.

Column 1: Week Number
Column 2: Water Level (m)

Example: *LakeOperation-Marsh.txt*

Week	Water Level (m)
1	656.234
2	656.234
3	656.234
.	.
.	.
.	.
52	656.234

Appendix A-5. Water levels of 10-year Rolling Average on Aishihik Lake:

Data format: 2 columns starting from the second line.

Column 1: Year Number
Column 2: Water Level (m)

Example: *RollingLevel.txt*

Year	Water Level (m)
1	913.00
2	913.74
3	914.48
.	.
.	.
.	.
10	914.26

Appendix A-6. The Minimum Flow Rates through Otter Falls:

Data format: 2 columns starting from the second line.

Column 1: Week Number
Column 2: Flow Rate (m^3/s)

Example: *Otterfalls.txt*

Week	Flow Rate (m^3/s)
1	0.142
2	0.142
3	0.142
.	.
.	.
.	.
52	0.142

Appendix A-7. Turbine Maximum Flows:

Data format: 2 columns starting from the second line.

Column 1: Week Number
Column 2: Flow Rate (m^3/s)

Example: *turbineFlow-WRGS.txt*

Week	Flow Rate (m^3/s)
1	160.0
2	160.0
3	160.0
.	.
.	.
.	.
52	160.0

Appendix A-8. The Increases in Tailwater Level due to Winter Ice Effects at the Whitehorse Rapids Generation Station:

Data format: 2 columns starting from the second line.

Column 1: Week Number
Column 2: Ice Thickness (m)

Example: *WinteeIce-WRGS.txt*

Week	Ice Thickness (m)
1	0.30
2	0.30
3	0.30
.	.
.	.
.	.
52	0.15

Appendix A-9. Total Energy Demand per Load Year:

Data format: 2 columns starting from the second line.

Column 1: Load Year
Column 2: Energy Demand (GWh/year)

Example: *EnergyDemand.txt*

Load Year	Energy Demand (GWh/year)
2001	468.10
2002	468.10
2003	468.10
.	.
.	.
.	.
2008	468.10

Appendix A-10. Diesel Energy Capacity per Load Year:

Data format: 2 columns starting from the second line.

Column 1: Load Year
Column 2: Energy Capacity (MW)

Example: *DieselEnergy.txt*

Load Year	Energy Capacity (MW)
2001	44.0
2002	44.0
2003	44.0
.	.
.	.
.	.
2008	44.0

Appendix A-11. The Factors that Define the Weekly Distribution of the Energy Demand throughout the Year:

Data format: 2 columns starting from the second line.

Column 1: Week Number
Column 2: Load Factor

Example: *Energyloadcurve.txt*

Week	Ice Thickness (m)
1	1.207
2	1.178
3	1.256
.	.
.	.
.	.
52	1.206

Appendix A-12. The Generic System Load Duration Curve:

Data format: 2 columns starting from the second line.

Column 1: Time of exceeded (%).
Column 2: Load Values

Example: *loadDuration.txt*

Time Exceeded (%)	Load Value
0	1.00
10	0.93
20	0.90
.	
.	
.	
100	0.53

APPENDIX B

RESERVOIR RULE CURVES – EXCERPT FROM “WATER RESOURCES ENGINEERING” BY E. KUIPER

Rule Curves

A rule curve may be defined as a diagram showing storage requirements during the year. As such, a rule curve provides guidance for the operation of a reservoir from day to day. In fact, rule curves, supplemented with appropriate tables and notes, may be worked into a complete set of instructions for reservoir regulation. We will discuss in the following paragraphs how rule curves are constructed.

Let us take first the simple case of a reservoir with seasonal storage, operated for an all-hydro system. (It was noted earlier that seasonal storage only requires a carry-over of water from the wet season to the dry season, whereas year-to-year storage requires the carry-over of water from a wet period to a subsequent dry period, maybe several years later.) It follows that a reservoir with seasonal storage does not need to be full at all times of the year. In fact, if we take the driest year on record as the criterion for making up the rule curve, we find that the reservoir only needs to be full during a very short period, as shown in *Figure 7.27*.

In *Figure 7.27(a)* are shown the stream flow of the river during the driest year on record and the energy requirements of the all-hydro system (both converted to the same scale). At time *A* the reservoir needs to be full and at time *B*, the reservoir will be empty. The shaded area between the supply and demand curve between *A* and *B* represents the volume of the reservoir release. If we translate this figure into a mass curve, we obtain *Figure 7.27(b)*. From point *A*, to the right, the supply and demand curves diverge, and the ordinate represents the required reservoir capacity. If we pursue the two curves to the right we may note that at time *D*, the reservoir will be full again. Now let us make a slightly different analysis of the same situation. At point *C* in *Figure 7.27(b)*, the reservoir is empty. From this point we plot backwards in time the energy demand and obtain curve *CE* which is simply curve *AB* lowered and extended to the left. The vertical ordinates between the supply curve *EAC* and the demand curve *EC* represent the volume of water that is in storage in the reservoir during the period from *E* to *C*. Since we have assumed that this is the driest year on record, to be considered as the criterion for preparing the rule curve, we may now draw the conclusion that whenever there is more water in the reservoir at certain dates, than indicated by the ordinates in *Figure 7.27(b)*, there is no danger of subsequent emptying of the reservoir.

To make *Figure 7.27(b)* more convenient for ready use, we can take the vertical ordinates and plot them on a horizontal base, as shown in *Figure 7.27(c)*.

We have now obtained a rule curve, showing the storage requirements of the reservoir as of any date, assuming that a repetition of the most adverse stream flow conditions on record is possible. This rule curve represents the accumulation, in reverse order of time, of the deficiency between energy requirements and available stream flow during the critical period.

It was assumed in the above that one critical year would determine the rule curve. It is not unlikely, however, that there are other, near-critical years. Such years should also be analysed and the corresponding deficiency curves prepared.

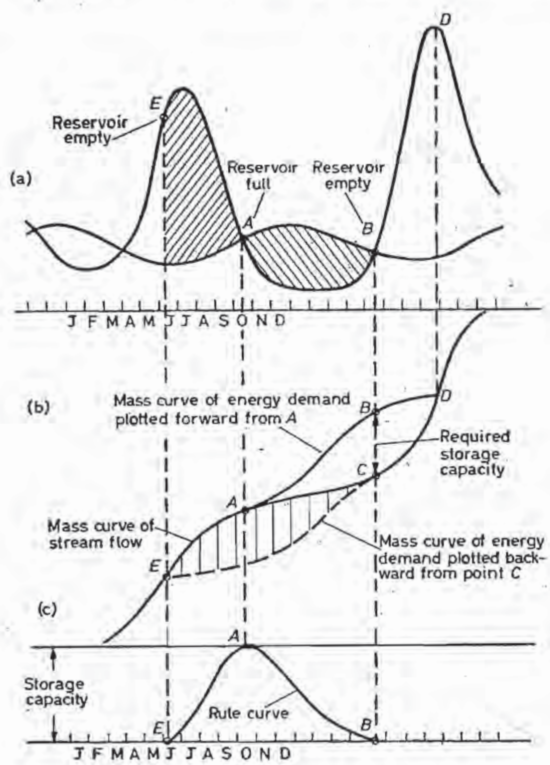


Figure 7.27. Preparation of rule curve

It is possible that these curves cross one another at places. It would then be advisable to draw the final rule curve as an enveloping curve of the various deficiency curves. We may even draw the rule curve some distance above the deficiency curves to guard against stream flow conditions that would be worse than recorded.

It may be pointed out that a rule curve for a reservoir that is exclusively operated for an all-hydro system is only of academic interest. Since there is no alternative use for the water there is no choice of operation: the required flow will be released when the reservoir is not full, and the inflow into the reservoir will be released when the full supply level is reached. From a mass curve study it has been ascertained that the reservoir capacity is adequate to guarantee the required flow during the critical flow period.

When there is alternative use for the water (e.g. irrigation or water supply), or alternative use for the storage capacity (e.g. flood control), it is evident that the rule curve becomes of practical interest. When the all-hydro system becomes a hydro-thermal system, as will be discussed shortly, the rule curve becomes a most important tool for economic operation of the whole power system.

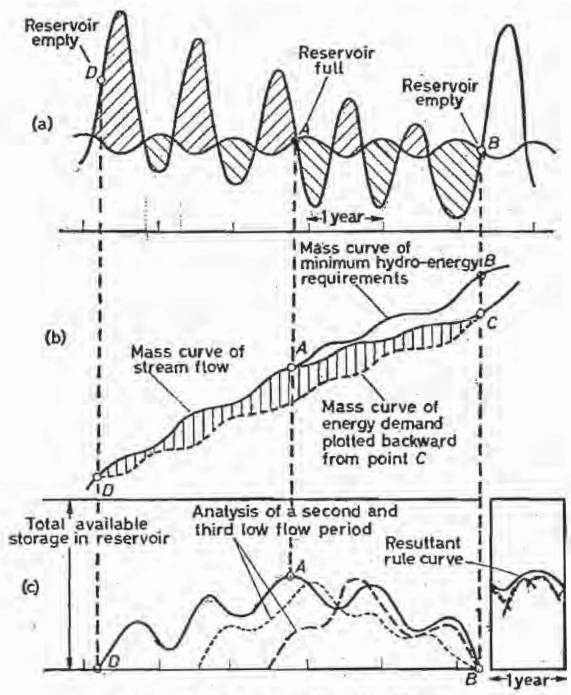


Figure 7.28. Preparation of rule curve

It should finally be noted that any rule curve, being the deficiency between energy requirements and dependable stream flow, is only valid for one particular load condition. If we go to another year, with different load conditions, we have to revise the rule curve.

Now let us consider a somewhat more complicated example of a reservoir with year-to-year storage, operated for a hydro-steam system, as shown in *Figure 7.28*. It was noted earlier that in a hydro-steam system part of the reservoir may be operated for dependable flow (place steam on the base, hydro in the peak, find the required minimum hydro energy and translate into stream flow) while the remainder of the reservoir is operated for maximum energy output (release all flow that can be converted into usable hydro energy). In view of this dual use of a storage reservoir it becomes now particularly important to what level we can draw the reservoir down as of any date during the year.

Figure 7.28(a) shows the stream flow during the most critical period on record and also the minimum hydro energy requirements for one given load condition. It may be seen that water has to be stored over a period of several years, the shaded areas above the energy demand line indicating water going into storage, and the shaded areas under this line indicating water released from storage. At time *B*, the end of the critical period, the reservoir is empty. From *Figure 7.28(b)*, it may be seen that the reservoir must be full at time *A*, and that the required volume of the reservoir for dependable flow is represented by ordinate *BC*. However, this volume does not have to be available at all times. If we plot the minimum hydro energy demand, starting at point *C* in *Figure 7.28(b)*, and working to the left, we find the required storage capacities, at any time, antecedent to the end of the critical period. When the ordinates of deficiency are plotted on a horizontal base, *Figure 7.28(c)* is obtained. Since this curve is spread over several years, we have to take the year with the highest ordinates in order to find the appropriate rule curve. If this procedure is repeated for other critical flow periods, other deficiency curves will be obtained. We have to scan *Figure 7.28(c)* month by month and plot the highest deficiency ordinates that are found on a one-year diagram shown in *Figure 7.28(d)*. After all the high points are plotted, an enveloping curve is drawn, representing the resultant rule curve for reservoir operation.

Operation of the reservoir will now take place as follows. When the reservoir as of any date is above the elevation of the rule curve as of that same date, all water that can be converted into usable electrical energy is released from the reservoir. When the available storage is only slightly above, or equals the critical storage capacity indicated by the rule curve, the release of water should be restricted to such a quantity that the reservoir storage does not fall below the rule curve. The lower limit of the release is, of course, the minimum hydro requirement as of that date. When, for some reason, the storage in the reservoir should fall below the rule curve, the release should be limited to the minimum hydro requirements, with the object of returning as soon as possible to the rule curve. It follows, that during such times, all steam plants in the system operate on the base of the load.

To illustrate the above discussion let us consider the same power system that was used for *Figure 7.19*, namely one hydro plant with a head of 148 ft., an efficiency of 0·80 and an installed capacity of 450 MW, plus one steam plant with a capacity of 450 MW. The load system has a peak demand of 900 MW and an annual load factor of 0·66. Spare capacity will not be considered. We shall assume that the steam plant can operate continuously on the base of the load, if needed. A reservoir with a capacity of 100,000 SFM (1 SFM = 1 second ft. month = 61 acre-ft.) is situated above the hydro plant. Part of the reservoir is used for maximum energy production, part is used to produce the required dependable flow. The 'rule curve' of the reservoir is shown as col. (7) in Table 7.1. The operation of the reservoir would be as shown in Table 7.1.

It should be noted that in regulating future flow conditions, there is always the possibility of encountering lower-than-recorded reservoir inflows. If we would operate, nevertheless, on the basis of a rule curve derived from recorded flow conditions, the result could be an empty reservoir with consequent power shortage! In other words, whenever we approach the basic rule curve we run the risk of capacity deficiency.

Table 7.1. *Rule Curve Regulation of One Reservoir*

Year	*Month* (1)	*Peak* (2)	*Ener.* (3)	*H. Cap* (4)	*Max. H* (5)	*Min. H* (6)	*Rule Curve* (7)	*Inflow* (8)	*Outflow* (9)	Δ *Stor.* (10)	*Stor.* (11)	*Th. En.* (12)
1940	April	730	530	450	430	100	10,000	45,000	43,000	+2,000	20,000	100
	May	690	500	400	380	75	12,000	80,000	38,000	+42,000	62,000	120
	June	680	500	350	340	75	15,000	135,000	97,000	+38,000	100,000	160
	July	670	490	350	340	70	25,000	80,000	80,000	—	100,000	150
	Aug.	680	500	350	340	75	37,000	20,000	34,000	−14,000	86,000	160
	Sept.	720	530	350	350	100	44,000	18,000	35,000	−17,000	69,000	180
	Oct.	800	580	400	400	145	47,000	16,000	38,000	−22,000	47,000	200
	Nov.	850	620	450	440	180	41,000	18,000	24,000	−6,000	41,000	380
	Dec.	880	640	450	450	200	32,000	12,000	21,000	−9,000	32,000	430
1941	Jan.	900	660	450	450	220	22,000	12,000	22,000	−10,000	22,000	440
	Feb.	850	620	450	440	180	15,000	11,000	18,000	−7,000	15,000	440
	Mar.	810	590	450	440	150	11,000	14,000	18,000	−4,000	11,000	410
	April	730	530	450	430	100	10,000	18,000	19,000	−1,000	10,000	340
	May	690	500	400	380	75	12,000	60,000	38,000	+22,000	32,000	120

Col. (1). The period of April 1940 to May 1941 is an arbitrary selection out of a much longer regulation study. The purpose of the study could have been to determine thermal energy requirements for future load conditions using past flow records as a criterion.
Col. (2) represents the peak demand in MW for every month.
Col. (3) represents the monthly energy demand in MW continuous.
Col. (4) represents the available hydro capacity, in MW. From May to November, deductions have been made to allow for maintenance outage.
Col. (5) represents the maximum hydro energy in MW continuous that can be used in the system, if the hydro capacity of col. (4) is placed on the base of the load.
Col. (6) represents the minimum hydro energy, in MW continuous, that is required if the steam plant is placed in the base of the load. These figures are obtained by deducting 450 MW from the figures of col. (2). The remainder is expressed in per cent of total peak. Using the monthly peak-percentage curve, the percentage of required energy is found. This figure is multiplied with the figures of col. (3).
Col. (7) represents the amount of storage required in the reservoir, in SFM. The figures are obtained from a study as shown in *Figures 7.27* and *7.28*, or in Table 7.2.
Col. (8) represents the average monthly inflow into the reservoir in cusec.
Col. (9). The outflow from the reservoir in cusec is found by applying the following rules: (*a*) The outflow should never be less than the minimum requirements indicated by col. (6); (*b*) The outflow should not be more than the maximum usable flow indicated by col. (5), unless the reservoir is full. In that case, the excess flow must be spilled; (*c*) The total storage in the reservoir should not fall below the level indicated by col. (7); (*d*) Staying within these limits, as much water should be released as possible.
Col. (10). The difference between cols. (8) and (9), in SFM.
Col. (11). The total storage in the reservoir in SFM. This figure cannot be more than its total capacity of 100,000 SFM, and should not be less than the figures of col. (7). Only in the driest year on record will this figure fall down to zero.
Col. (12) represents the thermal energy requirements in MW continuous. This figure is obtained by deducting the usable hydro energy of col. (9) from col. (3).

