ALASKA POWER AUTHORITY

SUSITNA HYDROELECTRIC PROJECT

SUBTASK 6.05 - DEVELOPMENT SELECTION REPORT

FIRST DRAFT

FEBRUARY 13, 1981

TABLE OF CONTENTS AND REPORT STATUS

These three sections have not been included and will appear in the second draft.

For first draft purposes, these two sections are identical to Chapters 4 and 6 in the Project Overview Report/POR and are, therefore, not reproduced here.

Essentially complete. More details on energy yield sensitivity analyses is to be added to the end of the section.

This section requires more details on costs of thermal alternatives and are the results of generation planning work, particularly the sensitivity analyses. A section on the multiobjective project selection process (i.e. including economic and environmental parameters) is to be added.

This section will be expanded to incorporate more details of the ongoing dam site layout and dam design work.

Complete.

6 - SUSITNA BASIN STUDIES

6 - SUSITNA BASIN STUDIES

6.1 - Introduction

This section outlines the preliminary Susitna Basin studies that have been carried out. The objective of these studies is to generate cost and energy yield information on the more promising Susitna Basin hydroelectric development options as input to the railbelt generation planning studies described in Section 7. More detailed engineering studies of the selected Watana/Devil Canyon development are described in Sections 8 and 9.

The first part of this section deals with pertinent climatologic, hydrologic, geotechnical and seismic aspects. A discussion of the site selection and screening process follows. It incorporates the results of the preliminary engineering layout studies used to develop capital cost estimates associated with development of the hydro potential at various sites within the basin. The results of detailed energy simulations for the more promising development options are also presented. The section concludes with an evaluation of a proposed tunnel scheme which could be substituted for the Devil Canyon dam scheme.

More detailed backup to the results presented here are contained in Appendices A through G.

6.2 - Climatology and Hydrology

This section briefly summarizes the available information for the Susitna Basin. For a more detailed outline of the existing data networks and data analyses carried out the reader is referred to Appendix E.

6.2.1 - Climate

(a) General

The climate of the Susitna Basin is generally characterized by cold, dry winters and warm, moderately moist summers. The upper basin upstream from Talkeetna is dominated by continental climatic conditions while the lower basin falls within a zone of transition between maritime and continental climatic influences.

Historical records of precipitation, temperature and other climatic parameters are collected by NOAA at several stations in and around the basin. However, there are no stations located upstream from Talkeetna. Therefore, no long-term records are available at or near the dam sites. The closest stations where long-term climate data is available are at Talkeetna to the south and Summit to the north. Typical data collected at the various stations is presented in Table 6.1. A summary of all historical data collected in the basin is presented in Table 6.2.

R&M Consultants have established six automatic climate stations in the upper basin during 1980 (see Figure 6.1). The data collected at these stations includes air temperature, average wind speed, wind direction, peak wind gust, relative humidity, precipitation, and solar radiation. Snowfall amounts are being measured in a heated precipitation bucket at the Watana station. Data are recorded at thirty minute intervals at the Susitna Glacier station and at fifteen minute intervals at all other stations.

(b) Precipitation

Precipitation in the basin varies from low to moderate amounts in the lower elevations to heavy in the mountains. Mean annual precipitation of over 80 inches is estimated at higher elevations (El +3000 ft) of the Talkeetna Mountains and the Alaskan Range whereas at Talkeetna station (El. 3.. ft) the average annual precipitation recorded is about 28 inches. The average precipitation reduces in a northerly direction as the continental climate starts to predominate. At Summit station (El. 2397 ft), the average annual precipitation is only 18 inches. The seasonal distribution of precipitation is similar for all the stations in and surrounding the basin. At Talkeetna, records show the 68 percent of the total precipitation occurs during the warmer months - May through October while only 32 percent is recorded in the winter months. Average recorded snowfall at Talkeetna is about 106 inches. Generally, snowfall is restricted to the months of October through April with some 82 percent snowfall recorded in the period November to March.

The U.S. Soil Conservation Service has established a network of snow course stations in the basin and records of snow depths and water content are available for varying periods extending from 1964. Stations within the Upper Susitna Basin are generally located at elevations below 3000 ft and indicate that annual snow accumulations are around 20 to 40 inches and that peak depths occur in late March. There is no historical data for the higher elevations. The basic network was expanded during 1980 with the addition of three new snow courses on the Susitna glacier (see Figure 6.1). R&M are cooperating with SCS in collecting information from the network during the study period.

(c) Temperature

Typical temperatures observed at the Talkeetna and Summit stations are presented in Table 6.3. It is expected that the temperatures at the dam sites will be somewhere between the values observed at these stations.

(d) River Ice

The Susitna River usually starts to freeze up by late October. River ice conditions such as thickness and strength vary according to the river channel shape and slope, and more importantly, with river discharge. Periodic measurements of ice thicknessness at several locations in the river have been carried out during the winters of 1961 through 1972. The maximum thicknessses observed at selected locations on the river are given in Table 6.4. Ice breakup in the river commences by late April or early May and ice jams occasionally occur ar river constrictions resulting in rises in water level of up to 20 ft.

