

September 22, 2021

Mr. Richard Buchan, Chair
Yukon Utilities Board
Box 31728
Whitehorse, Yukon Y1A 6L3

Dear Mr. Buchan:

Re: Yukon Energy 2021 General Rate Application – Rd 2 Revised IR Responses

On September 20, the Yukon Utilities Board (YUB) provided Order 2021-12, directing Yukon Energy to provide further and better responses to the IR responses identified in Appendix A of that Order by September 22, 2021.

Please find attached to this correspondence Yukon Energy's revised IR responses as required by Board Order 2021-12.

In reviewing the hearing record Yukon Energy also identified the following attachments that had not been provided in the Round 1 IR responses:

- YUB-YEC-1-35(c) Attachment 1 and Attachment 2
- UCG-YEC-1-91(d) Attachment 1.

These attachments are also provided with this correspondence.

If you have any questions regarding the above, please call.

Yours truly,



Ed Mollard
Chief Financial Officer

NY Round 2 – REVISED Responses

REFERENCE: Follow-up on NY-YEC-1-5, NY-YEC-1-8(a) and NY-YEC-1-13(a,c)
Original request was for an “updated Yukon Integrated System
Generation Inventory” and I was sent “Appendix A from the 10-Year
Renewable Electricity Plan” as what is current. However, some of the
capacities differ from the correspondence with the regulator provided in
response to NY-YEC-1-8(a)

	YEC GRA Nov 2020 in reply to NY-YEC-1-5 and YUB-YEC-1-50 and UCG-YEC-1-18	App to Regulator, Sep 2020 in reply to NY-YEC-1-8(a) and sound and dispersion studies NY-YEC-1-13(a,c)
FD1 Dependable Capacity:	3.0 MW	2.4 MW

The 3.0MW listed in the 10-Year Renewable Electricity Plan was given
as the current capacity list in IRs NY-YEC-1-5, UCG-1-18, YUB-YEC-
1-50 and others.

However that capacity was reduced to 2.4 for all communications with
the regulator – and for all sound and air dispersion studies. Noting that
the 2.4 MW is more convenient for regulation (allowing FD1+FD7+3
Rentals to be 10.6MW), but also that the 3.0 MW is needed for N-1
Capacity.

QUESTION:

- a) These numbers should be consistent and not arbitrarily chosen. Which is correct?
Why were the two different numbers used?
- b) Please provide a history of capacity of the FD1 generator – from nameplate
capacity of 5.15MW down to the 3.0MW or 2.4MW currently claimed.
- c) Please provide dated documentation used in support of each change in
dependable capacity.

ANSWER:

(a) through (c)

1 The dependable capacity for individual diesel units is subject to ongoing updates based
2 on available information and assessments. Dependable capacity of diesel generators
3 typically drops as the units age, and YEC's practice is to complete periodic assessments
4 to confirm the derated capacities of old diesel generators such as FD1. Updates are
5 summarized when applicable in updated resource plans or GRAs. Beyond reporting on
6 changes, there is no specific documentation that can be provided to support each such
7 change.

8
9 The Faro Diesel #1 unit with a nameplate installed capacity of 5.15 MW was
10 recommissioned with 5 MW capacity in 2008, later was rated at 4.0 MW in the 2011 and
11 2016 YEC Resource Plans with expected retirement in 2021. This rating was reduced to
12 3.0 MW by the time 10-Year Electricity Resource Plan was prepared [the work for the plan
13 was started in November 2019 after Yukon government released a draft of its Our Clean
14 Future strategy]. The following additional information is provided on this unit:

- 15
16 • Faro unit #1 is the oldest unit in the fleet (built in late 60's).
- 17
18 • It requires manual adjustment in order to run at its maximum output and YEC has
19 not had qualified mechanical maintenance staff located in Faro for approximately
20 5 years (staff in Whitehorse have the expertise to perform this function but Faro is
21 at least 4 hours drive so re-deploying forces would not meet the requirement of
22 keeping the lights on during an emergency).
- 23
24 • The unit has also experienced issues with its cooling system that restricts output.
- 25
26 • Based on internal review by YEC Mechanical Maintenance, YEC concluded that
27 the unit could be run up to 2.4 MW while in remote mode without risking over-
28 heating shutdown.
- 29

30 The 10-Year Electricity Resource Plan assumed the unit will retire in 2023. Please see
31 revised response to UCG-YEC-1-18 that provides copy of Appendix A to the 10-Year
32 Electricity Resource Plan with the list of existing hydro and thermal resources including
33 dependable capacity assumed in the 2016 Resource Plan and updated dependable
34 capacity and retirement assumptions for each unit.

35
36 The dependable capacity analysis for the 2021 GRA is based on 10-Year Electricity
37 Resource Plan, therefore it assumes 3.0 MW dependable capacity for Faro Diesel #1.

1 More recent assessments [the Noise Impact Assessment at Faro Facility (February 2021)
2 provided in NY-YEC-1-13(a) Attachment 1 and Air Dispersion Modelling Assessment for
3 Faro Facility (December 2020) provided in NY-YEC-1-13(c) Attachment 1] show Faro
4 Diesel #1 was derated from 3.0 MW to 2.4 MW, a reduction of 0.6 MW.

5
6 As noted in GRA Tab 2, page 2-14, the forecast dependable capacity based on the single
7 contingency (N-1) criterion is forecast for the YIS to be about 1.25 MW in excess of the
8 forecast non-industrial winter peak for 2021. Therefore, the reduction of 0.6 MW in
9 dependable capacity will not impact the 2021 GRA assessment that overall dependable
10 capacity exists to meet the N-1 requirement.

11
12 **REVISED RESPONSE**

13
14 Board Order 2021-10 Appendix A notes:

15 “The Board finds YEC’s references to capacity issues pertaining to the FGS on the
16 record to be, at times, inconsistent, and requires clarity on this issue. The Board
17 finds the IR to be useful and of probative value. Therefore, the Board directs YEC
18 to confirm the current rated capacity of FD1 as 2.4 MW. If YEC cannot confirm this
19 then YEC is to provided [sic] the current rated capacity of FD1 and explain why
20 that capacity differs from 2.4 MW.”

21
22 YEC confirms that the current rated capacity for FD1 is 2.4 MW.

23
24 The following additional comments are noted to clarify information on the record.

- 25
26 • Supporting material for the Faro diesel permitting applications and related YESAA
27 filings that were developed in fall 2020 cited 2.4 MW. IR responses note it was
28 determined at the time that the unit could be run up to 2.4 MW while in remote
29 mode without risking over-heating shutdown.¹

¹ The 2.4 MW was mentioned in: correspondence with Yukon Environment in September 2020 (provided in NY-YEC-1-8(a) REVISED); the Noise Impact Assessment at Faro Facility (February 12, 2021) provided in NY-YEC-1-13(a) Attachment 1; and Air Dispersion Modelling Assessment for Faro Facility (December 17, 2020) provided in NY-YEC-1-13(c) Attachment 1.

- 1 • The 2021 GRA relied on information reported in the 10-Year Renewable Electricity
2 Plan which was undertaken and largely completed prior to the update to the FD1
3 rated capacity in fall 2020, which showed dependable capacity for FD1 of 3.0 MW.²
4
5 • Updating the FD1 rated capacity from 3.0 MW to 2.4 MW has no material impact
6 to the capacity shortfall as indicated in response to NY-YEC-2-1.

² NY-YEC-1-5 and UCG-YEC-1-18 REVISED cross-reference to Appendix A of the 10-Year Renewable Electricity Plan [that shows FD1 with 3.0 MW dependable capacity]. NY-YEC-1-6 also notes total dependable capacity for Faro plant at 5.8 MW [3.0 MW for FD1 and 2.8 MW for FD7].

1 **REFERENCE:** Follow-up on NY-YEC-1-5, NY-YEC-1-8(a) and YUB-YEC-1-50(b)
2 GRA Page 2-14, "Installed YEC and AEY dependable grid capacity for
3 the winter peak in 2021, based on existing capacity today and any
4 planned additions/retirements and excluding Fish Lake hydro, is 139.1
5 MW in 2021 (70.5 MW of YEC hydro, 12.6 MW YEC LNG, 23.5 MW of
6 YEC diesel, 5.6 MW of AEY diesel and plus 27 MW²⁰ diesel from
7 rented diesel units in order to meet the N-1 criterion assessment).²¹"
8 and

9
10 "20 15 units at 1.8 MW for each unit to total 27 MW for 2021."

11
12 Of the 23.5MW of YEC diesel, Faro FD1&FD7 provide 5.8MW,
13 according to the 10-Year Renewable Plan. So in the GRA and for N-1
14 purposes, Faro diesel provides 14.8 MW (FD1+FD7=5.8MW + 5
15 Rentals @ 1.8MW Ea=9MW).

16
17 However, 14.8 MW clearly exceeds the maximum 10.6MW permitted
18 by the regulator or listed in the expired 2008 and 2011 decision
19 documents. YEC is counting 4.2MW (14.8 MW-10.6 MW)that it has no
20 authority to install or use to meet N-1.

21
22 And from GRA Page 2-15 "In summary, under N-1, there is surplus of
23 dependable capacity of approximately 1.25 MW in 2021. Without rented
24 diesel units, the N-1 capacity shortfall would be 25.75 MW in 2021."

25
26 This is not true, as YEC actually has an N-1 capacity shortfall of 2.95
27 MW. (1.25 – 4.2)

28
29 **QUESTION:**

30
31 a) Please explain how N-1 is affected with Faro capacity being limited to 8.15 or 10.6
32 MW, at least 4.2 MW less than the 14.8 MW cited on the GRA and 10-Year
33 Renewable Plan?

34
35 b) Please provide a corrected and complete answer to YUB-YEC-1-50(b).

1 **ANSWER:**

2
3 **(a) and (b)**

4
5 The N-1 requirement set out in this application was, and continues to be, met by YEC
6 installing the rented diesels at Faro. The volume of diesel rentals at this site were and are
7 needed to address higher N-1 dependable capacity requirements demonstrated by the
8 extraordinary cold spell in winter 2019/2020. In that regard -- the GRA N-1 requirement is
9 not affected by the 10.6 MW cap.

10
11 Further context is provided below.

12
13 Prior to the 2020/21 winter YEC was renting eight diesel generators plus one spare (all in
14 Whitehorse) to address the capacity shortfall under the N-1 criteria. However, the peak
15 forecasted by Yukon Energy's load forecasting model for the winter of 2019/2020 (which
16 was used to determine the number of diesel rental units required) was lower than the
17 actual peak demand experienced in January 2020 during an extraordinary cold snap. This
18 meant that during that cold snap Yukon Energy did not have sufficient capacity to meet
19 the N-1 criteria.

20
21 Yukon Energy updated its non-industrial peak capacity demand forecasting model to
22 account for that new peak. That update demonstrated a requirement for additional
23 capacity to meet the N-1 capacity criterion.

24
25 In order to address the capacity shortfall for winter 2020/21, Yukon Energy initiated rental
26 diesel infrastructure enhancements increasing the total number of rented diesel
27 generators from eight units in the winter of 2019/2020 to 15 units [plus two spares],
28 including six [plus one spare] in Faro. YEC was able to complete these changes in 2020
29 to ensure YEC had sufficient reserve to meet the N-1 criteria for the 2020/21 winter.

30
31 Starting in 2020 -- Yukon Energy also began the process to amend the Faro emissions
32 permit to take into account this added diesel generation capability. In October 2020 -- as
33 part of that process -- it was determined that the Faro air emissions permit needed to be
34 amended and further that it would need to go through a YESAA assessment process.
35 Appropriate consultations have been ongoing since that time (including with the RRDC)
36 and a formal amendment application was recently filed with YESAB (see NY-YEC-2-6 for

1 more details on engagement activities over this period). YEC expects that approval will be
2 received before this upcoming winter.

3
4 Because Yukon Energy believed that sufficient capacity was connected to prevent
5 outages under the emergency circumstances (such as N-1 event) in winter 2020/21, no
6 revisions are required to YUB-YEC-1-50(b).

7
8 **REVISED RESPONSE, Part (a)**

9
10 Board Order 2021-12, Appendix A notes:

11 “The Board finds the IR to be useful and of probative value. The Board directs YEC
12 to explain whether it has a capacity shortfall: (i) based on its permitted MW
13 (10.6MW); or (ii) based on the total capacity it is currently using (14.8MW installed
14 capacity).

15 In addition, the Board directs YEC to: (iii) confirm that it will comply with Yukon
16 Energy’s air emissions permit regardless of the capacity installed at the FGS; and
17 (iv) explain how the Board should consider the limitations of the current Faro
18 emissions permit in the context of a GRA, assuming YEC’s application to YESAA
19 to amend this permit is not approved prior to the close of record of this proceeding.”

20
21 **(i) and (ii)**

22
23 Please see Yukon Energy’s Rebuttal Evidence filed September 17, 2021 – as documented
24 in the evidence, sufficient dependable capacity has been installed on the system to meet
25 YEC’s N-1 dependable capacity requirements in the winter of 2020/21 and the winter of
26 2021/22.

- 27 1. For the additional N-1 dependable capacity requirements arising from the January
28 2020 peak – YEC had connected (i.e., ready to operate) by winter 2020/21 the six
29 rental diesels (10.8 MW) plus one spare located at Faro, in addition to updated
30 FD1 and FD7 capacity of 5.2 MW.
- 31 2. The permitted production capacity for Faro for normal operations for winter
32 2020/21 was 10.6 MW. YEC has filed a YESAA project proposal to increase Faro’s
33 permitted production capacity from 10.6 MW to 15.5 MW.
- 34 3. Until the amendment to YEC’s permitted production capacity is granted YEC had
35 and continues to have the capability to operate diesels in Faro beyond 10.6 MW
36 using the emergency exception set out in section 49 of YESAA. That section states
37 that no assessment is required in “*response to an emergency when it is in the*

1 *interest of public welfare, health or safety or of protecting property or the*
2 *environment that the activity be undertaken immediately”).¹*

3 4. If required to deal with an N-1 emergency event in winter 2021/22, the 17 rented
4 diesels installed at Whitehorse and Faro will ensure that YEC has full capability to
5 respond to the emergency as required.²

6
7 **(iii) and (iv)**

8
9 YEC confirms that it will comply with Yukon Energy’s air emissions permit regardless of
10 the capacity installed at the FGS.

11
12 As documented in Yukon Energy’s Rebuttal Evidence filed September 17, 2021, and in
13 response to (i) and (ii) above, YEC had and continues to have the capability to operate
14 diesels in Faro beyond 10.6 MW using the emergency exception set out in section 49 of
15 YESAA.

¹ Although diesels were installed and available to meet such a potential emergency in winter 2020/21, no such event occurred, and the Faro facility operated within its currently permitted production capacity limit of 10.6 MW.

² YEC has permits today that authorize normal diesel unit operation of 14.0 MW at Whitehorse and 10.6 MW at Faro; YEC also has an explicit permit authorization for an added 12 MW diesel capacity operation at Whitehorse under emergency conditions. NY-YEC-1-6 REVISED provides the stacking order for the existing YEC thermal unit operation in conformance with existing permit requirements and emergency condition operation.

1 **REFERENCE: Follow-up on NY-YEC-1-8(a)**

2 From Elizabeth Barker's reply to Travis Ritchie 23-Sept, 2020:

3
4 *"Specifically, the Faro generating station underwent a YESAA*
5 *assessment in 2014. In the assessment, FD1 and FD7 were assessed*
6 *with production capacities of 5.15MW and 3MW for a total of 8.15MW.*
7 *Currently, FD1 and FD7 have been derated to 2.4MW and 2.8MW*
8 *however, with the addition of YM20-22 (5.4MW) and the addition of the*
9 *YM23-25(5.4MW) as emergency backup, this brings the station*
10 *capacity to a total of 16MW. This is 7.85MW greater than the capacity*
11 *that was previously assessed in 2014. As the modification of production*
12 *capacity is greater than 50kW, this project will need to proceed through*
13 *YESAB before we can issue any permit amendments. Please let me*
14 *know if you would like to discuss this further.*

15
16 And from Travis Ritchie's email to Elizabeth Barker 24-Sept, 2020:

17 *"I was anticipating that either Decision Document 2008.0230 or*
18 *2011.0246 were technically still valid for the purposes of granting an*
19 *approval..."*

20
21 and

22
23 *"I understand the need to assess the additional capacity (beyond what*
24 *has been assessed historically) before it can be permitted, but I would*
25 *ask for approval to reinstall the previously relocated and de-rated*
26 *capacity pursuant to the 2008/2011 assessment findings and related*
27 *decision documents."*

28
29 and

30
31 *"If you need, I can resubmit the amendment application for reinstallation*
32 *of only the previously assessed capacity, removing reference to the 3*
33 *additional units (YM23-YM25). YEC can then work on getting a YESAA*
34 *assessment completed for the additional capacity, which could be*
35 *permitted afterward. Does that sound reasonable?"*
36

1 And from Elizabeth Barker's reply to Travis Ritchie 13-Oct, 2020: *"We*
2 *have determined that the information provided in YEC's previous Faro*
3 *station YESAA assessments (2008-0230 and 2011-0246) is still valid*
4 *for the proposed 2020 amendment of reinstalling capacity of*
5 *approximately 5.65MW at the Faro generating station. YEC has*
6 *authorization to reinstall previously relocated/de-rated capacity of up to*
7 *10.6MW, cumulative station capacity, without proceeding through the*
8 *YESAA assessment process. As discussed, any additional capacity*
9 *increase that will bring the Faro station's cumulative capacity above*
10 *10.6MW will need to proceed through the YESAA assessment process*
11 *before being considered."*

12 These documents were for the 2008 and 2011 permits and were not
13 considered valid for the 2014 permit in 2014. A new YESAB
14 assessment was required, and produced Decision Document
15 2014.0119.

16
17 **QUESTION:**
18

- 19 a) Were the 2008 and 2011 Decision Documents "still valid" in 2014 when a new
20 permit was required to replace the expiring 2008 and 2011 permits? And, if they
21 are "still valid" now, why were they not used for the 2014 permit?
22
- 23 b) In giving this exception, Elizabeth Barker specifically states that YEC can reinstall
24 5.65MW for "up to 10.6MW, cumulative station capacity" and "any additional
25 capacity increase that will bring the Faro station's cumulative capacity above
26 10.6MW will need to proceed through the YESAA assessment process before
27 being considered. and yet, YEC installed 6 generators at 1.8MW each, bringing
28 cumulative capacity to 16 MW. This is of course exactly what Elizabeth Barker
29 rejected in the email of 23-Sept. How does YEC justify this?
30
- 31 c) Exactly how many rental generators has YEC installed in Faro? Physically, it
32 seems to be seven – and the GRA uses the cost of installation and rental of 7
33 generators to justify a significant portion of the rate increase. However for purposes
34 of the N-1 Capacity, 5 generators are listed as operational in Faro, and for the
35 regulator, only 3 can actually be installed. So how many generators are there?
36 How can using these different numbers be justified? Which one is real?

1 d) What is the social license of asking the regulator to use documents created for
2 expired permits instead current documents? Having submitted the YESAB
3 documents in 2008, 2011 and 2014, Travis Ritchie must have known that the 2008
4 and 2011 permits had expired?

5
6 e) The original (rejected) application of 10-Sept, 2020 is to “Reinstall
7 relocated/derated capacity (aprx. 5.65 MW) & add 3 x1.8 MW emerg-only units.”
8 This is rejected in Elizabeth Barker’s email of 23-Sept, and Travis alters the
9 application and resubmits on 28-Sept, “removing reference to the 3 additional units
10 (YM23-YM25).” So three of the six generators were removed from the application
11 to get a pass from the regulator, but... then they were installed anyway, in direct
12 contradiction of the regulator and the regulators explanation of YESAA
13 requirements. Please explain.
14

15 f) I was under the impression that expired permits are no longer “still valid.” Are there
16 other examples or instances where the limits from expired permits can take
17 precedence over current limits? Most expired permits actually expire – ie the catch
18 limits of a 2008 or 2011 fishing permit would not be suddenly “still valid” in 2021,
19 but somehow limits on expired YEC pollution permits are “still valid.” What other
20 expired permits are “still valid” after expiration? What precedent did YEC have for
21 suggesting using expired documents in this way?
22

23 g) Explain the ethical and legal aspects of bypassing the clear intent of YESAA and
24 the regulator?
25

26 **ANSWER:**

27
28 **(a) (d) and (g)**

29
30 Part (a), (d) and (g) question whether the Decision Documents relied upon by the regulator
31 in issuing the permit amendment were “still valid”; the social licence for asking a regulator
32 to use decision documents for “expired permits” instead of current decision documents;
33 and the “ethical and legal aspects of bypassing the clear intent of YESAA and the
34 regulator.”
35

36 The presumptions in these questions are not valid.

1 The YESAA legislation is clear with respect to a Decision Body's role in determining
2 whether it needs a Decision Document (or a new Decision Document) in order to enable
3 its regulatory agencies to issue project approvals.

4
5 In this case, the Decision Body determined that a previous YESAA assessment and duly
6 issued Decision Document were sufficient for its regulatory agency to authorize the
7 reinstallation of previous site capacity under Yukon Energy's existing air emissions permit
8 as the proposed activity (previously assessed and recommended to proceed under
9 YESAA) was not a material departure or substantive change from what was previously
10 authorized at the FGS.

11
12 More specifically, the regulator confirmed in the October 13, 2020 correspondence [quoted
13 above] from Elizabeth Barker, Environmental Protection Analyst, Department of
14 Environment, Standards & Approvals Section, Yukon Government, as follows:

15
16 "We have determined that the information provided in YEC's previous Faro station
17 assessments (2008-0230 and 2011-0246) is still valid for the proposed 2020
18 amendment of reinstalling capacity of approximately 5.65MW at the Faro
19 generating station. YEC has authorization to reinstall previously relocated/de-rated
20 capacity of up to 10.6MW, cumulative station capacity, without proceeding through
21 the YESAA assessment process."

22
23 Therefore, in response to parts (a),(d) and (g), the regulator has determined that the
24 information available from the prior assessments, including prior decision documents, is
25 still valid and could be relied upon by the regulator for its determinations on reinstalling
26 capacity of approximately 5.65 MW at the Faro generating station. Consequently, the
27 intent of YESAA and the regulator were not bypassed.

28
29 **(b) and (e)**

30
31 The authority provided under the Air Emissions Regulation, and permits issued under that
32 regulation, is focused on contaminant emissions to the atmosphere, i.e., air pollution is the
33 target of the Regulations. As such, a proponent can have any number of emitting devices
34 at a site, but can only operate such equipment in a manner that is compliant with the
35 authority provided under their air emissions permit.

1 In her correspondence, the Yukon government representative was “rejecting” the
2 allowance to **operate** any capacity beyond the existing permit threshold without further
3 YESAA assessment, not rejecting the **installation** at the facility.

4
5 In this case, despite the total capacity of the generators on site at the Faro Generating
6 Station that includes connection of six rented diesels [plus one spare] during the critical
7 winter season, Yukon Energy is currently limited to operating only up to 10.6 MW of that
8 capacity at any one time, using a combination of any units at site. Yukon Energy has not
9 run more than 10.6 MW of diesel generation at this site over the past year.

10
11 As reviewed in response to NY-YEC-2-2, notwithstanding the current permit limit of 10.6
12 MW Yukon Energy ensured in winter 2020/21 (and is ensuring again in winter 2021/22)
13 that sufficient capacity is made available and connected at the Faro generating station to
14 prevent outages under the emergency circumstances (such as N-1 event). In the event of
15 an emergency (i.e., an N-1 event for which the back-up capacity was rented) YEC has
16 retained the required N-1 dependable capacity capability and would plan if required to
17 operate units as needed during the emergency.

18
19 Yukon Energy is also proceeding with assessments and permitting reviews as required to
20 authorize it to operate at any time in future installed capacity available at the FGS of up to
21 15.5 MW.

22
23 **REVISED RESPONSE to (b) and (e)**

24
25 Board Order 2021-12, Appendix A notes:

26 “Parts (a), (c), (d), and (g). The Board finds that YEC has adequately responded
27 to the IR. No further response is required from YEC.

28
29 Parts (b) and (e). The Board finds the IR to be useful and of probative value. YEC
30 is to provide the basis and support for its utilization and the applicability of
31 operating and installation capacity. YEC is to cite which regulations under YESAA
32 allow for distinguishing operating versus installed capacity for the purposes used
33 by YEC.”

34
35 For the purposes of the *Assessable Activities, Exceptions and Executive Committee*
36 *Projects Regulations* (YESAA Regulations), “production capacity” is the proponent’s
37 permitted operational production capacity, as opposed to the maximum capacity of all

1 onsite equipment including spare units maintained solely for backup purposes. The
2 production capacity of the Faro GS facility is limited by regulation under the *Environment*
3 *Act, Air Emissions Regulations* (via Air Emission Permit 60.010). This reflects the facility's
4 maximum permitted capacity to emit air pollutants, regardless of how many spare units
5 Yukon Energy may maintain on site for backup purposes and is currently equal to 10.6
6 MW.

7
8 As documented in Yukon Energy's Rebuttal Evidence filed September 17, 2021, YEC has
9 the capability to operate diesels in Faro beyond the permitted production capacity using
10 the emergency exception set out in section 49 of YESAA.

11
12 **(c)**

13
14 Seven (7) rental generators are installed at the FGS. Six units are required to address N-
15 1 dependable capacity requirements and one unit is a spare.

16
17 As mentioned in the response to NY-YEC-2-3(b) any number of units can be installed at
18 a facility, but the facility must comply with the capacity thresholds for air emissions. YEC
19 is currently authorized to operate 10.6MW - and this could be provided with five rental
20 units, as per the current stacking order for this site (see response to NY-YEC-1-6 Revised).
21 Capacity installed at the FGS beyond the current operating/emitting threshold is intended
22 to provide emergency back up as well as redundancy in case of unit failure or when
23 required maintenance or repair schedules coincide with system demand that calls on that
24 capacity to come online. As reviewed in response to "b and e" above, and in the current
25 stacking order for this site (see response to NY-YEC-1-6 Revised), YEC plans if required
26 to operate units as needed during an N-1 or other emergency.

27
28 YEC is currently proceeding with assessments and permitting reviews as required to
29 authorize it to operate at any time in future installed capacity available at the FGS of up to
30 15.5 MW.

1 **(f)**

2
3 The permit is not expired; YEC sought an approval, pursuant to its existing air emissions
4 permit (i.e., Part 2, Clause 5)¹, to install previously relocated and de-rated capacity based
5 on available assessment materials. Yukon Energy accordingly did not suggest that expired
6 *permits* should allow for reinstallation of previously assessed and permitted site capacity
7 at the FGS.

8
9 YEC suggested, and the Regulatory Authority agreed, that a previous *Decision Document*
10 and its related assessment information was still valid for decision making with respect to
11 Yukon Energy's request for approval to reinstall generation capacity at the site up to the
12 previously (and favorably) assessed and permitted capacity. See response to parts (a),
13 (d) and (g).

¹ This clause states: "The permittee shall obtain approval from an environmental protection analyst prior to: a) any addition, modification, removal or replacement of any equipment or components related to the release, abatement, control or treatment of air emissions; or b) any change in location of the source(s).

1 **REFERENCE: Follow-up on NY-YEC-1-10 – YESAB / Generating Capacity**

2
3 **From YEC's reply to NY-YEC-1-10, emphasis added:**

4
5 *"Yukon Energy is requesting a recommendation by the Designated*
6 *Office to allow the Permit amendment to proceed, on the basis that the*
7 *Project (i.e., the continuing operation of the Yukon Energy's Faro Diesel*
8 *Facility with the addition of **4.9 MW** of additional diesel generating*
9 *capacity (total of **15.5 MW** of generating capacity) in accordance with*
10 *the terms and conditions of the amended Permit and the applicable*
11 *provisions of the Environment Act and Air Emissions Regulations)..."*

12
13 **QUESTION:**

- 14
15 a) How did YEC come up with 15.5MW as a total? There is no combination of the
16 installed generators and rentals that actually adds up to this total?
17
18 b) The sound and air dispersion studies also note that given the capacities of the
19 generators, there is no actual way for this to be the total, and therefore no way to
20 model for it. The studies are based on 16MW (Derated FD1+FD7 + 6 Rentals)
21 which is physically and mathematically possible. How/why does YEC propose a
22 generating capacity of 15.5MW while the actual installed generation capacity will
23 be 16MW (or 16.6MW if using the 10-Year Renewable Plan for capacities)?
24
25 c) Why claim the addition of only 4.9 MW, when the proposal is for 5.4 MW, the 3
26 rentals actually being installed?
27

28 **ANSWER:**

29
30 **(a) and (c)**

31
32 The proposed site capacity expansion was limited to 4.9 MW so as not to trigger an
33 Executive Committee (EC) Screening, i.e., a 5 MW increase would trigger an EC
34 Screening.
35

36 All of Yukon Energy's previous twelve (12) diesel generating station assessments have
37 been conducted under YESAA at the Designated Office level. Based on Yukon Energy's

1 experience, a YESAA assessment at the Designated Office level can be completed on a
2 more timely basis than an Executive Committee level review. This would allow for the
3 assessment to be completed in order for the additional capacity to be available for the
4 upcoming winter.

5
6 **(b)**
7

8 As noted in response to NY-YEC-2-1, operating capacity will be directed by the limits
9 provided under Yukon Energy's air emissions permit regardless of the capacity installed
10 at the FGS. The 16 MW ceiling was chosen as the threshold for the air quality and noise
11 impact assessments (and related modelling) as a measure to ensure conservative
12 assessment results. The 15.5 MW threshold was selected for the purposes of assessment
13 and permitting as described in the response to question NY-YEC-2-2(a), above.
14

15 **REVISED RESPONSE**
16

17 Board Order 2021-12, Appendix A notes:

18 "To reduce confusion for this issue, YEC is to confirm it has installed an additional
19 12.4MW [seven rental generators in 2020 and is submitting a YESAB proposal in
20 2021 to allow operation of only an additional 4.9MW (2.722 rental generators)] to
21 avoid an EC screening."
22

23 YEC confirms the following with regard to the Faro diesel GS:

- 24 1. YEC connected six rental diesels at the Faro GS in 2020 (10.8 MW), plus one
25 spare unit.
- 26 2. The updated FD1 and FD7 permanent installed capacity at the Faro GS is 5.2 MW.
- 27 3. The permitted production capacity for Faro GS for normal operations for winter
28 2020/21 was 10.6 MW. In 2021 YEC filed a YESAA project proposal to increase
29 Faro's permitted production capacity from 10.6 MW to 15.5 MW. The proposed site
30 production capacity expansion was limited to 4.9 MW to avoid an Executive
31 Committee (EC) Screening, i.e., a 5 MW increase would trigger an EC Screening.
- 32 4. The amended permit will permit production capacity of up to 15.5 MW, e.g., full
33 use of six rental units (10.8 MW) plus up to 4.7 MW of the permanent installed
34 capacity, or the permanent installed capacity plus up to 10.3 MW of the rental units.
- 35 5. As noted in NY-YEC-2-1, the dependable capacity on the grid is forecast to be
36 about 0.65 MW above the forecast non-industrial winter peak for 2021. This

1 forecast assumes updated capacity rating for FD1 and reflects normal
2 quantification of the single contingency (N-1) criterion. The dependable capacity
3 required at the Faro GS to meet the 2021 N-1 dependable capacity requirements
4 is 15.4 MW, i.e., within the 15.5 MW permit production capacity currently applied
5 for at the Faro GS.

1 **REFERENCE: Follow-up on NY-YEC-1-9 Consultation, approval and thanks,**
2 **RRDC**

3
4 While YEC is unwilling to provide any of the actual correspondence with
5 RRDC, YEC did provide a list of attempts to contact RRDC in the
6 meeting notes of the Faro virtual meeting on 2-December, 2020 and a
7 comment by the RRDC representative in attendan[c]e on 2-December.

8
9 As stated in the YEC distributed meeting notes, previous to the
10 installation of the rental generators, YEC made only three attempts to
11 contact RRDC, all by email only, on April 9 and 17 and September 1,
12 2020.