On the other hand, if we would steer a safe distance away from the rule curve, we run the risk of subsequently filling our reservoirs too early and having to spill more water than otherwise. It appears that there is what we could call a 'risk zone' above the rule curve, where we have to take the risk of either capacity deficiency or energy waste. It may have merit to determine within the risk zone the probability of energy waste and of capacity deficiency. Such statistical information would provide further guidance to reservoir operation.

Another means to extend the usefulness of the rule curve for actual reservoir operation would be to devise a system of long range stream flow forecasting. In drainage basins where the spring run-off is mostly derived from snow melt, it may be feasible to devise a relationship between the volume of spring run-off on the one hand and the amount of snowfall and antecedent ground conditions on the other hand. Since the most critical flow conditions in such drainage basins usually occur at the end of the winter, the above relationship may greatly assist the selection of the proper reservoir release. If, for instance, a larger-than-normal spring run-off is expected, it would be permissible to draw the reservoir down below the normal rule curve, and thus increase the energy utilization of the stream.

The problem of regulating reservoirs by means of rule curves becomes somewhat complicated when there are several reservoirs in the system. We may distinguish the following situations:

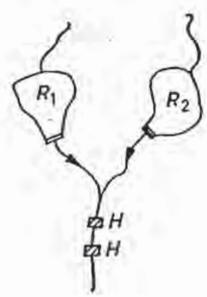


Figure 7.29. Parallel reservoirs

(*a*) Two or more reservoirs, parallel and above the hydro plants as shown in *Figure 7.29*. We may prepare one rule curve for the two reservoirs combined. This rule curve is found by analysing the combined inflow into the reservoirs and the combined minimum flow requirement of the hydro plants. When operating the two reservoirs with the one rule curve, we determine first the total outflow from the reservoirs and then distribute this outflow such that the resultant storage in one reservoir has approximately the same proportion to its full capacity as in the other reservoir.

(*b*) Two or more reservoirs, in series and above the hydro plants, as shown in *Figure 7.30*. We may also prepare one rule curve for the two reservoirs combined. If there is no appreciable inflow between the reservoirs, the problem may be reduced to one reservoir with the combined capacity. If there is significant inflow, the rule curve is found by analysing the inflow to the down-stream reservoir and the minimum hydro requirements. Operation of the reservoirs can take place as described under (*a*). In both (*a*) and (*b*) it would be advisable to check the validity of the rule curve by regulating the reservoirs for future load conditions and past stream flow records, in order to verify that all reservoirs have sufficient inflow at all times to perform their assigned function. If this is not so, a more conservative rule curve should be adopted.

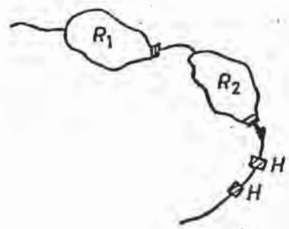


Figure 7.30. Reservoirs in series

(*c*) Two or more reservoirs, serving parallel groups of hydro plants as shown in *Figure 7.31*. In this case the release of a certain flow from one reservoir does not produce the same amount of energy as the release of an identical amount of flow from the other reservoir, since the amount of developed head below each reservoir may be different. For this reason it will be found more convenient to perform the book-keeping of reservoir releases and hydro energy requirements in terms of kWh instead of volumes of water. The storage in a reservoir thus becomes equal to the amount of kWh that would be produced when this volume of water would flow through the downstream power plants. The minimum hydro requirements, instead of being converted to stream flow, remain in terms of kWh. In this case of parallel plants, one rule curve will suffice for the two reservoirs. This rule curve is found by accumulating, in

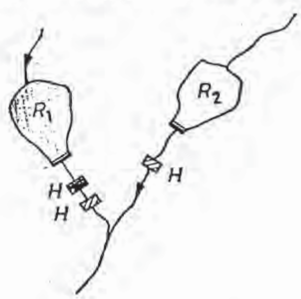


Figure 7.31. Parallel reservoirs

reverse order of time, the deficiency between the minimum hydro requirements in kWh, and the inflow into the reservoirs in kWh. Operation of the reservoirs may be such that in each reservoir the ratio of available storage, in kWh, to storage capacity, in kWh, is nearly the same. In addition to the requirement that the total release, in kWh, from all reservoirs, should be equal or greater than the total minimum hydro requirements, we must also make sure that each of the parallel groups receives enough energy to be firm when placed in the peak of the load curve.

(*d*) Two or more reservoirs, serving groups of hydro plants, placed in series as shown in *Figure 7.32*. We may again prepare one rule curve for all reservoirs. This rule curve is found by accumulating, in reverse order of time, the deficiency between the total minimum hydro requirements and the total amount of energy that would be produced by the natural, unregulated river discharge, flowing through the respective developed heads. Operation of the reservoirs may be performed again with the balancing principle, described above. The difference with case (*c*) is that it becomes somewhat more complicated to establish the appropriate additional requirements to ensure that each

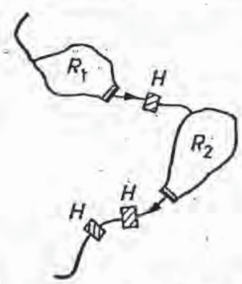


Figure 7.32. Reservoirs in series

hydro plant or group of hydro plants receives enough energy to be firm under the load curve. In fact, it may be desirable to establish supplementary rule curves for individual reservoirs in addition to the main rule curve for all reservoirs. Before a set of rule curves is applied to actual reservoir operation, it would be desirable to try it out first on the recorded flow conditions, so that any shortcomings may be corrected.

Table 7.2. *Preparation of Rule Curve for Two Parallel Reservoirs*

Year (1)	*Month*	*Nat. Flow* (2)	*Min. Req.* (3)	*Draw* (4)	*Acc. Storage* (5)
1940	April	25,000	12,000	−13,000	—
	May	28,000	11,000	−17,000	1,000
	June	18,000	10,000	−8,000	18,000
	July	24,000	9,000	−15,000	26,000
	Aug.	13,000	10,000	−3,000	41,000
	Sept.	9,000	12,000	+3,000	44,000
	Oct.	6,000	13,000	+7,000	41,000
	Nov.	12,000	15,000	+3,000	34,000
	Dec.	12,000	17,000	+5,000	31,000
1941	Jan.	10,000	20,000	+10,000	26,000
	Feb.	9,000	19,000	+10,000	16,000
	Mar.	10,000	16,000	+6,000	6,000
	April	20,000	12,000	−8,000	—

Col. (1). The period shown in the table is the most critical stream flow period on record.
Col. (2) lists the natural flow in cusec at the hydro sites. In other words, these figures equal the inflow into the two reservoirs plus the unregulated run-off between the reservoirs and the hydro plants.
Col. (3) shows the minimum hydro requirements expressed in SFM (cusec-months). These figures are obtained by assuming a certain load condition for the power system, placing the steam plants on the base and the hydro plants in the peak, determining the amount of hydro energy under the load curve, and converting this to average monthly stream flow.
Col. (4) shows the difference between cols. (2) and (3). Plus signs indicate flow deficiency and therefore draw from storage. Negative signs indicate flow surplus which may be stored in the reservoir.
Col. (5) represents the 'rule curve', in SFM, in storage. This column is computed backwards in time, starting at the last month with a flow deficiency: March 1941. The deficiencies are then accumulated until September 1940. From this month till May 1940 the accumulated storage is reduced to zero because of the flow surpluses. It must be noted that the storage volumes listed for every month are the minimum requirements at the beginning of every month. If we prepare the rule curve in the form of a graph, the values listed must be plotted on the first of the month and a smooth line drawn through the 12 points of the year. This curve can then be used for day-to-day regulation.

The following example will illustrate the preparation and use of rule curves, as discussed in the above. We shall assume that we have two parallel reservoirs, as shown in *Figure 7.29*. The hydro plants are assumed to be close together so that for practical purposes, they utilize the same river flow. The two hydro plants plus a number of steam plants form the entire power system. The preparation of the rule curve for regulating the two reservoirs is shown in the preceding Table 7.2.

It may be seen from Table 7.2 that the maximum storage requirement for dependable flow is 44,000 SFM in September. During the other months, the storage requirement is less. The actual storage capacity of the two reservoirs may be greater than 44,000 SFM, say 75,000 SFM. This would mean that a good deal of the reservoir capacity may be regulated for maximum energy output. An example of such regulation for two parallel reservoirs with downstream hydro plants, as shown in *Figure 7.29*, is presented in Table 7.3.

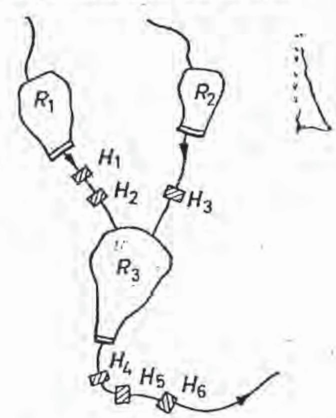


Figure 7.33. Reservoirs in series and parallel

We shall now discuss in principle how a complicated system of reservoirs and hydro plants would have to be operated as shown in *Figure 7.33*. First of all, we prepare a rule curve for the three reservoirs combined. The mechanics of preparing this curve is similar to the arrangement in Table 7.2. Col. (1) represents again the most critical stream flow period of the river system. In view of the larger storage capacity, this critical period may extend over several years and may be different for different load conditions. Col. (2) represents now the total amount of energy, in kWh, that would be available, if the natural unregulated river flow was converted at every hydro plant into electricity. Col. (3) represents the minimum hydro requirements, in kWh, of the total system (steam on the base). Col. (4) represents the surpluses and deficiencies of hydro energy, in kWh. Col. (5), computed backwards in time, represents the rule curve of the three reservoirs, in kWh.

However, this one rule curve is not sufficient to regulate the reservoirs. Let us assume, for instance, that the available storage, in kWh, is larger than the rule curve indicates, but all concentrated in the downstream reservoir, with the upstream reservoirs being empty. This would place the upstream hydro plants in a precarious position, particularly when the natural river flows fall below the minimum requirements! It is obvious that additional regulation rules are required. These rules may be listed as follows:

(1) The total hydro energy production of all plants should not exceed the maximum usable hydro energy. This figure is obtained by deducting the minimum thermal energy requirements (steam in the peak) from the total system energy requirements. This rule is similar to col. (2) in Table 7.3.
(2) The total hydro energy production of all plants should not be less than the minimum hydro requirements (all hydro in the peak). This rule is similar to col. (3) in Table 7.3.
(3) The energy production of plants H_1, H_2, and H_3 should not be less than what is required when these plants are placed in the peak of the load curve. If it is found that the energy provided by the natural river flow is at times less than this minimum requirement, a second rule curve has to be prepared for the regulation of R_1 and R_2 combined.
(4) The energy production of plants H_1 and H_2 should not be less than what is required when these plants are placed in the peak of the load curve. If it is found that the energy provided by the natural river flow is at times less than required, a third rule curve has to be prepared for the regulation of R_1. Similarly, a fourth rule curve may be required for R_2.

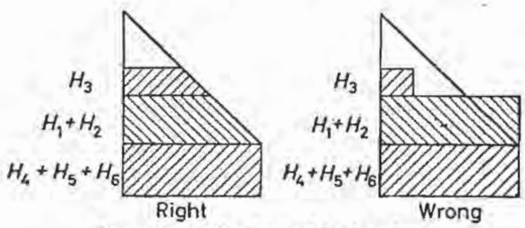


Figure 7.34. Stacking of hydro plants

(5) The energy production of all hydro plants, within the above described upper and lower limits, should moreover be such that the plants can be properly stacked under the load curve of the month, as shown in *Figure 7.34*.
(6) When a reservoir is full to capacity and its net inflow is greater than what may be used by the downstream plants, the reservoir outflow should equal the inflow, unless the outflow capacity is restricted. In that case the inflow has to be routed through the reservoir, using its storage curve and outflow rating curve. A separate account must be kept of spillage, since the usable hydro energy may never exceed what is set out under rules (1) and (5).

After having established the above rules and rule curves in quantitative terms, the actual operation of the system may be started. A table is prepared, in principle similar to Table 7.3, but somewhat more extensive, and all figures expressed in kWh instead of cusec. The regulation of the reservoirs becomes a trial and error procedure. The aim is to produce as much usable hydro energy as possible, while staying above the rule curves and within the rules. At the end of every month the reservoir storages should be in balance towards the rule curves, if possible. That is, for every reservoir or group of reservoirs the ratio of actual depletion to permissible depletion (rule curve value) should be the same. This has the advantage that all reservoirs reach the rule curves at the same time so that the whole system can simultaneously change from operation for maximum energy output to operation for dependable flow.

Table 7.3. *Rule Curve Regulation of Two Parallel Reservoirs*

Year	Month (1)	*Max. Hydro* (2)	*Min. Hydro.* (3)	*Rule Curve* (4)	*Unreg. R.O.* (5)	Reservoir 1 (Capacity: 50,000 SFM)				Reservoir 2 (Capacity: 25,000 SFM)				
						Inflow (6)	*Outflow* (7)	*Change in Storage* (8)	*Total Storage* (9)	*Inflow* (10)	*Outflow* (11)	*Change in Storage* (12)	*Total Storage* (13)	*Total Flow* (14)
1930	April								20,000				10,000	
	May	25,000	11,000	1,000	10,000	23,000	15,000	+8,000	28,000	4,000	0	+4,000	14,000	25,000
	June	24,000	10,000	18,000	9,000	9,000	6,000	+3,000	31,000	10,000	9,000	+1,000	15,000	24,000
	July	23,000	9,000	26,000	7,000	6,000	7,000	−1,000	30,000	9,000	9,000	0	15,000	23,000
	Aug.	24,000	10,000	41,000	5,000	−1,000	2,000	−3,000	27,000	8,000	9,000	−1,000	14,000	16,000
	Sept.	25,000	12,000	44,000	4,000	3,000	2,000	+1,000	28,000	6,000	6,000	0	14,000	12,000
	Oct.	26,000	13,000	41,000	6,000	3,000	3,000	0	28,000	3,000	4,000	−1,000	13,000	13,000

Col. (1). The seven months shown in the table are an arbitrary selection out of a regulation study that may extend over several decades. The purpose of such a study may be to find the hydro energy output for future load conditions, using the past flow records to represent the most likely future conditions.
Col. (2) represents the maximum usable hydro energy in the system, expressed in cusec. This figure is found by placing all hydro plants on the base of the load and converting the average energy into river flow.
Col. (3) represents the minimum hydro requirements in cusec as explained under Table 7.1, col. (6).
Col. (4) shows the minimum storage requirements in SFM obtained from Table 7.2, col. (5).
Col. (5) shows the unregulated run-off, in cusec, between the two storage reservoirs and the power plants.
Col. (6), Col. (10) show the net inflow into the reservoirs in cusec. This net inflow represents the actual inflow plus the precipitation, minus the evaporation over the reservoir. If such figures are not available in published records, they must be prepared by a preliminary study. Note that the inflow in Reservoir 1, during August 1930, has a negative value of −1,000 cusec, due to excess evaporation.
Cols (7)–(9) and Cols. (11)–(13) are now manipulated simultaneously and by trial and error. First we see how much energy we can use in May: 25,000 cusec. From unregulated run-off we receive 10,000 cusec. Hence we only have to draw from the reservoirs 15,000 cusec. We decide to draw all of this from Reservoir 1, and nothing from Reservoir 2, in order to conclude the month with a total storage in Reservoir 1 (28,000 SFM) which is twice the total storage in Reservoir 2 (14,000) SFM, this being the same ratio as the total storage capacities of the reservoirs.