Detailed field data collection programs and studies are underway to identify problem areas and develop mitigation measures. The field programs involve undertaking extensive observation of current freeze-up and breakup processes. This data will be used to calibrate computer models which can be used to predict the ice cover regime under post project conditions. It will then be possible to anticipate potential problems and to develop solutions to them.

6.2.2 - Hydrology

(a) Water Resources

The length of streamflow records at the gaging stations on the Susitna River and its tributaries vary from 30 years at Gold Creek to about five years at the Susitna station. There are no historical records of streamflow at any of the dam sites. The records at the gaging stations were extended using a multisite correlation technique (see Appendix E for details). The procedure used 30 year recorded data at Gold Creek and shorter records at other stations to fill in 30 year flows at each of the stations. The derived flow sets have been used to estimate streamflows at the dam sites using drainage basin areas as a basis.

A gaging station was established at the Watana dam site in June 1980 and continuous river stage data is being collected. It is proposed to develop a rating curve at the station with streamflow measurements taken over 1980 and 81 seasons. The flows will be calculated and used to check the procedure used to extrapolate streamflow data to the Watana site.

The Susitna River above the confluence wih the Chulitna River contributes approximately 20 percent of the mean annual flow measured near Cook Inlet (at Susitna station.) The average annual flow at Gold Creek is approximately 9300 cfs. Average annual flow and maximum and minimum values at other stations within the study area are given in Table 6.5.

Seasonal variation of flows is extreme and ranges from very low values in winter (October to April) to high summer values (May to September). For the Susitna River at Gold Creek the average winter and summer flows are 2100 and 20,250 cfs respectively (i.e. a 1 to 10 ratio). On average, approximately 88 percent of streamflow recorded at Gold Creek station occurs during the summer months. At higher elevations in the basin the distribution of flows is concentrated even more in the summer months. For the Maclaren River near Paxson (El. 4520 ft) the average winter and summer flows are 144 and 2100 cfs respectively (i.e. a 1 to 15 ratio). The monthly percent of annual discharge and mean monthly discharge for the Susitna River at the gaging stations are given in Table 6.6.

(b) Floods

The most common cause of flood peaks in the Susitna River Basin is snowmelt or a combination of snowmelt and rainfall falling over a large area. Annual maximum peak discharges generally occur between May and October with the majority, approximately 60 percent, occurring in June. Some of the annual maximum flood peaks have also occurred in August or later and are the result of heavy rains over large areas augmented by significant snowmelt from higher elevations and glacial runoff.

Flood frequency analyses have been carried out for the recorded floods in the Susitna and its tributaries, Copper, Matanuska and Tosina Rivers. These analyses were conducted for two different time periods within the year. One period selected was the open water period, i.e. after the ice breakup and before freezeup. This period contains the largest floods which must be accomodated by the project. The second period represented that portion of time during which ice conditions occur in the river. These floods, although smaller, can be accompanied by ice jamming, and must be considered during the construction phase of the project and used to check the size of coffer dams.

Using the results of the frequency analysis, a regional index curve has been developed which may be used for estimating floods in ungaged rivers and streams and to check the accuracy of the Gold Creek Station curve which is important in determining spillway design floods for Susitna River projects. Multiple regression equations have been developed using physiographic parameters of the basin such as catchment area, stream length, mean annual precipitation, etc. to assess flood peaks at the dam sites and intermediate points of interest in the river. Detailed discussion of the analyses are presented in Appendix E. Some of the results are summarized in Table 6.7.

Estimates of the probable maximum floods in the Susitna Basin were made by COE in their study in 1975. A river basin simulation model (SSARR) was used for the purpose. A detailed review of the input data to the model has been undertaken and discussions held with COE engineers to improve understanding of the model parameters used. A series of computer runs with the model were undertaken to study the effects of likely changes in the timing and magnitude of the three important parameters, i.e. probable maximum precipitation, snow pack and temperature. The objective of these runs was to examine the sensitivity of the estimated flood flows to changes in the principal parameters causing the floods. The results of these studies indicated that the changes in input data did not increase the flood peaks calculated by the COE by more than ( ) percent. Consideration is therefore being given to re-evaluating the PMF for purposes of project design. The sensitivity analyses are described in more detail in Appendix E.3. Table 6.7 indicates the COE PMF values which are currently used.

(c) River Sediment

Periodic suspended sediment samples have been collected by the USGS at the four gaging stations upstream from Gold Creek (see Figure 6.__) for varying periods between 1952 and 1979. Except for three samples collected at Denali in 1958, no bed load sampling has been undertaken at any stations. Data coverage during high-flow high sediment events is poor and consequently any estimate of total annual sediment yield has a high degree of uncertainty.