13
14 At the meeting on 2-December, 2020, the RRDC contact who was
15 supposedly emailed *“expressed his deep concern and disappointment*
16 *that Yukon Energy did not consult with Ross River Dena Council*
17 *(RRDC) before adding the temporary diesel generators to the Faro site.*
18 *Stanley noted that RRDC was not informed of the project or of the*
19 *procurement opportunities.”* (from YEC distributed meeting notes).

20
21 **QUESTION:**

22
23 a) Did YEC consider sending three (unanswered, possibly not received) emails to be
24 sufficient consultation and interaction with RRDC before proceeding to install the
25 generators?

26
27
28 b) Did YEC confirm the emails were received? Please provide confirmation if any
29 exists.

30
31 c) Why were no phone calls made to anyone at RRDC previous to installation of the
32 generators?

33 From the meeting handout: *“We give thanks to the Ross River Dena Council for*
34 *allowing our facilities and this project to take place on their Traditional Territory.”*

35 We give thanks, but can’t we also at least give them a call?

1 **ANSWER:**

2
3 **(a) to (c)**

4
5 Part (a), (b) and (c) question what YEC considered to be the appropriate level of
6 engagement prior to proceeding with installation of diesel generators; and whether YEC
7 was able to make contact with RRDC; and question the measures YEC undertook to share
8 information with RRDC. As noted below – YEC proceeded with a level of engagement
9 considered appropriate for the project activities it was undertaking at each stage; YEC has
10 also continued to make efforts to engage with RRDC and share information regarding the
11 project (as detailed in the table provided below).

12
13 Generally speaking, replacement of previously installed capacity (i.e., 3 of the rentals) is
14 a basic operational activity. This type of activity does not typically require public
15 engagement. With regard to expanded capacity at the site, consultation became
16 appropriate once an assessment by YESAB was determined to be required for the
17 expansion of the site air emissions permit. The project is required to be assessed at the
18 Designated Office level of YESAB and Yukon Energy has proceeded with engagement
19 activities taking this into consideration.

20
21 The table below summarizes consultation activities with RRDC/the community of Faro
22 after it was determined after winter 2019/20 that diesel rentals were needed at the Faro
23 generating station. Yukon Energy notes this level of consultation took place under COVID
24 19 conditions, and exceeds the minimum required by YESAB for projects assessed at the
25 Designated Office level.

Activity Description	Date
Town of Faro Council Presentation	July 2020
Information Brochure on Project mailed to all Faro addresses	September 2020
Virtual Community Meeting for RRDC and Ross River	December 2, 2020
Senior Leadership travelled to Ross River to meet with Chief and Council	October 15, 2020
Presentation and overview with RRDC Chief and Council and Development Corporation	June 2021
YEC engaged a RRDC owned environmental consulting firm to provide a third-party review of the YESAA application and recommendations were included in YESAA submission.	2021
Copy of YESAA application provided to RRDC lands management lead prior to submission.	August 2021
Copy of community presentations available on YEC website	As required

REVISED RESPONSE

Board Order 2021-12, Appendix A notes:

“In general, the Board finds that YEC provided an adequate response to the IR. However, the Board requires YEC to clarify its response regarding one of the RRDC meetings. The Board directs YEC to explain whether a meeting with RRDC took place on October 15, 2020. If YEC cannot provide confirmation then YEC is to explain why such a confirmation cannot take place.”

Yukon Energy confirms that a meeting with RRDC took place on October 15, 2020. Yukon Energy President and CFO met with the Chief and Council on that date for a general discussion on the relationship between RRDC and the Faro region and current and planned activities by YEC in the traditional territory of RRDC, including future plans for the Faro diesel generating facility.

Round 1 Attachments



October 11, 2019

Mr. Jason Epp
Controller
Yukon Energy Corporation
#2 Miles Canyon Road
Box 5920
Whitehorse, Yukon Y1A 6S7
Jason.Epp@yec.yk.ca

Re: IAS 19 - Estimate of 2020 and 2021 Defined Benefit Cost

Dear Jason:

At your request, we have prepared this letter to present the estimated 2020 and 2021 Defined Benefit Cost for the Yukon Energy Corporation Employees' Pension Plan (the "Plan"), the Yukon Energy Corporation Pension Plan for Executive Employee (the "IPP"), and Supplemental Executive Retirement Plan for David Morrison (the "SERP"). Amounts have been prepared under International Accounting Standards Section 19 (June 2011) ("IAS 19R").

Please refer to our "Report on the Actuarial Valuation of the Yukon Energy Corporation Employees' Pension Plan, IPP, and SERP as at December 31, 2018 for Accounting Purposes" (the "December 31, 2018 Accounting Report") for details on the methods and assumptions used to determine liabilities. The Plan membership data is the membership data as provided by Yukon Energy Corporation as at December 31, 2018 and are shown with a comparison as at December 31, 2017 in Appendix C. The IPP membership data is the membership data as provided in the Westcoast Actuaries report for funding purposes as at January 1, 2017.

Note that this letter does not include any results for the Group RRSP.

Assumptions

A brief summary of the actuarial assumptions can be found in Appendix A for the Plan and Appendix B for the IPP and SERP. The two material items that can significantly affect our estimate below are the discount rate and actual return on assets for 2019 as these will affect starting values for 2020 and 2021. We have assumed that the discount rate for the Plan of 3.9% used at December 31, 2018 will have increased to 3.0% at December 31, 2019, December 31, 2020 and December 31, 2021. The discount rate has been established based on market yields on high-quality corporate bonds in Canada as at September 30, 2019. We have considered the CIA Education Note on Accounting Discount Rate Assumptions for Pension and Post-Employment Benefit Plans and Fiera Capital's CIA Method Accounting Discount Rate Curve. The discount rate is a reasonable assumption at the present time based on interest rate movements over 2019 year-to-date. The same discount rate was used for the IPP and SERP.



We have estimated the assets of the Plan as of December 31, 2019 by increasing the market value of assets at August 31, 2019 by the expected contributions and subtracting the expected benefit payments to be made from the fund between August 31, 2019 and December 31, 2019. We assumed asset growth from investments between August 31, 2019 and December 31, 2019 of 3.9% annualized, which is equal to the discount rate assumption at the beginning of the year. For the IPP, assets were estimated based on June 30, 2019 financial statement values. Asset returns in 2020 and 2021 are assumed to be 3.0%, or the discount rate assumption at the beginning of the appropriate year.

Should you wish to test the sensitivity of these assumptions, please let us know and we can prepare additional information for your review.

2020 Estimated Defined Benefit Cost

The following table sets out the estimated defined benefit cost for fiscal 2020 in accordance with IAS 19R:

Estimated Defined Benefit Cost for Fiscal 2020	Employee Benefits Expense	Financing Costs	Other Comprehensive Income*	Total
	\$	\$	\$	\$
Employer current service cost	421,300			421,300
Past service costs	0			0
Administrative expenses	66,300			66,300
Net interest:				0
Interest cost on accrued benefit obligations		815,600		815,600
Interest income on plan assets		(583,000)		(583,000)
Remeasurements arising from:				0
Demographic assumptions			0	0
Financial assumptions			0	0
Total Pension Cost	487,600	232,600	0	720,200

* Please note that amounts to be charged to other comprehensive income cannot be determined until the end of fiscal year 2020.



2021 Estimated Defined Benefit Cost

The following table sets out the estimated defined benefit cost for fiscal 2021 in accordance with IAS 19R:

Estimated Defined Benefit Cost for Fiscal 2021	Employee Benefits Expense \$	Financing Costs \$	Other Comprehensive Income* \$	Total \$
Employer current service cost	433,900			433,900
Past service costs	0			0
Administrative expenses	67,600			67,600
Net interest:				0
Interest cost on accrued benefit obligations		833,400		833,400
Interest income on plan assets		(594,800)		(594,800)
Remeasurements arising from:				0
Demographic assumptions			0	0
Financial assumptions			0	0
Total Pension Cost	501,500	238,600	0	740,100

* Please note that amounts to be charged to other comprehensive income cannot be determined until the end of fiscal year 2021.

As the SERP and the IPP consist of only one retired member, there are no current service costs associated with either plan. As the SERP is unfunded and administrative expenses are not paid from the IPP assets, the defined benefit cost is comprised solely of the interest cost for each plan. Therefore, the total estimated defined benefit cost for the SERP and IPP is:

Estimated Defined Benefit Cost	IPP	SERP	Total \$
Fiscal 2020 – Interest cost	1,900	27,100	29,000
Fiscal 2021 – Interest cost	2,000	26,600	28,600



We trust that you find the foregoing to be in order. Should you have any questions or require anything further, please do not hesitate to contact us.

Sincerely,

A handwritten signature in dark ink, appearing to read "Tom Kowalczyk", with a long, sweeping flourish extending to the right.

Tom Kowalczyk, FCIA, FSA
Principal, George & Bell Consulting Inc.
Cell: 604-816-6554
tkowalczyk@georgeandbell.com

A handwritten signature in dark ink, appearing to read "Rory O'Connor", with a long, sweeping flourish extending to the right.

Rory O'Connor, ACIA, ASA
Associate, George & Bell Consulting Inc.
Tel: 604-259-7066
roconnor@georgeandbell.com

Mr. Jason Epp, Yukon Energy Corporation
Estimate of 2020 and 2021 Pension Expense

4



Appendix A - Plan Assumptions

The following summarizes the main assumptions used in preparing the estimated defined benefit cost for fiscal 2019-2021 for the Plan. The assumptions used in the prior accounting report are shown for comparison.

Period Ending	December 31, 2018	December 31, 2019	December 31, 2020 & December 31, 2021
Discount rate			
at beginning of year	3.4% per year	3.9% per year	3.0% per year
at end of year	3.9% per year	3.0% per year	3.0% per year
Expected return on assets	Not applicable	3.9% per year between September 1 st and December 31 st	3.0% per year
General wage increases	2.8% per year	Same	Same
Increase in Inflation	2.0% per year	Same	Same
Salary increases – merit & promotion	0.95% at age 42, scaled down to 0% by age 65.	Same	Same
Retirement	All active members retire when age plus service reaches 90 points, but not later than age 65. All active members are assumed to retire with Company consent.	Same	Same
Mortality	CPM2014 Private table, projected using MI-2017. Rates were applied to post retirement only.	Same	Same
Withdrawal	No allowance	Same	Same
Disability	No allowance	Same	Same
Family composition	Assume current marital status; male spouse 4 years older than female	Same	Same
Non-investment expenses	\$65,000, then increasing with inflation	Same	Same



Appendix B - IPP & SERP Assumptions

The following summarizes the main assumptions used in preparing the estimated defined benefit cost for fiscal 2019-2021 for the IPP and SERP. The assumptions used in the prior accounting report are shown for comparison.

Period Ending	December 31, 2018	December 31, 2019	December 31, 2020 & December 31, 2021
Discount rate at beginning of year	3.5% per year	3.9% per year	3.0% per year
at end of year	3.9% per year	3.0% per year	3.0% per year
Expected return on assets (IPP only)	Not applicable	3.9% per year between July 1 st and December 31 st	3.0% per year
Increase in Inflation	2.0% per year	Same	Same
Increase in annual pension	2.0% per year	Same	Same
Mortality	CPM2014 Private table, projected using MI-2017.	Same	Same
Non-investment expenses	None	Same	Same

Yukon Energy Corporation Employees' Pension Plan Actuarial Valuation as at January 1, 2020

Registration Numbers: OSFI 56997
CRA 1041011

PREPARED BY: Tom Kowalczyk & Rory O'Connor

June 26, 2020



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1. Executive Summary

Below we have provided an overview of the valuation's results and key assumptions. The next actuarial valuation should be conducted no later than January 1, 2021.

	January 1, 2019	January 1, 2020
Going Concern Funded Status	\$	\$
Going concern assets	17,906,900	18,896,200
Going concern liabilities	19,571,900	21,304,700
Actuarial excess (unfunded liability)	(1,665,000)	(2,408,500)
Funded ratio	91.5%	88.7%

	January 1, 2019	January 1, 2020
Solvency Funded Status	\$	\$
Solvency assets	17,192,600	19,822,700
Solvency liabilities	18,045,800	20,319,200
Solvency assets less solvency liabilities	(853,200)	(496,500)
Solvency ratio	95.3%	97.6%

	January 1, 2019 Annual	January 1, 2020 Annual
Employer Contribution Requirements	\$	\$
Current service cost (including non-investment expense)	335,900	369,400
Special payments	184,300	259,300
Total minimum required	520,200	628,700

	January 1, 2019	January 1, 2020
Going Concern Key Assumptions		
Discount rate	5.0% per year	4.6% per year
Wage inflation	2.8% per year	2.8% per year
Inflation rate	2.0% per year	2.0% per year
Retirement	Retire when age plus service reaches 90 points, but no later than age 65	Retire when age plus service reaches 90 points, but no later than age 65
Mortality (post-retirement only)	CPM2014 Private table projected using Scale MI-2017	CPM2014 Private table projected using Scale MI-2017



Solvency Key Assumptions	January 1, 2019	January 1, 2020
Discount rate	Transfers: 2.8% for 10 years, 3.2% thereafter; Annuity: 3.2%	Transfers: 2.5% for 10 years, 2.6% thereafter; Annuity: 2.6%
Retirement	Over age 55 or 90 points: immediately Otherwise: age 65	Over age 55 or 90 points: immediately Otherwise: age 65
Mortality	CPM2014 table projected using Scale CPM-B	CPM2014 table projected using Scale CPM-B



2. Introduction

We have been retained by Yukon Energy Corporation (the “Employer”) to conduct an actuarial valuation on the Yukon Energy Corporation Employees’ Pension Plan (the “Plan”) as at January 1, 2020.

The purposes of the valuation are to:

- report on the funded status of the Plan on both a going-concern and solvency basis;
- determine the minimum amount of contributions required by the Employer under the *Pension Benefits Standards Act, 1985* (the “Act”);
- determine the maximum amount of Employer contributions allowed under the *Income Tax Act* (Canada) (the “ITA”);
- provide information and the actuarial opinion required by the regulatory authorities.

The information contained in this report was prepared for the internal use of the Employer and for filing with the Office of the Superintendent of Financial Institutions (“OSFI”) and with the Canada Revenue Agency (“CRA”), in connection with our valuation of the Plan. This report is not intended, nor suitable, for any other purposes.

All of the attached sections and exhibits are integral parts of our report.

This report and any of its content may not be distributed, published, made available or relied upon by any person other than its intended users, without the express written permission of George & Bell Consulting Inc., unless and only to the extent otherwise required by law.

Changes since the Previous Valuation

The last actuarial valuation of the Plan filed with OSFI was prepared as at January 1, 2019. Since the last actuarial valuation, the following changes have occurred:

1. All assumptions were reviewed, and some were revised based on expected future experience and changes to plan provisions, if applicable.
2. During the inter-valuation period the Employer reviewed and revised the Statement of Investment Policies and Procedures (SIPP). The latest such document was approved by the Employer on April 3, 2020 and the same was used to determine the valuation discount rate.

Details of the above changes which affect the funded status and/or future minimum required contributions of the Plan are outlined in this report.



Terms of Engagement

Terms of our engagement for preparing this valuation included the following:

- The Employer contribution rates were determined as the minimum required to satisfy the Act.
- The smoothed market value of assets was used for the going-concern valuation, as approved by the Employer.
- The Canadian Institute of Actuaries' Standards of Practice specify that the going concern valuation use best estimate assumptions containing no deliberate margins for conservatism unless required by law or by the terms of an appropriate engagement. The assumptions, methods and use of margins were discussed at the Employer's meeting on April 3, 2020. At that meeting the going concern actuarial assumptions and methods used for this valuation were approved by the Employer and are disclosed in this report.

Subsequent Events

Economic Impact of COVID-19

The rapid spread of the COVID-19 virus around the world commencing in February 2020 and the economic implications of the same resulted in a significant decrease in the Plan's equity investments over the first quarter of 2020, which have mostly recovered following March 31, 2020. As the Plan has a significant portion of its assets invested in equities, a significant drop in equity markets because of future impacts of COVID-19 could materially impact the Plan's financial position. As the Plan utilizes a smoothing mechanism the impact of such an event would not be fully realized immediately. That said, the intent of this report is to disclose the financial condition of the Plan as at December 31, 2019 as well to estimate the required employer contributions to the next valuation date. The impact on the best-estimate assumptions used to determine the Plan's liabilities is difficult to assess given the unprecedented measures taken in response to COVID-19. Emerging experience will allow for the impact to be better understood.

Filings

An actuarial valuation must be filed with OSFI as at the effective date of the Plan and not more than three years after the last actuarial valuation. Unless the Plan specifies otherwise, the date of each actuarial valuation must be at the Plan's fiscal year-end. If an amendment to the Plan or a change in Plan membership materially affects the cost of benefits provided by the Plan or creates an unfunded liability, an actuarial valuation must be prepared. Further, annual valuations are required when the Plan's solvency ratio is less than 120%. In the intervening period, contributions must be made in accordance with the last filed valuation.

The last actuarial valuation filed with OSFI was prepared as at January 1, 2019. The next actuarial valuation must be prepared and filed with OSFI no later than as at January 1, 2021 as the solvency ratio at this valuation date is less than 120%.



In order for an employer contribution to be eligible under a defined benefit provision, it must be recommended by an actuary in whose opinion the contribution is required to be made and the actuary's recommendation must be approved by the CRA. As such, in accordance with Section 147.2 of the *Income Tax Act (Canada)*, this entire valuation report must be filed with the CRA in support of eligibility of employer contributions.

We will file this report with the appropriate regulatory authorities on the Employer's behalf.



3. Summary of Results

The principal results of the actuarial valuation are presented below. Further analysis of the results of the valuation is provided in Sections 4 and 5. The plan provisions, membership data, asset data, actuarial methods and assumptions are described in the appendices.

3.1 Funded Status - Going-Concern Basis

Based on the assumption that the Plan will continue indefinitely, the following is the funded status of the Plan on a going-concern basis:

	January 1, 2019	January 1, 2020
	\$	\$
Actuarial value of assets	17,906,900	18,896,200
Actuarial liability	19,571,900	21,304,700
Actuarial excess (unfunded liability)	(1,665,000)	(2,408,500)
Funded ratio	91.5%	88.7%

The calculation of the actuarial value of assets is given in Appendix C.5. Details of the actuarial liability are given in Section 4. The reconciliation of the unfunded liability at the previous valuation to the unfunded liability at this valuation date is given in Section 5.

3.2 Funded Status - Solvency

A solvency valuation is used to measure the funded status of the Plan should it wind up on the valuation date and is prescribed by the Act. It follows certain adjustments as required under legislation.

	January 1, 2019	January 1, 2020
	\$	\$
Solvency assets	17,192,600	19,822,700
Solvency liabilities	18,045,800	20,319,200
Solvency assets less solvency liabilities	(853,200)	(496,500)

In accordance with the Act and regulations, the solvency surplus (deficiency) is defined as the amount by which the aggregate of the *adjusted* solvency asset amount exceeds (is below) the solvency liabilities. For this purpose, the adjusted solvency asset amount is determined by multiplying the average solvency ratio by the amount of the solvency liabilities. The average solvency ratio and solvency deficiency are further described in Section 4.4.



3.3 Current Service Cost and Contribution Requirements

The following table shows the annual cost of accruing benefits and expenses for employee service after the valuation date:

	January 1, 2019	January 1, 2020
	\$	\$
Total cost of accruing benefits	316,700	350,900
Plus: Non-investment expenses	65,000	65,000
Less: Members' contributions	(45,800)	(46,500)
Company current service cost	335,900	369,400
Expected pensionable earnings	1,066,800	1,085,200
Company current service cost:		
As a % of pensionable earnings	31.5%	34.0%
As a % of member contributions	733%	794%
Minimum special payments	184,300	259,300
Minimum required Company contributions	520,200	628,700

A reconciliation of the current service cost is given in Section 5.3.

3.4 Minimum Required Contributions

The minimum required employer contribution is equal to the total of:

1. The employer current service cost for the year; plus
2. Special payments towards amortizing any going-concern unfunded liability over 15 years from the date on which the unfunded liability was established; plus
3. If there is a solvency deficiency, special payments equal to the amount by which the solvency deficiency divided by 5 exceeds the amount of the going concern special payments.

The employer current service cost is \$369,400.

As noted in Section 3.1, on a going concern basis the Plan has an unfunded liability of \$2,408,500 as at January 1, 2020. The following table summarizes the schedule of minimum required employer contributions that are necessary to fund this unfunded liability. The employer contributions outlined reflect the necessary adjustments of previously established amortization schedules in accordance with the applicable legislation and accepted actuarial practice.



Date Established	Unamortized Balance \$	Remaining Amortization Period \$	Minimum Annual Payment \$	Minimum Monthly Payment \$
January 1, 2013	254,800	8 years	38,000	3,200
January 1, 2014	364,200	9 years	49,300	4,100
January 1, 2018	599,300	13 years	61,000	5,100
January 1, 2019	373,300	14 years	36,000	3,000
January 1, 2020	816,900	15 years	75,000	6,200
Total	2,408,500		259,300	21,600

As noted in Section 4.4, the Plan does not have a solvency deficiency. Therefore, the solvency special payments are zero.

To satisfy the requirements of the Act and its Regulations, contributions to the fund must be made in accordance with the following rules:

- Required member contributions must be remitted to the pension fund within 30 days following the month in which the contributions were received from the member or deducted from his or her remuneration.
- Employer normal (i.e. current service) cost contributions and special payments must be remitted to the pension fund within 30 days after the end of the month for which the contributions are payable.

3.5 Maximum Allowable Employer Contribution

The maximum allowed employer contribution in the first year following the valuation date is equal to the total of:

1. The employer current service cost for the year; plus
2. The going-concern unfunded liability (if any); plus
3. The extra contribution required to fully fund the solvency deficiency (if any).

As of this valuation date, there is an unfunded liability and a solvency excess.

	2019 \$	2020 \$
Current service cost	335,900	369,400
Greater of unfunded liability and solvency deficiency	1,665,000	2,408,500
Maximum contribution	2,000,900	2,777,900



If the Employer wishes to make the maximum allowed employer contribution, it is advisable to contact the Plan actuary before making such contribution to ensure that contribution will be eligible and deductible and that any regulatory requirements are considered.

3.6 Excess Surplus

The ITA prescribes the maximum going concern surplus (before contingency reserves) that may be retained by the Plan while employer contributions continue. In general, this maximum is defined as 25% of the going concern actuarial liability allocated to the employer.

As at the valuation date, the Plan does not have an excess surplus, therefore employer contributions are not affected by the prescribed maximum surplus limit.

3.7 Subsequent Events

Subsequent events are events that transpire after the calculation date and before the date of this report. Subsequent events also include events that, as of the report date, are fully committed to occur in the future. The Employer has confirmed that there are no subsequent events that would materially affect the valuation results beyond those that have been noted in Section 2 above.

The impact of experience between the valuation date and the date of this valuation report differing from the actuarial assumptions will be determined at the next valuation.

3.8 Solvency Ratio

The Solvency Ratio is the ratio of the solvency assets to the solvency liabilities. If the Solvency Ratio is less than 1.0, certain conditions and restrictions, as prescribed by the Act, must be applied to the commutation of benefits from the Plan. Transfer values may be paid in full if the Company makes additional special payments to the Plan to cover the portion of the transfer value above the Solvency Ratio. As at January 1, 2020, the Solvency Ratio is less than 1.0, therefore an additional special payment must be remitted to the Plan at the time of transfer in order for transfer values to be paid in full. Otherwise, the transfer deficiency with interest will be transferred on the earlier of five years from the date of determination and the date on which the solvency ratio is determined to be 1.0.

3.9 Next Required Valuation

Subsection 12(2) of the Act and section 2 of the Directives require that the effective date of the next valuation is within one year from the valuation date, unless the solvency ratio is 1.20 or greater. Since the solvency ratio of the Plan is below 1.20, the effective date of the next valuation must be no later than January 1, 2021.



3.10 Actuarial Opinion

Yukon Energy Corporation Employees' Pension Plan
Office of the Superintendent of Financial Institutions Registration Number: 56997
Canada Revenue Agency Registration Number: 1041011

We have prepared an actuarial valuation for the Plan as at January 1, 2020. In conducting the valuation, we have used the membership data, the custodial statements of the fund provided by Canada Life, and the actuarial methods and assumptions described in this report.

In our opinion, for the purposes of this report:

1. The data on which the valuation is based are sufficient and reliable;
2. The assumptions are appropriate; and
3. The methods employed in the valuation are appropriate.

We hereby certify that, in our opinion, as at January 1, 2020:

1. The Plan is not fully funded on going-concern basis. The actuarial liability exceeds the actuarial value of assets by \$2,408,500. As such, there is no excess surplus in the Plan.
2. The Plan's liabilities would have exceeded the Plan's assets by \$496,500 if the Plan had been wound up as at January 1, 2020. The solvency ratio is 97.6%.
3. The average solvency ratio is 100.3% and the Plan has a solvency excess of \$61,000 as at January 1, 2020.
4. The total annual employer contributions of \$369,400, payable monthly, are required to fund the cost of the current year's benefits and non-investment expenses for 2020. The estimated 2020 required employee contributions are \$46,500. The employer current service cost is equivalent to 794% of required employee contributions.
5. The special payments required to fund the going concern unfunded liability in 2020 are \$259,300. Since there is no solvency deficiency, there are no additional solvency special payments required.
6. The Employer contributions recommended in this report are eligible contributions under Section 147.2(2) of the *Income Tax Act (Canada)*.
7. Our valuation took into account all significant subsequent events from January 1, 2020 up to the date of our report, as reported herein. We are not aware of any other such events that could have a significant impact on the financial position of the Plan.
8. The next actuarial valuation should be conducted with a valuation date no later than January 1, 2021.



The content herein has been prepared exclusively from a financial viewpoint. This report does not constitute a legal opinion on the rights and duties of the plan administrator, the Employer or the members concerning the Plan.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada and in accordance with applicable legislation.

Actuarial valuation results are estimates only and are based on assumptions and methods developed in accordance with actuarial standards of practice. Emerging experience differing from the assumptions will result in experience gains and losses that will be revealed in future valuations.

A handwritten signature in dark ink, appearing to read "Tom Kowalczyk", with a long, sweeping horizontal stroke at the end.

Tom Kowalczyk
Fellow, Canadian Institute of Actuaries

A handwritten signature in dark ink, appearing to read "Rory O'Connor", with a stylized, cursive script.

Rory O'Connor
Fellow, Canadian Institute of Actuaries

George & Bell Consulting Inc.
June 26, 2020



4. Assets and Liabilities

The following tables provide additional details of the assets and the liabilities of the Plan.

4.1 Plan Assets - Going-Concern Basis

The value of the assets used for this valuation is as follows:

	January 1, 2019	January 1, 2020
	\$	\$
Market value of assets	17,322,600	19,952,700
Smoothing adjustment	584,300	(1,056,500)
Smoothed value of assets (1. + 2.)	17,906,900	18,896,200

An analysis of the change in the market value of the assets is given in Appendix C.4. The development of the smoothing adjustment is shown in Appendix C.5.

4.2 Details of Plan's Funded Status - Going-Concern Basis

The following table shows details of the Plan's funded status on a going-concern basis, including the actuarial liabilities for the different categories of members.

	January 1, 2019	January 1, 2020
Going Concern	\$	\$
Actuarial value of assets	17,906,900	18,896,200
Actuarial liability		
Active members	7,869,600	9,127,800
Retired members	11,121,900	11,495,700
Deferred members	385,400	445,100
Flex contributions	195,000	236,100
Total	19,571,900	21,304,700
Funding deficiency	(1,665,000)	(2,408,500)
Funded ratio	91.5%	88.7%



4.3 Details of Plan's Funded Status - Solvency Basis

The solvency valuation is prescribed by the Act to measure the funded status of the Plan should it wind up on the valuation date. A hypothetical wind-up valuation measures the same funded status, with minor differences, and is required under accepted actuarial practice. Since all benefits have been valued under this solvency valuation and assuming that the asset liquidation value would be equal to the market value of assets, the hypothetical wind-up funded status would be the same as the solvency funded status shown below.

The following table shows details of the Plan's funded status on a solvency basis.

Solvency	January 1, 2019	January 1, 2020
	\$	\$
Plan assets		
Market value of assets	17,322,600	19,952,700
Estimated expenses on plan wind-up	(130,000)	(130,000)
Total hypothetical wind-up / solvency assets	17,192,600	19,822,700
Hypothetical wind-up / Solvency liabilities		
Active members	6,130,100	7,622,800
Retired members	11,208,900	11,858,400
Deferred members	511,800	601,900
Flex contributions	195,000	236,100
Total	18,045,800	20,319,200
Hypothetical wind-up surplus / (deficiency)	(853,200)	(496,500)
Solvency ratio	95.3%	97.6%
Average solvency ratio	101.7%	100.3%
Excess / (Solvency deficiency)	306,800	61,000

The hypothetical wind-up and solvency liabilities have been determined in accordance with a Plan wind-up scenario assuming no indexing would be provided to any Plan member (indexing is provided at the Plan sponsor's discretion).

The incremental cost of the solvency liabilities over the next year is estimated to be \$994,500.



4.4 Details of Solvency Excess (Deficiency)

The Average Solvency Ratio under the Regulations to the Act has been determined using the solvency ratios as at the valuation date and the two prior valuation dates.

The solvency ratios at the two prior valuation dates have been adjusted to increase the solvency assets by an amount not in excess of the present value of special payments made to the Plan in respect of the period between January 1, 2018 and January 1, 2020.

The average solvency ratio, adjusted solvency asset amount and solvency excess (deficiency) are determined as follows:

	January 1, 2018	January 1, 2019	January 1, 2020
	\$	\$	\$
Solvency assets	18,064,700	17,192,600	19,822,700
Present value of:			
Special payments made in 2018	146,100	0	0
Special payments made in 2019	181,600	182,000	0
Adjusted solvency assets	18,392,400	17,374,600	19,822,700
Solvency liabilities	17,159,700	18,045,800	20,319,200
Adjusted solvency ratio	107.2%	96.3%	97.6%
Average solvency ratio			100.3%
Solvency excess (deficiency)			61,000

4.5 Solvency Liability Sensitivity

We have determined that if the solvency discount rate was reduced by 1% in both the calculation of lump sum values and annuity values, the solvency liabilities would increase by \$3.2 million, or 15.9%.



5. Reconciliation of Funded Status

This section provides additional analysis of the results, including the changes in the funded status during the inter-valuation period.

5.1 Reconciliation of Funded Status - Going Concern Basis

The following table reconciles the unfunded liability at the previous valuation with the unfunded liability at this valuation.

Reconciliation of financial position		\$
Unfunded liability at January 1, 2019		(1,665,000)
Special payments and employer contributions in excess of annual cost		254,300
Interest		(113,800)
Expected funding excess at January 1, 2020		(1,524,500)
Plan experience		260,700
Gains and losses on assumption/method changes		
Discount rate		(1,144,700)
Unfunded liability at January 1, 2020		(2,408,500)

The Plan had a net experience gain of \$260,700 in the inter-valuation period because of experience differing from that assumed in the previous valuation. The analysis of the experience is given in Section 5.2.



5.2 Analysis of Experience

The preparation of an actuarial valuation requires the actuary to make assumptions about future economic and plan experience. When the actual experience deviates from the expected experience, the Plan has an experience gain or loss.

The following table shows the main sources of the experience gains and losses noted in Section 5.1.

Experience gains and losses	\$
Market value of investment experience	1,833,800
Gain/(loss) due to asset smoothing method	(1,640,800)
Salary increases less (greater) than expected	124,300
Data Corrections	(58,600)
Indexing less (greater) than assumed	24,500
Expenses less (greater) than assumed	27,000
Mortality	(49,000)
Miscellaneous	(500)
Total	260,700

5.3 Reconciliation of Current Service Cost

The following table reconciles the current service cost at the previous valuation with that at the current valuation.

Reconciliation of Current Service Cost (as % of employee contributions)	
2019 current service cost	733%
Change in demographics	14%
Change in discount rate	47%
2020 current service cost	794%



5.4 Provision for Adverse Deviation and Future Expenses

The going concern liabilities and normal cost were determined using a discount rate net of investment expenses and a margin for adverse deviation. As a result, the liabilities and normal cost figures include amounts attributed to future investment expenses and a margin. In addition, an allowance for non-investment expenses is included in the normal cost. The present value of those amounts at January 1, 2020 is summarized in the following table.