During June and July, we repeat the same procedure. In August, however, we cannot afford to draw the maximum usable flow, or the total storage in the two reservoirs would fall below the rule curve. Therefore we only draw 16,000 cusec, which makes the total reservoir content equal to the rule curve with a value of 41,000 SFM. In September, we find that we have to release at least 8,000 cusec from the reservoirs, in order to provide, with the uncontrolled flow of 4,000 cusec, the minimum hydro requirement of 12,000 cusec. However, the release of 8,000 cusec from the reservoirs results in a total storage of 42,000 SFM which is less than the rule curve value of 44,000 SFM. During the following month, September, our first concern is to get back to the rule curve. Therefore, we only release enough water to provide for the minimum hydro requirements, and as a result we are at the end of the month indeed back on the rule curve. It may be noted that consequently, during the months of August and September, the steam plants in the system have continuously operated on the base of the load.
Col. (14) represents the sum of cols. (5), (7) and (11) and therefore represents the total flow of water through the hydro plants. After having allowed for possible spillage during times of high river flows and full reservoirs, the figures of col. (14) represent the total amount of hydro energy production. When these figures are deducted from the total system energy requirements the thermal energy requirements are obtained.

There may be situations where such a balancing regulation is impossible or undesirable. For instance, the flow conditions may be such that the reservoirs cannot be kept in balance for some time; or one of the reservoirs may be the forebay of a power plant, thus making it desirable to keep its level high as long as possible. Another exception to the general rule would be if the reservoirs have drainage areas that are much different in size or water yield. In such circumstances it would be advisable to draft heavier from the easy-to-fill reservoirs so as to avoid subsequent spilling of these reservoirs.

Now that we have discussed in principle how a reservoir rule curve can be prepared and applied, we may introduce a few refinements. First of all we may question if the past stream flow record is the best criterion for future dependable flow operation. Although this principle is widely accepted there may be good reasons, for certain power utilities, to desire a greater or smaller degree of risk than is indicated by 30, 40, or 50 years of record. If this is the case, it becomes necessary to conduct probability studies of low flow periods, before the rule curve can be determined.

Another refinement may have to be made in connection with changing load patterns. In the derivation of the rule curve in *Figure 7.28*, the mass curve of energy demand was based on one particular load year; and the resultant rule curve was only valid for that particular load year. This method is quite satisfactory for system planning studies where thermal energy requirements must be determined for one particular load year, for one particular sequence. However, for actual reservoir operation we must allow for the growing load demand. Hence the mass curve of energy demand in *Figure 7.28* must reflect the change in load pattern from year to year.

Another refinement in reservoir regulation is to establish so-called 'no-spill rule curves'. Their preparation is similar to what we have discussed earlier, but instead of using low flow conditions we use flood conditions, and instead of specifying that the reservoir must contain at least a given storage on a given date, we specify that the reservoir should contain no more than a given storage on a given date. The purpose of no-spill rule curves is to prevent flood damage around the reservoir, to prevent spilling of water, and thus to increase the energy utilization of the river system. The preparation of no-spill rule curves is only meaningful when the reservoir capacity is relatively large and when the installed hydro capacity is relatively large. Otherwise the no-spill rule curves may fall well below the dependable flow rule curves, which would be meaningless.

It was noted earlier that the area immediately above the rule curve may be looked upon as a risk zone, where we run the risk of capacity deficiency if we keep releasing maximum usable river flows, till we reach the rule curve, and where we run the risk of more spilling during subsequent flood flows if we would be more cautious and start cutting back flows before we reach the rule curve. It may be feasible to establish within this risk zone a bundle of so-called 'economy guide lines', more or less parallel to, and slightly above, the rule curve. When we reach the first line, we stop the generation of all surplus hydro energy; when the second line is reached, the least costly thermal energy producers are put on the line; when the third line is reached, the next best thermal plants are placed in operation, and so on. When finally the rule curve is reached, all thermal capacity must be placed in operation.

It will be readily appreciated that a great deal of tedious work is involved in reservoir regulation studies. For this reason, it would have merit to consider the use of a computer for the performance of the routine computations.

SYSTEM PLANNING

Nearly all power utilities are continuously faced with the necessity of having to decide upon increases in their generating capacity to meet the growing load demand. In this section we shall first discuss what general considerations may be applied to the most economic composition of a power system. After that, we shall discuss how a numerical analysis of alternative sequences of system development can be conducted.

Future System Composition

In general, we may observe that a power system may be composed of: gas turbines, steam plants, hydro plants and nuclear plants. Since the most economic combination, for given load conditions, depends very much on the costs of these generating sources, let us discuss cost aspects first.

Gas turbines are relatively new in the field of generating electricity. Presently, their cost per kilowatt of installed capacity ranges from $100 to $200. It is believed, however, that with the advance of technology in this field, the capital cost may be reduced to $100 or somewhat less. The cost of fuel depends much on local conditions. Even if the local cost of fuel is high, gas turbines may become attractive because of their low capital cost. For the purpose of the present discussion we shall assume the cost of figures quoted in Table 7.4.

Table 7.4. *Gas Turbines*

Capital cost	$100 per kW
Interest	6%
Depreciation (25-year life)	2%
Taxes and insurance	2%
Operation and maintenance	$3·00 per kW per year
Fuel	7 mills per kWh

The cost structure of steam plants has been discussed earlier. Assuming some further advance in the technology of steam plants, aimed at lower capital costs, higher efficiencies and bigger units, we shall use for the present purpose the figures quoted in Table 7.5.

Table 7.5. *Steam Plants*

Capital cost	$150 per kW
Interest	6%
Depreciation (25-year life)	2%
Taxes and insurance	2%
Operation and maintenance	$3·00 per kW per year
Fuel	4 mills per kWh

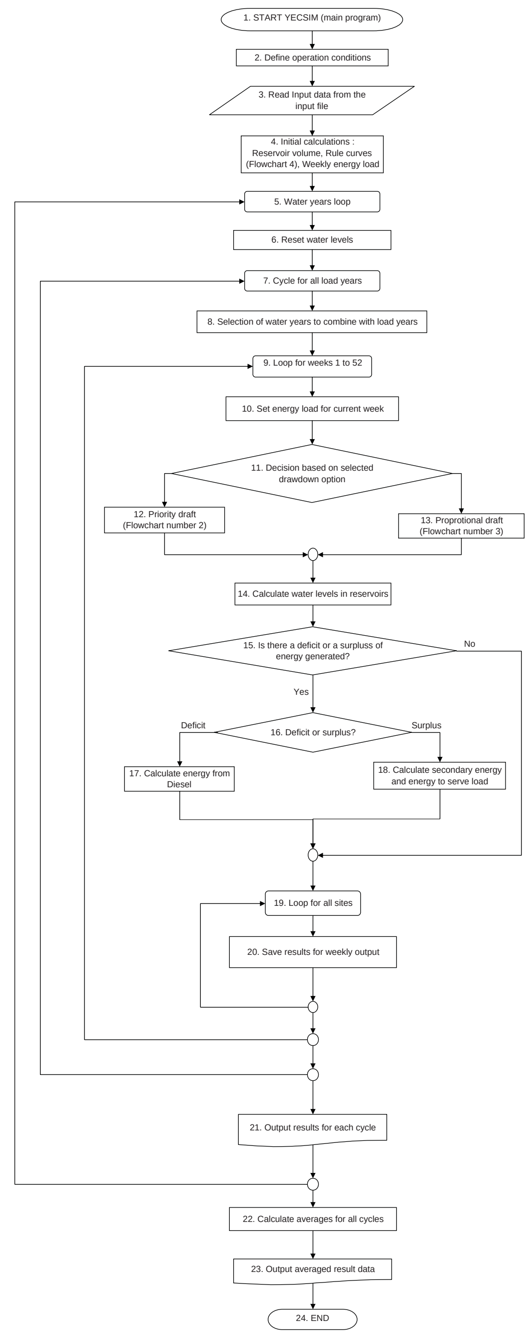
The cost of hydro development varies tremendously, depending on the available stream flow, head, site topography, and distance from the load centre. We may assume that by now nearly all feasible hydro sites close to load centres have been developed and that the problem of future hydro development is

APPENDIX C

PROGRAM FLOWCHARTS

KGS GROUP CONSULTING ENGINEERS

Client:	Yukon Energy
File No:	08-1404-04
Project:	YEC System Model
Appendix C:	Program Flowcharts
Flowchart:	Main Program Conceptual
Flowchart:	No 1
Sheet:	1 of 1
Date:	By: PL
Checked:	7-Jan-09 By: FC



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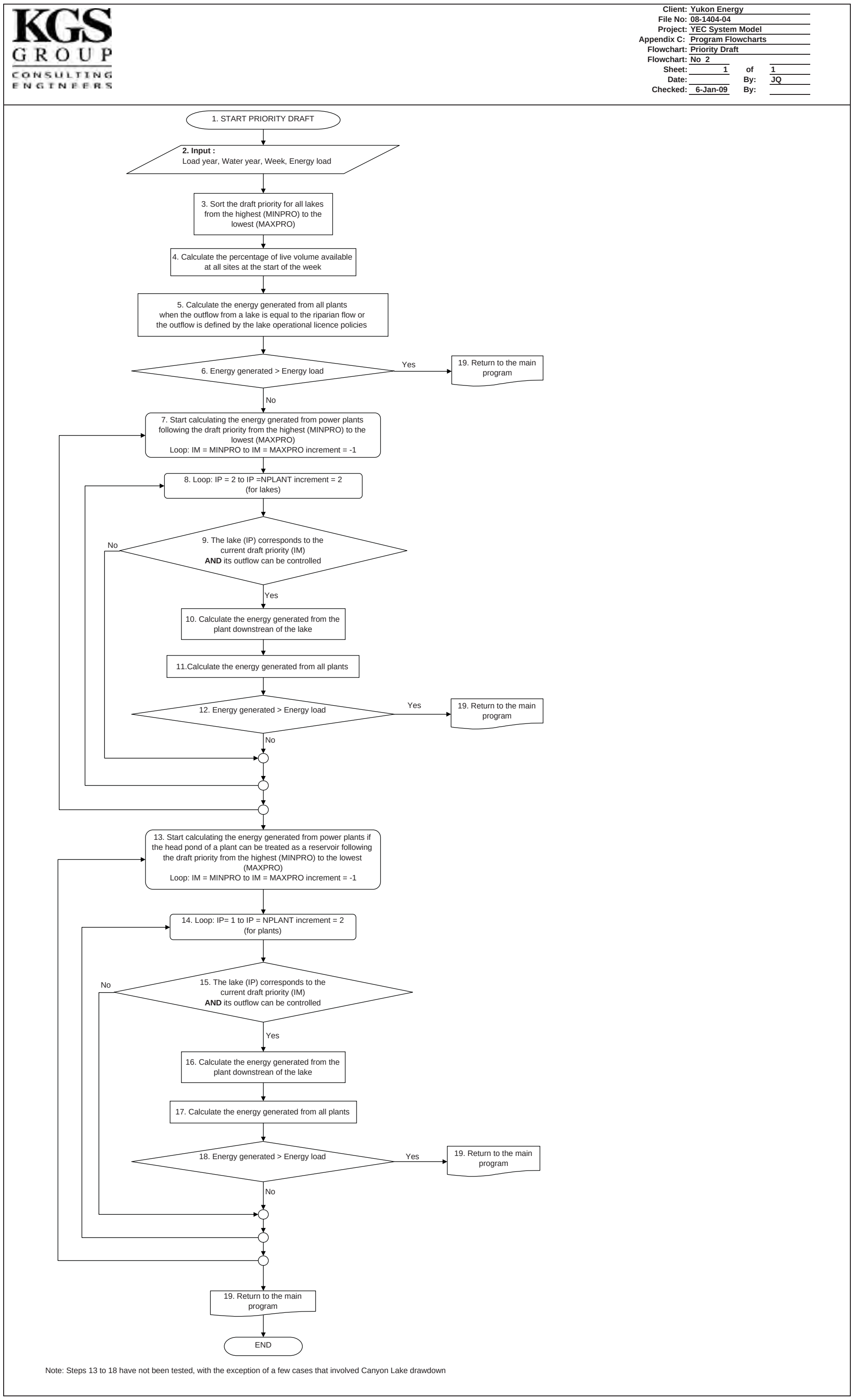
Appendix C: Program Flowcharts
Main-Flowchart1
March 2009



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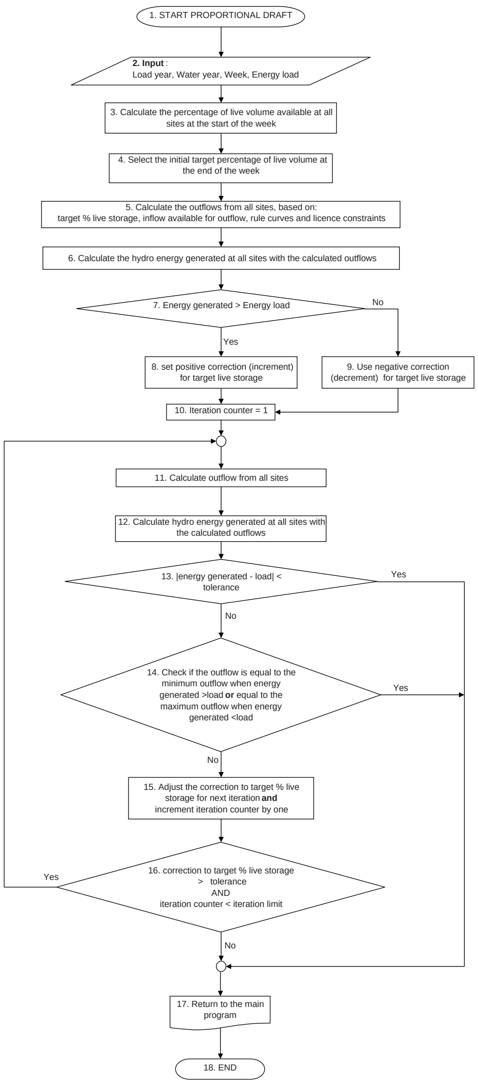
Appendix C: Program Flowcharts
Priority Draft-Flowchart2
March 2009

KGS GROUP CONSULTING ENGINEERS

Client:	Yukon Energy
File No:	08-1404-04
Project:	YEC System Model
Appendix C:	Program Flowcharts
Flowchart:	Proportional Draft Conceptual
Flowchart:	No 3
Sheet:	1 of 1
Date:	By: PL
Checked:	7-Jan-09 By: FC



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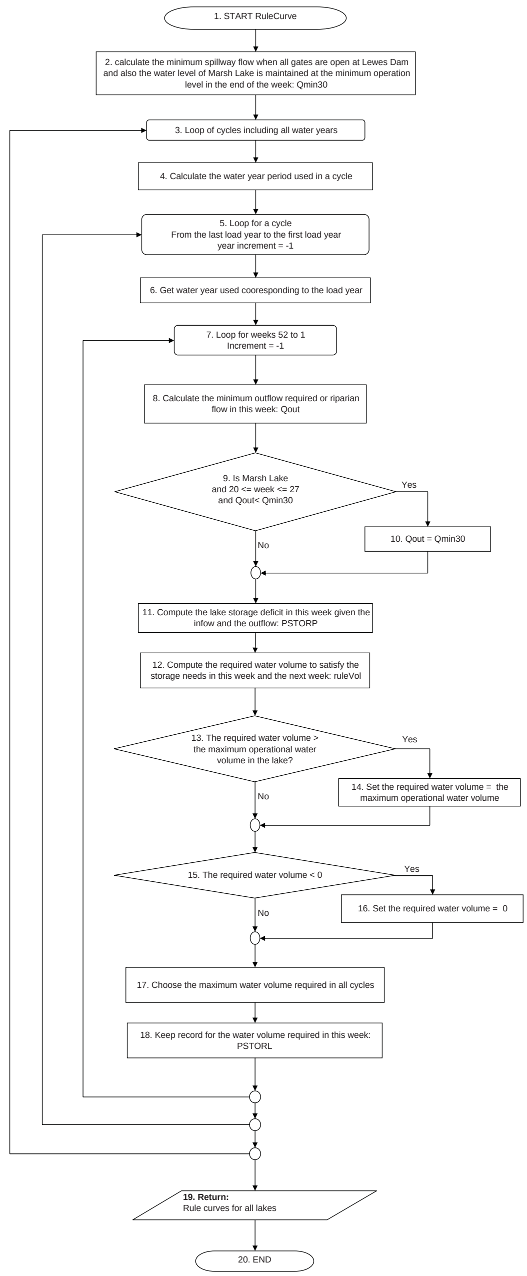
Appendix C: Program Flowcharts
Proportional Draft-Flowchart 3
March 2009

KGS GROUP
CONSULTING ENGINEERS

Client: Yukon Energy
File No: 08-1404-04
Project: YEC System Model
Appendix C: Program Flowcharts
Flowchart: RuleCurve Conceptual
Flowchart: No 4
Sheet: 1 of 1
Date: By: PL
Checked: 7-Jan-09 By: FC



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Appendix C: Program Flowcharts
Rule Curve-Flowchart 4
March 2009

APPENDIX D

TABLES OF INPUT PARAMETERS

APPENDIX D – TABLES OF INPUT PARAMETERS

The following tables lists the important input parameters used in YECSIM.

Table D.1 – Coefficients for Elevation-Storage Volume Calculation

Lake/Reservoir	Coefficient		
	C1	C2	C3
Schwatka Lake	650.000	2.36842E-03	1.00000
Marsh Lake	652.000	6.47715E-06	1.00000
Canyon Lake	904.000	4.14740E-04	1.00000
Aishihik Lake	911.712	8.00375E-05	0.90487
Wareham Lake	570.000	9.83600E-04	1.00000
Mayo Lake	660.000	3.81400E-05	1.00000

Table D.2 – Operating Water Levels

Lake/Reservoir	Water Level (m)	
	Minimum	Maximum
Schwatka Lake	653.070	653.070
Marsh Lake	653.796	656.234
Canyon Lake	905.870	907.420
Aishihik Lake	913.000	915.160
Wareham Lake	573.900	573.900
Mayo Lake	663.270	665.870

Table D.3 – Three-tier System of Turbine-Generator Efficiencies

Generating Station	Tier	Discharge - Q (m^3/s)	Efficiency
Whitehorse Rapids Generating Station	Low	85.000	0.825
	Average	85.0<Q<285.0	0.825
	Full capacity	285.000	0.806
Aishihik Generating Station (2 Units)	Low	3.00	0.680
	Average	6<Q<19.46	0.860
	Full capacity	19.460	0.870
Aishihik Generating Station (3 Units)	Low	3.000	0.880
	Average	6.0<Q<23.96	0.872
	Full capacity	23.960	0.863
Mayo A Generating Station	Low	3.00	0.475
	Average	4.0<Q<15.0	0.808
	Full capacity	15.00	0.864
Mayo A Generating Station (Mayo B Generating Station is in operation)	Low	6.00	0.837
	Average	7.0<Q<15.0	0.830
	Full capacity	15.00	0.864
Mayo B Generating Station	Low	4.00	0.68
	Average	5.0<Q<19.0	0.849
	Full capacity	19.00	0.898

Table D.4 – Coefficients for Tailwater Level Calculation			
Generating Station	Coefficient		
	C_1	C_2	C_3
Whitehorse Rapids Generating Station	631.700	0.096	0.590
Aishihik Generating Station	718.414	0.320	0.680
Mayo A Generating Station	536.000	0.000	0.000
Mayo B Generating Station	508.74	0.000	0.000

Table D.5 – Coefficients for Head Loss Calculation			
Generating Station	Coefficient		
	C_1	C_2	C_3
Whitehorse Rapids Generating Station	0.000	0.000	0.000
Aishihik Generating Station	0.0076758	0.018	19.460
Mayo A Generating Station	1.500	2.000	15.000
Mayo B Generating Station	0.0672	2.000	19.000

Table D.6 – Spillway Rating Curves at Lewes Dam

No.	Water Level of Marsh Lake (m)	Discharge at All Gates Open (m^3/s)	Discharge at 10 Gates Open (m^3/s)
1	653.0	25.0	20.0
2	653.5	90.0	53.0
3	654.0	158.0	85.0
4	654.5	220.0	119.0
5	655.0	294.0	157.0
6	655.5	370.0	200.0
7	656.0	448.0	245.0
8	656.5	526.0	292.0
9	657.0	610.0	347.0
10	657.5	690.0	403.0
11	658.0	760.0	510.0
12	658.5	860.0	600.0
13	659.0	960.0	670.0
14	659.5	1060.0	714.0

Table D.7 – Spillway Rating Curves at Canyon Lake

No.	Water Level (m)	Discharge (m^3/s)
1	907.400	15.934
2	907.450	17.135
3	907.500	19.035
4	907.550	21.535
5	907.600	24.331
6	907.650	27.527
7	907.700	31.223
8	907.750	35.119
9	907.800	39.316
10	907.850	43.912
11	907.900	48.808
12	907.950	54.004
13	908.000	59.400
14	908.050	65.096
15	908.100	71.192
16	908.150	77.488
17	908.200	84.084
18	908.250	90.880
19	908.300	97.977
20	908.350	105.673
21	908.400	112.669
22	908.450	121.665
23	908.500	128.661

Table D.8 – Spillway Rating Curve at Mayo Lake Outlet

No.	Flash Boards Up		Flash Boards Down	
	Water Level (m)	Discharge (m^3/s)	Water Level (m)	Discharge (m^3/s)
1	660.80	0.00	660.80	0.00
2	661.00	0.15	661.00	0.15
3	661.10	0.50	661.10	0.50
4	661.20	0.89	661.20	0.89
5	661.30	1.34	661.30	1.34
6	661.40	1.83	661.40	1.83
7	661.50	2.37	661.50	2.37
8	661.60	2.95	661.60	2.95
9	661.70	3.58	661.70	3.58
10	661.80	4.26	661.80	4.26
11	661.90	4.99	661.90	4.99
12	662.00	5.76	662.00	5.76
13	662.10	6.59	662.10	6.59
14	662.20	7.46	662.20	7.46
15	662.30	8.37	662.30	8.37
16	662.40	9.33	662.40	9.33
17	662.50	10.35	662.50	10.35
18	662.60	11.40	662.60	11.40
19	662.70	12.51	662.70	12.51
20	662.80	13.66	662.80	13.66
21	662.90	14.86	662.90	14.86
22	663.00	16.11	663.00	16.11
23	663.04	16.50	663.04	16.50
24	663.24	18.60	663.24	18.60
25	663.25	18.70	663.25	18.70
26	663.44	20.48	663.44	20.48

Table D.8 – Spillway Rating Curve at Mayo Lake Outlet (Contd.)				
No.	Flash Boards Up		Flash Boards Down	
	Water Level (m)	Discharge (m^3/s)	Water Level (m)	Discharge (m^3/s)
27	663.64	22.20	663.64	22.20
28	663.84	23.79	663.84	23.79
29	664.04	25.28	664.04	25.28
30	664.24	26.69	664.24	26.69
31	664.44	28.02	664.44	28.02
32	664.64	29.30	664.64	29.30
33	664.84	30.51	664.84	30.51
34	665.04	31.68	665.04	31.68
35	665.24	32.81	665.24	32.81
36	665.31	33.20	665.31	33.20
37	665.39	33.63	665.39	33.63
38	665.51	34.27	665.51	39.03
39	665.73	35.42	665.73	58.10
40	665.78	36.75	665.78	63.54
41	665.83	38.95	665.83	69.32
42	665.84	39.46	665.84	70.51
43	665.88	41.71	665.88	75.42
44	665.93	44.94	665.93	81.82
45	665.98	48.58	665.98	88.52
46	666.03	52.59	666.03	95.49
47	666.08	56.93	666.08	102.73
48	666.13	61.59	666.13	110.23
49	666.18	66.55	666.18	117.98
50	666.23	71.79	666.23	125.96
51	666.28	77.30	666.28	134.18
52	666.33	83.07	666.33	142.62

APPENDIX E

LICENSES FOR YEC RESERVOIRS AND PLANTS

YUKON TERRITORY WATER BOARD

WATER USE LICENCE

Pursuant to the *Yukon Waters Act* and Regulations, the Yukon Territory Water Board hereby grants a Type A Water Use Licence for a power undertaking to:

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon
Y1A 5L6

LICENCE NUMBER:	HY99-010
LICENCE TYPE:	A
UNDERTAKING:	Power, Class 4
LOCATION:	Yukon River at Whitehorse
EFFECTIVE DATE:	The effective date of this licence shall be the date on which the signature of the Minister of Indian and Northern Affairs Canada is affixed.
EXPIRY DATE:	May 31, 2025
PURPOSE:	Operation of the Whitehorse Rapids Generating Station and the Lewes Dam as proposed in Water Use Applications HY99-009 and HY99-010.

This licence shall be subject to the restrictions and conditions contained herein and to the restrictions and conditions contained in the Yukon Waters Act and the Regulations made thereunder.

Dated this 13th day of January, 2000

YUKON TERRITORY WATER BOARD

Witness

Chairperson

Dated this 14 day of February, 2000

APPROVED BY:

Witness

Minister of Indian Affairs and Northern Development

PART A - GENERAL CONDITIONS

1. Definitions

(a) "Act" means the Yukon Waters Act and any amendments thereto.

(b) "Regulations" means the Regulations made under the Act.

(c) "Board" means the Yukon Territory Water Board.

(d) "Application" and "Water Use Application" mean Water Use Applications HY99-009 and/or HY99-010, including any additional submissions and/or revisions, submitted to the Board by the Licensee.

(e) "Deleterious Substance" means deleterious substance as defined in Section 34(1) of the Fisheries Act.

Representations, Warranties and Undertakings

2. The Board has relied on the representations, warranties and undertakings provided by the applicant in the material filed as Applications HY99-009 and HY99-010. Such representations, warranties and undertakings are considered by the Board to be a part of the licence, but shall be subject to, and may be modified by the terms and conditions of the licence.

Other Laws

3. No term of this licence limits the application of any other Federal, Territorial or First Nation Law.

Correspondence

4. Where any direction, notice, order, or report under this licence is required to be in writing, it shall be given:

(a) To the Licensee, if left at, faxed to, or mailed by registered mail to the following address:

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon
Y1A 5L6

Fax: (867) 393-6909

and shall be deemed to have been given to the Licensee on the day it was left or faxed, or seven (7) days after the day it was mailed, as the case may be.

(b) To the Board, if left at, faxed to, or sent by registered mail to the following address:

Yukon Territory Water Board
Suite 106, 419 Range Road
Whitehorse, Yukon
Y1A 3V1

Fax: (867) 668-3628

and shall be deemed to have been given to the Board on the day it was left or faxed, or seven (7) days after the day it was mailed, as the case may be.

Non-Compliance

5. In the event that the Licensee fails to comply with any provision or condition of this licence, the Board may, with the approval of the Minister and subject to the Act, cancel the licence.

Deleterious Substances

6. Subject to the provisions of this licence, deleterious substances shall be used, transported, stored and disposed of in such a manner that they are not deposited in, or allowed to be deposited in, any waters.

Water Use

7. Subject to the terms of this licence, the Licensee is hereby authorised to :

(a) store the flow of the Yukon River, except for a minimum flow of 85 m^3/s, behind the Lewes Dam for the purposes of a power undertaking;

(b) store the flow of the Yukon River, except for a minimum flow of 85 m^3/s, behind the Whitehorse Rapids Dam for the purposes of a power undertaking; and

(c) divert the flow of the Yukon River through the Whitehorse Rapids Powerhouse for the purposes of a power undertaking.

Term of Licence

8. The term of this licence is from the effective date to May 31, 2025.

Reports

9. All reports shall be submitted to the Board in an unbound printed form that is reproducible by standard photocopier and shall be accompanied by five (5) copies.

10. All monitoring data and reports shall be submitted in digital form on diskette using an IBM compatible format readable using commonly available software.

Annual Reports

11. Annual reports shall be submitted to the Board by the Licensee. The initial report shall cover the period from the effective date of this licence to March 31, 2000 and shall be submitted to the Board on or before May 31, 2000. Subsequent reports shall cover the period from April 1 to March 31 of each year and shall be submitted to the Board on or before May 31 in the year in which the reporting period ends.

12. Annual reports shall include the information required by this licence and by the Regulations, including, but not necessarily limited to:

(a) monthly maximum and minimum mean daily water levels on Schwatka Lake and Marsh Lake;

(b) monthly maximum and minimum mean daily water levels in the Whitehorse Rapids powerhouse tailrace;

(c) monthly maximum and minimum mean daily flows through the Whitehorse Rapids powerhouse turbines;

(d) monthly maximum and minimum mean daily flows through the Whitehorse Rapids spillway;

(e) monthly maximum and minimum number of gate openings at the Lewes Dam;

(f) information regarding the purpose, nature and extent of any significant maintenance work carried out; and

(g) any other information or reports required by this licence or the Regulations.

Quarterly Reports

12. Quarterly reports shall be submitted to the Board by the Licensee. The reports shall cover the periods ending March 31, June 30, September 30 and December 31 of each year and shall be submitted to the Board within 30 days of the end of each reporting period.

13. Quarterly reports shall include the information required by this licence and by the Regulations, including, but not necessarily limited to:

    (a) mean daily water levels on Schwatka Lake and Marsh Lake;

    (b) mean daily water levels in the Whitehorse Rapids powerhouse tailrace;

    (c) mean daily flows through the Whitehorse Rapids powerhouse turbines;

    (d) mean daily flows through the Whitehorse Rapids spillway;

    (e) daily number of gate openings at the Lewes Dam; and

    (f) any other information or reports required by this licence or by the Regulations.

<u>Dam Safety Monitoring Reports</u>

14. An annual dam safety inspection and monitoring report for the Whitehorse Rapids and Lewes Dams and related structures shall be submitted to the Board by the Licensee. The report shall be submitted by November 30 of each year and shall contain the following information:

    (a) monitoring instrumentation readings for the previous year;

    (b) graphical and/or tabulated historic data for the monitoring instrumentation;

    (c) notes of visual observations;

    (d) analysis of the data and observations; and

    (e) recommendations for any additional monitoring or actions arising from the results of the monitoring.