		Present value in liability \$	Present value in normal cost \$
Margin for adverse deviation	Inherent in discount rate - 0.3%	868,000	17,000
Investment expenses – passive	Inherent in discount rate - 0.1%	296,000	6,000
Investment expenses – active	Inherent in discount rate - 0.4%	1,145,000	23,000
Non-investment expenses	\$65,000 per year	n/a	65,000



6. Stress Testing and Sensitivity

Accepted actuarial practice requires the disclosure of certain sensitivity results as well as the consideration of plausible adverse scenarios and their impact on the plan's funded status and current service cost.

6.1 Asset-Liability Mismatch: Interest/Discount Rate Sensitivity

As the assumed discount rate has a significant impact on the Plan's going concern liabilities, accepted actuarial practice requires that the impact on the going concern liabilities and current service cost of a 1.0% decrease in the assumed discount rate be disclosed.

The following table illustrates the effect of an immediate 1.0% decrease in future return expectations leading to a 1.0% decrease in the discount rate. The effect of this change on fixed income assets has also been included (as such a change would mean that fixed income yields would have decreased by 1.0% resulting in an immediate capital gain on the Plan's fixed income assets).

	Current Interest & Discount Rate	Interest Rate & Discount Rate 1% Lower	Percentage Change
Actuarial value of assets	18,896,200	19,108,700	1.1%
Actuarial liability	21,304,700	24,652,900	15.7%
Actuarial excess (unfunded liability)	(2,408,500)	(5,544,200)	
Funded ratio	88.7%	77.5%	
Current service cost	369,400	437,100	18.3%



6.2 Asset-Liability Mismatch: Deterioration of Asset Values

Investment policy may create an asset-liability mismatch should one asset class not produce the actual returns necessary to match the liabilities.

The following table shows the effect on the Plan's funded status of an immediate 20% decrease in the Plan's non-fixed income assets as at December 31, 2019:

	Current Status	Immediate 20% Drop in Non-Fixed Income Assets	Percentage Change
Actuarial value of assets	18,896,200	18,413,100	(2.6%)
Actuarial liability	21,304,700	21,304,700	0.0%
Actuarial excess (unfunded liability)	(2,408,500)	(2,891,600)	
Funded ratio	88.7%	86.4%	
Current service cost	369,400	369,400	0.0%

6.3 Demographic Experience: Increased Longevity

This stress test offsets the mortality rates applicable to each member by one year, extending their life expectancy. The timing of all other decrements was unchanged.

The following table shows the effect this increased longevity has on the Plan's funded status and current service cost:

	Current Longevity	Increased Longevity	Percentage Change
Actuarial value of assets	18,896,200	18,896,200	0.0%
Actuarial liability	21,304,700	21,771,800	2.2%
Actuarial excess (unfunded liability)	(2,408,500)	(2,875,600)	
Funded ratio	88.7%	86.8%	
Current service cost	369,400	376,100	1.8%



Appendix A - Plan Provisions

This summary contains the main provisions of the Plan as at the valuation date. For a complete description, reference should be made to the Plan text.

Background	The Plan became effective December 1, 1997 to replace the Retirement Plan for Employees of Canadian Utilities Limited and Participating Companies Plan 2 ("CU Plan") for employees of Yukon Energy. The provisions are identical to those of the CU Plan. Prior to January 1998, certain employees of Yukon Electrical Company Limited were given the choice to become employees of Yukon Energy effective January 1, 1998. The pension credits earned by these transferring employees under the CU Plan up to January 1, 1998 were transferred to the Plan together with assets to cover the pension credits transferred. Employees who transferred employment from the Yukon Electrical Company Limited to Yukon Energy joined the Plan effective January 1, 1998. The assets were transferred from the CU Plan to the Plan in December 1999. Effective January 1, 2002, the Plan was closed to employees hired on or after December 31, 2001. These employees will participate in the company Group RRSP. Active participants in the Plan have the option to transfer to the Group RRSP at any time.
Eligibility for Membership	Permanent full-time and part-time employees are eligible to join the Plan on the first of the month coinciding with or following the date of hire. Employees hired after December 31, 2001 are not eligible to join the Plan.
Continuous Service	The Period of an employee's uninterrupted employment with the Company, beginning with the date of employment. Includes Continuous Service under the CU Plan for employees who transferred from the CU Plan on January 1, 1998.
Pensionable Service	Expressed in years and completed months. Period of Continuous Service during which an employee made contributions to the Plan. Includes service transferred from the CU Plan as at January 1, 1998. Pensionable Service is pro-rated for part-time employees.
Pensionable Age	The earliest age at which a pension benefit is payable to the member under the terms of the plan without consent of the administrator and without reduction by reason of early retirement. Pensionable age is age 65.
Employee Contributions	Members are required to contribute 3.5% of earnings up to the Year's Maximum Pensionable Earnings (YMPE) plus 5% of earnings above the YMPE. Permanent part-time members will have required contributions as above multiplied by their permanent part-time service ratio. As part of the flex plan provision, employees can make additional contributions to purchase ancillary benefits on a cost-neutral basis to the Plan. Members choose the ancillary benefit on termination of service or on retirement.
Company Contributions	The Company pays the balance of the cost of the Plan over the employee contributions, as determined by the actuary.



Retirement Dates	Normal Retirement Date - The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date - A member may retire without company consent starting at age 55. With Company consent, a member may retire starting at the earlier of age 55 and the date the member's age and service sum to 90. Postponed Retirement Date - A member who remains employed with the Company after age 65 continues to make pension contributions and accrue benefits under the Plan up to the earlier of his actual retirement and age 71.																		
Normal Retirement Pension	An annual pension for each year of Pensionable Service of: 1.4% of final average earnings up to the final average YMPE plus 2% of final average earnings in excess of the final average YMPE. Final average earnings are the annual average of the highest five years of pensionable earnings. Pensionable earnings are an employee's basic earnings, excluding northern allowance. Final average YMPE is the annual average of the YMPE's over the same period used to calculate the final average earnings. In addition, members may purchase ancillary benefits with their flex contribution balances upon retirement, termination or death.																		
Early Retirement Pension	If a member retires from active service with Company consent, the pension payable will be reduced as follows: - If age and service sum to 90 years or more, no reduction applies; - Reduced by the following percentages (but no more than an actuarial equivalent reduction), if age and service are less than 90: <table> <tr> <th><u>Age</u></th><th><u>Reduction</u></th></tr> <tr> <td>62-64</td><td>0%</td></tr> <tr> <td>61</td><td>3%</td></tr> <tr> <td>60</td><td>6%</td></tr> <tr> <td>59</td><td>12%</td></tr> <tr> <td>58</td><td>18%</td></tr> <tr> <td>57</td><td>24%</td></tr> <tr> <td>56</td><td>30%</td></tr> <tr> <td>55</td><td>36%</td></tr> </table> If retirement is not from active service, or if Company consent for retirement was not obtained, an actuarial equivalent reduction from normal retirement date applies instead of the foregoing rules.	<u>Age</u>	<u>Reduction</u>	62-64	0%	61	3%	60	6%	59	12%	58	18%	57	24%	56	30%	55	36%
<u>Age</u>	<u>Reduction</u>																		
62-64	0%																		
61	3%																		
60	6%																		
59	12%																		
58	18%																		
57	24%																		
56	30%																		
55	36%																		
Normal Form of Pension	If the member has an eligible spouse at the earlier of retirement or termination, 60% of the retired member's pension continues to the surviving spouse. Otherwise, the pension is payable for the lifetime of the retired member, with a guarantee that pension payments will be at least equal to the member's contributions with interest. There is no reduction to the initial pension amount for a member with an eligible spouse to reflect the value of the spousal benefit.																		



Death before Retirement	Commutated value of the member's pension, plus refund of contributions with interest, which exceed 50% of the commuted value of the member's pension.
Disability	Prior to January 1, 2008, a disabled member continued to accrue pensionable service and was not required to contribute to the plan. Effective January 1, 2008, a disabled member continues to accrue pensionable service provided he makes contributions during the period of disability. During a period which a disabled member accrues pensionable service, pensionable earnings is equal to his earnings rate immediately prior to becoming disabled and increased annually at 100% of the increase in the Consumer Price Index to a maximum of 3.0% per annum.
Termination Benefits	A deferred lifetime pension, based on the member's Pensionable Earnings, contributions and credited service up to the date of termination. If the member's contributions, plus interest, exceed 50% of the commuted value of the deferred pension, then the excess contributions are retained in the Plan, accumulated with interest, and used to provide additional benefits at retirement. Deferred pensions are payable commencing at age 65. However, a member may elect to receive an actuarially reduced early retirement pension as early as age 55. Alternatively, a terminated member who is entitled to a deferred pension (including the pension in respect of any excess contributions) may, prior to his attainment of age 55, elect to transfer the commuted value of his benefits to another locked-in vehicle, such as a locked-in RRSP or LIRA.
Credited Interest	Member contributions are credited with interest at a rate based on the average of Canadian chartered banks' 5-year Personal Fixed Term deposit rates.
Indexing	Pensions payable to members (including deferred vested members) are indexed only after the normal retirement date. Pensions payable to members who retire prior to the normal retirement date with Company consent are indexed after pension commencement. The indexing adjustment is determined annually at each January 1 st by the Company, based on changes in the Consumer Price Index, subject to a maximum of 3% per year.
Maximum Pension Limit	The annual pension amount payable at retirement, excluding additional amounts due to any voluntary contributions, to a member is subject to the limitations under the Income Tax Act (Canada) and Regulations.



Appendix B - Plan Membership

B.1 Source of Data

In performing the calculations, we obtained data as at January 1, 2020 from the Employer, including active members, pensioners and deferred pensioners. We have reviewed the data to ensure its completeness, accuracy and consistency with the data used in the previous valuation. Specific tests include:

- A member by member reconciliation of the membership group from the previous valuation to this valuation date;
- A reconciliation of birth, hire, and participation dates against the corresponding dates provided for the last valuation to ensure consistency of data;
- A reconciliation of credited service against the corresponding amount provided for the last valuation;
- A reconciliation of pensionable earnings against the corresponding amounts provided for the last valuation to identify any unusual increases or decreases;
- The accrued pension amounts for terminated members and pensioners were reconciled with corresponding data from the previous valuation;
- A reconciliation of any stated benefit payments in the inter-valuation period for retired, terminated or deceased members against the financial statements of the pension fund.

There was no information missing from the data, so no assumptions were required with respect to such data. The results of our tests were satisfactory and, in our opinion, the membership data are sufficient and reliable for the purposes of the valuation.

B.2 Summary of Membership Data

The following tables summarize the key characteristics of the Plan membership as of the calculation date.

Number of Members	January 1, 2019	January 1, 2020
Active Members	9	9
Inactive Member – working, not accruing future service	0	0
Terminated Members with deferred pension	4	4
Retired Members (including beneficiaries)	23	23
Total	36	36



B.3 Changes in Plan Membership

The following table shows the changes in the Plan's membership since the previous valuation:

	Active	Retired, including beneficiaries	Deferred pensioners
Members at January 1, 2019	9	23	4
Retirements	0	0	0
Deaths	0	0	0
Terminations	0	0	0
Members at January 1, 2020	9	23	4

B.4 Members - Details

	January 1, 2019	January 1, 2020
Active Members		
Number	9	9
Average age (years)	54.9	55.9
Average years of pensionable service	24.8	25.8
Average compensation for the following year	\$121,500	\$123,300
Proportion female	11.1%	11.1%
Deferred Members		
Number	4	4
Average age (years)	53.2	54.2
Average annual pension	\$10,700	\$10,700
Proportion female	25%	25%
Retired Members / Beneficiaries		
Number	23	23
Number with bridge pensions	3	3
Average age	67.0	68.0
Average annual lifetime pension	\$28,500	\$29,000
Average annual bridge pension	\$1,400	\$1,400
Proportion female	26.1%	26.1%



Appendix C - Plan Assets

C.1 Source of Plan Asset Information

The assets of the Plan are held in an insurance company policy with Canada Life and are managed by a number of different investment managers. This type of arrangement governs only the investment of the assets deposited into the fund and in no way guarantees the benefits provided under the Plan or the costs of providing such benefits. In performing the actuarial valuation and preparing the following summaries, we have relied on Canada Life's unaudited financial statements of the fund, and on other information provided by the Employer including the detailed contributions and expenses of the Plan during the inter-valuation period.

We have tested the asset value and have reconciled it with the value at the previous valuation. We have also examined the benefits paid from the fund and tested the amounts against the membership data, and the consistency of the investment earnings with the fund's asset mix and market rates of return in the inter-valuation period.

The results of our tests were satisfactory and, in our opinion, the asset data are sufficient and reliable for the purposes of the valuation.

C.2 Composition of Assets and Asset Mix

The Plan had invested assets (rounded) as of the current and previous valuations as follows:

	January 1, 2019		January 1, 2020	
	\$	\$	%	%
Universe Bonds	1,675,200	9.7%	1,696,900	8.5%
Long Bonds	5,468,200	31.5%	6,173,900	30.9%
Canadian Equities	3,889,100	22.4%	4,646,200	23.3%
U.S. Equities	2,282,700	13.2%	2,815,500	14.1%
International Equities	2,139,200	12.4%	2,590,900	13.0%
Real Estate	1,872,300	10.8%	2,029,600	10.2%
Invested Assets	17,326,700	100.0%	19,953,000	100.0%
Contributions receivable	0		(300)	
Benefits payable	(200)		0	
Expenses payable	(3,900)		0	
Market Value of Assets	17,322,600		19,952,700	



C.3 Investment Policy Asset Mix

The Statement of Investment Policies and Procedures outlines the long-term target asset mix by market value as follows:

	Target
Long Bonds	40.0%
Canadian Equities	25.0%
U.S. Equities	12.5%
International Equities	12.5%
Real Estate	10.0%

The Plan's assets are automatically rebalanced quarterly when allocation to any asset class is not within 2.5% of target.

C.4 Changes to the Plan Assets

The following table shows the changes to the assets, by market value, from the previous valuation date to this valuation date. The amounts were taken from the plan's fund statements, and include amounts receivable/payable, if any.

	\$
January 1, 2019	17,322,600
PLUS	
Company contributions	
current service	349,300
special payments	231,300
Member contributions	47,700
Flex contributions	10,100
Investment income	2,812,200
	<u>3,450,600</u>
LESS	
Pensions paid	688,300
Lump-sum refunds	0
Non-investment expenses	38,000
Investment expenses	94,200
	<u>820,500</u>
December 31, 2019	19,952,700
Gross rate of return	16.3%
Rate of return net of expenses	15.5%



C.5 Actuarial Value of Assets

As described in Appendix D, the actuarial value of assets is determined by modifying the adjusted market value of assets to recognize asset gains (losses) (i.e., the difference between actual investment return and expected investment return based on the valuation discount rate assumptions) over a 5-year period.

The smoothed value of the assets, including amounts receivable/payable, is derived as follows:

	Year	Multiplier	\$
Adjusted Market Value of Assets			19,952,700
Less			
Unrecognized investment gains losses	2019	1,854,100 x 80%	1,483,300
	2018	(1,282,000) x 60%	(769,200)
	2017	601,400 x 40%	240,600
	2016	509,000 x 20%	101,800
			1,056,500
Preliminary smoothed value of assets			18,896,200
90% of market value of assets			17,957,400
110% of market value of assets			21,948,000
Adjusted smoothed value of assets			18,896,200



Appendix D - Actuarial Methods

D.1 Components of the Minimum Required Contribution

The minimum required Employer contribution consists of three components:

- the current service cost, for service in the year following the valuation date;
- an amount to liquidate the unfunded liability, if any, on a going-concern basis; and
- an amount to liquidate the solvency deficiency, if any, on a solvency basis.

The value of the current service cost, the actuarial liability on both the going-concern and solvency basis, the value of the assets on the going-concern and the solvency basis, depend on the methods used in the valuation.

D.2 Actuarial Cost Method - Going-Concern Basis

As in the previous valuation, we have used the projected unit credit method to determine the actuarial liability and the current service cost of the Plan on the going-concern basis. Under this method, the actuarial liability is the present value of benefits earned for credited service up to the valuation date, based on pensionable earnings projected to retirement. The current service cost is the present value of benefits being earned for service in the year following the valuation date, based on projected earnings. The actuarial liability for the flex plan provision was taken to be the accumulated flex plan contributions with interest.

When calculating the actuarial present value of benefits at the valuation date, the present value of all retirement, withdrawal and pre-retirement death benefits are included. For each member, the retirement, withdrawal and pre-retirement death benefits for a particular period of service are first projected each year into the future taking into account early retirement entitlements and minimum pension entitlements. These projected benefits for each future year are then multiplied by the probability of the member leaving the Plan in that year and discounted with interest and survivorship to the valuation date. The actuarial present value of benefits for the particular period of service is then determined by summing the present values of these projected benefits.

As the Plan is now closed to new members, the average age of the active members will tend to increase over time. If all other things being equal, the current service cost will likely increase as a percentage of members' required contributions over time, although the dollar amount of current service cost will probably decline as the membership falls.

An actuarial excess is the excess of the actuarial value of assets over the actuarial liability; an unfunded liability is the excess of the actuarial liability over the actuarial value of assets, as the case may be.



D.3 Actuarial Cost Method - Solvency Basis

We have used the accrued benefit method to determine the solvency liability. Under this method, we have estimated the amount of accrued benefits earned by each member as of the valuation date, and determined the actuarial present value of those benefits as of the valuation date as if the Plan had been wound up on that date.

We have calculated the liabilities as if the plan was terminated on the valuation date and the Employer exercised its discretion to determine the amount of future post-retirement indexing adjustment to be nil. The liability for the flex plan provision was taken to be the accumulated flex contributions with interest.

This valuation method is the same as the one used in the previous valuation. The actuarial assumptions used in the valuation are described in Appendix E.

D.4 Asset Valuation Methods

As in the previous valuation, the actuarial value of assets used in the going concern valuation has been determined by applying a smoothing methodology to the Plan's market value of assets at the valuation date.

Under this method, the actuarial value of the investment income for each year, net of investment expenses, is determined as the sum of the actuarially required net investment income on the market value of the assets plus an amortization adjustment. The actuarially required net investment income is determined as the amount of net investment income that results in a net rate of return on the market value of the assets equal to the assumed valuation discount rate for the year.

The amortization adjustment is determined by amortizing over a five-year period, the difference between the actual net investment income and the actuarially required net investment income.

The smoothed value is constrained to not fall outside the range of 90%-110% of the market value. The actuarial value of assets is also adjusted for contributions receivable and benefits and expenses payable as of the calculation date. The calculation is shown in Appendix C.

As in the previous valuation, the actuarial value of assets used in the solvency valuation was the market value of assets. The adjusted solvency asset amount is determined by multiplying the average solvency ratio by the amount of the solvency liabilities. The average solvency ratio, adjusted solvency asset amount and solvency excess/(deficiency) are determined in Section 4.4.

D.5 Margin for Adverse Deviation

We have included a margin for adverse deviation of 0.3% in the going-concern discount rate, as described in Appendix E, to provide a level of conservatism in the funding of the Plan. No margin for adverse deviation is included in the solvency valuation.



D.6 Incremental Cost on a Solvency Basis

The incremental cost represents the present value, at the beginning of each period shown (time t), of the expected aggregate change in the solvency liabilities between time t and time $t+1$, adjusted upwards for expected benefit payments between time t and time $t+1$.

The calculation methodology can be described as follows:

1. the present value at time t of expected benefit payments between time t and time $t+1$, discounted to time t ; plus
2. the projected solvency liabilities at time $t+1$, discounted to time t , allowing for, if applicable to the pension plan being valued:
 - expected decrements and related changes in membership status between time t and time $t+1$,
 - accrual of service to time $t+1$,
 - expected changes in benefits to time $t+1$, and
 - a projection of pensionable earnings to time $t+1$; less
3. the solvency liabilities at time t .

The actuarial assumptions used to calculate the incremental cost can be described as follows:

- The assumptions for expected benefit payments in item 1. above and decrement probabilities, service accruals, and projected changes in benefits and pensionable earnings in the item 2. above are consistent with the assumptions used in the Plan's going concern valuation.
- The assumptions used to calculate the projected solvency liabilities at time $t+1$ would generally be consistent with the assumptions for the solvency liabilities at time t , assuming that discount rates remain at the levels applicable at time t , that the select period is reset at time t for discount rate assumptions that are select and ultimate, and that the Standards of Practice for the calculation of commuted values and the guidance for estimated annuity purchase costs in effect at time t remain in effect at time $t+1$.
- No new entrants are considered in calculating the incremental cost.



Appendix E - Actuarial Assumptions

In preparing the valuation, we used the following assumptions as estimates of future conditions that will affect the Plan.

The solvency valuation assumptions correspond to those prescribed by the applicable legislation.

Emerging experience, differing from the assumptions, will result in gains or losses, which will be revealed in future valuations.



E.1 Assumptions Used in the Going-Concern Valuation

The going concern valuation is based on the assumption that the pension plan will continue to operate indefinitely into the future. We have made the following assumptions in the going concern valuation.

At each valuation, the past experience is compared to the assumptions made at the previous valuation to determine if, together with expectations of future trends, the assumptions should be changed. The experience gains and losses since the previous valuation are quantified and summarized in Section 5.2.

Going Concern Assumptions	January 1, 2019	January 1, 2020
Discount rate	5.0%	4.6%
Annual increase in general wages for Canada	2.8% per year	No change
Salary increases due to merit and promotion	See table below	See table below
Inflation rate	2.0% per year	No change
Increase in the Income Tax Act maximum pension	2.8% per year	No change
Retirement	Retire when age plus service reaches 90 points, but not later than age 65. All active members are assumed to retire with Company consent	No change
Mortality	CPM2014 Private table projected using Scale MI-2017; rates applied to post retirement only	No change
Withdrawal	No allowance	No change
Disability	No allowance	No change
Family composition	Current marital status; female spouse 4 years younger than male spouse if spousal age unknown	No change
Non-investment expenses	\$65,000 per year	No change
Interest on member contributions	2.2% per year	No change

Economic assumptions

Discount rate – The primary economic assumption used in the going concern valuation is the discount rate, which is the rate of return that the assets are expected to earn over the long term, net of investment management expenses and a margin for adverse deviation. In this valuation, we have used a discount rate of 4.6% in the going concern valuation, determined as follows.



Derivation of Fund Rate of Return	Rate
Expected inflation	2.0%
Expected real return	2.8%
Value added for rebalancing/diversification	0.3%
Value added for active management	0.3%
Expected investment expenses	
Active investment management fees	(0.4%)
Passive investment management fees	(0.1%)
Non-investment fees	n/a
Margin for adverse deviation	(0.3%)
Discount rate	4.6%

In deriving the discount rate, we have assumed that the assets would be invested according to the Plan's investment policy.

Referring to the Bank of Canada's monetary policy, the inflation target is at 2.0% per year, the midpoint of the 1% to 3% inflation-control target range. Given this policy, historical inflation in Canada, and market expectations, an expected rate of inflation of 2.0% has been used.

The expected returns for the fund were estimated using our expected returns for applicable asset classes taking into account the target asset mix as outlined under the Plan's investment policy. Return assumptions for all asset classes are based on long-term expectations of at least 25 years.

The frequency of rebalancing the fund's weight in each asset class to its target in the investment policy, the weights themselves, and the time horizon, will all have an effect on the long-term return. The long-term return is also influenced by the diversification of the fund. The expected effect of rebalancing and diversification on the fund's return was estimated on the basis of a log-normal distribution.

Wage increases due to Merit and Promotion – As in the previous valuation, we have assumed that members would receive wage increases based on merit and promotion (in addition to the general wage increases assumption). Sample rates at select ages are as follows:

Age	Rate
45	0.77%
50	0.47%
55	0.36%
60	0.24%



Interest on Member Contributions – Interest is assumed to be credited on member contributions at 2.2% per year.

Non-investment Expenses – An explicit provision for non-investment expenses expected to be paid from the pension fund has been made by adding \$65,000 to the current service cost, based on recent experience and future expectation.

Investment Expenses – It is assumed that future total investment expenses will be 0.5% of assets based on recent experience.

The goal of active management is to outperform the applicable benchmark index, after reduction for additional expenses. We expect for this portfolio that expenses for passive investment management would be approximately 0.1%. For the purpose of this valuation, it is assumed that additional returns due to active management will be 0.3%.

Benefit subject to consent – Assumed all members are granted consent for retirement and each year inflationary adjustments are made to pensions for eligible pensioners.

Demographic assumptions

Mortality (post retirement) – For the current valuation we used the 2014 Canadian Pensioner Mortality (CPM) Private Sector Table projected using improvement scale MI-2017. The incidence of pre-retirement mortality is assumed to be nil.

Retirement – We have assumed that members will retire and commence receiving their pensions at their earliest unreduced retirement date assuming that the necessary consent is obtained (the earlier of age 65 or when age plus service reaches 90 points).

Termination of Membership – No allowance has been made for termination of employment prior to retirement due to plan experience and on the basis that the impact of including such an assumption would not have a material impact on the valuation results.

Disability – No allowance has been made for disability on the basis that the impact of including such an assumption would not have a material impact on the valuation results.

Family Composition – Current marital status is used and male spouses are assumed to be 4 years older than female spouses if spouse's age is unknown.



E.2 Assumptions Used in Solvency Valuation

The solvency valuation is prescribed by the Act and is intended to determine the funded status of the Plan had it been terminated and wound up on the valuation date, but with certain differences and adjustments as required under legislation.

The benefits payable are determined as of the valuation date, without allowance for future salary escalation, and are assumed to be settled at that time. Active members at the valuation date who are eligible to retire are assumed to retire immediately with Employer consent; this assumption maximizes the value of benefits and reflects current Employer practice.

Solvency Assumptions	January 1, 2019	January 1, 2020
Discount rate		
Transfer value basis	2.8% per year for 10 years; 3.2% per year thereafter	2.5% per year for 10 years; 2.6% per year thereafter
Annuity purchase basis	3.2% per year	2.6% per year
Increase in the Income Tax Act maximum pension limit	2.8% per year	No change
Mortality table	CPM2014 Combined Table with generational improvements using scale B (sex distinct rates)	No change
Termination rates	Not applicable	No change
Retirement age	Immediate if over age 55 or with 90 points, deferred to 65 otherwise	No change
Percent of liability assumed to be settled by purchase of annuity	50% of all active and deferred members, 100% of retired members	No change
Percent of liability assumed to be settled by lump sum transfer	50% of all active and deferred members, 0% of retired members	No change
Family composition	Current marital status; female spouse 4 years younger than male spouse if spousal age unknown	No change
Windup expenses	\$130,000	No change

In performing the solvency valuation, we assumed that annuities would be purchased for all of the pensioners, and that 50% of all active and deferred members would choose to receive an annuity and 50% would choose to receive a lump sum. We have assumed that if a member chooses an annuity, it would be payable immediately if the member is eligible for an immediate pension, otherwise at age 65.

The discount rates and mortality tables for immediate and deferred annuity purchases are the rates implicit in the price of group annuities as at January 1, 2020, as determined by the Canadian



Institute of Actuaries in their Guidance for Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates between December 31, 2019 and December 30, 2020.

The duration of the liabilities expected to be settled by annuity purchase is 13 years.

The discount rates used to calculate the value of lump sum payments are the applicable rates as at January 1, 2020, determined in accordance with the Canadian Institute of Actuaries' Standards of Practice. These rates are 2.5% per year for 10 years, then 2.6% per year; the mortality table is the CPM2014 Combined Table with generational improvements using scale CPM-B.

The weighted average on solvency liabilities of the annuity purchase rate and the commuted value rate as at January 1, 2020 was 2.58%. The weighted average rates used in the prior two valuations are as follows and were used to calculate the special payments used to adjust prior solvency ratios:

Valuation Date	Valuation Weighted Solvency Rates
January 1, 2020	2.58% per year
January 1, 2019	3.12% per year
January 1, 2018	3.04% per year

Termination Scenario

The termination scenario used in the solvency and hypothetical wind-up valuation includes the following assumptions:

- Plan wind-up would not result from employer insolvency.
- All assets would be realized at their reported market value.
- Employment and membership in the Plan ceases on the valuation date.
- Active members not yet eligible to retire receive the termination benefit under the Plan.
- Active members already eligible to retire receive the retirement benefit under the Plan. Employer consent is granted for early retirement.
- Terminated vested members, retired members and beneficiaries receive the benefit to which they are entitled on the valuation date.
- Future post-retirement indexing adjustment is \$nil.

This approach is the one used in the last valuation.

We did not make any projections of salary or YMPE increases in the solvency valuation.

We have projected the ITA maximum pension limit to the date of retirement in the calculation of the solvency liabilities. The ITA maximum pension limit was projected using a rate of 2.8% per year. The previous valuation used the same increase rate.

We have assumed the cost of winding up the Plan would be \$130,000 and it includes expected expenses associated with operating the plan until all benefits are fully settled. It is assumed that all



benefits would be fully settled one year after the wind-up date. The same assumption was used in the previous valuation.

Finally, actual marital status was used and male spouses are assumed to be 4 years older than female spouses if spousal birth dates are unknown. The same assumption was used in the previous valuation.



Appendix F - Data Certificate

EMPLOYER CERTIFICATE OF DATA

I hereby certify that the data submitted to George & Bell Consulting Inc. for the purpose of completing the January 1, 2020 Funding Valuation, the 2019 year-end calculations and producing annual member statements as at December 31, 2019 for the Yukon Energy Corporation Employees' Pension Plan is, to the best of my knowledge, accurate and complete. The data provided includes, for each individual, 2019 pensionable earnings, 2019 plan contributions and 2019 credited service. Any anomalies queried by George & Bell Consulting Inc. with regard to inconsistencies in age, service, earnings, or contributions have been confirmed or corrected.

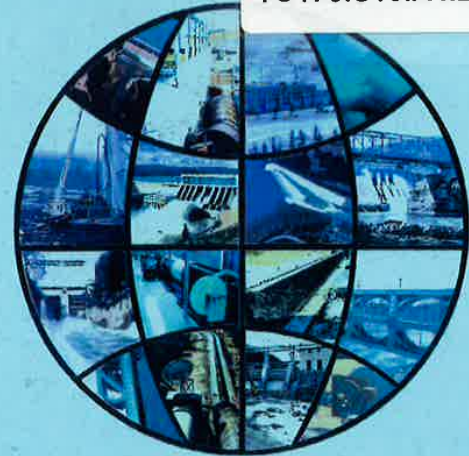
Date

June 24, 2020

A handwritten signature in blue ink, appearing to read "Ed Mollard", written over a horizontal line.

Ed Mollard
Chief Financial Officer
Yukon Energy Corporation

TC175.S10.A4.21



**YUKON ELECTRICAL COMPANY LIMITED
PMF STUDY FOR AISHIHIK LAKE**

September 1992

Prepared by

**Monenco Inc.
801 - 6th Avenue S.W.
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YEC 8375-3/7541

**YUKON ENERGY CORPORATION
LIBRARY
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1992-09-30
YEC 8375-3/7541

The Yukon Electrical Company Limited
First Avenue and Elliott Street
Box 4190
Whitehorse, Y.T.
Y1A 3T4

Attention: Mr. J.W. Murray, P.Eng.
Supervising Engineer

Dear Sir:

Re: PMF STUDY FOR AISHIHIK LAKE

In accordance with YECL's requirements for carrying out the Probable Maximum Flood (PMF) evaluation for Aishihik and Canyon Lakes, we are pleased to submit the report entitled "PMF Study for Aishihik Lake".

Yours truly,

R.J. Slopek, P.Eng.
Project Manager

RJS/hwl

Monenco Inc.
400 Monenco Place, 801 - 6th Avenue S.W., Calgary, Alberta Canada T2P 3W3
Tel: 403-298-4170 Fax: 403-298-4125 Telex: 063671029

EXECUTIVE SUMMARY

For the purpose of this study, a PMP/PMF analyses was undertaken to evaluate the development and its existing spill facilities.

The PMF analysis indicated that the peak inflow occurred during the July flood. However, the May PMF which contains snow melt runoff although producing a lower peak inflow provided a larger volume of inflow affecting peak reservoir elevations to a greater extent. The peak May PMF reservoir elevation under existing conditions assuming the culverts and timber crib structure were not operational was approximately 3011.6 ft. and 2989.1 ft. at Aishihik and Canyon Lakes, respectively. For the purpose of this evaluation it was assumed that the units were not operational. This results in overtopping of the low earthfill structures adjacent to the existing spillway at Aishihik Lake. A minimal amount of modifications are required to raise the low sections so that overtopping does not occur. The estimated cost for this work is approximately \$5300. It is recommended that the effects on structures located on Canyon Lake be evaluated.

In the event of an emergency such as a PMF it is considered that both the timber crib and the six culverts could be utilized. The peak May PMF reservoir elevations in this case would be approximately 3011.0 ft and 2990.2 ft at Aishihik and Canyon Lake, respectively.

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PART 3 - SUMMARY

REFERENCES

PART 1 - INTRODUCTION

1.0 INTRODUCTION

For the Aishihik project is located in southwest Yukon in the Aishihik basin, approximately ninety miles northwest of Whitehorse. The Aishihik basin covers an area of 1630 square miles, and its principal hydrographic feature consists of a series of elongated lakes which are connected by short channels and are eventually drained by the Aishihik River, an eighteen mile long tributary of the Dezadeash River.

The main lakes in the basin are Sekulmun, Aishihik and Canyon. Aishihik Lake, the largest of the series, is thirty-five miles long and on average less than two miles wide. Sekulmun flows into Aishihik Lake, which then flows into Canyon Lake.

The Aishihik River, which flows out of Canyon Lake, is the site of the hydroelectric development. The project utilizes most of the 625 foot difference in elevation between Canyon Lake and the confluence of the Aishihik and West Aishihik Rivers.

This study evaluates Probable Maximum Flood (PMF) inflows into Aishihik Lake. Control at Aishihik Lake is currently provided by a low head regulating dam, which was designed to regulate Aishihik Lake down to Elevation 2993.5 ft. There are also six 4 ft diameter culverts and a timber crib sluice structure located to the right of the regulating dam which in the event of an emergency, such as PMF, can be activated. For the purpose of this study the following two scenarios were studied:

1. low head regulating dam only;
2. low head regulating dam plus culverts and timber crib sluice.

In addition the discharges from Aishihik and local PMF inflows into Canyon Lake were evaluated.

PART 2 - HYDROLOGY

2.0 HYDROLOGY

2.1 PROBABLE MAXIMUM PRECIPITATION (PMP)

211 GENERAL

Data on major storm events in Yukon are inadequate for application of moisture maximization methods recommended for estimation of the Probable Maximum Precipitation by the World Meteorological Organization. The Hershfield relationship was employed as a first estimate, using data from existing statistical studies of maximum 24 hour rainfall at various stations surrounding Aishihik Lake. Results from this approach were compared with values determined in previous reports of PMP studies for neighbouring areas.

212 CLIMATOLOGICAL CONSIDERATIONS; SOURCES OF MOISTURE

Aishihik Lake watershed is located approximately 62 miles, north-west of Whitehorse, just east of the St. Elias Mountains. This mountain range protects Aishihik Lake from Pacific Ocean influences, thus making the climate in this area more continental. Chapter 9 of 'Climate of Yukon' (AES, 1987) provides a more detailed discussion of the precipitation trends across this area of the Yukon. It is worth noting here, however, that the slow moving 'cold low' phenomenon common to the prairie region of western Canada is also felt in Yukon. Such cold lows are best known for heavy rainfall over the foothills of the Rockies where upslope circulation may contribute to significantly higher precipitation amounts than occur on the prairies. Although prevailing upper winds in Yukon are generally westerly, winds from other quadrants in individual storms contribute to orographic precipitation. In fact, most of the highest precipitation amounts in the Yukon interior occur with upslope northerly or easterly winds associated with synoptic scale systems.

213 STATISTICAL ANALYSIS

The main source of data for the statistical analysis of maximum 24 hour rainfall is 'Climate of Yukon', (AES, 1987). Table 9.2 of this document presents expected annual maximum 24 hour rainfall (mm) for various return periods. This table was calculated using Gumbel distributions, with no values being given for return periods greater than twice the record length. Table 2.1.1 of the present report is an extract from that table for stations which are of interest in this study. Means and standard deviations were back-calculated on the basis of the known frequency factors used for Gumbel distributions. Using these means and standard deviations, the Hershfield relationship:

$$PMP_T = \text{Mean} + K_T (\text{std dev.}),$$

PART 2 - HYDROLOGY

and applying Hershfield's frequency factor for 24 hour PMP, i.e.

$$K_{24} = 19(10)^{-0.000965(\text{mean})},$$

the following values were calculated

<u>STATION</u>	<u>24 hour PMP</u>
Aishihik	210
Burwash	200
Carmacks	95
Haines Junction	287
Kluane	150
Whitehorse	133

Adjustments recommended by Hershfield to mean and standard deviations to make allowances for the maximum observed event at each location and record length were not undertaken, since, in general "the significance of these adjustments appears to be dwarfed by the magnitude of the frequency factors..." (Watt, 1989).

214 RESULTS FROM OTHER STUDIES (OR APPROACHES)

1. Hogg (1979, 1983) made a study of the Stikine River basin in which he proposed 24 hour point PMP's of 158 mm, using the Hershfield relationship, and 148 mm, using moisture maximization techniques. The point rainfall estimate by moisture maximization techniques incorporates an area reduction factor of 58 %.
2. From the "Rainfall Frequency Atlas for Canada" (AES, 1985), a PMP of 137 mm was estimated, by application of the Hershfield relationship with a mean of 19 mm and a standard deviation of 6.5 mm read from maps B-1 and B-2 of that report, respectively.
3. Miller (1963) presented an extensive study of probable maximum precipitation for Alaska. Extrapolation of the curves given in Figure 2.12 of Miller's report would suggest a 24 hour point PMP of 200 to 254 mm in the Aishihik Lake area.

215 CONSIDERATION GIVEN TO VARIOUS ESTIMATES

Due to relatively short record lengths, it is considered that sufficient confidence cannot be placed on results derived from 'Climate of Yukon' alone. The isolines of mean precipitation and standard deviation given in the 'Rainfall Frequency Atlas for Canada' also are based on limited data from the few stations in the region of interest and can only be considered to provide a rough estimate of the PMP. Hogg (1979, 1983) presented a comprehensive study for the Stikine area, which is South-East of

PART 2 - HYDROLOGY

Aishihik. He employed two methods which gave results that are in good agreement with each other. Miller's 1963 study of the PMP and rainfall frequency in Alaska can be used to interpret values for an area North to North-West of Aishihik. Due to the extensive nature of Miller's study these values are believed to be quite reliable. It is considered that a judicious combination of the statistical estimates described above, Hogg's estimates for the Stikine region, and the isolines from Miller's Alaska study should yield an acceptable estimate of the PMP in the Aishihik Lake drainage basin. A 24 hour point PMP of 225 mm is recommended for use. Orographic influences were not studied in detail due to lack of appropriate data, but it is expected they are small and applicable to less than 25 % of the watershed.

216 AREA REDUCTION AND DURATION RATIOS

There are virtually no site-specific data for analysis of these parameters. Calculations were thus undertaken using gross estimates of duration ratios, and area reduction curves proposed for a different geographic region.

For the duration ratios, the following table was derived from Figures 25 to 27 of the "Atlas of Rainfall Intensity-Duration Frequency Data for Canada; Climatological Studies, number 8" (Bruce, 1968).

<u>Duration (hrs)</u>	<u>Ratio</u> (X hr/24 hr rainfall)
6	0.7
24	1.0
48	1.2
72	1.3

Using Figure 16 of 'Statistical Estimates of Precipitation Extremes for The Prairie Provinces' (McKay, 1965), and the data in Hogg's study of the Stikine, area reduction ratios were derived for the Aishihik area of 1080 square miles.

<u>Duration (hrs)</u>	<u>Percentage of point rainfall</u>
6	63
24	77
48	84
72	85

Applying these two tables to the 225 mm 24 hour PMP proposed above yields:

PART 2 - HYDROLOGY

<u>Duration (hrs)</u>	<u>Area reduced PMP for Aishihik Lake Basin (mm)</u>
6	100
24	173
48	227
72	249

PART 2 - HYDROLOGY

Duration (hrs)	Area reduced PMP for Aishihik Lake Basin (mm)
6	100
24	173
48	227
72	249

PART 2 - HYDROLOGY

TABLE 2.1.1
AISHIHIK PRECIPITATION DATA
Expected Annual Maximum 24-hour Rainfall (mm) for various T
Taken from Table 9.2 of Climate of Yukon (AES, 1987)

T (yrs)	2	5	10	15	20	25	30	50	rain	yrs of	Mean	std	PMP
K values	-0.164	0.719	1.305	1.635	1.866	2.044	2.189	2.592	max	record		dev	(24 hr.)
STATION													
Aishihik	17.2	26.5	32.6	36.1	38.5	40.4	41.9	46.2	34.5	> 25	18.9	10.5	210.1
Burwash	22.0	30.6	36.3	39.5	41.7	43.5	44.9		38.4	> 15	23.6	9.7	198.6
Carmacks	14.3	18.1	20.6	22.1	23.1	23.9	24.5		23.6	> 15	15.0	4.3	94.7
Haines J.	19.0	320.0	40.6	45.4	48.8	51.5	53.6	59.5	58.4	> 25	21.4	14.7	287.4
Kluane	20.6	26.8	30.9	33.2	34.9				29.8	> 10	21.8	7.0	149.3
Whiteho.	15.0	20.7	24.3	26.5	27.9	29.2	30.2	33.0	30.7	> 25	16.0	6.4	132.6

Note: -K value for PMP is $19 \cdot 10^{(-0.0009565 \cdot \text{Mean})}$
-Mean and standard deviation have not been
adjusted for maximum observed precipitation
and record length.

PART 2 - HYDROLOGY

2.2 SEASONAL VARIATION OF MAXIMUM RAINFALL

Due to the importance of snowmelt with respect to runoff in the Aishihik watershed, a seasonal analysis of rainfall is necessary. Although maximum rainfall usually occurs after most of the snow has already melted (i.e. in July), high rains can also be experienced in April to June. A combination of these high spring precipitations and rapid snowmelt may become the critical condition for estimation of the Probable Maximum Flood (PMF).

Estimates of the seasonal variation in rainfall potential were based mainly on data from 'Climate of Yukon'. Figures 8.20 to 8.44 of that report present the greatest recorded 24 hour precipitations on a monthly basis for a number of relevant stations. Table 2.1 herein summarizes these data for five locations near Aishihik. The precipitation amounts were converted to percentages of the maximum all-time observed precipitation at a station (i.e. at Aishihik the maximum all-time precipitation is 45 mm; therefore, the May maximum of 25 mm is 55.56 % of the yearly maximum). Average values of these percentages were calculated for each month. This yielded a peak in July of 92.50 %. The monthly averages were all multiplied by 1.08, as required to bring the July value up to 100%. The percentages are plotted on Figure 2.2.1. The computed average is plotted also. Although the Haines Junction data are included in Table 2.2.1 they were not used in the seasonal distribution analysis nor are they plotted on Figure 2.2.1 because it is believed that the precipitation at this station is more strongly affected by the Pacific Ocean. This would explain the higher precipitation from September to December at Haines Junction. Area reduced seasonal PMP values are plotted on Figure 2.2.2 and tabulated in Table 2.2.2.

No analysis was undertaken to define the seasonal distribution with respect to duration. It is assumed that the 72, 48 and 6 hour distributions will have the same shape as the 24 hour seasonal PMP distribution.

PART 2 - HYDROLOGY

TABLE 2.2.1

Greatest precipitation in 24 hours (mm)
Based on Figures 8.20 to 8.44 in Climate of the Yukon (AES, 1987)

STATION	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Aishihik	11	7.5	16	15	25	25	45	38	19	18	9	7
peak=45	24%	17%	36%	33%	56%	56%	100%	84%	42%	40%	20%	16%
Burwash	12.5	5	23	12	25	37	38	26	18	9	15	14
peak=38	33%	13%	61%	32%	66%	97%	100%	68%	47%	24%	39%	37%
Carmacks	15	7.5	8	12	11	17	24	17	19	10	13	8
peak=24	63%	31%	33%	50%	46%	71%	100%	71%	79%	42%	54%	33%
Haines J.	33	19	14	12	25	33	28	25	32.5	67.5	55	58
peak=67.5	49%	28%	21%	18%	37%	49%	41%	37%	48%	100%	81%	86%
Kluane	NO DATA											
Whiteho.	9	10	27	14	12.5	30	21	30	22	23	11	19
peak=30	30%	33%	90%	47%	42%	100%	70%	100%	73%	77%	37%	63%
Ave %	37%	24%	55%	40%	52%	81%	93%	81%	61%	46%	38%	37%
Ave%*1.08	40%	26%	59%	44%	56%	88%	100%	87%	65%	49%	41%	40%

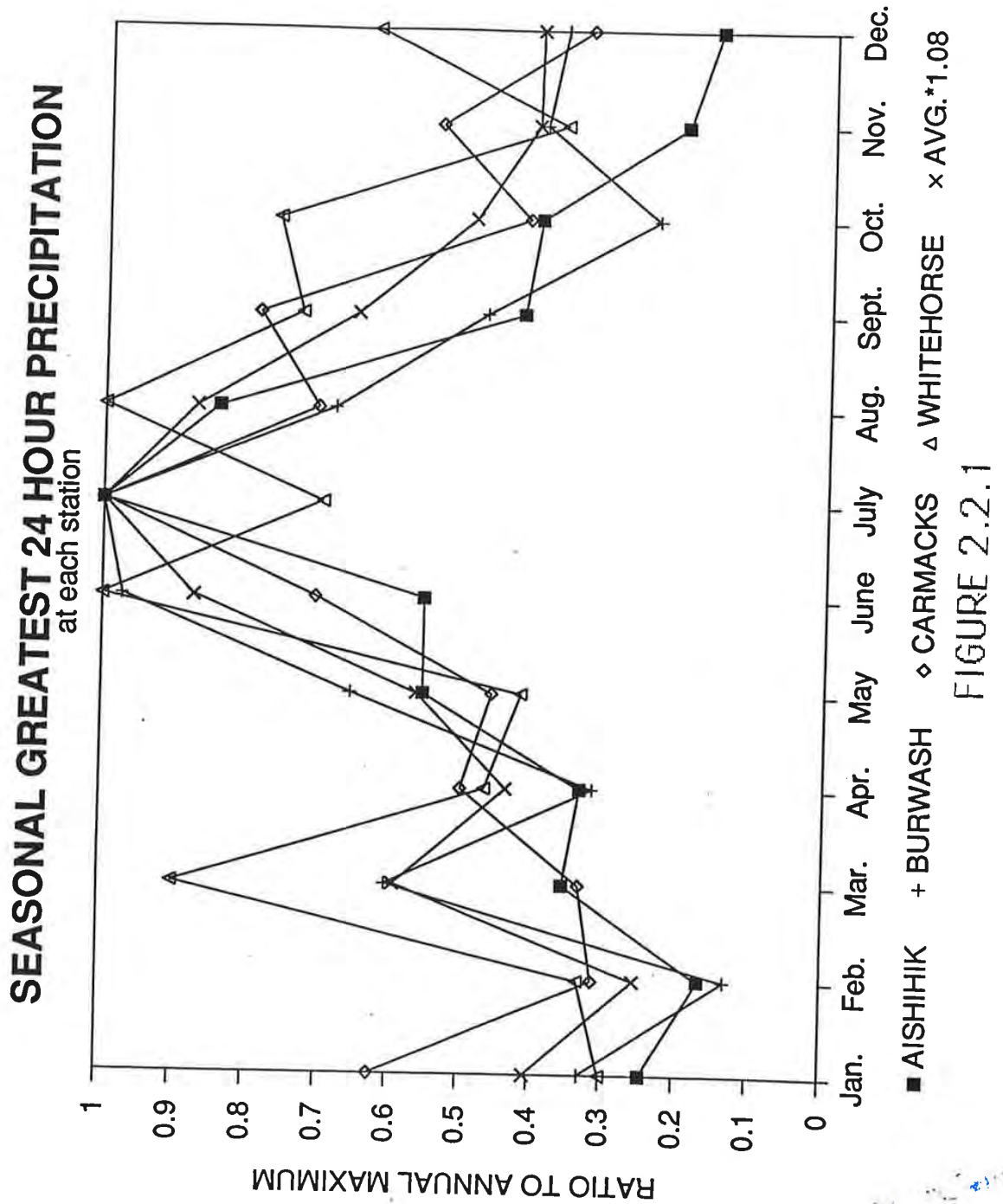
NOTE: AVERAGES DO NOT INCLUDE VALUES FROM HAINES JUNCTION
SINCE THESE ARE EXTREMELY HIGH IN FALL PRESUMABLY AS
A RESULT OF A GREATER INFLUENCE FROM THE PACIFIC OCEAN

Table 2.2.2

Seasonal distribution of PMP values calculated using average
values of distribution of greatest 24 hour precipitation
from Climate of Yukon and an annual PMP of 225 mm.
(values have been adjusted for area and duration)

	Jan.	Feb.	Mar.	Apr.	May	mid-May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Average	0.405	0.255	0.593	0.437	0.565	0.720	0.875	1.000	0.875	0.654	0.492	0.406	0.403
Duration													
6	41	26	59	44	56	72	88	100	87	65	49	41	40
24	70	44	103	76	98	125	151	173	151	113	85	70	70
48	92	58	135	99	128	163	199	227	199	149	112	92	91
72	101	64	148	109	141	179	218	249	218	163	122	101	100

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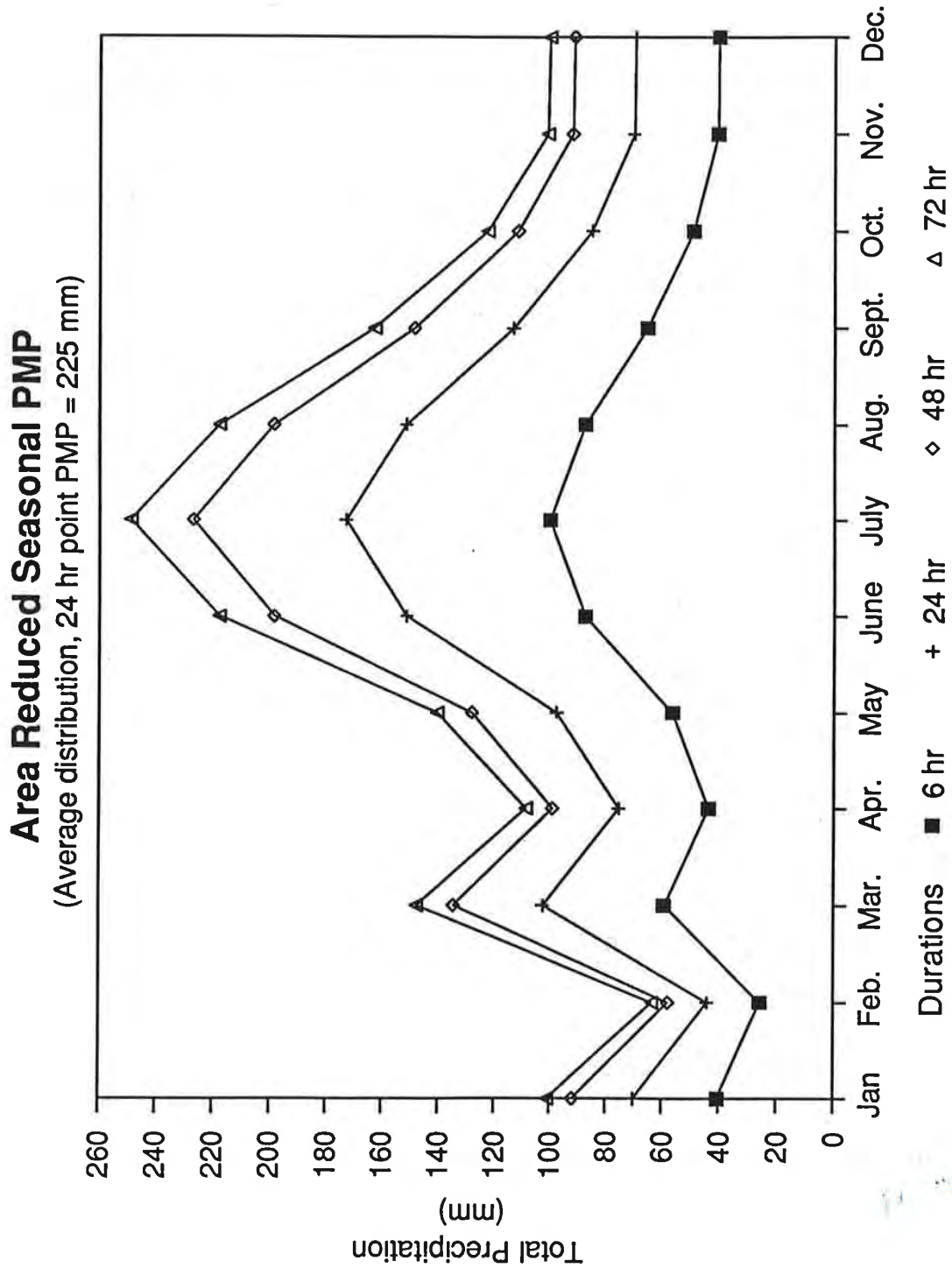


FIGURE 2.2.2

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2.3 SNOW ACCUMULATION

231 INTRODUCTION

Three methods have been used in the past (e.g. AES, 1981) for estimation of extreme snowpack accumulations:

- i) **Partial Season Method.** This method divides the winter into a number of periods of equal duration, the duration depending on the average interval between the passage of two weather systems. The maximum period snowfalls from all years of record are combined into one synthetic year, in which the maximum snowfalls occur for all periods.
- ii) **Snow Storm Maximization.** This method is similar to the storm maximization technique for PMP. A winter of heavy snowfall is selected and all storms are maximized, accumulating the resulting snowpack through the winter.
- iii) **Statistical analysis of the Snowpack.** In this approach snowcover data for the region of interest are analyzed using a number of frequency distributions to estimate the water equivalent of a snowpack with a selected return period.

Both the partial season method and the snow storm maximization method tend to give results which are very high and are considered to be unreasonable for combination with the PMP (rainfall). In some cases studies have been made in which these methods were used to estimate a Probable Maximum Snowpack, which was then combined with a moderate rainfall to estimate the PMF. In Yukon the necessary data for these approaches are either unavailable or not readily available and it was considered the most reliable course would be to combine the PMP (rainfall), as developed in Sections 1 and 2, with a heavy snowpack estimated by statistical analysis of observed snow course data.

232 AVAILABLE DATA

Snow course data were obtained from the Department of Indian and Northern Affairs (D.I.A.N.A., 1989). Seven snow courses were selected on the basis of their proximity to Aishihik Lake watershed. The Whitehorse Airport snow course is slightly farther from the Aishihik watershed than the other seven locations, but was included in the analysis due to its longer length of record: i.e. 23 years as compared with 10 to 15 years at the other seven snow courses. These eight locations are shown on Figure 2.3.1.

Snow course observations are made at five dates during the winter; February 1, March 1, April 1, May 1 and May 15. The observed snowpacks, in water equivalent, for eight snow courses are tabulated in the five sheets of Table 2.3.1, herewith.

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233 SPATIAL VARIATION OF SNOWPACK

Snow cover at Summit is considerably greater than at the other seven stations in close proximity to Aishihik Lake (see Figure 2.3.2). This station's data does not however contradict the snow cover results obtained by Hogg (1979, 1983) for the Stikine River Basin in British Columbia. From Figure 2.3.1 we can see that the April 1 snow cover seems to increase southward from Aishihik towards the Stikine. It has been suggested that these high snow covers are due to a low pressure system (high in moisture content) coming from the Gulf of Alaska over the Coastal mountains south of the St. Elias range. On the other hand a dry Arctic high pressure system centered North-East of the St. Elias mountains tends to yield less snowfall and, therefore, produce less snow cover on areas farther inland. The Summit snow course seems to be located just on the edge of the Alaska Gulf low, thus explaining the higher values of snow cover at that location.

Burwash Airstrip snow course data indicate a sudden decrease in snow cover in the 'shadow' of the St. Elias mountains. This station seems to be influenced more by the Arctic high and less by the Gulf of Alaska low. Also, a Chinook effect (warm dry wind blowing down the leeward slopes of a mountain range) on the north east slopes of the St. Elias mountains often causes snow cover to disappear completely at Burwash in the middle of winter. The Chinook effect is not felt quite as strongly just east of Burwash at the Canyon Lake and MacIntosh snow courses (i.e. at Aishihik Lake).

For the reasons listed above the snow course data of Summit and Burwash Airstrip were not used in the estimates of probable snow cover in the Aishihik Lake watershed.

234 TEMPORAL VARIATION OF SNOWPACK

Mean snowpack values for all eight stations, as derived in Table 2.3.1, are plotted on Figure 2.3.2. It can be seen by examination of that figure that snow melt appears to begin sometime between April 1 and May 1 at each of these stations. In many areas the snow cover is nearly gone by May 15. Snow melt at Casino Creek begins later than at the other stations, this station being significantly farther North.

Table 2.3.2 presents the temporal variation of snowpack in a more quantitative fashion. In Table 2.3.2 the mean monthly snowpacks for the available six snow courses (Summit and Burwash A. snow courses are not used in this analysis, see Section 2.3.3) have been averaged for each month. A percentage of the yearly maximum was then calculated and tabulated for each month in Table 2.3.2. These percentages will be applied to the yearly maximum snowpack of specified return period, to yield the seasonal snowpack for that return period.

PART 2 - HYDROLOGY

235 STATISTICAL ANALYSIS

The statistical analysis of snow cover will be limited to the following six snow courses:

Casino Creek	Canyon Lake
MacIntosh	Mt. Berdoe
Whitehorse Airport	Mt. Nansen

Due to the close proximity to Aishihik Lake of both Canyon Lake and MacIntosh, these snow courses were assumed to be of primary significance. The Whitehorse snow course, on the other hand, was considered important because of its length of record, 23 years, which is almost twice the record length of any other snow course in the Aishihik Lake area. Casino Creek, although situated farther north, does not drastically contradict the data from the other snow courses listed above, except in respect of the date of melting, as noted earlier.

Recorded snowpacks for the stations of interest are presented in Table 2.3.1. Gumbel distributions seemed to best fit the data and were thus used for frequency calculations. Due to the relatively short record lengths it is believed that distributions other than Gumbel or normal would not have given noticeably better fits (no classical statistical tests were undertaken for the same reason). Table 2.3.3 contains the results of frequency analyses using the theoretical Gumbel distribution for each station.

Keeping the above discussions in mind it is considered reasonable to use Canyon Lake's snow course data as being representative of the snow cover in the Aishihik Lake watershed. Therefore, the maximum snow water equivalent can be approximated as being:

205 mm for 100 year return period
250 mm for 500 year return period
270 mm for 1000 year return period.

PART 2 - HYDROLOGY

TABLE 2.3.1

sheet 1 of 5

Snow Course Observations
Accumulation in mm of water equivalent

Whitehorse Airport

No. 09AB-SC2 ELEV. 700 M Lat. 60-42 Long. 135-04

Year	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
1965		79	79	0	0	79
1966	71	102	112	10	0	112
1967	71	97	122	71	0	122
1968	74	81	84	15	0	84
1969	31	104	84	0	0	104
1970	79	86			0	86
1971	104	107	122	76	0	122
1972		138		127	0	138
1973	91	91	89	0	0	91
1974	89	96	102		0	102
1975	48	64	76	0	0	76
1976	71	84	79	0	0	84
1977	39	61	71	0	0	71
1978	41	46	48	0	0	48
1979	93	107	127	18	0	127
1980	89	91	100	0	0	100
1981	80	88	96	0	0	96
1982	56	86	102	86	0	102
1983	82	91	94	0	0	94
1984	41	51	61	0	0	61
1985	104	131	135	125	0	135
1986	53	80	130	97	0	130
1987		76	89	0	0	89
MEAN	70.35	88.57	95.33	29.76	0	97.96

PART 2 - HYDROLOGY

TABLE 2.3.1

sheet 2 of 5

Snow Course Observations
Accumulation in mm of water equivalent

Canyon Lake
No. 08AA-SC1 ELEV. 1160 M Lat. 61-07 Long. 136-39

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1975		97	124	0	0	124
1976	64	69	69	0	0	69
1977	30	31	69	0	0	69
1978	75	76	86	0	0	86
1979	56	88		0	0	88
1980	78	80	82	32	0	82
1981	46	60	60	16	0	60
1982	48	80	100	116	44	116
1983	94	115	96	11	0	115
1984	44	42	38	0	0	44
1985	74	103	113			113
1986						
1987						
1988		47	85	18	0	85
1989		79	180	0	0	180
MEAN	60.9	74.38	91.83	16.08	3.667	94.69

Burwash Airstrip
No. 09CA-SC3 ELEV. 810 M Lat. 61-23 Long. 139-03

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1977	17	9	11	0	0	17
1978	16	12	0	0	0	16
1979	17	45	37	0	0	45
1980	40	49	57	0	0	57
1981	0	0	0	0	0	0
1982	18	39	57	39	0	57
1983	33	38	42	0	0	42
1984	11	15	10	0	0	15
1985	37	69	74	35	0	74
1986		51	68	68	0	68
1987		13	26	0	0	26
1988		33	26	0	0	33
1989		26	51	0	0	51
MEAN	21	30.69	35.31	10.92	0	38.54

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TABLE 2.3.1

sheet 3 of 5

Snow Course Observations
Accumulation in mm of water equivalent

MacIntosh
No. 09CA-SC2 ELEV. 1160 M Lat. 61-43 Long. 137-20

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1976	48	76	90	60	0	90
1977	34	42	59	0	0	59
1978	60	68	88	70	0	88
1979	50	65	94	0	0	94
1980	53	70	119	92	0	119
1981	35	45	55	34	0	55
1982	92	114	140	160	0	160
1983	72	78	87	0	0	87
1984	38	45	35	0	0	45
1985	95	115	122	130	105	130
1986		99	134	126	69	134
1987		41	59	0	0	59
1988		91	84	51	0	91
1989		68	101	65	25	101
MEAN	57.7	72.64	90.5	56.29	14.21	93.71

Mt. Berdoo
No. 09AH-SC1 ELEV. 1035 M Lat. 62-02 Long. 136-14

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1975		91	109			109
1976		104	107	89	0	107
1977	51	60	79	0	0	79
1978	59	72	75	41	0	75
1979	44	63	79	12	0	79
1980	60	80	75	32	0	80
1981	61	71	75	34	0	75
1982	61	72	94	89	0	94
1983	91	100	100	43	0	100
1984	56	82	94	62	0	94
1985	94	111	156	160	118	160
1986		117	167	169	102	169
1987		89	72	40	0	89
1988		81	82	31	0	82
1989		110	130	23	18	130
MEAN	64.11	86.87	99.6	58.93	17	101.5

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TABLE 2.3.1

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Snow Course Observations
Accumulation in mm of water equivalent

Mt. Nansen
No. 09CA-SC1 ELEV. 1021 M Lat. 62-02 Long. 137-03

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1975						
1976	48	66	66	20	0	66
1977	44	48	63	0	0	63
1978	53	64	51	0	0	64
1979	36	56	87		0	87
1980	45	76	60	0	0	76
1981	44	52	56	0	0	56
1982	60	69	65	0	0	69
1983	69	70	80	0	0	80
1984	49	65	60	0	0	60
1985	74	95	104	101	0	104
1986		59	82	78	0	82
1987		28	51	0	0	51
1988		77	67	0	0	77
1989		79	99	0	0	99
MEAN	52.2	64.57	70.79	15.31	0	73.86

SUMMIT
No. 08AB-SC3 ELEV. 1000 M Lat. 60-51 Long. 137-47

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1975						
1976						
1977						
1978						
1979						
1980	126	186	165	118	0	186
1981	171	190	202	113	0	202
1982	101	118	132	102	45	132
1983	205	217	230	110	0	230
1984	77	178	191	143	58	191
1985	218	239	252	259	164	259
1986		230	298	301	205	301
1987		211	207	210	39	211
1988		305	305	268	76	305
1989		329	366	190	0	366
MEAN	149.7	220.3	234.8	181.4	58.7	238.3

PART 2 - HYDROLOGY

TABLE 2.3.1

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Snow Course Observations
Accumulation in mm of water equivalent

CASINO CREEK SWE in mm
No. 09CD-SC1 ELEV. 1065 M Lat. 62-44 Long. 138-48

	Feb 1	Mar 1	Apr 1	May 1	May 15	MAX
Year						
1977	53	68	80	125		125
1978	80	90	98	86		98
1979	97	113	170	145		170
1980	40	68	81	95	0	95
1981	45	70	78	88	0	88
1982	94	110	118	165	173	173
1983	43	118	120	80	0	120
1984	86	105	110	139	72	139
1985	116	130	143	180	166	180
1986		108	127	168	150	168
1987		63	92	101	117	117
1988						
1989						
MEAN	72.67	94.82	110.6	124.7	84.75	133.9

PART 2 - HYDROLOGY

TABLE 2.3.2

SEASONAL VARIATION OF SNOWPACK

DATE	AVERAGE WATER EQUIVALENT FOR SIX SNOW COURSES*	PERCENTAGE OF MAXIMUM
	mm	%
FEB. 1	63.0	68
MAR. 1	80.2	86
APR. 1	93.1	100
MAY. 1	50.2	54
MAY. 15	20.0	21

* Note: Six snow courses used are, as stated in Section 2.3.3,
Whitehorse, Canyon Lake, MacIntosh, Mount Berdoe,
Mont Nansen and Casino Creek.