15. Every five years, or more frequently if recommended as a result of any dam safety inspection, the Licensee shall submit a report detailing the results of a comprehensive dam safety review. The first report shall be submitted by November 30, 2000. Subsequent reports shall be submitted by November 30 of the year in which the inspection is carried out. The report shall contain the following information:

    (a) monitoring data;

    (b) notes of observations;

    (c) analysis of the data and observations; and

    (d) recommendations for actions arising from the analysis.

Spills and Unauthorized Discharges

16. The Licensee shall immediately contact the 24-hour Yukon Spill Report telephone number (867) 667-7244, should a spill or an unauthorized discharge occur. A detailed written report on any such event, including but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Board not later than fifteen (15) days after its occurrence.

Hazardous Materials Storage

17. A complete inventory of chemicals, fuels, oils and other hazardous materials and their locations shall be maintained by the Licensee. A spill contingency plan suitable for each material shall be developed and submitted to the Board as part of the first annual report. Any revisions to the plan shall be submitted to the Board within 60 days of the revision.

PART B - OPERATING CONDITIONS

18. A minimum instantaneous flow of 85 m^3/s shall be maintained in the channels downstream of the Lewes Dam and of the Whitehorse Rapids Powerhouse.

19. The water surface elevation on Schwatka Lake shall be maintained between a minimum of 652.272 m and a maximum of 653.339 m as measured from Geodetic Survey of Canada benchmark 86G114A.

20. The mean daily water surface elevation on Marsh Lake shall be maintained between a controlled minimum of 653.796 m and a controlled maximum of 656.234 m as measured from Water Survey of Canada gauge 9AB004.

21. With respect to the Lewes Dam, the Licensee shall comply with the following:

    a) Except as permitted by sub-clause b) of this licence, or as required for repairs and maintenance, all gates shall remain open from May 15 to August 15 of each year.

    b) The following exceptions shall be permitted to the requirements of sub-clause a) of this licence:

        i) If, on July 7 of any year, the water surface elevation of Marsh Lake is less than 654.82 metres, then up to twenty gates may be closed and at least ten gates must remain open. If the water surface elevation equals or exceeds 654.82 metres, then all gates must remain open.

        ii) If, on July 21 of any year, the water surface elevation of Marsh Lake is less than 655.15 metres, then up to twenty gates may be closed and at least ten gates must remain open. If the water surface elevation equals or exceeds 655.15 metres, then all gates must remain open.

        iii) If, on August 10 of any year, the water surface elevation of Marsh Lake is less than 655.65 metres, then up to twenty gates may be closed and at least ten gates must remain open. If the water surface elevation equals or exceeds 655.65 metres, then all gates must remain open.

22. The Licensee shall maintain existing fish passage facilities at the Whitehorse Rapids and Lewes Dams and shall ensure that the fish passage facilities are open and functioning from April 1 to November 15 of each year.

23. Existing boat passage facilities at the Lewes Dam shall be maintained by the Licensee.

24. Annually, the Licensee shall carry out a dam safety monitoring inspection of all water management structures associated with the Whitehorse Rapids and Lewes Dams. The inspection shall be carried out by a qualified professional engineer licenced to practice in the Yukon, and shall follow the recommendations contained in the most current edition of the *Canadian Dam Safety Guidelines*.

25. Every five years, or more often if recommended as a result of any dam safety inspection, the Licensee shall engage an independent, qualified, professional engineer, licenced to practice in the Yukon, to carry out a comprehensive dam safety inspection and review of all water management structures associated with the Whitehorse Rapids and Lewes Dams. The inspection and review shall be carried out in accordance with the recommendations contained in the most current edition of the *Canadian Dam Safety Guidelines*.

26. All works associated with this licence shall be maintained by the Licensee in good order, consistent with sound engineering and environmental practices.

Yukon Territory Water Board
Office des eaux du Territoire du Yukon

March 28, 2000

Rob McWilliam, President & CEO
Yukon Energy Corporation
PO Box 5920
Whitehorse, Yukon
Y1A 3V1

RE: WATER USE LICENCE HY99-010, WHITEHORSE RAPIDS AND LEWES DAM

In response to concerns raised by your office, we have undertaken a review of this water use licence and I can confirm that the licence does have some typographical errors. These errors are of a minor nature, and this letter will provide sufficient correction.

1. Clause 12 (page 3 of 7)

Subsections (a) through (d) of this clause should reference "monthly maximum and minimum of the mean daily water levels", as follows

12. Annual reports shall include the information required by this Licence and by the Regulations, including, but not necessarily limited to:

   (a) monthly maximum and minimum of the mean daily water levels on Schwatka Lake and Marsh Lake;

   (b) monthly maximum and minimum of the mean daily water levels in the Whitehorse Rapids powerhouse tailrace;

   (c) monthly maximum and minimum of the mean daily flows through the Whitehorse Rapids powerhouse turbines;

   (d) monthly maximum and minimum of the mean daily flows through the Whitehorse Rapids spillway;

   (e) monthly maximum and minimum number of gate openings at the Lewes Dam;

Suite 106, 419 Range Road, Whitehorse, Yukon Y1A 3V1 Ph: 867-667-3980 Fax: 867-668-3628
419 Chemin Range, bureau 106, Whitehorse (Yukon) Y1A 3V1 Tél: 867-667-3980 Fax: 867-668-3628

(f) information regarding the nature, extent and significance of any significant maintenance work carried out; and

(g) any other information or reports required by this Licence or the Regulations.

Clause 22, page 6 of 7

The intent of this clause is that fish passage facilities are maintained at both locations and are kept open at Lewes Dam between April 1 and November 15, and the words "at Lewes Dam" should have been included, as follows:

22. The Licensee shall maintain existing fish passage facilities at the Whitehorse Rapids and Lewes Dams and shall ensure that the fish passage facilities at Lewes Dam are open and functioning from April 1 to November 15 of each year.

3. Clause 11, Annual Reports page 3 of 7

The intent of this clause is that the first report would cover January 1, 1999 to March 31, 2000.

4. Numbering

The licence includes two clause #12. This is unfortunate, but I don't think it will prove to be a serious problem.

I apologize for any inconvenience these errors may cause.

Kindest Regards,

Dale J. Eftoda, Chairperson
Yukon Territory Water Board

cc DIAND Water Resources
DFO, EP

WHITEHORSE RAPIDS / MARSH LAKE

YUKON TERRITORY WATER BOARD

WATER USE LICENCE

Pursuant to the *Yukon Waters Act* and Regulations, the Yukon Territory Water Board hereby grants a Type A Water Use Licence for a power undertaking to:

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon
Y1A 5L6

LICENCE NUMBER: HY99-010

LICENCE TYPE: A

UNDERTAKING: Power, Class 4

LOCATION: Yukon River at Whitehorse

EFFECTIVE DATE: The effective date of this licence shall be the date on which the signature of the Minister of Indian and Northern Affairs Canada is affixed.

EXPIRY DATE: May 31, 2025

PURPOSE: Operation of the Whitehorse Rapids Generating Station and the Lewes Dam as proposed in Water Use Applications HY99-009 and HY99-010.

This licence shall be subject to the restrictions and conditions contained herein and to the restrictions and conditions contained in the Yukon Waters Act and the Regulations made thereunder.

Dated this 13th day of January, 2000

YUKON TERRITORY WATER BOARD

Witness

Chairperson

Dated this 14 day of February, 2000

APPROVED BY:

Witness

Minister of Indian Affairs and Northern Development

PART A - GENERAL CONDITIONS

1. Definitions

   (a) "Act" means the Yukon Waters Act and any amendments thereto.

   (b) "Regulations" means the Regulations made under the Act.

   (c) "Board" means the Yukon Territory Water Board.

   (d) "Application" and "Water Use Application" mean Water Use Applications HY99-009 and/or HY99-010, including any additional submissions and/or revisions, submitted to the Board by the Licensee.

   (e) "Deleterious Substance" means deleterious substance as defined in Section 34(1) of the Fisheries Act.

Representations, Warranties and Undertakings

2. The Board has relied on the representations, warranties and undertakings provided by the applicant in the material filed as Applications HY99-009 and HY99-010. Such representations, warranties and undertakings are considered by the Board to be a part of the licence, but shall be subject to, and may be modified by the terms and conditions of the licence.

Other Laws

3. No term of this licence limits the application of any other Federal, Territorial or First Nation Law.

Correspondence

4. Where any direction, notice, order, or report under this licence is required to be in writing, it shall be given:

   (a) To the Licensee, if left at, faxed to, or mailed by registered mail to the following address:

   Yukon Energy Corporation
   P.O. Box 5920
   Whitehorse, Yukon
   Y1A 5L6

   Fax: (867) 393-6909

and shall be deemed to have been given to the Licensee on the day it was left or faxed, or seven (7) days after the day it was mailed, as the case may be.

(b) To the Board, if left at, faxed to, or sent by registered mail to the following address:

Yukon Territory Water Board
Suite 106, 419 Range Road
Whitehorse, Yukon
Y1A 3V1

Fax: (867) 668-3628

and shall be deemed to have been given to the Board on the day it was left or faxed, or seven (7) days after the day it was mailed, as the case may be.

Non-Compliance

5. In the event that the Licensee fails to comply with any provision or condition of this licence, the Board may, with the approval of the Minister and subject to the Act, cancel the licence.

Deleterious Substances

6. Subject to the provisions of this licence, deleterious substances shall be used, transported, stored and disposed of in such a manner that they are not deposited in, or allowed to be deposited in, any waters.

Water Use

7. Subject to the terms of this licence, the Licensee is hereby authorised to :

(a) store the flow of the Yukon River, except for a minimum flow of 85 m^3/s, behind the Lewes Dam for the purposes of a power undertaking;

(b) store the flow of the Yukon River, except for a minimum flow of 85 m^3/s, behind the Whitehorse Rapids Dam for the purposes of a power undertaking; and

(c) divert the flow of the Yukon River through the Whitehorse Rapids Powerhouse for the purposes of a power undertaking.

Term of Licence

8. The term of this licence is from the effective date to May 31, 2025.

Reports

9. All reports shall be submitted to the Board in an unbound printed form that is reproducible by standard photocopier and shall be accompanied by five (5) copies.

10. All monitoring data and reports shall be submitted in digital form on diskette using an IBM compatible format readable using commonly available software.

Annual Reports

11. Annual reports shall be submitted to the Board by the Licensee. The initial report shall cover the period from the effective date of this licence to March 31, 2000 and shall be submitted to the Board on or before May 31, 2000. Subsequent reports shall cover the period from April 1 to March 31 of each year and shall be submitted to the Board on or before May 31 in the year in which the reporting period ends.

12. Annual reports shall include the information required by this licence and by the Regulations, including, but not necessarily limited to:

(a) monthly maximum and minimum mean daily water levels on Schwatka Lake and Marsh Lake;

(b) monthly maximum and minimum mean daily water levels in the Whitehorse Rapids powerhouse tailrace;

(c) monthly maximum and minimum mean daily flows through the Whitehorse Rapids powerhouse turbines;

(d) monthly maximum and minimum mean daily flows through the Whitehorse Rapids spillway;

(e) monthly maximum and minimum number of gate openings at the Lewes Dam;

(f) information regarding the purpose, nature and extent of any significant maintenance work carried out; and

(g) any other information or reports required by this licence or the Regulations.

Quarterly Reports

12. Quarterly reports shall be submitted to the Board by the Licensee. The reports shall cover the periods ending March 31, June 30, September 30 and December 31 of each year and shall be submitted to the Board within 30 days of the end of each reporting period.

13. Quarterly reports shall include the information required by this licence and by the Regulations, including, but not necessarily limited to:

    (a) mean daily water levels on Schwatka Lake and Marsh Lake;

    (b) mean daily water levels in the Whitehorse Rapids powerhouse tailrace;

    (c) mean daily flows through the Whitehorse Rapids powerhouse turbines;

    (d) mean daily flows through the Whitehorse Rapids spillway;

    (e) daily number of gate openings at the Lewes Dam; and

    (f) any other information or reports required by this licence or by the Regulations.

<u>Dam Safety Monitoring Reports</u>

14. An annual dam safety inspection and monitoring report for the Whitehorse Rapids and Lewes Dams and related structures shall be submitted to the Board by the Licensee. The report shall be submitted by November 30 of each year and shall contain the following information:

    (a) monitoring instrumentation readings for the previous year;

    (b) graphical and/or tabulated historic data for the monitoring instrumentation;

    (c) notes of visual observations;

    (d) analysis of the data and observations; and

    (e) recommendations for any additional monitoring or actions arising from the results of the monitoring.

15. Every five years, or more frequently if recommended as a result of any dam safety inspection, the Licensee shall submit a report detailing the results of a comprehensive dam safety review. The first report shall be submitted by November 30, 2000. Subsequent reports shall be submitted by November 30 of the year in which the inspection is carried out. The report shall contain the following information:

    (a) monitoring data;

    (b) notes of observations;

    (c) analysis of the data and observations; and

    (d) recommendations for actions arising from the analysis.

Spills and Unauthorized Discharges

16. The Licensee shall immediately contact the 24-hour Yukon Spill Report telephone number (867) 667-7244, should a spill or an unauthorized discharge occur. A detailed written report on any such event, including but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Board not later than fifteen (15) days after its occurrence.

Hazardous Materials Storage

17. A complete inventory of chemicals, fuels, oils and other hazardous materials and their locations shall be maintained by the Licensee. A spill contingency plan suitable for each material shall be developed and submitted to the Board as part of the first annual report. Any revisions to the plan shall be submitted to the Board within 60 days of the revision.

PART B - OPERATING CONDITIONS

18. A minimum instantaneous flow of 85 m^3/s shall be maintained in the channels downstream of the Lewes Dam and of the Whitehorse Rapids Powerhouse.

19. The water surface elevation on Schwatka Lake shall be maintained between a minimum of 652.272 m and a maximum of 653.339 m as measured from Geodetic Survey of Canada benchmark 86G114A.

20. The mean daily water surface elevation on Marsh Lake shall be maintained between a controlled minimum of 653.796 m and a controlled maximum of 656.234 m as measured from Water Survey of Canada gauge 9AB004.

21. With respect to the Lewes Dam, the Licensee shall comply with the following:

    a) Except as permitted by sub-clause b) of this licence, or as required for repairs and maintenance, all gates shall remain open from May 15 to August 15 of each year.

    b) The following exceptions shall be permitted to the requirements of sub-clause a) of this licence:

        i) If, on July 7 of any year, the water surface elevation of Marsh Lake is less than 654.82 metres, then up to twenty gates may be closed and at least ten gates must remain open. If the water surface elevation equals or exceeds 654.82 metres, then all gates must remain open.

        ii) If, on July 21 of any year, the water surface elevation of Marsh Lake is less than 655.15 metres, then up to twenty gates may be closed and at least ten gates must remain open. If the water surface elevation equals or exceeds 655.15 metres, then all gates must remain open.

        iii) If, on August 10 of any year, the water surface elevation of Marsh Lake is less than 655.65 metres, then up to twenty gates may be closed and at least ten gates must remain open. If the water surface elevation equals or exceeds 655.65 metres, then all gates must remain open.

22. The Licensee shall maintain existing fish passage facilities at the Whitehorse Rapids and Lewes Dams and shall ensure that the fish passage facilities are open and functioning from April 1 to November 15 of each year.