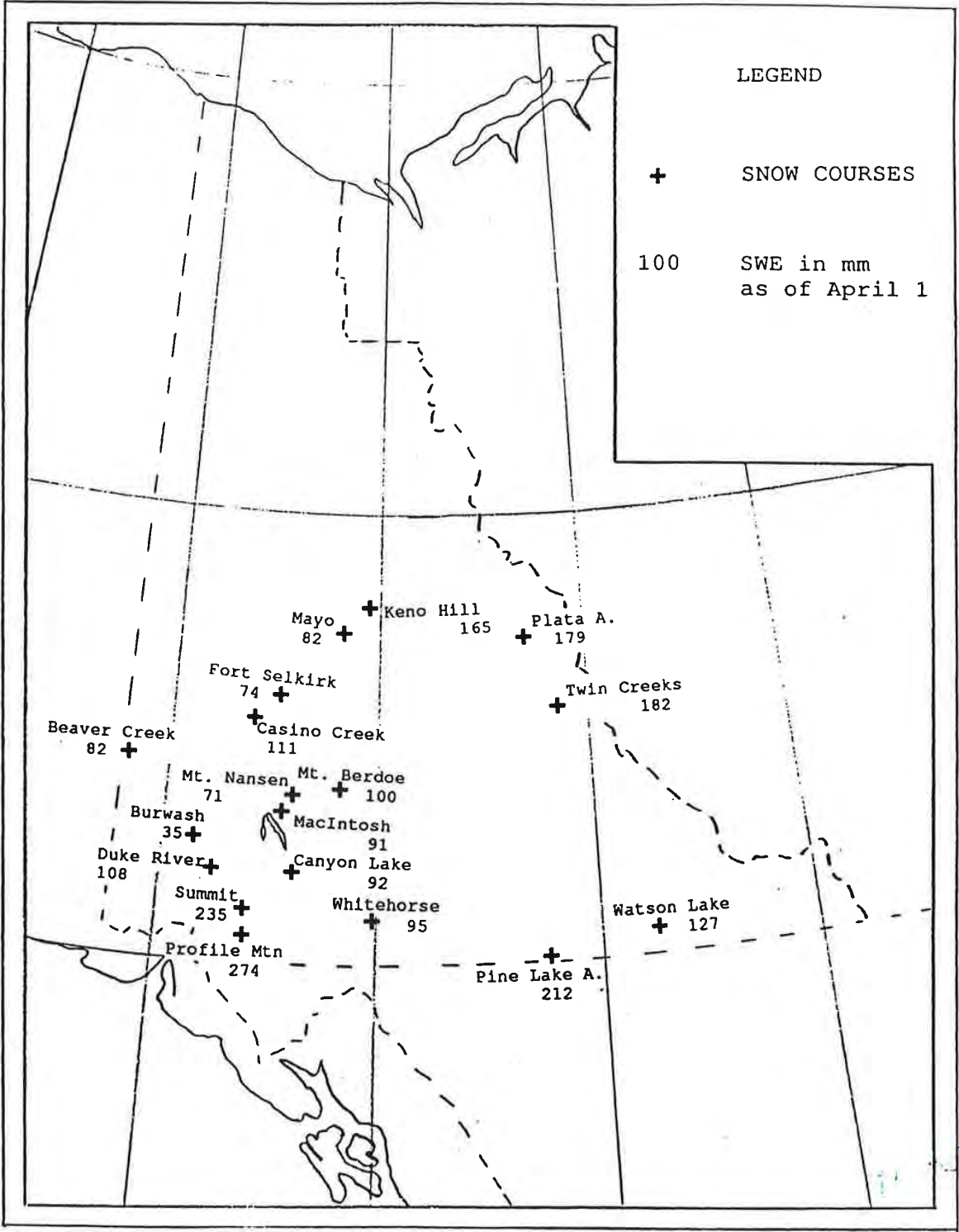
TABLE 2.3.3

Maximum Snow Pack Accumulation
Theoretical Gumbel Distribution
(mm of water equivalent)

RETURN PERIOD (YEARS)		2	5	10	25	50	100	500	1000	5000	10000
PROBABILITY OF EXCEEDANCE		0.5	0.2	0.1	0.04	0.02	0.01	0.002	0.001	0.0002	0.0001
FREQUENCY FACTOR		-0.16	0.719	1.305	2.004	2.592	3.137	4.395	4.936	6.19	6.73
	Mean	Std. dv.	SWE in mm								
Whitehorse	98.0	23.7	94.1	115.0	128.9	146.4	159.4	172.3	202.2	215.0	244.7
Canyon Lake	95.0	35.1	89.2	120.2	140.8	166.7	186.0	205.1	249.3	268.3	312.3
MacIntosh	93.7	33.3	88.2	117.6	137.2	161.8	180.0	198.2	240.1	258.1	299.8
Mt. Berdoe	101.5	29.8	96.6	122.9	140.4	162.4	178.7	195.0	232.5	248.6	286.0
Mt. Nansen	73.9	15.6	71.3	85.1	94.3	105.8	114.3	122.8	142.5	150.9	170.5
Casino Creek	133.9	34.1	128.3	158.4	178.4	203.6	222.3	240.9	283.8	302.2	345.0

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FIGURE 2.3.1



PART 2 - HYDROLOGY

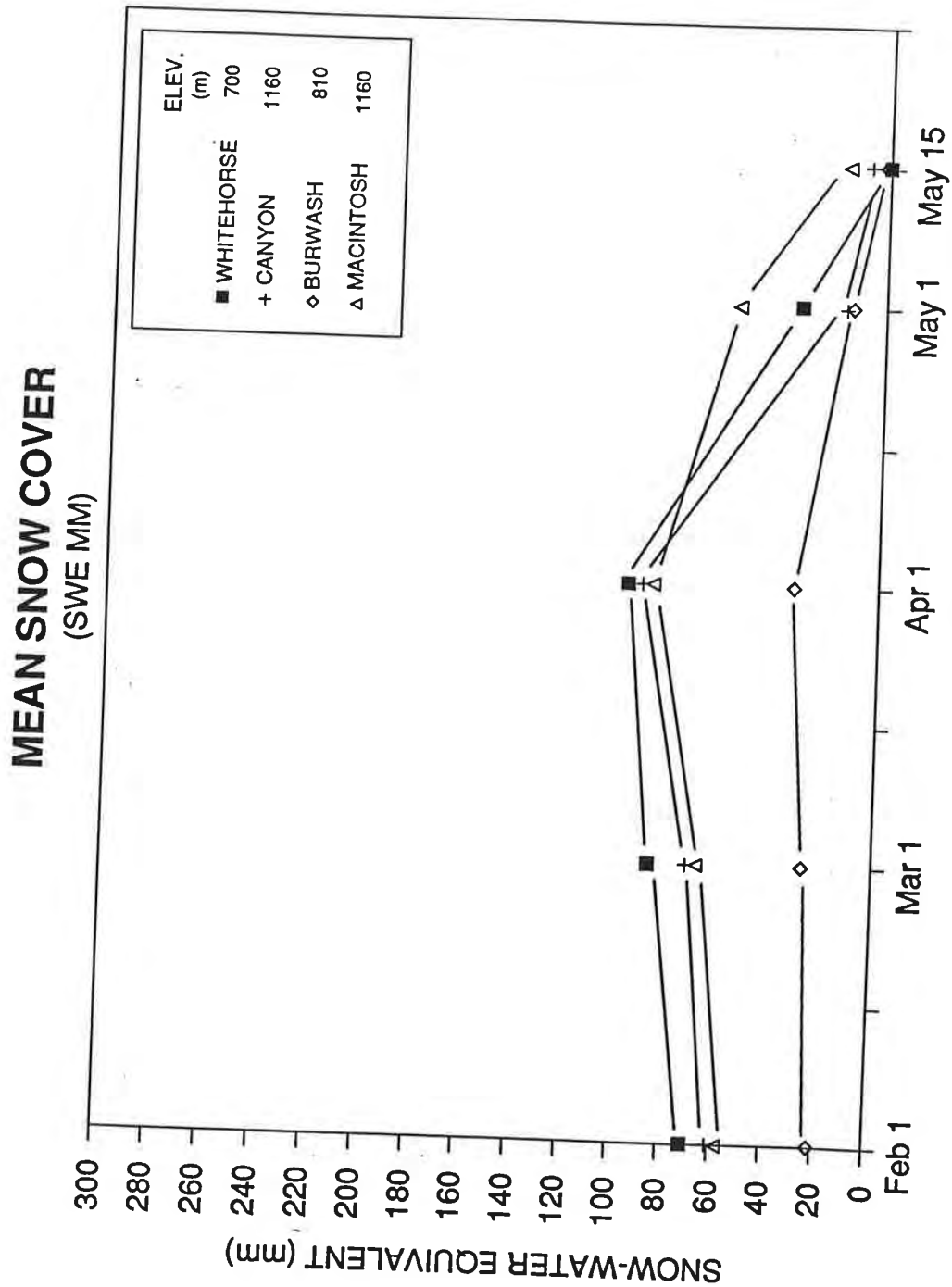


FIGURE 2.3.2
(sheet 1 of 2)

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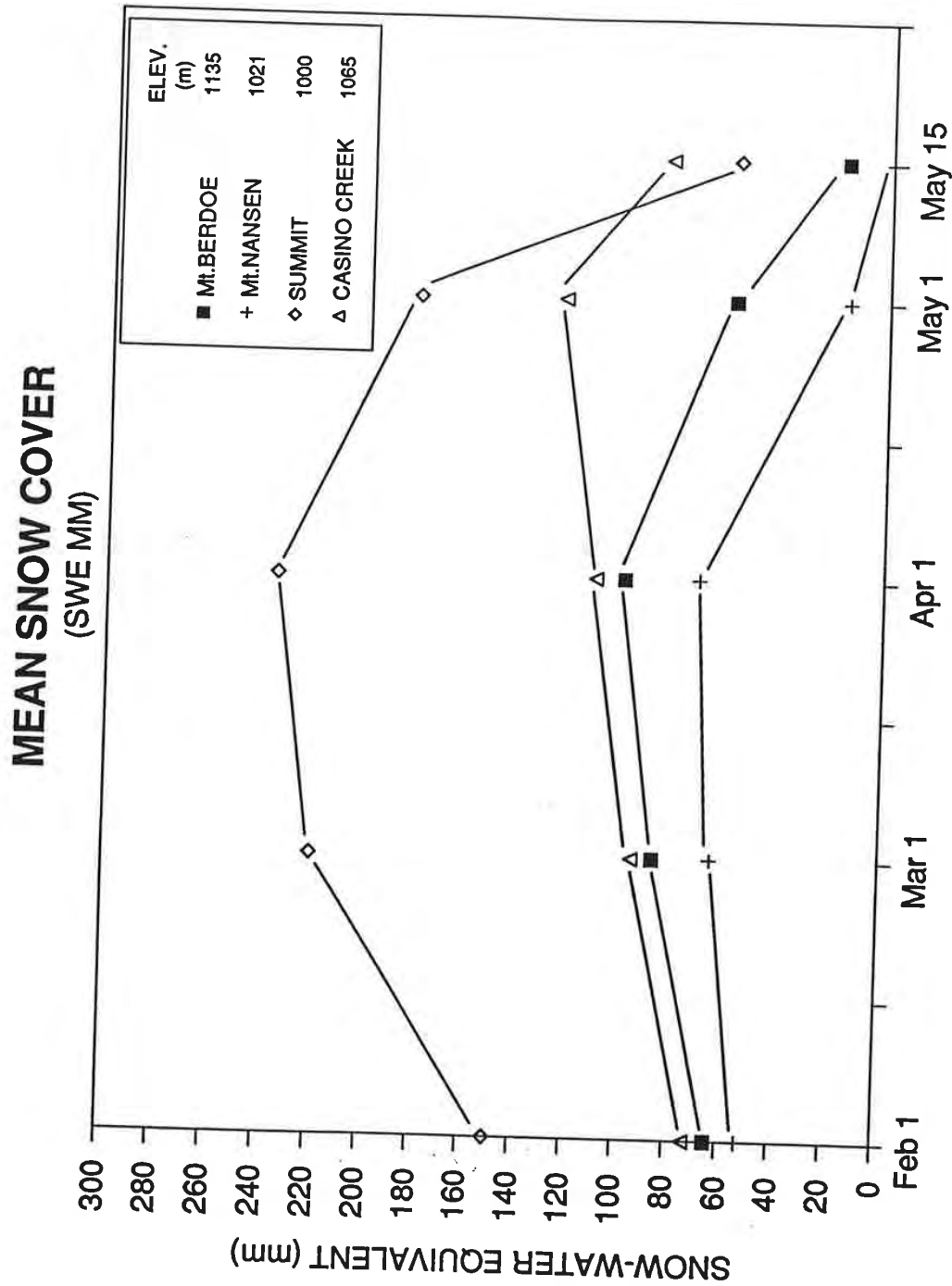


FIGURE 2.3.2
 (sheet 2 of 2)

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2.4 SNOWMELT: TEMPERATURE SEQUENCE

241 INTRODUCTION

Snowmelt is often a major contributor to maximum annual floods. Its contribution to the PMF is calculated as part of the hydrologic modelling of a basin, usually by means of a degree-day algorithm. The most critical temperature sequence must be determined for use in the algorithm. "This usually means low temperatures during the latter part of the snow accumulation period to prevent premature melt followed by rapidly increasing temperatures to maximize melt rates", (Hogg, 1983). Sequences must, of course, be within the range of possible temperatures for the given time of year.

242 TEMPERATURE LIMITS

Data relevant to snowmelt analysis were made available by Atmospheric Environment Service's Canadian Climate Centre. These data provide estimates of temperature extremes at both Aishihik (elevation 3169.3 ft) and Whitehorse (elevation 2306.4 ft). The determination of the maximum and minimum temperature series was based on temperatures averaged over durations of 4, 7, 15 and 30 days. The values in the daily maximum temperature series are the maximum values of the averaged maximum temperatures for the total record. Similarly, the values in the daily minimum temperature series are the maximum values of the averaged minimum temperatures for the total record. Tables 2.4.1 and 2.4.2 present the data for the snowmelt period at Aishihik Lake. Figures 2.4.1 and 2.4.2 provide a more visual indication of the trends in temperature extremes. The values from Tables 2.4.1 and 2.4.2 were averaged over ten-day periods and plotted on the sixth day of each of these periods to minimize unrealistic peaks in the data. It should be noted that a lapse rate of 0.63 °C/328 ft ('Climate of Yukon' AES, 1987) was applied to the Whitehorse data for the 862.9 ft difference in elevation, thus transposing them for comparison with the Aishihik data.

The hydrologic model must therefore be used with a temperature series which remains within the bounds depicted by the extreme limits shown in Figures 2.4.1 and 2.4.2. The sequence must also be synthesized in a manner such that the combination of snowmelt with the seasonal PMP described in Sections 1 and 2 yields maximum runoff. This is undertaken as an iterative process during the hydrologic modelling stage of the study. In general the temperature series follows a scenario described in the "Flood Hydrology Guide for Canada" (AES, 1981):

During the few weeks before the peak flooding, temperatures must be slightly above the freezing point to permit the snow cover to ripen. The snowmelt during this period must saturate both the snow cover and the underlying ground with water. The period that follows must be very warm and humid in order to promote maximum melt. Finally, the heaviest possible rain must fall over the entire basin. (AES, 1981).

PART 2 - HYDROLOGY

These daily sequences can be arranged in any order to maximize the snowmelt contribution to the PMF, as long as the maximum period averages remain unchanged and the diurnal variations stay within the bounds outlined below.

243 DIURNAL TEMPERATURE PATTERN

To convert the PMP and snowmelt to PMF runoff some consideration must be given to the diurnal temperature variation. To improve the realism of the melt model, 6-hour temperature patterns can be developed from the hourly temperature data for Whitehorse, as tabulated in Table 2.4.3. When these data are plotted on Figure 2.4.3 it can be seen clearly that the diurnal pattern differs significantly between January and June. The diurnal pattern used to modify the temperature sequence(s) selected from data given in Section 2.4.2 must reflect these seasonal changes.

PART 2 - HYDROLOGY

Table 2.4.1

Daily Maximum Temperature Series for Aishihik and Whitehorse
(based on running totals for 4, 7, 15 and 30 day durations)
Values are the record's maximum value
(degrees C)

Duration	Aishihik (966 m)				Whitehorse (703 m)				Duration	Aishihik (966 m)				Whitehorse (703 m)			
	4	7	15	30	4	7	15	30		4	7	15	30	4	7	15	30
Mar 1	1.1	2.1	-0.6	-5.2	7.9	4.2	-0.2	-0.4	May 1	13.3	13.8	8.4	6.5	17.9	16.4	12.4	7.9
2	2.4	0.9	-1.0	-4.6	6.8	4.3	-0.5	-0.5	2	13.2	13.2	8.7	6.5	16.6	16.1	12.9	7.8
3	2.2	0.1	-0.6	-4.1	4.8	4.9	-0.4	-0.5	3	12.8	12.4	9.4	6.6	14.1	15.1	12.8	8.0
4	2.5	1.6	0.0	-4.3	3.8	5.8	0.3	-0.6	4	12.6	12.9	10.1	6.7	14.5	14.1	13.0	8.1
5	3.4	2.1	-0.2	-4.5	3.6	5.3	1.4	-0.6	5	13.2	13.2	10.8	6.7	14.9	13.3	13.0	8.3
6	3.7	2.3	0.0	-4.3	3.6	4.4	2.7	-0.8	6	14.7	13.1	11.3	7.0	15.1	13.0	13.2	8.7
7	3.3	3.0	0.4	-3.6	4.4	3.5	3.4	-0.6	7	15.4	13.2	12.0	7.2	15.4	13.4	12.7	8.8
8	4.8	3.8	0.8	-2.7	5.0	3.8	3.5	-0.5	8	16.1	14.3	11.7	7.4	16.1	13.7	12.4	8.9
9	6.6	4.8	0.6	-2.4	6.1	4.2	3.5	-0.6	9	14.6	13.9	11.7	7.7	15.1	14.1	12.0	9.0
10	7.3	5.7	0.6	-2.3	7.2	5.4	3.5	-0.7	10	14.2	13.6	11.6	7.9	16.8	14.1	11.9	9.1
11	6.2	6.2	1.3	-2.1	7.5	6.1	3.6	-0.9	11	16.5	14.0	11.5	8.1	17.0	14.3	12.0	9.3
12	7.3	6.4	2.3	-1.7	7.6	6.6	3.4	-0.4	12	15.6	13.3	11.6	8.6	16.8	14.4	12.3	9.5
13	4.8	5.9	2.4	-1.0	6.2	6.3	2.7	-0.3	13	14.0	13.2	11.7	9.0	16.8	14.2	12.6	9.8
14	2.5	5.0	3.0	-0.3	2.9	5.2	3.2	-0.2	14	14.3	14.1	12.1	9.2	16.3	14.9	13.1	10.1
15	5.0	2.5	3.1	-0.1	5.2	3.1	3.3	-0.2	15	15.4	13.9	12.5	9.5	17.3	15.5	13.3	10.3
16	5.7	2.3	2.4	0.0	6.3	3.1	2.4	-0.2	16	17.5	13.9	12.8	10.0	18.7	15.6	13.3	10.7
17	5.7	3.9	1.7	0.1	6.6	3.8	2.1	-0.2	17	16.9	14.8	12.9	10.2	17.7	15.7	13.4	11.1
18	5.5	5.2	2.3	0.3	6.8	5.7	2.0	-0.2	18	16.9	16.0	12.8	10.5	17.2	17.1	13.6	11.2
19	5.2	5.4	2.8	0.7	6.8	6.4	2.3	-0.1	19	17.2	16.7	13.1	10.9	17.6	17.6	13.9	11.4
20	4.5	5.0	2.8	0.9	5.6	6.1	2.5	0.0	20	17.5	17.3	13.5	11.2	18.6	17.2	13.8	11.7
21	3.8	4.7	2.7	1.2	4.5	5.6	2.4	0.2	21	18.7	17.5	13.9	11.6	19.8	17.4	14.2	12.0
22	3.3	4.2	2.6	1.5	6.2	4.7	2.5	0.3	22	20.5	17.5	14.3	12.0	21.6	18.5	14.6	12.4
23	2.7	3.7	2.8	1.6	7.2	4.9	3.0	0.4	23	19.1	17.7	14.4	12.2	19.5	18.1	14.9	12.8
24	2.9	3.2	2.9	1.7	5.8	5.0	3.0	0.6	24	21.0	16.5	14.8	12.7	20.3	17.4	15.6	13.1
25	2.9	2.9	3.5	1.7	4.7	4.8	3.6	0.8	25	21.9	17.7	15.4	13.0	19.9	18.0	16.5	13.6
26	3.0	3.0	4.1	1.7	3.7	4.5	4.5	1.1	26	20.7	17.8	16.0	13.1	21.6	17.9	17.3	13.9
27	3.3	3.0	4.1	1.7	4.7	3.4	4.6	1.4	27	23.0	19.4	16.8	13.3	23.8	19.8	17.3	13.9
28	3.9	2.5	3.7	1.6	5.6	3.6	4.2	1.8	28	24.8	21.7	17.3	13.3	25.6	22.2	17.5	13.8
29	5.4	2.0	3.3	1.5	6.1	4.5	3.7	2.1	29	26.4	23.5	17.1	13.3	26.6	24.1	17.5	13.9
30	5.5	2.6	2.8	1.4	6.2	5.3	3.6	2.4	30	25.1	23.7	16.8	13.4	25.1	24.1	17.0	14.2
Apr 1	5.1	2.8	2.1	1.3	5.4	5.4	3.7	2.6	31	22.3	23.1	17.5	13.7	24.3	22.4	17.9	14.5
2	5.5	2.7	1.3	1.3	5.6	5.3	3.7	2.6	Jun 1	21.3	22.1	18.0	14.0	23.9	21.5	18.7	14.7
3	4.8	4.1	1.0	1.4	5.5	4.5	3.5	2.8	2	22.0	21.5	18.6	14.3	23.7	21.2	19.9	15.1
4	4.3	4.6	1.6	1.3	6.8	5.0	3.7	2.8	3	22.4	20.9	19.1	14.7	24.1	22.2	19.9	15.1
5	5.3	4.9	2.4	1.0	7.4	5.6	4.0	2.9	4	21.4	21.1	19.1	15.0	24.1	23.0	20.4	15.4
6	6.1	4.5	3.0	0.9	9.3	6.4	4.0	2.9	5	21.7	21.7	19.3	15.3	24.2	23.7	21.1	15.7
7	6.4	5.1	3.5	1.0	7.7	6.9	4.7	2.8	6	23.2	22.5	19.7	15.6	24.9	24.8	21.7	16.3
8	6.4	5.3	3.7	1.0	7.2	7.2	5.3	2.7	7	24.0	23.4	20.2	16.0	26.5	25.6	22.3	17.1
9	5.0	5.3	3.9	0.9	7.2	7.6	5.4	2.7	8	25.3	23.4	20.7	16.4	27.2	25.7	22.9	17.7
10	4.1	5.0	3.5	1.0	6.6	7.2	5.4	2.7	9	24.2	22.9	20.8	16.8	26.8	25.5	23.2	18.3
11	5.3	4.8	3.3	1.2	7.0	6.8	5.5	2.8	10	24.1	22.9	20.8	17.2	26.6	25.0	23.2	18.7
12	5.7	4.7	3.7	1.2	8.4	6.6	5.8	2.9	11	23.6	23.3	21.2	17.4	27.4	24.9	23.3	19.1
13	4.6	4.3	4.0	1.1	8.0	6.4	6.1	3.2	12	22.9	22.4	21.4	17.5	28.3	26.7	23.5	19.6
14	5.1	4.2	4.3	1.1	6.6	6.4	6.2	3.5	13	24.0	21.3	21.1	17.7	29.1	28.0	23.3	19.8
15	5.2	4.4	4.5	1.3	5.9	6.4	6.4	3.8	14	24.8	23.1	20.8	17.9	30.6	29.1	22.9	20.0
16	4.7	4.1	4.6	1.4	5.8	6.0	6.5	4.0	15	25.7	24.4	20.8	18.0	31.6	29.9	23.5	20.1
17	6.7	4.9	4.5	1.8	6.8	5.9	6.4	4.2	16	26.4	25.0	21.0	18.3	27.4	28.5	24.7	20.4
18	8.2	5.0	4.4	1.9	7.7	5.5	6.3	4.4	17	26.5	25.5	21.2	18.4	27.4	27.8	25.5	20.5
19	7.3	4.8	4.4	2.1	8.8	6.0	5.8	4.5	18	26.7	26.1	22.1	18.6	28.3	27.1	26.3	20.8
20	6.7	5.8	4.0	2.5	8.8	6.6	5.7	4.8	19	28.0	25.5	22.8	19.0	26.1	25.9	26.6	21.3
21	6.5	6.6	4.2	2.9	8.6	7.0	6.0	5.0	20	26.8	25.2	23.0	19.4	25.2	24.5	26.4	21.3
22	7.1	7.2	4.4	3.3	9.4	7.9	6.5	5.2	21	24.2	24.7	22.6	19.6	24.1	24.1	26.1	21.3
23	7.2	6.8	4.8	3.3	11.0	8.2	6.7	5.3	22	23.2	24.1	22.3	19.5	24.0	24.3	25.0	21.5
24	7.4	6.3	4.8	3.4	11.7	8.6	6.7	5.4	23	21.5	23.5	22.4	19.5	23.8	24.4	24.0	21.5
25	8.9	7.0	5.1	3.5	12.4	9.5	6.7	5.5	24	22.5	22.2	22.2	19.6	25.5	23.6	23.4	21.3
26	9.7	7.5	5.3	3.8	13.1	10.9	6.9	5.5	25	20.4	21.2	22.0	19.4	26.0	23.3	22.9	21.3
27	10.7	8.8	5.6	4.3	15.0	12.5	7.6	5.9	26	20.5	20.7	21.9	19.5	25.3	23.4	22.3	21.3
28	12.6	9.0	6.0	4.9	16.7	13.3	8.6	6.5	27	21.1	21.6	22.0	19.8	24.9	23.5	22.3	21.3
29	15.4	10.7	6.8	5.5	16.3	14.1	9.3	7.0	28	21.1	21.5	22.0	20.2	24.3	23.6	21.8	21.5
30	17.4	13.2	7.8	6.1	17.8	15.1	10.5	7.5	29	22.7	21.5	21.7	20.5	24.1	23.3	21.3	21.8
	16.8	14.3	8.4	6.5	18.3	15.9	11.5	7.9	30	23.3	21.5	21.4	20.7				

Note: lapse rate of 0.63 oC/100 m was applied
to Whitehorse data for 263 m for comparison
with the Aishihik data.

PART 2 - HYDROLOGY

Table 2.4.2

Daily Minimum Temperature Series for Aishihik and Whitehorse
(based on running totals for 4, 7, 15 and 30 day durations)
Values are the record's maximum value
(degrees C)

Duration	Aishihik (966 m)				Whitehorse (703 m)				Duration	Aishihik (966 m)				Whitehorse (703 m)			
	4	7	15	30	4	7	15	30		4	7	15	30	4	7	15	30
Mar 1	-10	-7.9	-13.9	-18.3	0.543	-5.46	-8.36	-9.16	May 1	-2.1	-2.3	-3.4	-6.5	-0.96	-1.16	-2.06	-2.96
2	-9.6	-7.5	-12.7	-17.7	1.143	-4.16	-6.66	-9.06	2	-1.2	-1.9	-3.2	-6.2	-0.66	-1.16	-2.06	-3.06
3	-10.7	-9.6	-11.8	-17.1	0.043	-2.16	-7.86	-9.16	3	-1.2	-2.1	-3.4	-6.3	0.343	-0.66	-2.26	-3.16
4	-10	-10.2	-10.6	-16.9	-0.06	-0.36	-7.16	-9.26	4	-1	-1.6	-3.5	-6.1	0.543	-0.36	-2.36	-3.26
5	-7.1	-9.3	-10.1	-17	-1.36	-0.06	-6.06	-9.16	5	-1.1	-1.8	-3.6	-6	0.943	-0.06	-1.86	-3.06
6	-6.7	-10	-11	-16.9	-2.36	-1.16	-5.06	-9.36	6	-1	-1.2	-3.2	-5.7	0.743	0.243	-1.76	-2.86
7	-6	-8.6	-11.1	-16	-3.76	-2.76	-4.56	-8.66	7	-0.8	-0.9	-2.3	-5.4	1.343	0.743	-0.96	-2.66
8	-4.2	-5.5	-11.2	-15.3	-2.26	-3.36	-4.36	-7.96	8	0	-0.8	-2.1	-4.9	2.243	1.043	-0.76	-2.56
9	-2.6	-5.1	-11	-14.6	-1.16	-2.86	-4.86	-8.26	9	1.2	-1.1	-1.9	-4.4	1.643	0.243	-0.66	-2.26
10	-2.1	-4.2	-11.9	-14.9	-1.66	-2.76	-5.06	-8.66	10	1.8	0	-2.1	-4.5	2.543	0.743	-0.66	-2.36
11	-2.8	-3.4	-11.8	-15.5	-2.06	-2.16	-5.06	-9.16	11	0.5	-0.1	-2.1	-4.3	2.243	0.743	-0.66	-2.26
12	-4	-3.8	-11.3	-15.7	-2.06	-2.06	-4.56	-9.16	12	0.1	0.2	-2.1	-4.1	1.843	1.443	-0.66	-2.26
13	-6.5	-4.7	-10.3	-15.2	-1.96	-2.58	-5.16	-8.76	13	0	0.1	-1.8	-3.5	1.543	1.943	-0.66	-1.96
14	-9.4	-6.2	-9.4	-15.7	-3.48	-3.48	-5.56	-8.66	14	1.7	0	-2	-3	3.043	2.143	-0.36	-1.56
15	-5.1	-8.7	-8.3	-15.6	-1.76	-3.48	-4.86	-8.46	15	2.2	-0.1	-1.6	-2.9	3.343	1.743	-0.16	-1.46
16	-2.2	-10.2	-8.4	-14.9	1.143	-4.06	-5.66	-8.76	16	1.5	0	-1.5	-2.6	3.343	1.743	0.243	-1.16
17	-2.2	-7.2	-9.6	-14.8	1.143	-3.46	-6.76	-8.76	17	2.6	1.1	-1	-2.5	3.643	2.243	0.443	-1.06
18	-5	-5	-10.6	-14.9	-0.56	-1.56	-6.86	-8.76	18	2.1	1.5	-0.6	-2.3	3.343	3.343	0.843	-0.76
19	-4	-3.5	-10.7	-14.5	-1.16	-0.46	-6.56	-8.76	19	1.5	1.1	-0.4	-2.3	4.143	3.443	1.143	-0.66
20	-6.1	-4.3	-10.6	-14	-2.76	-0.86	-6.16	-8.76	20	1	0.9	-0.4	-2.1	4.043	3.143	1.543	-0.46
21	-7.3	-6	-11.1	-13.6	-3.46	-1.56	-6.26	-8.76	21	1.9	0.9	-0.2	-2	4.943	3.843	1.743	-0.46
22	-8	-6.8	-10.7	-13.2	-3.26	-2.46	-5.66	-8.46	22	1.1	0.8	-0.5	-1.9	5.843	3.743	1.943	-0.16
23	-5.5	-8.8	-10.3	-13.3	-3.56	-3.86	-5.46	-8.36	23	2.1	0.6	0	-1.5	5.943	3.543	2.243	0.243
24	-4.2	-8.9	-10	-12.8	-4.86	-3.76	-5.06	-8.26	24	2.9	1.3	0.4	-1.2	4.443	3.943	2.343	0.543
25	-5.1	-7.3	-8.9	-12.4	-3.56	-3.96	-3.96	-7.96	25	2.6	1.7	0.6	-1.1	5.243	4.043	2.543	0.643
26	-5.3	-5.9	-7.4	-11.8	-3.66	-4.76	-2.96	-7.56	26	3	1.9	1.1	-1	5.143	4.243	2.943	0.743
27	-6.8	-5.7	-7.4	-11.6	-3.36	-4.26	-2.86	-7.06	27	2.3	2.5	0.8	-0.9	4.543	4.343	3.143	1.143
28	-8.7	-6.3	-7.9	-11.1	-2.26	-3.86	-3.46	-6.46	28	4.3	3.2	1.1	-0.9	6.343	4.343	3.043	1.143
29	-9.4	-8.5	-8.6	-10.8	-2.96	-3.56	-3.96	-6.16	29	3.9	2.8	1	-0.8	6.943	4.543	3.043	1.143
30	-10.7	-10.2	-9.2	-10.1	-2.86	-2.86	-4.66	-5.76	30	3.2	2.9	0.9	-0.6	6.443	5.243	2.743	1.243
31	-7.3	-9.9	-10.1	-9.8	-1.36	-2.86	-4.56	-5.46	31	3.1	3.4	1.1	-0.7	9.443	6.043	3.143	1.543
Apr 1	-8.5	-10.4	-10.4	-10	-2.56	-3.26	-4.46	-5.56	2	2.1	2.6	1.5	-0.5	8.443	5.443	3.943	1.543
2	-6.3	-9.7	-9.6	-10.1	-2.76	-3.46	-4.16	-5.56	3	2	1.9	1.9	-0.3	7.043	5.943	4.143	1.643
3	-7.1	-7.9	-9	-9.9	-3.16	-2.26	-4.16	-5.46	4	4.8	2.4	2.3	0	6.743	6.643	4.443	1.743
4	-6.9	-7.8	-8.8	-9.9	-2.86	-2.46	-3.96	-5.36	5	4.6	3	2.6	0.2	6.743	5.543	4.743	2.043
5	-5.3	-7.9	-8.6	-10.2	-0.86	-3.16	-3.76	-5.26	6	5.1	3.8	3	0.4	6.243	6.143	4.643	2.343
6	-4.9	-7.6	-8.8	-10.5	-0.06	-3.86	-3.76	-5.26	7	6.1	4.7	2.9	0.8	6.843	6.743	4.943	2.443
7	-6.4	-7.4	-8.9	-10.6	-1.16	-3.76	-4.06	-5.36	8	5.5	4.8	3.3	1.1	8.643	7.143	5.443	2.743
8	-6.6	-7.4	-8.7	-11	-2.46	-1.76	-4.36	-5.36	9	6.5	5.6	3.5	1.5	8.643	7.243	5.643	3.343
9	-5.8	-7	-9.4	-11.5	-2.76	-1.76	-4.86	-5.66	10	6.1	5.8	3.8	1.9	10.44	7.643	6.043	3.743
10	-3.6	-6.5	-10.2	-11.7	-1.96	-2.66	-5.06	-5.86	11	6.9	6.2	4.1	2.2	9.043	8.043	6.343	4.043
11	-5.1	-7.4	-10	-11.6	-1.86	-3.26	-4.86	-5.96	12	8.7	7	4.4	2.6	8.343	8.043	6.643	4.443
12	-6.8	-7.1	-9.5	-11.6	-3.06	-3.46	-4.76	-5.96	13	7.3	6.6	4.7	2.8	8.043	8.043	7.143	4.743
13	-6.2	-6.5	-9.3	-11.9	-1.66	-3.56	-4.26	-5.86	14	6.7	6	4.9	2.8	8.643	7.643	7.143	4.843
14	-5	-6.9	-9.1	-11.4	-2.06	-3.66	-4.26	-5.56	15	7.6	6.5	5	2.9	9.643	8.143	6.943	4.943
15	-5.6	-6.7	-8.8	-10.8	-1.66	-2.76	-3.86	-5.06	16	8.5	7.4	5.3	3.2	11.64	9.643	7.043	5.343
16	-6.8	-7	-8.5	-10.2	-0.86	-2.46	-3.56	-4.86	17	9.5	8.2	5.8	3.6	12.24	10.34	7.243	5.543
17	-5.3	-6.8	-8.9	-9.5	-0.66	-2.26	-3.56	-4.76	18	10	8.9	6.4	3.6	10.84	10.04	7.043	5.743
18	-3.8	-7.1	-8.4	-9.3	-1.76	-1.86	-3.86	-4.96	19	10.6	9.2	6.9	3.7	11.24	10.04	7.243	5.843
19	-3.5	-6.3	-8	-9.5	-1.66	-2.16	-3.36	-4.66	20	10.4	9.7	7.1	3.8	10.84	10.34	7.943	5.943
20	-2.2	-4.1	-7.6	-9.6	-1.36	-2.46	-3.26	-4.36	21	8.5	9.3	7.3	4.1	9.543	9.943	8.243	6.243
21	-3.3	-4.1	-7.1	-9.7	-1.36	-1.96	-3.26	-4.26	22	6.9	8.6	7.3	4.2	9.343	9.243	8.643	6.343
22	-3.1	-4.7	-6.7	-9.4	-2.48	-2.06	-3.16	-4.16	23	6.8	8.2	7.6	4.3	9.743	8.743	8.543	6.343
23	-3.5	-4.3	-6.6	-9.5	-1.86	-2.16	-2.76	-4.16	24	8.2	7.4	7.7	4.4	9.143	8.943	8.443	6.343
24	-3.9	-4.4	-6	-9	-1.36	-2.36	-2.66	-4.06	25	9	7.2	7.8	4.8	9.143	8.743	8.243	6.443
25	-2.8	-4.3	-6.1	-8.7	-1.76	-2.36	-2.66	-3.76	26	10.3	8.1	7.6	4.9	8.443	9.043	8.243	6.543
26	-2.3	-4.4	-5.4	-8.3	-1.36	-1.76	-2.76	-3.66	27	9.6	8.6	7.3	5	8.343	8.943	8.043	6.643
27	-2.6	-4.3	-5.4	-8.1	-0.26	-1.46	-2.56	-3.36	28	8.7	8.8	7.2	5.5	8.343	8.543	8.043	6.843
28	-1.4	-3.4	-4.3	-7.5	0.143	-1.36	-2.26	-3.26	29	7.9	8.8	7.3	5.7	8.843	7.843	8.143	6.843
29	-1.2	-2.4	-3.9	-7	-1.06	-1.46	-2.16	-2.96	30	6.8	8.1	7.2	5.9	8.743	7.743	7.843	6.843
30	-2.3	-2.7	-3.9	-6.8													
Note: lapse rate of 0.63 oC/100 m was applied																	

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Table 2.4.3

WHITEHORSE A. HOURLY TEMPERATURE SERIES
(mean in degrees Celsius)

TIME	Jan	Feb	Mar	Apr	May	June	July	Aug
0	-19.0	-13.5	-8.9	-2.0	3.7	8.9	11.2	9.6
1	-19.0	-13.7	-9.4	-2.6	2.9	7.8	10.4	8.9
2	-19.1	-14.0	-9.8	-3.0	2.2	7.0	9.6	8.3
3	-19.2	-14.1	-10.2	-3.5	1.7	6.4	9.0	7.9
4	-19.2	-14.4	-10.6	-3.9	1.4	6.2	8.6	7.5
5	-19.3	-14.5	-11.0	-4.2	1.6	6.7	8.8	7.3
6	-19.5	-14.7	-11.4	-4.0	2.7	8.0	9.9	7.7
7	-19.6	-14.8	-11.4	-3.0	4.2	9.4	11.1	8.9
8	-19.6	-15.0	-10.9	-1.7	5.7	10.9	12.4	10.3
9	-19.7	-14.8	-9.7	-0.3	7.1	12.2	13.7	11.6
10	-19.4	-14.0	-8.0	1.2	8.5	13.5	15.1	13.0
11	-19.0	-12.8	-6.4	2.3	9.5	14.7	16.2	14.3
12	-18.3	-11.7	-5.1	3.2	10.2	15.5	17.1	15.2
13	-17.6	-10.7	-4.0	3.8	10.7	16.1	17.8	15.9
14	-17.2	-9.9	-3.3	4.2	11.1	16.5	18.2	16.4
15	-17.1	-9.5	-2.9	4.4	11.3	16.6	18.5	16.7
16	-17.3	-9.5	-2.9	4.3	11.2	16.5	18.5	16.7
17	-17.8	-10.1	-3.2	4.1	11.0	16.3	18.2	16.4
18	-18.0	-10.9	-4.1	3.6	10.5	15.9	17.8	15.9
19	-18.2	-11.5	-5.2	2.7	9.8	15.3	17.2	15.0
20	-18.3	-12.0	-6.2	1.5	8.7	14.4	16.2	13.7
21	-18.5	-12.4	-6.9	0.4	7.5	13.2	15.1	12.4
22	-18.6	-12.8	-7.5	-0.5	6.0	11.6	13.6	11.3
23	-18.8	-13.1	-8.2	-1.3	4.8	10.2	12.3	10.3
Avg.	-18.6	-12.6	-7.4	0.2	6.8	12.1	14.0	12.1

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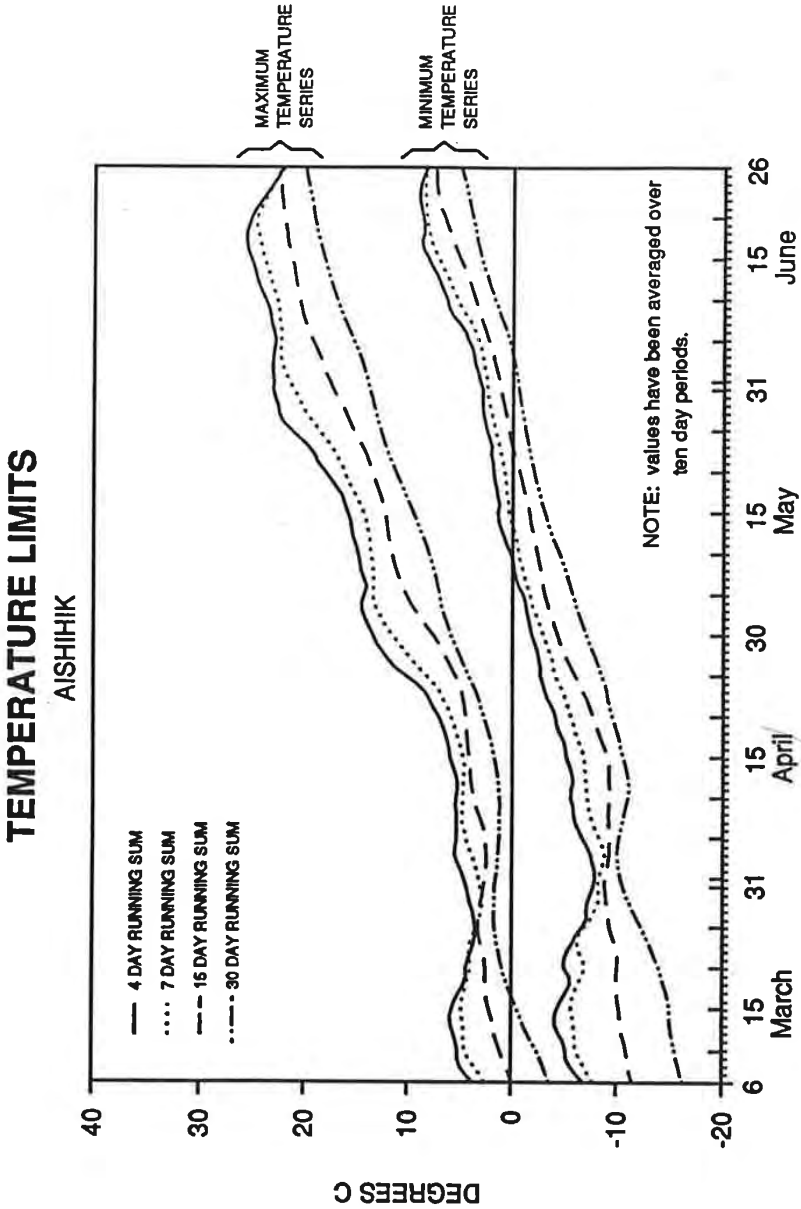


FIGURE 2.4.1

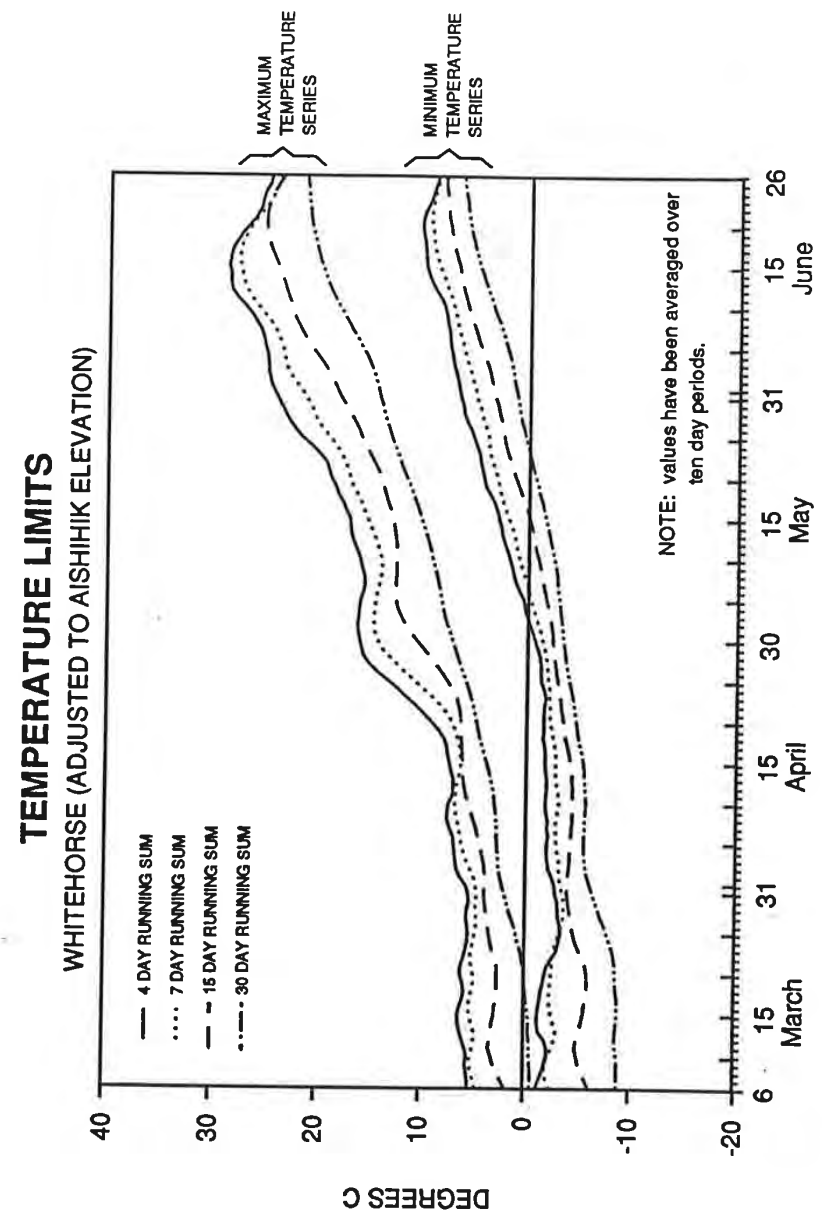


FIGURE 2.4.2

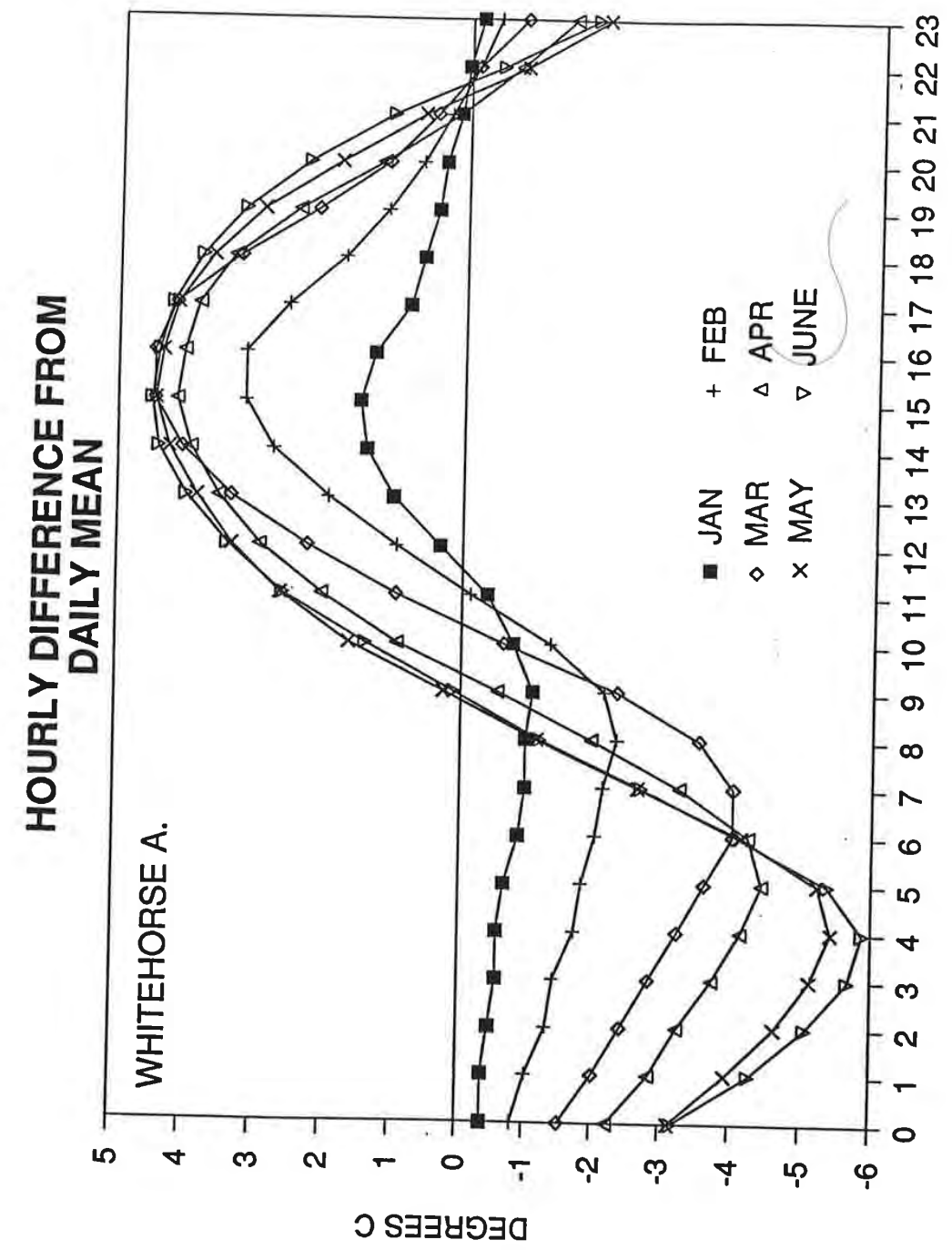


FIGURE 2.4.3

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2.5 ESTIMATION OF THE PROBABLE MAXIMUM FLOOD

251 GENERAL

The Probable Maximum Flood (PMF) is generally described as the most severe flood that is reasonably possible at a site, given the present geologic and climatic conditions. Estimation of the PMF normally follows three steps:

- i) definition of potential critical runoff contributing events for the basin, (e.g. seasonal PMP which may or may not be combined with maximum snowmelt).
- ii) simulation of the runoff of excess precipitation from individual sub-basins during the pre-defined runoff events.
- iii) routing the cumulating flood hydrograph through the river/reservoir system.

PMP computations, snow cover estimates and temperature Constraints are described in sections 1 to 4 of this report. Snowmelt, runoff simulation and flood routing are undertaken using an event simulation model (HEC-1) as described in the following sub-sections.

The initial estimation of the PMF was for Aishihik Lake. This was later extended to include Canyon Lake. The procedure is described in more detail in Section 2534.

252 RUNOFF CONTRIBUTING EVENTS

As shown in sections 2.1 to 2.4 of the present report, the PMP and snowmelt potentials are not static, but vary with the seasons. The PMP analysis clearly indicates a July event as the source of the most intense rainfall, but suggests that the spring event strongly augmented by snowmelt runoff might result in the PMF occurrence. Accordingly, two (2) seasonal PMF scenarios have been modelled for Aishihik Lake.

- a mid-July (all-season maximum) PMP falling on a catchment saturated by prior heavy rainfall.
- a mid-May PMP superimposed on runoff from a maximized seasonal snowpack, ripened and melting under a record high temperature series for that period.

It is assumed that both of the storms mentioned above cover the entire Aishihik and Canyon Lake watershed evenly. Limited climatological data did not permit the development of rainfall isohyets. Also the varied topography of the area would have made this type of analysis very difficult. As a result a rather simple model of the Aishihik and Canyon Lake watershed was used to simulate the PMF events.

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The reduction of PMP for initial and continuous losses, to yield excess rainfall for runoff; the variable contributions of snowmelt at different elevations and times; the hydrologic routing of this runoff to each sub-basin outlet using a unit hydrograph; and the hydraulic routing of these accumulated flood flows through each reservoir were simulated using the HEC-1 Flood Hydrograph Package, (HEC, 1985).

253 BASIN SIMULATION MODEL, HEC-1

2531 OVERVIEW

The HEC-1 model is designed to simulate the surface runoff response of a river basin to precipitation or snowmelt by representing the basin as an interconnected system of hydrologic and hydraulic components. Each component models an aspect of the precipitation-runoff and the snowmelt-runoff processes within a portion of the basin, commonly referred to as a sub-basin. In theory these sub-basins must be small enough that the assumption of average conditions is appropriate; although, in practice, calibration becomes impossible if sub-basins are too small. A schematic diagram of the Aishihik and Canyon Lake basins model used to simulate the PMF is shown in Figure 2.5.1.

2532 COMPUTATION INTERVAL

Computer models such as HEC-1 evaluate their controlling algorithms using a discrete computation interval. Between these computation nodes, values of parameters in the model are assumed to vary linearly. The computation interval used in the basin simulation model should be short enough that the assumption of average conditions within the computation interval is a reasonable approximation of reality, but long enough that input data are available for the chosen time duration.

In practice, the computation interval is selected as a compromise between desired accuracy and available information. In the Aishihik and Canyon Lake flood hydrograph simulation models a 1-hour computation interval has been used. This time step was chosen for the following reasons:

- a longer interval would have been greater than the time to peak and would, therefore, not have been acceptable - this time interval is adequate to simulate flood routing through both Aishihik Lake and Sekulmun Lake since these are quite large and also through Canyon Lake and Giltane Creek subbasins.

2533 SUB-BASIN RUNOFF COMPONENT

The sub-basin runoff component of HEC-1 handles all the hydrologic computations required to convert precipitation and/or snowmelt over the sub-

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basin to a flood flow hydrograph at the basin outlet. The structure of the sub-basin runoff component consists of:

- moisture inflow (precipitation and/or snowmelt);
- moisture loss rates (infiltration, depression storage, etc.);
- conversion of excess moisture to flows via a unit hydrograph.

The moisture inflow and loss rates may differ for the summer and spring PMFs, but their respective unit hydrographs are the same in the present simulations. Different seasonal hydrographs were not derived due to limited calibration data.

.1 Probable Maximum Precipitation (PMP)

Precipitation data are entered into the model as a time series of storm rainfall depths. The 6-hour increments of rainfall for both the summer and spring storms are given in the body of Table 2.5.1 (derived from Table 2.2.2).

The series represent average rainfall for the time intervals over the whole basin.

.2 Snowmelt

Mid-May was selected as the time of year having the potential for the greatest snowmelt contribution to the PMF, as a result of the historic snowpack and temperature analyses undertaken in sections 3 and 4.

Within the HEC-1 model the available snow (water equivalent) existing in each sub-basin at the start of the PMF is separated into zones of elevation. The snowmelt runoff from each elevation zone in the sub-basin is computed as the product of the depth of snow (water equivalent) melted during the computation interval and the sub-basin area in the elevation zone. For the Aishihik basin all sub-basins were divided into 1000 foot (304.8 m) elevation zones, as shown in Table 2.5.2.

Meltwater from the snowpack was calculated in HEC-1 using the degree-day method, i.e.

$$SNWMT = COEF (TMPR - FRZTP)$$

where: SNWMT is the snowmelt in mm/day in the elevation zone,
COEF is the melt coefficient in mm/degree-day ($^{\circ}\text{C}$),
TMPR is the air temperature in $^{\circ}\text{C}$ lapsed to the midpoint of the elevation zone,
FRZTP is the temperature in $^{\circ}\text{C}$ at which snow melts.

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Values of $COEF = 3.2 \text{ mm/degree-day}$ and $FRZTP = 0.0 \text{ }^{\circ}\text{C}$ were used in the degree-day equation, on the basis of previous studies (HEC 1981 and WATT 1989).

Table 2.5.3 shows the timing of the 6-hourly air temperature sequence (at Aishihik Lake level) used to ripen and then melt the snowpack. These air temperatures were lapsed to the midpoint of each elevation zone using a lapse rate of $0.63 \text{ }^{\circ}\text{C}/328 \text{ ft.}$ ('Climate of Yukon', AES, 1987).

The temperature sequence in Table 2.5.3 was prepared to adhere to the following objectives and restrictions:

- to ripen and commence maximum melting of the snowpack prior to the advent of the PMP,
- to maximize the resulting spring PMF,
- to maintain the daily maximum temperature within the range defined in section 4 of this report,
- the rainfall is timed to maximize the overall PMF once the temperature series has been defined.

.3 Loss Rates

General

Loss rates determine what proportion of the PMP and snowmelt runs off as flood water. Losses may occur due to infiltration, depression storage or interception by vegetation. Although some of these losses may later return to the river as groundwater flow they are effectively removed from the flood hydrograph and are not considered further by HEC-1.

The selection of loss rates appropriate to each PMF simulation has a direct impact on the resulting flood; losses must, therefore, be considered carefully. However, the estimation of loss rates is the most arbitrary component of the PMF computation process. Where possible the basin simulation model is calibrated from historic flood events. Due to the scarcity of climatological stations in the Aishihik Lake area calibration of the model had to be undertaken with a certain amount of conservatism.

It is anticipated that the large surface area of Sekulmun Lake and Aishihik Lake, with the corresponding routing effect will render the choice of loss rates less critical than it is generally considered to be.

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Summer

One of the loss rate options in HEC-1 is the U.S. Soil Conservation Service Method, (SCS, 1972). This method, based on experimentation and experience, allows the user to relate the drainage characteristics of soil groups to a curve number, CN. This curve number is incorporated, with accumulating rainfall, in a function that yields accumulating rainfall excess. The HEC-1 calibration option was used in analyses of three major flood events to determine the event curve numbers:

- July 9 to 15, 1988
- July 1 to 3, 1986
- June 28 to July 5, 1984.

These analyses suggest very high losses in the Aishihik Watershed (i.e. low CN of 75) while those in the Sekulmun lake watershed appear to be quite low (i.e. high CN of 95).

Since extreme conditions are to be simulated the low losses experienced in the Sekulmun Lake sub-basin were considered to be applicable to PMF simulations for that sub-basin, although lower values were used to test the sensitivity of the simulation of the summer PMF.

The higher losses experienced in the Aishihik Lake sub-basin can be attributed to a variety of factors. Perhaps the most important are the facts that the sub-basin is relatively flatter and depression storage is significant especially in the north end of the sub-basin. There is also some evidence of gravel beds and banks at Aishihik's lake head. This may allow for some infiltration in summer and other dry periods.

Since PMF simulations are aimed at finding critical conditions it was assumed that the sub-basin would be saturated before the PMP event in summer, thus reducing the possible infiltration (even in the gravel fields). The Aishihik Lake sub-basin's loss rate should therefore be assumed to be slightly lower than estimated by calibration. Curve numbers ranging from 75 to 95 were used to test the sensitivity of the summer PMF simulation.

Spring

In some years the flooding from snowmelt is worse than others, even though snow cover and temperature conditions in the spring are similar. This happens when the preceding winter was extremely cold in the early months, before the snow cover accumulated. Without the insulating blanket of snow the moist ground freezes solid near the surface, like a

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layer of permafrost. This layer is virtually impermeable and results in small losses from spring snowmelt and rainfall.

There is some evidence which suggests that these conditions can be experienced in the Aishihik and Sekulmun lake watersheds; the early cold winters, and limited early winter precipitation (AES, 1987) will lead to such conditions.

This frozen ground beneath the snowpack will be included as an antecedent condition in the spring PMF model by assigning an SCS Curve Number (CN) of 95 to the drainage areas. This will ensure almost 100% runoff from the snowmelt and seasonal PMP, with just a slight allowance for depression storage.

.4 Unit Hydrographs

A unit hydrograph is defined as the sub-basin surface outflow due to one inch of rainfall (or snowmelt) excess applied uniformly over this sub-basin in a period equal to the duration of the unit hydrograph. The unit hydrograph technique is based on two important assumptions:

- the unit hydrograph is characteristic for a sub-basin and is not storm dependent,
- the runoff due to excess amounts from different periods of rainfall excess can be linearly superimposed

HEC-1 supports three synthetic unit hydrograph approaches:

- i). The Clark Unit Hydrograph requires 3 parameters: time of concentration, storage coefficient and time-area curve (optional).
- ii) The Snyder Unit Hydrograph requires 3 parameters: standard lag, peaking coefficient and time-area curve (optional).
- iii) The SCS Dimensionless Unit Hydrograph requires one parameter: lag or time to peak.

The first two approaches require considerable data (particularly from calibration events) to permit reliable definition of parameters. The SCS unit hydrograph, however, requires as input only one parameter, which can be estimated with empirical equations and calibration events. SCS Dimensionless Unit Hydrographs were therefore used for both sub-basins in the Aishihik Lake model.

The lags (T_L in hours) were estimated using:

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- an equation proposed by the SCS

$$T_L = [L^{0.8}(S + 1)^{0.7}]/[1900^{0.5}]$$

where L = length to divide in feet,
Y = average watershed slope in percent,
s = potential maximum retention (in.),
= (1000/CN)-10.

- an equation proposed by Watt and Chow (1985),

$$T_L = 0.000326(L/S)^{0.79}$$

where L = basin length,
S = main channel slope.

Both empirical equations suggest TL's ranging from 3 to 5 hours. As mentioned by Watt and Chow (1985), however, storage elements along the length of the channels are expected to increase the time to peak. This is the case in the Aishihik watershed and as such the TL's were increased to 6 hours for the Sekulmun and Aishihik sub-basins. This time to peak seemed to agree quite well with the values obtained while using the HEC-1 calibration options.

A lag time of 6 hours was therefore assumed for both sub-basins in the model for each PMF event.

.5 Baseflow

The general criterion assumed for baseflow was the long term monthly mean outflow from each sub-basin. In the case of Sekulmun lake the July mean baseflow was estimated to be 424 ft³/s (this value is the mean July outflow from the lake for 1981 the 1987; the 1988 outflow was abnormally high due to the record storm for this sub-basin). The mid-May (spring) baseflow was taken as 272 ft³/s which is the average of the May and June long term mean monthly flows.