23. Existing boat passage facilities at the Lewes Dam shall be maintained by the Licensee.

24. Annually, the Licensee shall carry out a dam safety monitoring inspection of all water management structures associated with the Whitehorse Rapids and Lewes Dams. The inspection shall be carried out by a qualified professional engineer licenced to practice in the Yukon, and shall follow the recommendations contained in the most current edition of the *Canadian Dam Safety Guidelines*.

25. Every five years, or more often if recommended as a result of any dam safety inspection, the Licensee shall engage an independent, qualified, professional engineer, licenced to practice in the Yukon, to carry out a comprehensive dam safety inspection and review of all water management structures associated with the Whitehorse Rapids and Lewes Dams. The inspection and review shall be carried out in accordance with the recommendations contained in the most current edition of the *Canadian Dam Safety Guidelines*.

26. All works associated with this licence shall be maintained by the Licensee in good order, consistent with sound engineering and environmental practices.

Yukon Territory Water Board
Office des eaux du Territoire du Yukon

March 28, 2000

Rob McWilliam, President & CEO
Yukon Energy Corporation
PO Box 5920
Whitehorse, Yukon
Y1A 3V1

RE: WATER USE LICENCE HY99-010, WHITEHORSE RAPIDS AND LEWES DAM

In response to concerns raised by your office, we have undertaken a review of this water use licence and I can confirm that the licence does have some typographical errors. These errors are of a minor nature, and this letter will provide sufficient correction.

1. Clause 12 (page 3 of 7)

Subsections (a) through (d) of this clause should reference "monthly maximum and minimum of the mean daily water levels", as follows

12. Annual reports shall include the information required by this Licence and by the Regulations, including, but not necessarily limited to:

(a) monthly maximum and minimum of the mean daily water levels on Schwatka Lake and Marsh Lake;

(b) monthly maximum and minimum of the mean daily water levels in the Whitehorse Rapids powerhouse tailrace;

(c) monthly maximum and minimum of the mean daily flows through the Whitehorse Rapids powerhouse turbines;

(d) monthly maximum and minimum of the mean daily flows through the Whitehorse Rapids spillway;

(e) monthly maximum and minimum number of gate openings at the Lewes Dam;

(f) information regarding the nature, extent and significance of any significant maintenance work carried out; and

(g) any other information or reports required by this Licence or the Regulations.

Clause 22, page 6 of 7

The intent of this clause is that fish passage facilities are maintained at both locations and are kept open at Lewes Dam between April 1 and November 15, and the words "at Lewes Dam" should have been included, as follows:

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3. Clause 11, Annual Reports page 3 of 7

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4. Numbering

The licence includes two clause #12. This is unfortunate, but I don't think it will prove to be a serious problem.

I apologize for any inconvenience these errors may cause.

Kindest Regards,

Dale J. Eftoda, Chairperson
Yukon Territory Water Board

cc DIAND Water Resources
DFO, EP

AISHIHIK

YUKON TERRITORY WATER BOARD

Pursuant to the *Yukon Waters Act* and *Regulations*, the Yukon Territory Water Board, hereinafter referred to as the Board, hereby grants to

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon Y1A 6S7

hereinafter called the Licensee, the right to divert, store, alter or otherwise use water subject to the restrictions and conditions contained in the *Yukon Waters Act* and *Regulations* made thereunder and subject to and in accordance with the conditions specified in this licence:

Licence Number: HY99-011

Water Management Area: 03 Alsek

Licence Type: A

Nature of Undertaking: Power, Class 4

Location: Aishihik Lake, Sekulmun River, Canyon Lake and East Aishihik River and West Aishihik River.

Tributary of: Dezadeash River

Latitude: 61° 38' (max) Longitude: 137° 34' (max)
Latitude: 61° 02' (min) Longitude: 136° 58' (min)

Purpose: To divert water, store and alter a flow of water and to carry out shoreline works for a Power Undertaking.

Effective Date of Licence: November 30, 2002

Expiry Date of Licence: December 31, 2019

This licence is a renewal of water use licence Y3L5-0307, and all amendments thereto.

PART A - GENERAL CONDITIONS

1. Definitions

a) "*Act*" means the *Yukon Waters Act* and any amendments thereto.

b) "Application" collectively means Water Use Application HY99-011 and any additional submissions and/or revisions submitted to the Board by the Licensee up to the date of the Board's decision to issue this licence.

c) "Board" means the Yukon Territory Water Board.

d) "Dam Safety Guidelines" means the Dam Safety Guidelines issued by the Canadian Dam Association (1999) or its most recent revision.

e) "Deleterious Substance" means deleterious substance as defined in Section 34(1) of the *Fisheries Act*.

f) "Draft Fisheries Authorization" means the document that was accepted as exhibit 13.5.2 to water use register HY99-011 on May 4, 2002.

g) "Fisheries Authorization" means an authorization issued pursuant to Section 35(2) of the *Fisheries Act*.

h) "Generating Station" means that part of the facility containing generators and located underground, as described in exhibit 1.7 of the Application, and also known as the powerhouse.

i) "Inspector" means any person designated as an inspector under the *Act*.

j) "*Regulations*" means the *Yukon Waters Regulations*

k) "Waste" means any substance defined in Section 2 of the *Act*.

Representations, Warranties and Undertakings

2. The Board has relied on the representations, warranties and undertakings provided by the Licensee in the material filed in the Application. Such representations, warranties and undertakings are considered by the Board to be a part of the licence, but shall be subject to, and may be modified by, the conditions of the licence.

3. Where there is a discrepancy between the Application and the conditions of this licence, the conditions of this licence shall prevail.

4. If, subsequent to the issuing of this licence, the Licensee uses water and/or deposits waste in one or more ways not authorized in this licence, and the combined effect of those uses and/or deposits of wastes, as determined by an Inspector:

   a) has no potential for significant adverse environmental effects;
   b) does not interfere with existing rights of other water users or waste depositors; and
   c) satisfies the criteria set out in column II of Schedule IX of the *Regulations*,

   no amendment to this licence will be required for that use of water and/or deposit of waste.

Other Laws

5. No condition of this licence limits the application of any other federal, territorial, first nation or municipal legislation.

Correspondence

6. Where any direction, notice, order, or report under this licence is required to be in writing, it shall be given:

   a) To the Licensee, if delivered, faxed or mailed by registered mail to the following address:

      Yukon Energy Corporation
      P.O. Box 5920
      Whitehorse, Yukon Y1A 6S7
      Fax: (867) 393-5323

      and shall be deemed to have been given to the Licensee on the day it was delivered or faxed, or seven (7) days after the day it was mailed, as the case may be.

   b) To the Board, if delivered, faxed or sent by registered mail to the following address:

      Yukon Territory Water Board
      Suite 106, 419 Range Road
      Whitehorse, Yukon Y1A 3V1
      Fax: (867) 668-3628

      and shall be deemed to have been given to the Board on the day it was delivered or faxed, or seven days after the day it was mailed, as the case may be.

Non-Compliance

7. In the event that the Licensee fails to comply with any condition of this licence, the Board may, with the approval of the Minister and subject to the *Act*, cancel the licence.

Deleterious Substances

8. Subject to the conditions of this licence, deleterious substances shall be used, transported, stored and disposed of in such a manner that they are not deposited in, or allowed to be deposited in, any waters.

Term of Licence

9. The term of this licence is from the Effective Date to December 31, 2019.

Reports

10. All monitoring data and reports shall be submitted to the Board in an unbound printed form that is reproducible by standard photocopier and shall be accompanied by five copies.

11. All monitoring data and reports shall also be submitted in digital form on diskette using an IBM compatible format that is readable using commonly available software, or by e-mail.

Quarterly Reports

12. Quarterly reports shall be submitted to the Board by the Licensee. The reports shall cover the periods ending March 31, June 30, September 30 and December 31 of each year and shall be submitted to the Board within 30 days of the end of each reporting period.

13. Quarterly reports shall include, but not necessarily be limited to:

a) mean daily water levels on Aishihik (Water Survey of Canada Stations Nos. 08AA005 and 08AA012), Sekulmun (Water Survey of Canada Station No. 08AA007) and Canyon Lakes (Yukon Energy Corporation's Benchmark #2 located on the top of the concrete sill of the Canyon Lake Control Structure at elevation 907.423 metres);

b) mean daily flows in the East Aishihik River below Aishihik Lake (Water Survey of Canada Station No. 08AA010),

c) mean daily flows in Giltana Creek near the mouth (Water Survey of Canada Station No. 08AA009);

d) mean daily flows through the Canyon Lake Control Structure;

e) mean daily flows through the Aishihik Generating Station;

f) any other quarterly information or reports required by this licence.

Annual Reports

14. Annual reports shall be submitted to the Board by the Licensee. The reports shall cover the period from January 1 to December 31 of each year and shall be submitted to the Board on or before May 1 of the following year.

15. Annual reports shall include the information required by this licence and by the *Regulations*, including, but not necessarily limited to:

   a) monthly maximum, minimum and mean water levels on Aishihik (Water Survey of Canada Stations Nos. 08AA005 and 08AA012), Sekulmun (Water Survey of Canada Station No. 08AA007) and Canyon Lakes (Yukon Energy Corporation's Benchmark #2 located on the top of the concrete sill of the Canyon Lake Control Structure at elevation 907.423 metres);

   b) monthly maximum, minimum and mean flows in the East Aishihik River below Aishihik Lake (Water Survey of Canada Station No. 08AA010);

   c) monthly maximum, minimum and mean flows in Giltana Creek near the mouth (Water Survey of Canada Station No. 08AA009);

   d) monthly maximum, minimum and mean flows through the Canyon Lake Control Structure;

   e) monthly maximum, minimum, mean and total flows through the Aishihik Generating Station;

   f) an annual energy demand and power generating forecast for the Aishihik Generating Station;

   g) an annual forecast of the level of Aishihik Lake, based on available snowcourse information, precipitation data, historical data and the generating forecast for the Aishihik Generating Station;

   h) information regarding the purpose, nature and extent of any maintenance work carried out to keep the works in good order in accordance with sound engineering and environmental practices;

   i) an identification of any recommendations from the annual physical monitoring inspections or the most recent five year dam safety review that were either not implemented or that did not comply with a schedule proposed in an inspection or dam safety review report, and an explanation of why any recommendation was not implemented;

   j) a description of work undertaken during the preceding year and work planned to be undertaken during the upcoming year to develop and implement a community based monitoring program to monitor the ongoing environmental and socio-economic effects of the undertaking on traditional users, including applicable components of the Lake Whitefish Monitoring Program; and

   k) any other information or reports required by this licence or the *Regulations*.

Spills and Unauthorized Discharges

16. The Licensee shall keep the spill contingency plan current. Any revisions to the plan shall be delivered to the Board within ten days of the revision.

17. The Licensee shall immediately contact the 24-hour Yukon Spill Report telephone number (867) 667-7244 and implement the most recent spill contingency plan that has been filed with the Board, should a spill or an unauthorized discharge occur. A detailed written report on any such event, including but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be delivered to the Board not later than ten days after its occurrence.

Hazardous Materials Storage

18. A complete inventory of chemicals, fuels, oils, lubricants and other hazardous materials, and their locations, shall be maintained by the Licensee.

19. Except at the Generating Station, construction equipment and materials shall be stored a minimum of thirty metres from any watercourse. Except at the Generating Station, fuel, lubricants, hydraulic fluids and coolants shall be stored or transferred a minimum of thirty metres from any watercourse.

PART B - COMPENSATION

20. The Licensee shall provide compensation to the Champagne and Aishihik First Nations, in the total amount of two hundred and seventy thousand dollars ($270,000.00).

21. The schedule and purpose of payment of the compensation to the Champagne and Aishihik First Nations shall be as follows:

    a) Twenty thousand dollars ($20,000.00) within sixty days of the Effective Date of this licence, and an additional twenty thousand dollars ($20,000.00) on each anniversary of the Effective Date commencing in 2003 and continuing until 2011, for a total amount of two hundred thousand dollars ($200,000.00), for the purpose of constructing and maintaining a heritage camp; and

    b) Five thousand dollars ($5,000.00) within sixty days of the Effective Date of this licence, and an additional five thousand dollars ($5,000.00) on each anniversary date of the Effective Date, commencing in 2003 and continuing until 2011, for a total amount of fifty thousand dollars ($50,000.00), for the purpose of conducting programs at a heritage camp; and

    c) Twenty thousand dollars ($20,000.00) within sixty days of the Effective Date of this licence, for the purpose of providing drinking water at Aishihik Village.

22. The Licensee shall provide compensation to the following individuals in the following amounts, within sixty days of the Effective Date of this Licence.

NAME	AMOUNT
Allen, Chris	$ 1,004.25
Blanchard, Michelle	$ 1,004.25
Brown, Frieda Salina	$ 2,008.50
Brown, Karrie Ann	$ 3,012.75
Brown, Kathleen M	$ 2,008.50
Brown, Fred Jr.	$ 2,008.50
Brown, Shanita	$ 1,004.25
Brown, Brittney	$ 1,004.25
Brown, Mathew	$ 1,004.25
Kushniruk, Rosemarie	$ 3,012.75
Kushniruk, Jonnie-Lyn	$ 1,004.25
O'Brien, Joanne	$ 1,004.25
Green, Sophie	$ 1,004.25
Green, Angelica	$ 1,004.25
Patchet, Amanda	$ 1,004.25
Patchet, Natalee	$ 1,004.25
Green, Thearon Isaac	$ 1,004.25
Green, Bruce	$ 1,004.25
Green, Michael	$ 2,008.50
Green, Shayla	$ 1,004.25
Gleason, Ryan	$ 1,004.25
Gleason, Chris	$ 1,004.25
Green, Victor	$ 1,004.25
Green, Tyrel	$ 1,004.25
Green, Kelsey	$ 1,004.25
MacDonald, Delmer	$ 2,008.50
MacDonald, Amy	$ 1,004.25
MacDonald, Mariah Caroline	$ 1,004.25
Smith, Dallayce	$ 1,004.25
Smith, Dayna	$ 1,004.25
Smith, Derrick	$ 1,004.25
Smith, Kara	$ 1,004.25
Smith-Tutin, Marlene	$ 2,008.50
Smith-Tutin, Chase	$ 1,004.25
Stick, Fred	$ 1,004.25
Total	$45,191.25

23. Where compensation is payable to a minor, the Licensee may provide payment to a parent, legal guardian or authorized representative of that minor.

PART C - OPERATING CONDITIONS

Water Use

24. Subject to the conditions of this licence, the Licensee is hereby authorised to:

    a) store the flow of the East Aishihik River, except for minimum flows specified in this licence, in Aishihik and Canyon Lakes for the purposes of a power undertaking, and

    b) divert the flow of the East Aishihik River, except for minimum flows specified in this licence, through the Aishihik Generating Station for the purposes of a power undertaking, and

    c) modify the bed and banks of Sekulmun River for the purpose of maintaining a weir

    all as described in the Application and subject to the conditions of this licence.

25. a) A minimum flow shall be maintained over Otter Falls in accordance with the following schedule:

Period	Minimum Flow
May 1 to 18, inclusive	0.425 m^3/s
May 19 to September 7, inclusive	0.708 m^3/s
September 8 to 21, inclusive	0.425 m^3/s
September 22 to April 30, inclusive	0.142 m^3/s

    b) During the period of May 1 to May 18 of any year, the minimum flow over Otter Falls shall be increased gradually to 0.708 m^3/s. If, during that period, a minimum flow cannot be achieved because of ice conditions, then the average minimum flow shall be at least 0.425 m^3/s.