At Aishihik Lake further analyses were required to estimate seasonal baseflow since the outlet of this lake has been regulated since 1974. Ratios of mean monthly flow to mean annual flow were calculated using 1950 to 1973 data from WSC Station No. 087AA001 which is on Aishihik river downstream of Aishihik Lake. The ratios of monthly mean to annual mean for May, June and July are 1.2, 2.3 and 1.9 respectively. Applying these ratios to the mean annual flow at Aishihik Lake yields 360 692 and 572 ft³/s as the baseflow for May, June and July, respectively. Therefore, local inflows to Aishihik Lake are these

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last values minus the inflows due to Sekulmun Lake and Giltana Creek (WSC Station No. 08AA009; Giltana Creek flows into Aishihik River immediately downstream of Aishihik Lake and just upstream of WSC Station No. 08AA010). Hence, baseflows into Aishihik Lake from the Aishihik Lake sub-basin are 113 ft³/s and 191 ft³/s for July and Mid-May respectively.

2534 RESERVOIR/LAKE COMPONENT

The reservoir component of the basin simulation model receives upstream inflows and routes these flows through a reservoir using the modified Puls method. Outflows from the reservoir via a low-level outlet, a spillway or over the top of the dam can be accommodated through a storage-outflow relationship. Computed outflows are entirely dependent on the water level behind the dam, or the volume of storage, with no account taken of possible backwater effects from downstream reaches. The present model's data requirements for the reservoir component include:

- storage-outflow relationships
- initial conditions

.1 Storage-outflow relationships

Sekulmun Lake was assumed to behave as a simple reservoir.

Although the outlet at Sekulmun Lake has natural controls an expression of the storage-discharge curve was easily derived from a water surface/flow analysis using data from WSC stations 08AA007 (daily water levels) and 08AA008 (daily discharge) and with the assumption that the lake with surface area equal to 19.3 mi² has vertical banks.

Table 2.5.4 contains the storage-discharge curve which was used in the HEC-1 model for Sekulmun Lake. Figure 2.5.2 presents the same information graphically. A more accurate representation of the lake's storage/elevation function was considered to be of little use due to the relative size of the lake (a one metre increase in depth increases the lake's area by a very small percentage). Table 2.5.5 contains the elevation-discharge curves which were used in the HEC-1 model for Aishihik Lake.

.2 Initial Conditions

The initial water level in Sekulmun Lake was assumed to be such that the long term seasonal mean flow would be spilling into Aishihik Lake at the outset of the simulation. For July simulations the initial flow out

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of Sekulmun Lake was 424 ft³/s, while in mid-May the initial flow was 272 ft³/s as noted above.

The initial water level for Aishihik Lake was set at its FSL (3002.5').

.3 Extension to Canyon Lake

In extending the Aishihik PMF analysis to Canyon Lake it has been assumed that the areal PMP and the antecedent conditions derived for Aishihik can be used directly, without modification for the additional 9% drainage area.

.4 Giltana Creek

Giltana Creek drains an area of 188 km², extending from an elevation of 3000 ft at the outlet to 5905 ft at its highest point. Using the equations for Aishihik gives an average time lag of 4 hours. Open water covers 5.1 km² and the area is distributed; 80 km² between 3000 and 4000 ft, 98.5 km² between 4000 and 5000 ft, and 9.5 km² above 5000 ft. The mean annual flows at the outlet of Giltana Creek for May and July are 2.05 m³/sec, respectively.

.5 Canyon Lake

Canyon Lake subbasin has an area of 56.8 km², comprising 12.0 km² and 44.8 km² above and below 4000 ft, respectively. At 2950 ft, approximately, Canyon Lake occupies 9.0 km² and at 3000 ft 13.1 km². This area-elevation rate of change, 0.27 km²/m, has been used to estimate the variation of live storage in Canyon Lake with water level. SCS curve numbers of 95 and 90 have been used for the May and July PMFs, respectively, for both Giltana Creek and Canyon Lake subbasins.

The estimated time lag for Canyon Lake subbasin is one hour. This time lag requires a computational interval of 15 minutes, which is too short to enable the full PMF to be routed within the operational restrictions of the HEC-1 model. To overcome this problem the PMF/PMF inflow to Canyon Lake from its own subbasin was modelled separately using a 15-minute time step and ordinates from the inflow hydrograph were entered directly in the full basin model on an hourly basis.

The elevation-discharge relation for Canyon Lake is given in Table 2.5.6. It should be noted that weir flow over the structure commences at 2977 ft. It was assumed that the Aishihik powerhouse units were not operational for the purpose of this study and that no overtopping of structures would occur. The peak elevations must be evaluated to

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determine if these elevations can be contained by the existing structures.

254 PROBABLE MAXIMUM FLOOD SIMULATION RESULTS

As noted earlier, two events were evaluated as being critical in terms of Probable Maximum Flood:

- i) July rain storm event (annual PMP).
- ii) Mid-May snowmelt with seasonal PMP event.

The inflow and outflow hydrographs for Aishihik and Canyon Lakes are shown on Figures 2.5.3 to 2.5.10. The corresponding data is provided in Tables 2.5.7 to 2.5.10.

2541 SUMMER (JULY OR ANNUAL PMP)

The simulation of the PMF resulting from the July PMP for a range of assumed loss rates (SCS curve numbers) was undertaken. The flood runoff from the Aishihik Lake sub-basin varies with changing curve numbers by enough to cause the total flood inflow to Aishihik Lake to vary by nearly 17%. Calibration suggested curve numbers of 75 for the Aishihik Lake sub-basin and 95 for the Sekulmun Lake sub-basin. Increasing the Aishihik Lake sub-basin curve number to a more conservative 90 yields a PMF inflow of 173,228 ft³/s. It is concluded that the peak of the July PMF into Aishihik Lake can be estimated, conservatively, to be 173,228 ft³/s with a peak reservoir elevation of 3009.6 ft assuming only the low head regulating dam is used. The resulting peak elevations at Canyon Lake is 2985 ft. In the event of an emergency, the six culverts and the timber crib structure may be utilized. The resulting peak elevations at Aishihik and Canyon Lake would be 3009.4 and 2986 ft, respectively.

2542 SPRING (MID-MAY SNOWMELT WITH SEASONAL PMP)

As outlined in section 2533, in order to account for the possibility of frozen ground beneath the snowpack during the mid-May PMF event, a SCS curve number of 95 was assigned to the entire drainage basin. Given the temperature series presented in Table 2.5.3, the beginning of the rainfall was timed to yield maximum discharge at Aishihik Lake outlet. The resultant peak PMF inflow and elevation are estimated to be 161,603 ft³/s and 3011.6 ft, respectively assuming only the low head regulating dam is used. The resulting peak elevation at Canyon Lake is 2989.1 ft. Utilizing the six culverts and the timber crib structure results in peak elevations of 3011.0 and 2990.2 ft at Aishihik and Canyon Lakes, respectively.

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2543 PROBABLE MAXIMUM FLOOD

Although the summer PMF peak inflow is higher than the spring PMF peak, a comparison of the hydrographs indicates a greater total flood volume in the spring flood. This is evident in the corresponding peak Aishihik Lake elevations which indicate the spring PMF peaks at a higher elevation. It was determined that the peak reservoir level would result in overtopping of the low earthfill structures adjacent to the existing spillway structure. It is estimated that sufficient protection can be added to retain the peak reservoir levels for approximately \$5300.

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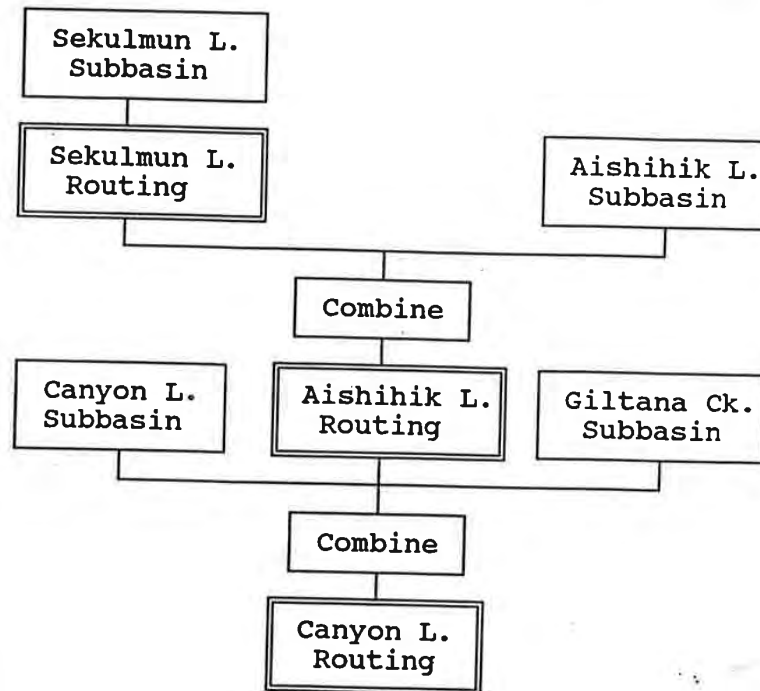


FIGURE 2-5-1
 Schematic Diagram of Aishihik Lake
 Watershed Model

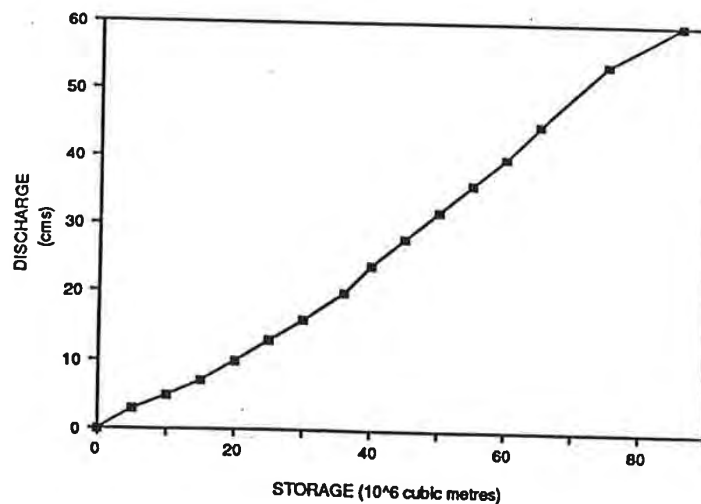
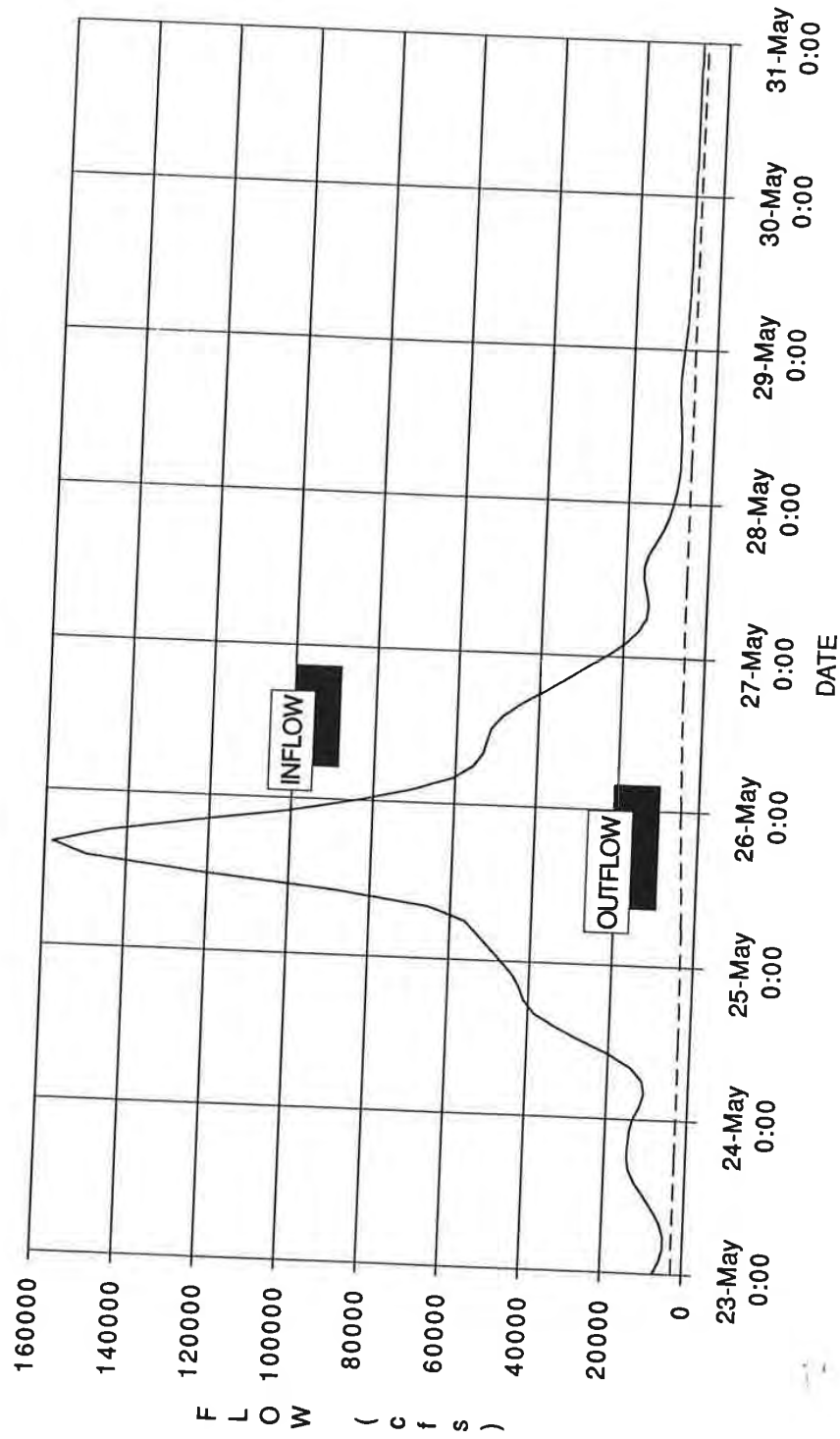


FIGURE 2-5-2: Sekulmun Lake Storage-Discharge Curve

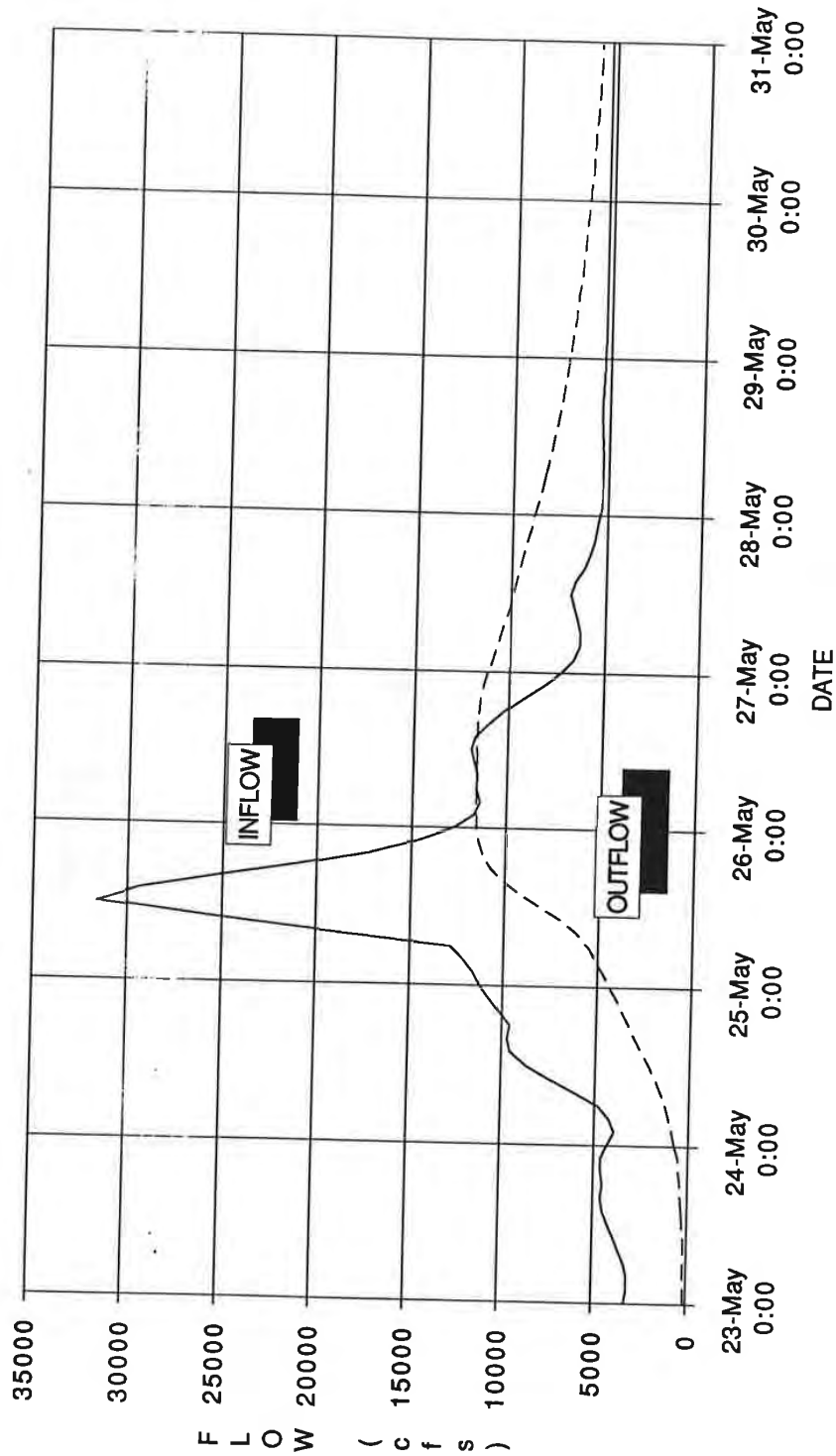
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FIGURE 2.5.3
 MAY PMF
 LOW HEAD REGULATING DAM ONLY
 AISHIHIK LAKE



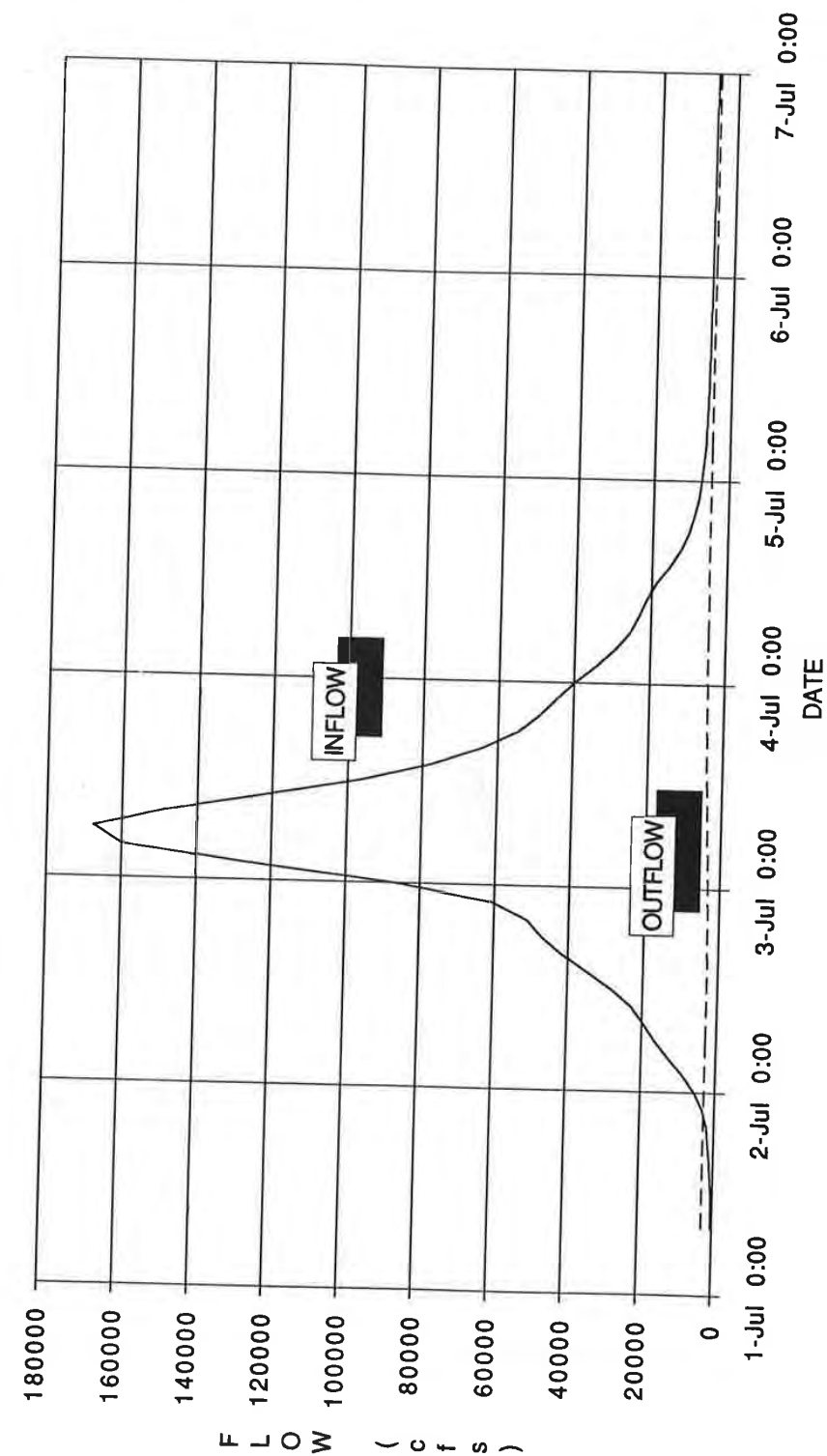
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FIGURE 2.5.4
 MAY PMF
 LOW HEAD REGULATING DAM ONLY
 CANYON LAKE



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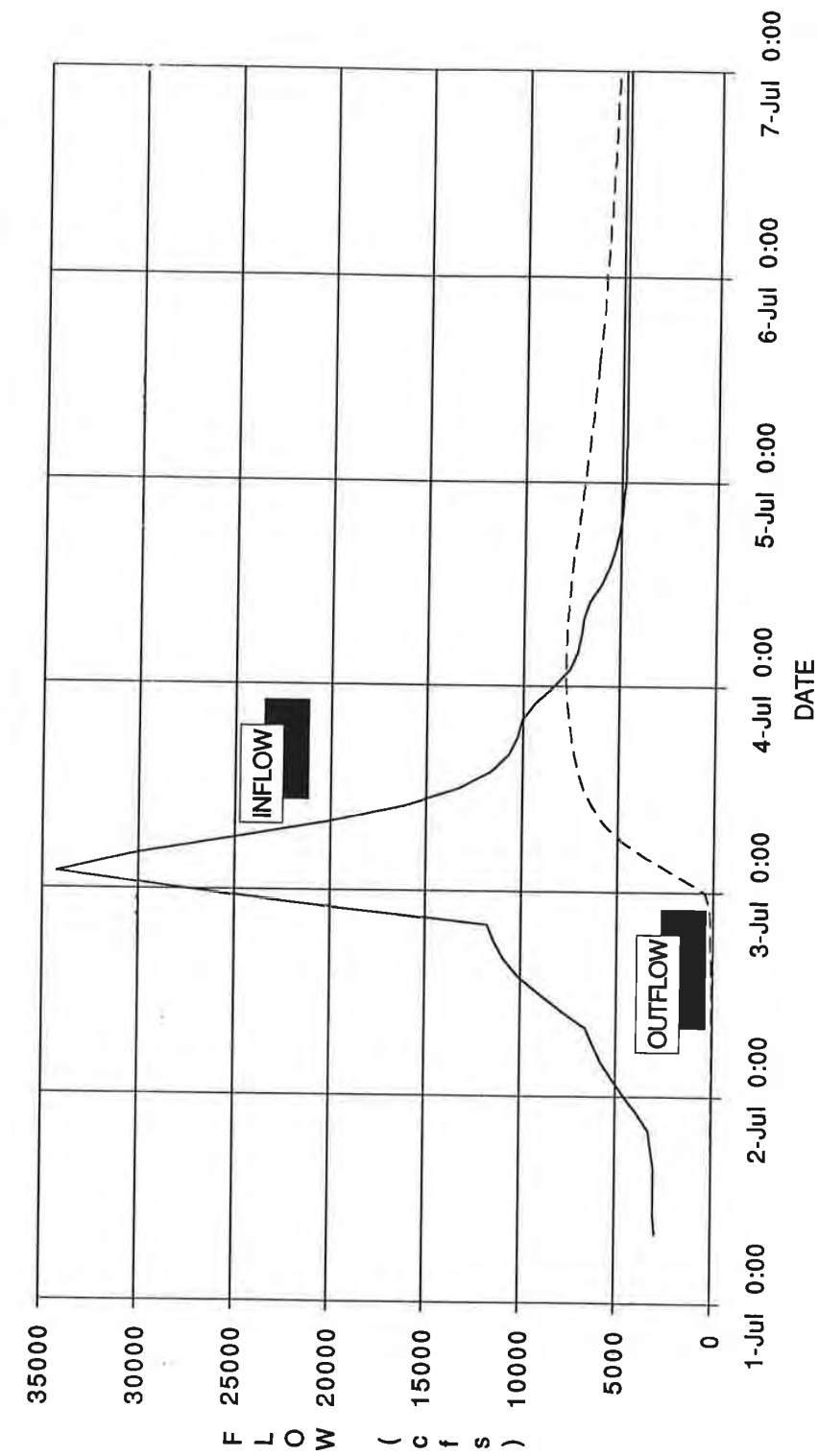
FIGURE 2.5.5
JULY PMF
LOW HEAD REGULATING DAM ONLY
AISHIHIK LAKE



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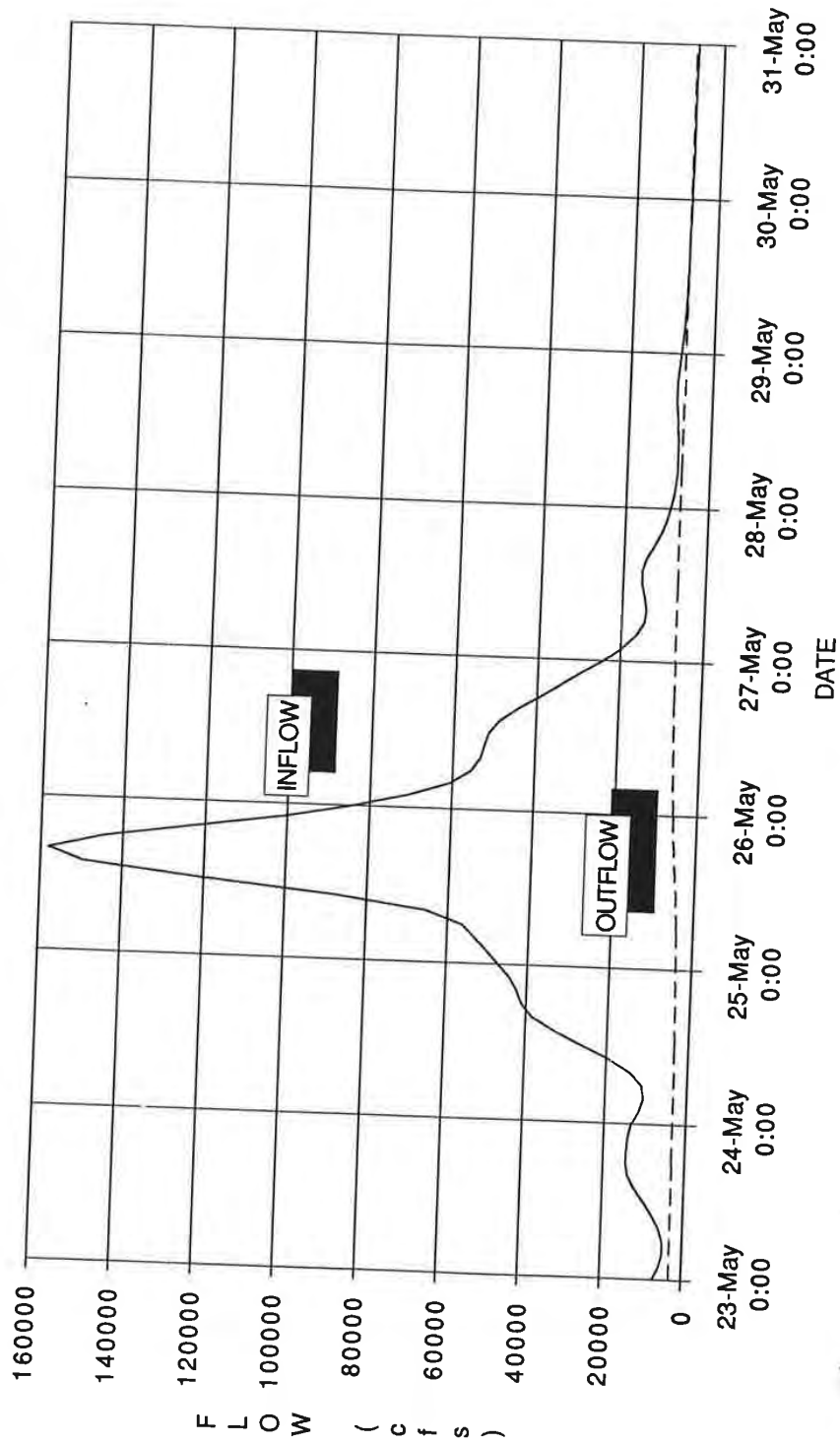
FIGURE 2.5.6
JULY PMF
LOW HEAD REGULATING DAM ONLY
CANYON LAKE



2-45

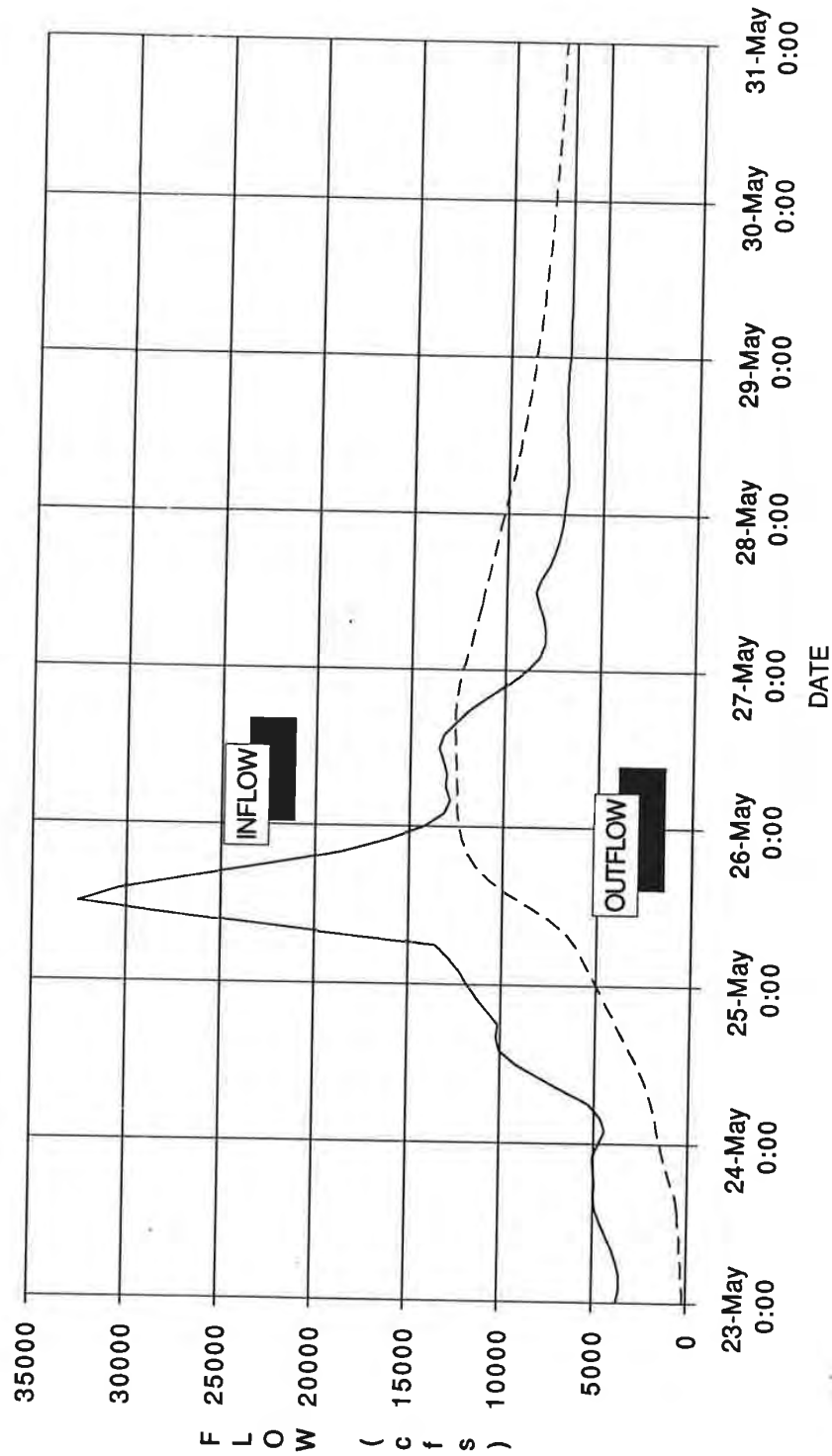
PART 2 - HYDROLOGY

FIGURE 2.5.7
 MAY PMF
 LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB
 AISHIHIK LAKE