Aishihik Lake

26. The mean daily water surface elevation on Aishihik Lake shall be maintained between a controlled minimum of 913.0 metres and a controlled maximum of 915.16 metres (Water Survey of Canada datum 08AA005), subject to the following requirements:

    a) The minimum of the mean daily water surface elevation on Aishihik Lake, during any calendar year, may be below 913.7 metres only twice in any five year period. During those two years, there is no restriction on the time that the water level may be below 913.7 metres or the number of times that the level may be lowered below 913.7 metres.

b) Paragraph 26 a) does not apply where the provisions of a Fisheries Authorization are in place, including all of the provisions contained in the Draft Fisheries Authorization.

c) The mean daily water surface elevation on Aishihik Lake shall not be below 914.0 metres (Water Survey of Canada datum 08AA005) after April 30, 2005 until boat access to the lake has been provided for Aishihik Village for all lake levels within the licenced range. The Licensee shall report on progress towards development of this access in the annual report.

d) The level of Aishihik Lake shall not be above 914.86 metres (Water Survey of Canada datum 08AA005) until physical berms and erosion stabilization structures are constructed to protect sites JjVi-07, JjVi-01, JjVi-30, and Aishihik Village Grave Sites #2, as identified in exhibit 1.8.7 of the Application.

Canyon Lake

27. The mean daily water surface elevation on Canyon Lake shall be maintained between a controlled minimum of 905.87 metres and a controlled maximum of 907.42 metres as measured from Yukon Energy Corporation's Benchmark #2 located on the top of the concrete sill of the Canyon Lake Control Structure at elevation 907.423 metres.

28. All outlet gates in the Canyon Lake Control Structure shall be in the fully open position whenever the water surface elevation on Canyon Lake reaches 907.42 metres.

Canyon River and Canyon Pond

29. The minimum flow release from Aishihik Lake is to be no less than 4.64 m^3/s. The minimum flow downstream of Canyon Pond is to be no less than 9.29 m^3/s, including Giltana Creek flows.

PART D - DESIGN, CONSTRUCTION AND MAINTENANCE

30. During the term of this licence, the Licensee shall maintain all works in good order in accordance with sound engineering and environmental practices.

31. At least ten days prior to the proposed date of commencement of construction of any structure or facility, the Licensee shall submit to the Board a written notification, together with a detailed construction schedule and the name and contact number(s) of the construction superintendent.

32. During construction, where site conditions require minor design modifications to a structure or facility authorized by this licence, the Licensee shall notify the Board, in advance of implementation, of the details of any modifications or variations from final detailed designs, specifications and quality assurance/quality control procedures previously submitted to the Board. The notice shall include an explanation of the reasons for the change and an assessment of the potential impact on the performance of the structure. The notice shall be sealed by a Professional Engineer licenced to practice in Yukon.

33. As-constructed (record) drawings and construction reports for all structures and facilities shall be submitted to the Board within ninety days of the completion of construction. Each submission shall be sealed by a Professional Engineer licenced to practice in Yukon.

34. No later than December 31, 2003, the Licensee shall carry out repairs to the stop-logs in the spillway overflow structure adjacent to the Aishihik Lake Control Structure to ensure that the stop-logs are in an operable condition.

35. No later than December 31, 2003, the Licensee shall submit to the Board detailed design construction drawings and specifications for modifications to the earth-fill structures adjacent to the Aishihik Lake Control Structure to prevent overtopping during a Probable Maximum Flood event. The modifications shall be completed by December 31, 2004.

36. The Licensee shall carry out and complete a data collection program and stability analysis for the Aishihik Power Canal in accordance with the Dam Safety Guidelines. The results of the analysis, together with recommendations and an implementation plan for any modifications required to conform with the Guidelines, shall be submitted to the Board no later than December 31, 2003. The Licensee shall carry out the implementation plan according to the schedule submitted with the plan.

37. The Licensee shall maintain public safety measures, including but not limited to warning signs, booms, or grablines, at the Aishihik Lake Control Structure, the Canyon Lake Control Structure, in the power canal at the pressure tunnel intake, and at the tailrace during each open water season. A report on the safety measures implemented shall be submitted to the Board no later than 10 days after the start of the open water season each year. Any changes to the safety measures implemented shall be submitted to the Board within ten days.

38. No later than September 30, 2003, the Licensee shall install signage at all public vehicular access points to Canyon Lake warning of unpredictable ice conditions, and shall maintain these signs for the duration of the licence.

Third Turbine

39. Subject to the conditions of this licence, the Licensee is hereby authorised to install a third turbine and associated appurtenances with a maximum generating capacity of 7 MW.

40. The Licensee shall submit to the Board a plan that describes the operating protocols for the third turbine. Until the plan has been submitted to the Board, and the Board has instructed the Licensee to implement the plan, the Licensee shall not operate more than two turbines at any one time. The Licensee must operate the third turbine in compliance with the plan.

Submissions

41. The Licensee shall submit to the Board final detailed design construction drawings, specifications, quality assurance/quality control procedures and/or operating procedures for the construction of any facilities or structures authorized by this licence, but shall not begin construction until such time as the Board has notified the Licensee to proceed. These facilities and structures shall include but not be limited to:

    a) modifications to the earth-fill structures adjacent to the Aishihik Lake Control Structure; and

    b) the third turbine and associated appurtenances.

42. As a part of the design submission for the third turbine, the Licensee shall submit a assessment of the acid rock drainage potential of material to be excavated as part of the construction of the turbine and related appurtenances, together with a plan for the handling and disposal of any rock identified as having an acid rock drainage potential.

Heritage Mitigation Plan

43. The Licensee shall, by March 1, 2005, submit a plan to carry out the projects described in the Heritage Mitigation Plan, dated February 18, 2000 and the addendum dated June 15, 2001, that was submitted as exhibit 2.3.3 of the Application. The Licensee shall obtain the necessary approvals and implement those projects when instructed to do so by the Board.

PART E - PHYSICAL MONITORING AND SURVEILLANCE

44. All water retaining structures, appurtenances and erosion control structures shall be inspected by September 30 of each year of this licence by a Professional Engineer licenced to practice in Yukon. The results of the inspection, including all problems identified, remedial measures proposed, and remedial measures implemented, shall be compiled in a report that shall be submitted to the Board by November 30 of each year. The report shall contain the following at a minimum:

    a) instrumentation readings for the previous year;

    b) graphical and/or tabulated historic data for the instrumentation;

    c) notes of visual observations;

    d) analysis of the data and observations; and

    e) recommendations for any additional monitoring or actions arising from the results of the monitoring.

45. The Licensee shall complete a dam safety review for all water retaining structures and appurtenances at least once every five years, or more frequently if so recommended as a result of any dam safety inspection. The first review shall be completed and reported to the Board no later than November 30, 2005. Subsequent reports shall be submitted by November 30 of the year in which the inspection is carried out. The review shall be conducted in accordance with the Dam Safety Guidelines and shall include, but not necessarily be limited to:

    a) documentation of the dam safety review process, procedures, activities and results;

    b) any recommendations for maintenance, operation, surveillance, reporting and/or emergency preparedness;

    c) documentation of actions taken on the recommendations of previous dam safety reviews and annual inspection reports; and

    d) the planned response to each recommendation in the dam safety review report, including schedules for completion.

46. Details of any maintenance, inspection and/or surveillance activities undertaken in the previous year in relation to dam safety shall be included in the Annual Report.

Operation, Maintenance and Surveillance Manual

47. No later than December 31, 2002, the Licensee shall submit to the Board an operation, maintenance and surveillance manual ("OMS Manual") that documents procedures for safe operation, maintenance and surveillance of all dams and appurtenances. The Licensee shall prepare the OMS Manual in accordance with the Dam Safety Guidelines and shall provide an updated manual when the results of the annual dam safety inspections and/or the five year dam safety reviews recommend that an update is necessary. The OMS Manual shall include, but not necessarily be limited to:

    a) procedures for operation, maintenance and surveillance that are consistent with the recommendations contained in the Dam Safety Guidelines; and

    b) a program for recording and reporting inspection and maintenance activities.

Emergency Preparedness Plan

48. No later than December 31, 2002, the Licensee shall submit to the Board an emergency preparedness plan that documents procedures for dealing with emergencies for all dams and appurtenances. The plan shall be prepared in accordance with the Dam Safety Guidelines.

PART F - BIOLOGICAL MONITORING AND SURVEILLANCE

Implementation of Study Plans

49. Where this licence requires the Licensee to submit a study plan, the Licensee shall not implement the plan until notified by the Board to do so. This requirement applies to the Fish and Aquatic Habitat Monitoring Program, the Lake Whitefish Monitoring Program, and the Littoral Habitat Monitoring Program.

Lake Whitefish Monitoring Program

50. By April 30, 2005, the Licensee shall submit to the Board a plan for detailed index-gillnetting programs to be undertaken in 2007 and 2017 to obtain age-class strength for adult lake whitefish in Aishihik Lake. The program methodology shall be described in sufficient detail to be replicated at a future date. The plan shall include a schedule for reporting data, conclusions and any proposed mitigative measures. The Licensee shall implement the program when instructed to do so by the Board.

51. Within three months of the effective date of this licence, the Licensee shall submit to the Board a plan for a monitoring program to follow the health and recruitment of juvenile lake whitefish in Aishihik Lake. The plan should address the estimation of potential suitable spawning habitat substrates at various lake levels. The plan shall also include a schedule for reporting data, conclusions and any proposed mitigative measures. The Licensee shall implement the program when instructed to do so by the Board.

52. Within one year of the effective date of this licence, the Licensee shall submit to the Board a plan for a subsistence fishery monitoring program to be carried out on an annual basis through the term of this license. The plan shall include a schedule for reporting data and conclusions. The Licensee shall implement the program when instructed to do so by the Board.

Littoral Habitat Monitoring Program

53. Within three months of the effective date of this licence, the Licensee shall submit to the Board a plan for a monitoring program to follow changes in the area and quality of littoral habitat in Aishihik Lake. The plan shall include, but not necessarily be limited to, those areas of the lake to the north of latitude 61° 34' and to the west of longitude 137° 23'. The program shall identify and monitor aquatic plants as an indicator of primary productivity and/or changing conditions in the lake, and the quality and quantity of suitable spawning substrates potentially available to lake whitefish. The plan shall include a schedule for reporting data, conclusions, and any proposed mitigative measures. The Licensee shall implement the program when instructed to do so by the Board.

PART G - DECOMMISSIONING

54. In the event of decommissioning of the undertaking, the Licensee shall ensure that all structures and appurtenances authorized by this licence are either removed or left in stable condition which does not present a risk to people or the environment. Prior to the commencement of decommissioning work, the Licensee shall submit to the Board a final plan for the reclamation of the project site. The plan shall be designed to ensure long-term stability, maintenance and/or replacement of any structures remaining after closure, minimize and/or mitigate environmental impacts, and provide for ongoing monitoring.

Approved by the Minister of Indian Affairs and Northern Development

This 21 day of

November, 2002

R. House
Witness

Minister of Indian Affairs and
Northern Development

Issued by the Yukon Territory Water Board

This 26 day of

November, 2002

Witness

Chairperson

Yukon Territory Water Board | **Office des eaux du Territoire du Yukon**

November 25, 2002

Don Willems, President & CEO
Yukon Energy Corporation
PO Box 5920
Whitehorse, YT Y1A 5L6

Re: WATER USE LICENCE HY99-011, CORRECTION TO CLAUSE 29

Please note the following correction to Clause 29 of Water Use Licence HY99-011

<u>Canyon River and Canyon Pond</u>

29. The minimum flow release from Aishihik Lake is to be no less than 1.416 m^3/s. The minimum flow downstream of Canyon Pond is to be no less than 2.832 m^3/s, including Giltana Creek flows.

The Board's intention, as indicated in the Reasons for Decision, was that the minimum flow requirements stipulated in Clause 4 of Water Use Licence Y3L5-0307 should be carried forward into water use licence HY99-011. The Board's technical advisor has confirmed that a calculation error occurred when the numbers were converted from imperial to metric.

In situations such as this, where the licence does not express the decision that was actually made, or where there is a clerical error in the drafting of the licence, then the licence can be amended by attaching a letter of correction.

The Board has asked me to express their regret for any inconvenience that this error may have caused.

Judi White, Manager
Water Board Secretariat

cc Distribution List, HY99-011

Suite 106, 419 Range Road, Whitehorse, Yukon Y1A 3V1 Ph: 867-667-3980 Fax: 867-668-3628
419 chemin Range, bureau 106, Whitehorse (Yukon) Y1A 3V1 Tél: 867-667-3980 Fax: 867-668-3628

COPY

YUKON WATER BOARD
AMENDMENT OF LICENCE

2006 JUN 22 PM 12: 07

LICENSEE: Yukon Energy Corporation

LICENCE NUMBER: HY99-011

AMENDMENT NUMBER: One (1)

Application Number: HY05-015

Pursuant to the *Waters Act*, Water Use Licence HY99-011 is hereby amended as follows:

1. Clause 35 is hereby withdrawn and replaced by:

35. No later than June 30, 2006, the Licensee shall submit to the Board detailed design construction drawings and specifications for modifications to the earth-fill structures adjacent to the Aishihik Lake Control Structure to pass an Inflow Design Flood. The modifications shall be completed by December 31, 2007.

Dated this 9 day of June, 2006

Witness

YUKON WATER BOARD

Chairperson

Dated this 19 day of June, 2006

Witness

Minister, Executive Council Office

MAYO

YUKON WATER BOARD

Pursuant to the *Waters Act* and *Waters Regulations*, the Yukon Water Board hereby grants a Type A Water Use Licence for a power undertaking to:

Yukon Energy Corporation
P.O. Box 5920
Whitehorse, Yukon Y1A 5L6

APPLICATION:	**HY10-056**	**LICENCE NUMBER:**	HY99-012

AMENDMENT: This licence shall be deemed to be amendment 2 of licence number HY99-012.

LICENCE TYPE: A

UNDERTAKING: Power, Class 3

LOCATION: Mayo River and Mayo Lake

PURPOSE: Operation of the Mayo Generating Station and the Mayo Lake Dam as proposed in Water Use Application HY99-012, and the Mayo B Generating Station with modified operation of the Mayo A Generating Station as proposed in Water Use Application HY10-056.

EFFECTIVE DATE: The effective date of this licence shall be the date on which the signature of the Chairperson of the Yukon Water Board is affixed.

EXPIRY DATE: December 31, 2025

This licence shall be subject to the restrictions and conditions contained herein and to the restrictions and conditions contained in the *Waters Act* and the *Waters Regulations* made thereunder.

Approved this 12th day of

May, 2011

Witness

Minister, Executive Council Office
GOVERNMENT OF YUKON

Issued this 16th day of

May, 2011

Witness

Chairperson
YUKON WATER BOARD

PART A - DEFINITIONS

"Act" means the *Waters Act* and any amendments thereto.

"Regulations" means the Regulations made under the *Act*.

"Board" means the Yukon Water Board.

"Application" and "Water Use Application" mean Water Use Application HY99-012, HY07-016, and HY10-056, including any additional submissions and/or revisions, submitted to the Board by the Licensee.

"Deleterious Substance" means deleterious substance as defined in Section 34(1) of the *Fisheries Act*.

PART B - GENERAL CONDITIONS

Other Laws

1. No condition of this water use licence limits applicability of any statutory authority.

2. All construction or installation of works authorized by this licence shall occur on property that the Licensee has the right to enter upon and use for that purpose.

Correspondence

3. Where any direction, notice, order, or report under this licence is required to be in writing, it shall be given:

   a. To the Licensee, if delivered, faxed to, or mailed by registered mail to the following address:

      Yukon Energy Corporation
      P.O. Box 5920
      Whitehorse, Yukon
      Y1A 5L6
      Fax: (867) 393-5323

      and shall be deemed to have been given to the Licensee on the day it was delivered or faxed, or 7 days after the day it was mailed, as the case may be.

b. To the Board, if delivered, faxed to, or sent by registered mail to the following address:

Yukon Water Board
Suite 106, 419 Range Road
Whitehorse, Yukon
Y1A 3V1
Fax: (867) 456-3890

and shall be deemed to have been given to the Board on the day it was delivered or faxed, or 7 days after the day it was mailed, as the case may be.

c. The Board or the Licensee may, be notice in writing, change its address for delivery.

Non-Compliance

4. In the event that the Licensee fails to comply with any provision or condition of this licence, the Board may, subject to the Act, cancel the licence.

Term of Licence

5. The term of this licence is from the effective date to December 31, 2025.

Reports

6. All reports required to be submitted to the Board will be unbound and reproducible by standard photocopier, accompanied by one electronic copy on a CD/DVD.

7. The Licensee shall provide to the Board 5 additional copies of all reports. The additional copies may be either 5 bound paper copies or 5 electronic copies on individual CDs/DVDs.

8. Electronic copies shall be IBM compatible in one of the following formats: Word 97 – 2003, Excel 97 – 2003 workbooks, or Adobe pdf format. Water quality results must be presented in Excel 97 – 2009.xls format.

Annual Reports

9. Annual reports shall be submitted to the Board by the Licensee. The reports shall cover the period from April 1 to March 31 of each year and shall be submitted to the Board on or before May 31 in the year in which the reporting period ends.

10. Annual reports shall include the information required by this licence and by the Regulations, including, but not limited to:

a. monthly maximum and minimum of the mean daily water levels on Mayo Lake and Wareham Lake;

b. monthly maximum and minimum of the mean daily water flows through the gates of the Mayo Lake Dam;

c. monthly maximum and minimum of the mean daily flows through the Mayo A Generating Station turbines and the Mayo B Generating Station turbines;

d. monthly maximum and minimum of the mean daily flows through the Wareham Dam spillway;

e. summaries of all data generated as a result of the monitoring requirements of this licence, including analysis and interpretation by a qualified individual or firm and a discussion of any variances;

f. detailed results of the annual ice-jam occurrence monitoring;

g. ramping protocol, associated monitoring results, and any proposed modifications to protocol;

h. all reports as required by the Fisheries Act Authorization;

i. information regarding the purpose, nature and extent of any significant maintenance work carried out; and

j. any other information or reports required by this licence or the Regulations.

<u>Quarterly Reports</u>

11. Quarterly reports shall be submitted to the Board by the Licensee. The reports shall cover the periods ending March 31, June 30, September 30 and December 31 of each year and shall be submitted to the Board within 30 days of the end of each reporting period.

12. Quarterly reports shall include the information required by this licence and by the Regulations, including, but not necessarily limited to:

a) mean daily water levels on Mayo Lake and Wareham Lake;

b) mean daily flows through the gates of the Mayo Lake Dam;

c) mean daily flows through the Mayo A Generating Station turbines and the Mayo B Generating Station turbines;

d) mean daily flows through the Wareham Dam spillway; and

e) any other information or reports required by this licence or by the Regulations.

Dam Safety Monitoring Reports

13. An annual dam safety inspection and monitoring report for the Mayo Lake Dam, Wareham Lake Dam, Mayo A Generating Station and Mayo B Generating Station, and related structures shall be submitted to the Board by the Licensee. The report shall be submitted by November 30 of each year and shall contain the following information:

    a) monitoring instrumentation readings for the previous year;

    b) graphical and/or tabulated historic data for the monitoring instrumentation;

    c) notes of visual observations;

    d) analysis of the data and observations; and

    e) recommendations for any additional monitoring or actions arising from the results of the monitoring.

14. Every five years, or more frequently if recommended as a result of any dam safety inspection, the Licensee shall submit a report detailing the results of a comprehensive dam safety review. Reports shall be submitted by November 30 of the year in which the inspection is carried out. The report shall contain the following information:

    a) monitoring data;

    b) notes of observations;

    c) analysis of the data and observations; and

    d) recommendations for actions arising from the analysis.

Spills and Unauthorized Discharges

15. Where a spill or an unauthorized discharge occurs, that is of a reportable quantity under the Yukon *Spills Regulations,* the Licensee shall immediately contact the 24-hour Yukon Spill Report number, (867) 667-7244 and implement the Spill Contingency Plan. A detailed written report on any such event including, but not limited to, dates, quantities, parameters, causes and other relevant details and explanations, shall be submitted to the Board not later than 10 days after the occurrence.

16. The Licensee shall apply the relevant procedures in the Spill Contingency Plan. The Licensee shall review the Spill Contingency Plan annually and shall provide a summary of that review, including any revisions to the plan, as a component of the annual report.

17. The Licensee shall maintain a log book of all spill or unauthorized discharge occurrences, including spills that are less than the reportable quantities under the Yukon *Spills Regulations*. The log book shall be made available at the request of an Inspector. The log book shall include, but not necessarily be limited to:

    a) date and time of the spill;

    b) substance spilt or discharged;

    c) approximate amount spilt or discharged;

    d) distance between the spill or discharge and the nearest Watercourse; and

    e) remedial measures taken to contain and clean-up the spill area or to cease the unauthorized discharge.

18. The Licensee shall include a summary of all spills or unauthorized discharges that occurred during the year reported, as part of the annual report.

19. All personnel shall be trained in procedures to be followed and the equipment to be used in the containment of a spill.

20. The Spill Contingency Plan shall be posted on site for the duration of the operation.

Fuel Storage and Transfer

21. Fuel, lubricants, hydraulic fluids, coolants and similar substances shall be stored and/or transferred a minimum of 30 metres from the Natural Boundary of any Watercourse, in such a way that said substances are not deposited in or allowed to be deposited in waters.

PART C - OPERATING CONDITIONS

Description of Water Use

22. Subject to the terms of this licence, the Licensee is hereby authorised to :

a) store the flow of the Mayo River, except for a minimum flow of 2.8 cubic metres per second (100 cubic feet per second), behind the Mayo Lake Dam for the purposes of a power undertaking;

b) store the flow of the Mayo River, except for the minimum flows specified in this licence, behind the Wareham Dam for the purposes of a power undertaking; and

c) construct, maintain, and operate the Mayo B generating station as proposed in application HY10-056. Any in stream activities, including alterations of the bed and banks of the Mayo River shall not be commenced or continued without a valid Fisheries Act Authorization from the Department of Fisheries and Oceans Canada authorizing the activities; and

d) divert the flow of the Mayo River, except for the minimum flows specified in this licence, through the Mayo A generating station and the Mayo B generating station for the purposes of a power undertaking.

23. A minimum instantaneous flow of 2.8 cubic metres per second (100 cubic feet per second) shall be maintained in the channels downstream of the Mayo Lake Dam. The following minimum instantaneous flows shall also be maintained:

a) In the channels downstream of the Mayo A Powerhouse, a minimum instantaneous flow of 6 cubic metres per second (212 cubic feet per second) from May 1 to September 30 and minimum flow of 5 cubic metres per second (176.6 cubic feet per second) for the remainder of the year; and

b) In the channels downstream of the Mayo B Powerhouse, a minimum instantaneous flow of 11 cubic metres per second (388 cubic feet per second) from May 1 to September 30.

24. The mean daily water surface elevation on Mayo Lake shall be maintained between a controlled minimum of 2203.0 feet and a controlled maximum of 2211.5 feet as measured from Yukon Energy Corporation's datum at the site.

25. When the water surface elevation on Mayo Lake exceeds 2211.5 feet, all gates shall be open.

26. The mean daily water surface elevation on Wareham Lake shall be maintained between a controlled minimum of 1894.0 feet and a controlled maximum of 1901.5 feet as measured from Yukon Energy Corporation's datum at the site.

27. The Licensee shall implement the ramping protocol at the Wareham Dam and related monitoring, as required by the Fisheries Act Authorization, to minimize the potential for fish stranding downstream of control structures.

28. Annually, the Licensee shall carry out a dam safety monitoring inspection of all water management structures associated with the Mayo Lake Dam, Wareham Dam, Mayo A Generating Station and Mayo B Generating Station. The inspection shall be carried out by a qualified professional engineer licensed to practice in the Yukon, and shall follow the recommendations contained in the most current edition of the *Canadian Dam Safety Guidelines*.

29. Every five years, or more often if recommended as a result of any dam safety inspection, the Licensee shall engage an independent, qualified, Professional Engineer, who did not partake in the design or construction and does not normally participate in the annual inspections, to carry out a comprehensive dam safety inspection and review of all water management structures associated with the Mayo Lake Dam, Wareham Dam, Mayo A Generating Station and Mayo B Generating Station. The inspection and review shall be carried out in accordance with the recommendations contained in the most current edition of the *Canadian Dam Safety Guidelines*.

30. The Licensee shall implement the recommendations arising from the annual and 5-year inspections.

31. All works associated with this licence shall be maintained by the Licensee in good order, consistent with sound engineering and environmental practices.

32. The Licensee shall continue to implement the stream flow monitoring system downstream of the Mayo Lake and Wareham Dams as recommended in the *Dam Breach Flood Inundation Study for Wareham Dam,* dated 1999-01-08. For clarity, this is the study that was prepared for Yukon Energy Corporation by AGRA Monenco Inc., reference number YEC1100045, and which was submitted as exhibit 1.8.3 to water use application HY99-012. Data from the monitoring system shall be reported to the Board in each annual report.

PART D – EFFLUENT QUALITY STANDARDS

33. All water at sampling station D/S1 during instream construction activities shall not exceed the following limits:

Parameter	Maximum Concentration in a Grab Sample	
	Construction Activities with discharge duration > 24 hours (i.e. Tail Race)	**All other Construction Activities**
pH	6.5 to 9.0 pH Units	6.5 to 9.0 pH Units

Unionized Ammonia	0.019mg/L	0.019mg/L
Nitrite - N	13 mg/L	13 mg/L
Nitrate - N	0.06 mg/L	0.06 mg/L
Turbidity	2 NTU above background	8 NTU above background
Suspended Solids	5 mg/L above background	25 mg/L above background

34. Waste rock stockpiles from excavation activities related to the penstock, powerhouse, and other related construction shall be placed in waste rock storage facilities that enable the collection of any water run off from the waste rock. Runoff from the waste rock stockpiles shall be monitored according to the schedule and at the stations identified in Appendix A, and shall meet the following limits listed before being released to land where there is no direct discharge to surface waters.

Parameter	Maximum Concentration in a Grab Sample
Nitrite	10 mg/L
Aluminum (total)	5.0 mg/L
Arsenic (total)	0.025 mg/L
Cadmium (total)	0.080 mg/L
Chromium (total)	0.050 mg/L
Copper (total)	0.50 mg/L
Lead (total)	0.10 mg/L
Nickel (total)	1.0 mg/L
Zinc (total)	5.0 mg/L

PART E – MONITORING AND SURVEILLANCE

35. The Licensee shall comply with the Water Quality Surveillance Monitoring Program that is specified in Appendix A.

36. Within 30 days of determining the final sampling stations for waste rock stockpiles (WR1, WR2, and WR3), the licensee shall submit to the Board the location coordinates of the sampling stations.

37. The Licensee shall provide the Board with monthly reports regarding the water quality surveillance program, including all field and laboratory data, and each report shall be submitted to the Board no more than 30 days after the completion of the month being reported.

38. All data collection and analysis shall be conducted in accordance with the current edition of *Standard Methods for the Examination of Water and Waste Water*, prepared and published by the American Water Works Association and the Water Pollution Control Federation.

PART F – PROGRAMS AND STUDIES

39. Within 60 days of the effective date of this licence, the Licensee shall submit to the Board a detailed assessment of the correlation between Total Suspended Solids and Turbidity in the Mayo River that will be used as the basis for the proposed on-site monitoring program for particulate matter.

40. Within 60 days of the effective date of this licence, the Licensee shall submit to the Board a detailed plan outlining the proposed contingencies for on-site and/or off-site treatment of non-compliant water.

Flooding and Ice-Hydraulics Assessment Study

41. Within 90 days of the effective date of this licence, the Licensee shall submit to the Board, for review and approval, a Flooding and Ice Hydraulics Assessment Study Plan for a detailed assessment to evaluate flooding conditions and ice hydraulics in the Lower Mayo River. At a minimum, the plan shall include identification of any relationship between the Mayo B operational/water management regime and revised minimum flows and downstream flooding.

42. Upon receipt of approval from the Board, the Licensee shall implement the Flooding and Ice Hydraulics Assessment Study Plan and submit the results of the study to the Board by September 30, 2012.

43. Annual monitoring and documentation of ice-jam occurrence in the Lower Mayo River shall be carried out and the results, including any recommendations, shall be submitted to the Board as part of the Annual Report.

Wareham Lake and Mayo Lake Water Level Assessment

44. Within 90 days of the effective date of this licence, the Licensee shall submit to the Board, for review and approval, a Wareham Lake and Mayo Lake Water Level Assessment Study Plan for a detailed assessment to evaluate the impacts on the revised minimum flow requirements on the water levels in Wareham and Mayo Lakes, including comparison to historical levels.

45. Upon receipt of approval from the Board, the Licensee shall implement the Wareham Lake and Mayo Lake Water Level Assessment Study Plan and submit the results of the study to the Board by September 30, 2013.

Post-Construction ARD/ML Monitoring Program

46. Within 90 days of the effective date of this licence, the Licensee shall submit to the Board, for review and approval, a post-construction monitoring plan for monitoring of acid rock drainage, metal leaching and blasting residuals from the rock stockpiles. The plan shall include, but not be limited to, a detailed monitoring program, including parameters, frequency and duration of the monitoring program.

47. Upon receipt of approval from the Board, the Licensee shall implement the Post-Construction ARD/ML Monitoring Program and submit the results as part of the annual report.

Appendix A - Water Quality Surveillance Monitoring Program

Table A-1 Location of Monitoring Stations

Station	Description
U/S1	East bank of Mayo River 100m upstream of instream construction activities.
D/S1	East bank of Mayo River 100m downstream of instream construction activities.
WR1	Waste rock stockpile disposal area WR1
WR2	Waste rock stockpile disposal area WR2
WR3	Waste rock stockpile disposal area WR3

Table A-2 Sampling Locations and Parameters

Monitoring Location/Parameter	**U/S1**	**D/S1**	**WR1**	**WR2**	**WR3**
pH (in-situ and lab)	2D	2D	S/F	S/F	S/F
Temperature (in-situ)	2D	2D	S/F	S/F	S/F
Conductivity (in-situ and lab)	2D	2D	S/F	S/F	S/F
Dissolved Oxygen (in-situ)	2D	2D			
Turbidity (in-situ)	2D	2D			
Total Suspended Solids	2D	2D	S/F	S/F	S/F
Alkalinity			S/F	S/F	S/F
Hardness			S/F	S/F	S/F
Ammonia	2D	2D	S/F	S/F	S/F
Nitrate	2D	2D	S/F	S/F	S/F
Nitrite	2D	2D	S/F	S/F	S/F
Total Metals			S/F	S/F	S/F
Dissolved Metals			S/F	S/F	S/F

Table A-3 Sampling Frequency

Key	**Frequency**
2D	Twice daily during instream construction activities
S/F	Twice annually, during spring freshet and fall.

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