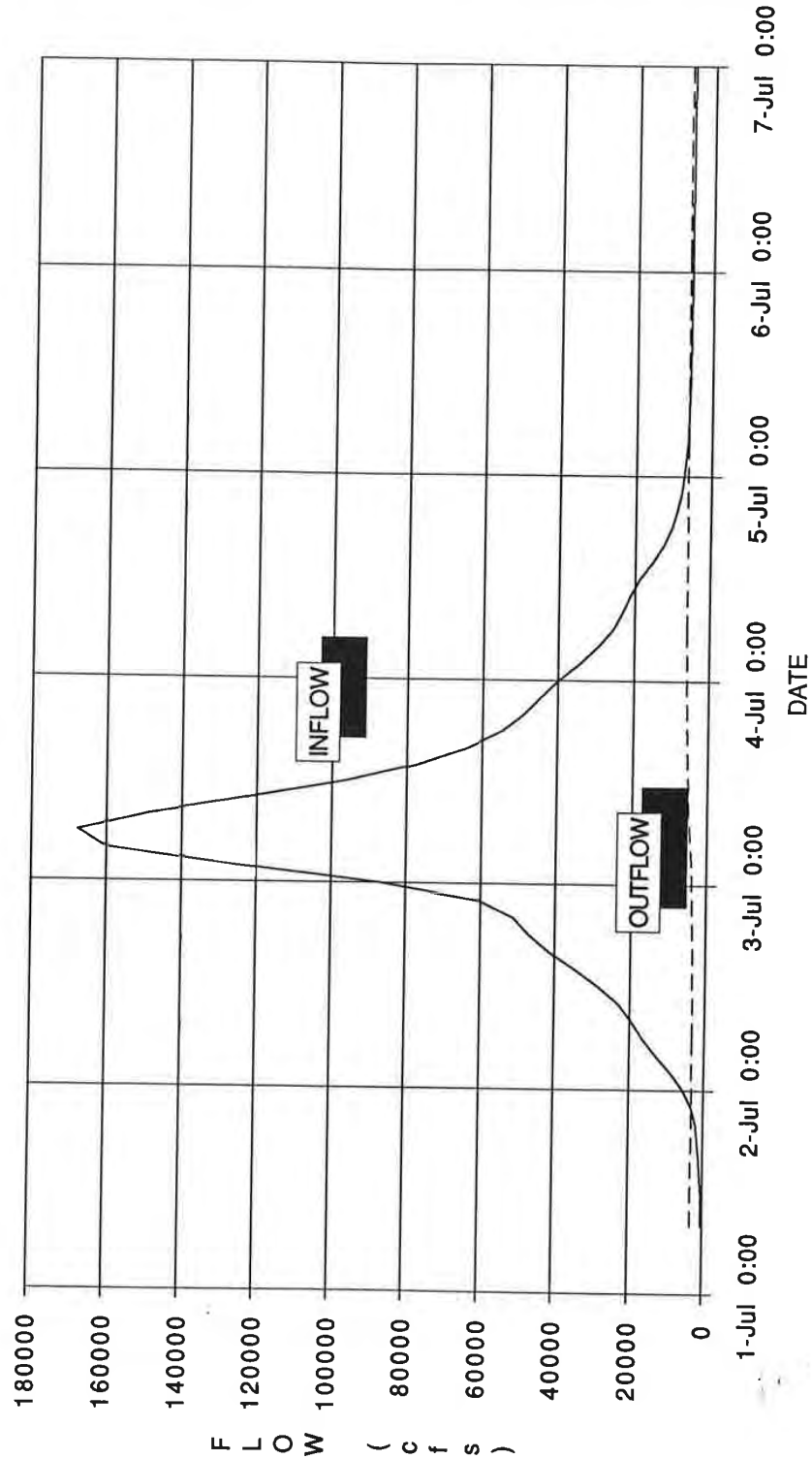
PART 2 - HYDROLOGY

FIGURE 2.5.8
 MAY PMF
 LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB
 CANYON LAKE



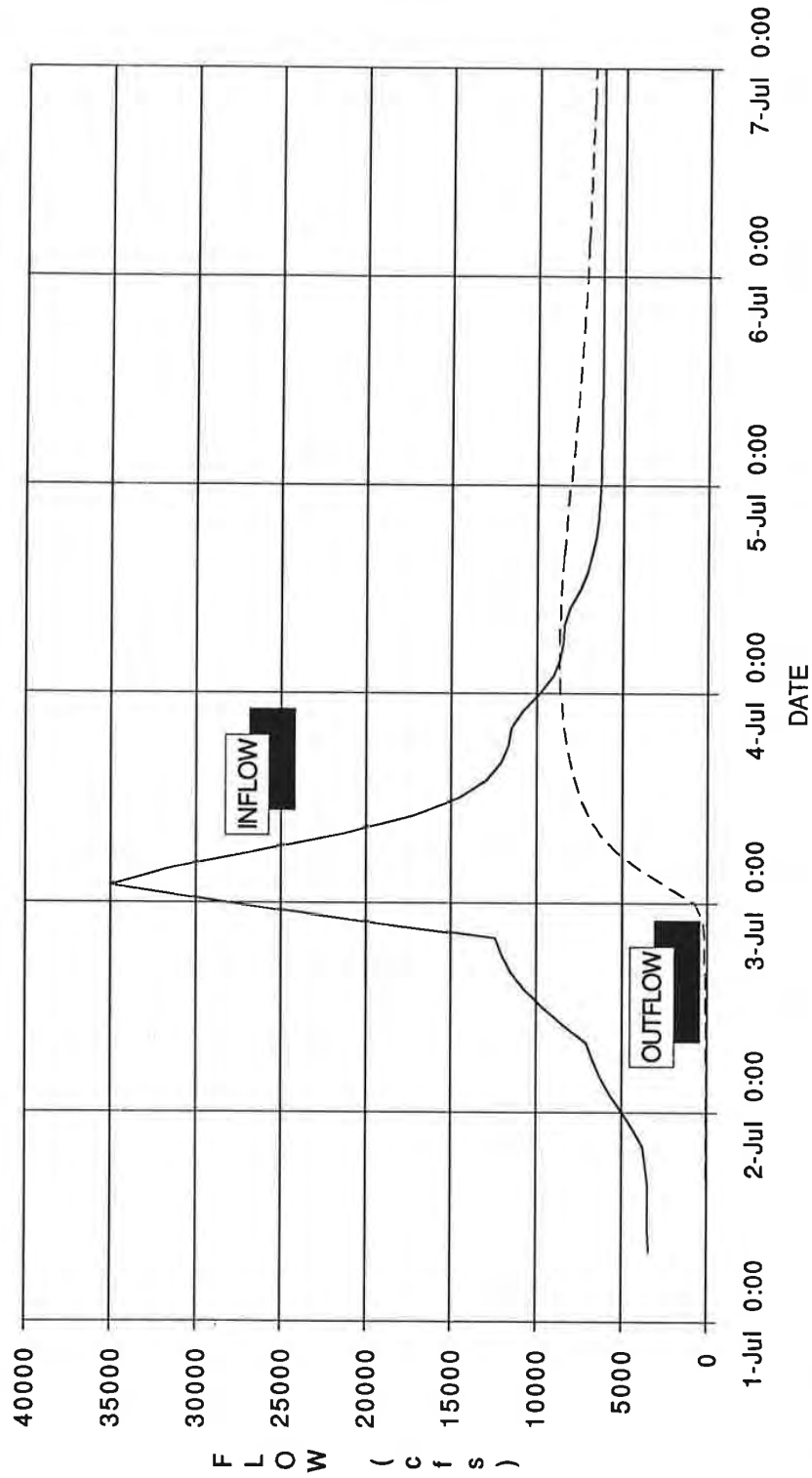
PART 2 - HYDROLOGY

FIGURE 2.5.9
 JULY PMF
 LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB
 AISHIHIK LAKE



PART 2 - HYDROLOGY

FIGURE 2.5.10
 JULY PMF
 LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB
 CANYON LAKE



PART 2 - HYDROLOGY

TABLE 2.5.1

Six-Hour Increments of Rainfall

TIME INTERVAL (hours)	July (PMP=250 mm)	Mid-May (PMP=179 mm)
1 - 6	5.5	3.75
6 - 12	5.5	3.75
12 - 18	13.5	9.75
18 - 24	13.5	9.75
24 - 30	24.3	17.70
30 - 36	24.3	17.70
36 - 42	100.1	72.00
42 - 48	24.3	17.70
48 - 54	13.5	9.75
54 - 60	13.5	9.75
60 - 66	5.5	3.75
66 - 72	5.5	3.75

Table 2.5.2

Elevation Sub-Zone Areas

ELEVATION INTERVAL (FT.)	AISHIHIK SUB-BASIN (SQR. KM)	SEKULMUN SUB-BASIN (SQR. KM)
3000 - 4000	840.00	320.25
4000 - 5000	462.10	426.60
5000 - 6000	84.20	358.90
6000 - 7000	5.70	92.30
+ 7000	0.00	1.75

PART 2 - HYDROLOGY

Table 2.5.3

Mid-May Temperature Sequence
(degrees C)

DATE	TIME INTERVAL (HOURS)			
	0 - 6	6 - 12	12 - 18	18 - 24
MAY 15	0	2.5	5	2.5
MAY 16	0	2.5	5	2.5
MAY 17	0	2.5	5	2.5
MAY 18	0	2.5	5	2.5
MAY 19	0	2.5	5	2.5
MAY 20	0	2.5	5	2.5
MAY 21	1	5	9	5
MAY 22	1	5	9	5
MAY 23	2	7	11	7
MAY 24	2	8	14	8
MAY 25	6.5	13.5	23	13.5
MAY 26	7	14	24	14
MAY 27	6.5	13.5	23	13.5
MAY 28	6	13	22	13
MAY 29	5.6	12.5	21	12.5
MAY 30	5.4	12	19.5	12
MAY 31	5	11.5	18.5	11.5

Table 2.5.4

Storage-Discharge Curve
for Sekulmun Lake

STORAGE 10 ⁶ m ³	DISCHARGE m ³ /s
0	0.0
5	3.0
10	5.0
15	7.2
20	10.0
25	13.0
30	16.0
36	20.0

STORAGE 10 ⁶ m ³	DISCHARGE m ³ /s
40	24.0
45	28.0
50	32.0
55	36.0
60	40.0
65	45.0
75	54.0
86	60.0

PART 2 - HYDROLOGY

TABLE 2.5.5
ELEVATION-DISCHARGE CURVE FOR AISHIHIK LAKE

LOW HEAD REGULATING DAM		CULVERTS (6) & TIMBER CRIB SLUICE		TOTAL	
ELEVATION (ft)	DISCHARGE (cfs)	ELEVATION (ft)	DISCHARGE (cfs)	ELEVATION (ft)	DISCHARGE (cfs)
2989.3	4	2989.3	0	2989.3	4
2992.1	259	2992.1	0	2992.1	259
2995.4	898	2995.4	0	2995.4	898
2998.7	1816	2998.7	0	2998.7	1816
3002.0	2758	3002.0	367	3002.0	3125
3005.2	3623	3005.2	973	3005.2	4596
3008.5	4471	3008.5	1445	3008.5	5916
3011.8	5329	3011.8	1782	3011.8	7111
3014.1	5933	3014.1	1993	3014.1	7926

TABLE 2.5.6
ELEVATION-DISCHARGE CURVE FOR CANYON LAKE

ELEVATION (ft)	DISCHARGE (cfs)
2968.0	0
2970.0	42
2972.0	72
2972.4	91
2974.1	165
2975.7	208
2977.4	580
2979.0	2122
2982.3	5227
3002.0	23767

PART 2 - HYDROLOGY

TABLE 2.5.7
MAY PMF
LOW HEAD REGULATING DAM ONLY

Sheet 1 of 3

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
23-May 0:00	7204	2798	3320	177
23-May 2:00	5827	2798	3178	177
23-May 4:00	5015	2834	3178	212
23-May 6:00	5085	2834	3355	212
23-May 8:00	6145	2834	3637	212
23-May 10:00	7946	2834	3920	247
23-May 12:00	10135	2834	4238	283
23-May 14:00	12325	2834	4520	353
23-May 16:00	13949	2869	4626	424
23-May 18:00	14585	2869	4556	459
23-May 20:00	14479	2869	4626	530
23-May 22:00	14161	2904	4662	565
24-May 0:00	13384	2904	4344	777
24-May 2:00	11936	2904	3991	953
24-May 4:00	10948	2940	4273	1130
24-May 6:00	11477	2940	4838	1307
24-May 8:00	14338	2940	6180	1554
24-May 10:00	19776	2975	7522	1836
24-May 12:00	26733	2975	8758	2154
24-May 14:00	33478	3010	9570	2543
24-May 16:00	38670	3046	9747	2931
24-May 18:00	41283	3116	9606	3284
24-May 20:00	42589	3152	10171	3637
24-May 22:00	44426	3187	10736	3991
25-May 0:00	47322	3258	11230	4379
25-May 2:00	50323	3293	11619	4732
25-May 4:00	53290	3334	12184	5121
25-May 6:00	56433	3399	12855	5509
25-May 8:00	65473	3470	19494	6074
25-May 10:00	87828	3576	25850	6922
25-May 12:00	121341	3682	31607	8052
25-May 14:00	149734	3823	29382	9182
25-May 16:00	158104	3964	25497	10135
25-May 18:00	144755	4141	21189	10806
25-May 20:00	123213	4282	17340	11230
25-May 22:00	101353	4388	14762	11477
26-May 0:00	83978	4494	12819	11583
26-May 2:00	70312	4565	11724	11619
26-May 4:00	60671	4636	11442	11619

PART 2 - HYDROLOGY

TABLE 2.5.7
MAY PMF
LOW HEAD REGULATING DAM ONLY

Sheet 2 of 3

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
26-May 6:00	55585	4706	11654	11619
26-May 8:00	53431	4742	11583	11619
26-May 10:00	52619	4812	11760	11619
26-May 12:00	51489	4848	11972	11654
26-May 14:00	48840	4883	11724	11654
26-May 16:00	44355	4954	11018	11619
26-May 18:00	39376	4989	10277	11583
26-May 20:00	34326	5024	9288	11513
26-May 22:00	29382	5025	8228	11371
27-May 0:00	24332	5060	7310	11159
27-May 2:00	19812	5095	6674	10948
27-May 4:00	16527	5095	6357	10736
27-May 6:00	14762	5095	6321	10524
27-May 8:00	14302	5130	6463	10312
27-May 10:00	14832	5131	6710	10100
27-May 12:00	15609	5131	6886	9923
27-May 14:00	15715	5166	6639	9782
27-May 16:00	14691	5166	6180	9606
27-May 18:00	13031	5166	5898	9429
27-May 20:00	11336	5166	5686	9252
27-May 22:00	10100	5166	5544	9041
28-May 0:00	9217	5201	5438	8864
28-May 2:00	8546	5201	5368	8687
28-May 4:00	8087	5201	5333	8511
28-May 6:00	7840	5201	5297	8370
28-May 8:00	7769	5201	5297	8193
28-May 10:00	7875	5201	5333	8052
28-May 12:00	8052	5201	5368	7910
28-May 14:00	8299	5201	5403	7769
28-May 16:00	8476	5201	5403	7663
28-May 18:00	8511	5201	5403	7522
28-May 20:00	8440	5237	5368	7416
28-May 22:00	8228	5237	5333	7310
29-May 0:00	7981	5237	5297	7204
29-May 2:00	7663	5237	5297	7134
29-May 4:00	7416	5237	5262	7028
29-May 6:00	7240	5237	5262	6922
29-May 8:00	7098	5237	5262	6851
29-May 10:00	6992	5237	5262	6780
29-May 12:00	6922	5237	5262	6674

PART 2 - HYDROLOGY

TABLE 2.5.7
MAY PMF
LOW HEAD REGULATING DAM ONLY

Sheet 3 of 3

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
29-May 14:00	6886	5237	5262	6604
29-May 16:00	6851	5237	5262	6533
29-May 18:00	6816	5237	5262	6463
29-May 20:00	6780	5237	5262	6427
29-May 22:00	6745	5237	5262	6357
30-May 0:00	6710	5237	5262	6286
30-May 2:00	6674	5237	5262	6251
30-May 4:00	6639	5237	5262	6180
30-May 6:00	6604	5237	5262	6145
30-May 8:00	6569	5272	5262	6109
30-May 10:00	6569	5272	5262	6074
30-May 12:00	6533	5272	5262	6003
30-May 14:00	6533	5272	5262	5968
30-May 16:00	6533	5272	5262	5933
30-May 18:00	6498	5272	5262	5898
30-May 20:00	6498	5272	5262	5862
30-May 22:00	6463	5272	5262	5827
31-May 0:00	6427	5272	5262	5827

PART 2 - HYDROLOGY

TABLE 2.5.8
JULY PMF
LOW HEAD REGULATING DAM ONLY

Sheet 1 of 2

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
1-Jul 8:00	530	2904	2931	0
1-Jul 10:00	565	2904	3002	0
1-Jul 12:00	706	2904	3002	0
1-Jul 14:00	953	2904	3002	0
1-Jul 16:00	1271	2904	3037	0
1-Jul 18:00	1695	2904	3178	35
1-Jul 20:00	2260	2904	3320	35
1-Jul 22:00	3390	2904	3885	35
2-Jul 0:00	5650	2904	4556	35
2-Jul 2:00	9041	2904	5227	35
2-Jul 4:00	12925	2904	5792	35
2-Jul 6:00	16633	2940	6251	35
2-Jul 8:00	19741	2940	6604	71
2-Jul 10:00	23202	2975	7910	71
2-Jul 12:00	28393	2975	9076	71
2-Jul 14:00	35138	3010	10171	106
2-Jul 16:00	41813	3046	10948	141
2-Jul 18:00	47357	3116	11442	177
2-Jul 20:00	51312	3152	11795	177
2-Jul 22:00	61094	3222	19847	212
3-Jul 0:00	87051	3293	27475	494
3-Jul 2:00	127027	3434	34255	1907
3-Jul 4:00	160187	3576	30477	3531
3-Jul 6:00	167780	3752	25321	4838
3-Jul 8:00	148851	3929	20165	5756
3-Jul 10:00	121694	4070	16139	6392
3-Jul 12:00	96232	4176	13349	6851
3-Jul 14:00	77798	4282	11654	7134
3-Jul 16:00	64308	4353	10736	7345
3-Jul 18:00	54808	4424	10277	7487
3-Jul 20:00	49052	4459	10065	7628
3-Jul 22:00	44708	4494	9394	7734
4-Jul 0:00	39906	4565	8405	7805
4-Jul 2:00	34432	4565	7593	7805
4-Jul 4:00	29452	4600	7204	7805
4-Jul 6:00	25674	4636	7028	7769
4-Jul 8:00	23343	4671	6922	7734
4-Jul 10:00	21401	4671	6604	7663
4-Jul 12:00	18752	4706	6039	7593

PART 2 - HYDROLOGY

TABLE 2.5.8
JULY PMF
LOW HEAD REGULATING DAM ONLY

Sheet 2 of 2

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
4-Jul 14:00	15397	4706	5615	7522
4-Jul 16:00	12537	4706	5333	7416
4-Jul 18:00	10524	4706	5121	7275
4-Jul 20:00	9111	4742	4979	7169
4-Jul 22:00	8158	4742	4909	7063
5-Jul 0:00	7451	4742	4838	6957
5-Jul 2:00	6992	4742	4803	6851
5-Jul 4:00	6639	4742	4803	6745
5-Jul 6:00	6392	4742	4767	6639
5-Jul 8:00	6215	4742	4767	6533
5-Jul 10:00	6074	4742	4767	6463
5-Jul 12:00	6003	4742	4767	6357
5-Jul 14:00	5933	4742	4767	6286
5-Jul 16:00	5862	4742	4767	6215
5-Jul 18:00	5827	4742	4767	6109
5-Jul 20:00	5756	4742	4767	6039
5-Jul 22:00	5721	4742	4767	5968
6-Jul 0:00	5721	4742	4767	5933
6-Jul 2:00	5686	4742	4767	5862
6-Jul 4:00	5650	4742	4767	5792
6-Jul 6:00	5615	4742	4767	5756
6-Jul 8:00	5615	4742	4767	5686
6-Jul 10:00	5580	4742	4767	5650
6-Jul 12:00	5544	4742	4767	5615
6-Jul 14:00	5544	4742	4767	5544
6-Jul 16:00	5509	4777	4767	5509
6-Jul 18:00	5474	4777	4767	5474
6-Jul 20:00	5474	4777	4767	5438
6-Jul 22:00	5438	4777	4767	5403
7-Jul 0:00	5438	4777	4767	5368

PART 2 - HYDROLOGY

TABLE 2.5.9 Sheet 1 of 3
MAY PMF
LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB SLUICE

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
23-May 0:00	7204	3178	3708	212
23-May 2:00	5827	3178	3567	247
23-May 4:00	5015	3178	3567	283
23-May 6:00	5085	3178	3743	318
23-May 8:00	6145	3178	3991	388
23-May 10:00	7946	3214	4308	424
23-May 12:00	10135	3214	4626	494
23-May 14:00	12325	3214	4909	530
23-May 16:00	13949	3249	5015	671
23-May 18:00	14585	3284	4944	918
23-May 20:00	14479	3284	5050	1130
23-May 22:00	14161	3320	5085	1342
24-May 0:00	13384	3320	4767	1519
24-May 2:00	11936	3355	4450	1695
24-May 4:00	10948	3355	4697	1836
24-May 6:00	11477	3390	5297	2013
24-May 8:00	14338	3390	6639	2225
24-May 10:00	19776	3426	7981	2507
24-May 12:00	26733	3461	9217	2825
24-May 14:00	33478	3531	10065	3178
24-May 16:00	38670	3567	10277	3567
24-May 18:00	41283	3637	10171	3920
24-May 20:00	42589	3743	10771	4273
24-May 22:00	44426	3814	11371	4626
25-May 0:00	47322	3885	11866	5015
25-May 2:00	50323	3991	12290	5368
25-May 4:00	53290	4061	12890	5756
25-May 6:00	56433	4167	13631	6145
25-May 8:00	65473	4273	20306	6710
25-May 10:00	87828	4414	26698	7557
25-May 12:00	121341	4626	32560	8687
25-May 14:00	149734	4838	30441	9853
25-May 16:00	158104	5085	26627	10806
25-May 18:00	144755	5335	22389	11513
25-May 20:00	123213	5544	18611	11972
25-May 22:00	101353	5721	16139	12219
26-May 0:00	83978	5898	14232	12395
26-May 2:00	70312	6003	13172	12466
26-May 4:00	60671	6074	12890	12466

PART 2 - HYDROLOGY

TABLE 2.5.9 Sheet 2 of 3
MAY PMF
LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB SLUICE

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
26-May 6:00	55585	6145	13137	12501
26-May 8:00	53431	6215	13066	12537
26-May 10:00	52619	6286	13243	12572
26-May 12:00	51489	6357	13490	12607
26-May 14:00	48840	6427	13243	12643
26-May 16:00	44355	6498	12572	12643
26-May 18:00	39376	6533	11830	12643
26-May 20:00	34326	6569	10842	12572
26-May 22:00	29382	6604	9817	12466
27-May 0:00	24332	6639	8899	12290
27-May 2:00	19812	6674	8264	12113
27-May 4:00	16527	6674	7981	11901
27-May 6:00	14762	6710	7946	11724
27-May 8:00	14302	6710	8087	11548
27-May 10:00	14832	6710	8334	11371
27-May 12:00	15609	6745	8511	11230
27-May 14:00	15715	6745	8228	11053
27-May 16:00	14691	6780	7805	10912
27-May 18:00	13031	6780	7522	10736
27-May 20:00	11336	6780	7310	10559
27-May 22:00	10100	6780	7169	10418
28-May 0:00	9217	6780	7063	10241
28-May 2:00	8546	6780	6992	10065
28-May 4:00	8087	6816	6922	9923
28-May 6:00	7840	6816	6886	9747
28-May 8:00	7769	6816	6922	9606
28-May 10:00	7875	6816	6922	9464
28-May 12:00	8052	6816	6957	9358
28-May 14:00	8299	6816	6992	9217
28-May 16:00	8476	6816	6992	9111
28-May 18:00	8511	6816	6992	9005
28-May 20:00	8440	6816	6992	8899
28-May 22:00	8228	6816	6957	8793
29-May 0:00	7981	6816	6922	8723
29-May 2:00	7663	6816	6886	8617
29-May 4:00	7416	6816	6886	8511
29-May 6:00	7240	6816	6886	8440
29-May 8:00	7098	6816	6851	8370
29-May 10:00	6992	6816	6851	8299
29-May 12:00	6922	6816	6851	8228

PART 2 - HYDROLOGY

TABLE 2.5.9

Sheet 3 of 3

MAY PMF

LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB SLUICE

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
29-May 14:00	6886	6816	6851	8158
29-May 16:00	6851	6816	6851	8087
29-May 18:00	6816	6816	6851	8016
29-May 20:00	6780	6816	6851	7946
29-May 22:00	6745	6816	6851	7910
30-May 0:00	6710	6816	6851	7840
30-May 2:00	6674	6816	6851	7805
30-May 4:00	6639	6816	6851	7734
30-May 6:00	6604	6816	6851	7699
30-May 8:00	6569	6816	6851	7663
30-May 10:00	6569	6816	6851	7593
30-May 12:00	6533	6816	6851	7557
30-May 14:00	6533	6816	6851	7522
30-May 16:00	6533	6816	6851	7487
30-May 18:00	6498	6816	6851	7451
30-May 20:00	6498	6816	6851	7416
30-May 22:00	6463	6816	6851	7416
31-May 0:00	6427	6816	6851	7381

PART 2 - HYDROLOGY

TABLE 2.5.10

Sheet 1 of 2

JULY PMF

LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB SLUICE

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
1-Jul 8:00	530	3355	3390	0
1-Jul 10:00	565	3355	3461	0
1-Jul 12:00	706	3355	3461	0
1-Jul 14:00	953	3355	3461	0
1-Jul 16:00	1271	3355	3496	35
1-Jul 18:00	1695	3320	3637	35
1-Jul 20:00	2260	3320	3779	35
1-Jul 22:00	3390	3320	4344	35
2-Jul 0:00	5650	3320	4979	35
2-Jul 2:00	9041	3355	5686	35
2-Jul 4:00	12925	3355	6251	35
2-Jul 6:00	16633	3390	6710	71
2-Jul 8:00	19741	3426	7098	71
2-Jul 10:00	23202	3461	8405	71
2-Jul 12:00	28393	3496	9606	106
2-Jul 14:00	35138	3531	10700	106
2-Jul 16:00	41813	3602	11477	141
2-Jul 18:00	47357	3708	12042	177
2-Jul 20:00	51312	3779	12431	177
2-Jul 22:00	61094	3885	20518	318
3-Jul 0:00	87051	4026	28216	777
3-Jul 2:00	127027	4238	35032	2437
3-Jul 4:00	160187	4485	31395	4097
3-Jul 6:00	167780	4767	26345	5403
3-Jul 8:00	148851	5050	21295	6357
3-Jul 10:00	121694	5262	17340	7028
3-Jul 12:00	96232	5438	14585	7487
3-Jul 14:00	77798	5580	12960	7805
3-Jul 16:00	64308	5686	12078	8052
3-Jul 18:00	54808	5756	11654	8264
3-Jul 20:00	49052	5862	11477	8440
3-Jul 22:00	44708	5933	10806	8546
4-Jul 0:00	39906	5968	9853	8652
4-Jul 2:00	34432	6003	9041	8687
4-Jul 4:00	29452	6074	8652	8687
4-Jul 6:00	25674	6074	8476	8687
4-Jul 8:00	23343	6109	8405	8687
4-Jul 10:00	21401	6145	8052	8652
4-Jul 12:00	18752	6145	7487	8617

PART 2 - HYDROLOGY

TABLE 2.5.10 Sheet 2 of 2
JULY PMF
LOW HEAD REGULATING DAM, CULVERTS & TIMBER CRIB SLUICE

DAY	AISHIHIK LAKE		CANYON LAKE	
	INFLOW (cfs)	OUTFLOW (cfs)	INFLOW (cfs)	OUTFLOW (cfs)
4-Jul 14:00	15397	6180	7098	8546
4-Jul 16:00	12537	6180	6816	8476
4-Jul 18:00	10524	6180	6604	8370
4-Jul 20:00	9111	6215	6463	8299
4-Jul 22:00	8158	6215	6392	8193
5-Jul 0:00	7451	6215	6321	8087
5-Jul 2:00	6992	6215	6286	8016
5-Jul 4:00	6639	6215	6286	7910
5-Jul 6:00	6392	6215	6251	7840
5-Jul 8:00	6215	6215	6251	7734
5-Jul 10:00	6074	6215	6251	7663
5-Jul 12:00	6003	6215	6215	7593
5-Jul 14:00	5933	6215	6215	7522
5-Jul 16:00	5862	6215	6215	7451
5-Jul 18:00	5827	6215	6215	7381
5-Jul 20:00	5756	6215	6215	7345
5-Jul 22:00	5721	6215	6215	7275
6-Jul 0:00	5721	6215	6215	7204
6-Jul 2:00	5686	6215	6215	7169
6-Jul 4:00	5650	6215	6215	7134
6-Jul 6:00	5615	6215	6215	7063
6-Jul 8:00	5615	6215	6215	7028
6-Jul 10:00	5580	6215	6215	6992
6-Jul 12:00	5544	6215	6215	6957
6-Jul 14:00	5544	6215	6215	6922
6-Jul 16:00	5509	6215	6215	6886
6-Jul 18:00	5474	6215	6215	6851
6-Jul 20:00	5474	6180	6215	6816
6-Jul 22:00	5438	6180	6215	6780
7-Jul 0:00	5438	6180	6215	6745

PART 3 - SUMMARY

3.0 SUMMARY

The purpose of this study was to carry out a PMP/PMF analyses and to evaluate the development and its existing spill facilities.

The PMF analysis indicated that the peak inflow occurred during the July flood. However, the May PMF which contains snow melt runoff although producing a lower peak inflow provided a larger volume of inflow affecting peak reservoir elevations to a greater extent. The peak May PMF reservoir elevation under existing conditions was 3011.6 ft assuming only the low head regulating dam was used. If the existing culverts and timber crib sluice structure were utilized the peak elevation would be 3011.0 ft. This results in overtopping of the low earthfill structures adjacent to the existing spillway. A minimal amount of modifications are required to raise the low sections so that overtopping does not occur. The estimated cost for this work is approximately \$5300. The corresponding peak elevation at Canyon Lake is 2989.1 ft when only the regulating dam is used and 2990.2 ft when the culverts and timber crib are utilized at Aishihike Lake.

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