The most comprehensive analysis of sediments had in the river to date is that undertaken by the COE in 1975. Table 6.8 gives the COE estimates of sediment transport at the gaging stations.

6.3 - Geology and Geotechnical Aspects

6.3.1 - Geology

(a) Regional Geology

The Upper Susitna Basin lies within what is geologically called the Talkeetna Mountains area. This area is geologically complex and has a history of at least three periods of major tectonic deformation. The oldest rocks (250-300 m.y.b.p.)* exposed in the region are volcanic flows and limestones which are overlain by sandstones and shales dated approximately 150-200 m.y.b.p. A tectonic event approximately 135-180 m.y.b.p. resulted in the intrusion of large diorite and granite plutons, which caused intense thermal metamorphism. This was follwed by marine deposition of silts and clays. The argillites and phyllites at Devil Canyon were formed from the silts and clays during faulting and folding of the Talkeetna Mountains area in the Late Cretaceous period (65-100 m.y.b.p.)[5]. As a result of this faulting and uplift, the eastern portion of the area was elevated, and the oldest volcanics and sediments were thrust over the younger metamorphics and sediments. The major area of deformation during this period of activity was southeast of Devil Canyon and included the Watana area. The Talkeetna Thrust Fault, which trends northwest through this region, was one of the major mechanisms of this overthrusting from southeast to northwest. The Devil Canyon area was probably deformed and subjected to tectonic stress during this period, but no major deformations are evident at the site (Figure 6.2).

*m.y.b.p.: million years before present

The diorite pluton that forms the bedrock of the Watana site was intruded into sediments and volcanics about 65 m.y.b.p. The andesite and basalt flows near the site may have been formed immediately after this plutonic intrusion, or after a period of erosion and minor deposition.

During the Tertiary period (20-40 m.y.b.p.) the area surrounding the sites was again uplifted as much as 3,000 feet. Since then widespread erosion has removed much of the older sedimentary and volcanic rocks. During the last several million years at least two alpine glaciations have carved the Talkeetna Mountains into the ridges, peaks, and broad glacial plateaus as seen today. Post-glacial uplift has induced downcutting of streams and rivers, resulting in the 500 to 700 feet deep V-shaped canyons that are evident today, particularly at the Vee and Devil Canyon dam sites. This erosion is believed to be presently active and so virtually all streams and rivers in the region are considered to be actively downcutting. This continuing erosion has removed much of the glacial debris at higher elevations but very little alluvial deposition has occurred. The resulting landscape consists of barren bedrock mountains, glacial till covered plains, and exposed bedrock cliffs in canyons and along streams. The arctic climate has retarded development of topsoil.

(b) Site Geology

The dam site at Watana is underlain by a dioritic intrusion (pluton). The site has a favorable configuration because the river has cut down through the intrusion, resulting in a narrow canyon. The pluton is bounded at the upstream and downstream edges by sedimentary rocks that show evidence of being deformed and/arched upwards by the plutonic intrusion (Figure 6.3). The evidence to date indicates that the sedimentary rock has been eroded from the top of the pluton at the immediate site. Following intrusion, at intervals that have not yet been determined, volcanics erupted into the area. These volcanics form the basalt flows exposed in the canyon near Fog Creek downstream of the site, and the andesite flows over the pluton at the dam site. There is no indication of basalt flows within the immediate dam site, but the andesite has been detected in several borings in the western portion of the site. The nature and characteristics of the diorite-andesite contact will be further investigated in the 1981 program. The surficial material at the dam site is predominantly talus and very thin glacial sediments on the abutments, with limited deposits of river alluvium and lake clay at isolated locations. The river channel is filled up to 80 feet of alluvial deposits derived from till and talus material. The drilling and seismic lines indicate that the bedrock weathering averages ten to twenty feet, with a very distinct gradation from weathered to unweathered rock. The surficial weathering processes seem to be primarily physical rather than chemical. Bedrock quality below 60 feet is uniform to the maximum depths drilled. The pattern of sound, unweathered rock zones are separated by shear zones of rock altered by injection of felsite and andesite dikes, with subsequent deterioration of the broken rock by groundwater. The basic conditions are favorable to construction of both surface and underground structures, with remedial treatment likely to be limied to shear zones.

Devil Canyon is a very narrow V-shaped canyon cut through relatively homogeneous argillite and graywacke. This rock was formed by low-grade metamorphism (application of tectonic heat and pressure) of marine shales, mudstones, and clayey sandstones. The bedding strikes about 15° northeast of (subparallel to) the river alignment through the canyon and dips at about 65° to the southwest. The rock has been deformed and moderately sheared by the southeast to northwest acting regional tectonic forces, causing shearing and jointing parallel to this force (Figure 6.4). The glaciation of the past few million years apparently preceded the erosion of the canyon by the river. Glacial deposits blanket the valley above the V-shaped canyon, while deposits in the canyon itself are limited to a large gravel bar just upstream of the canyon entrance, and boulder and talus deposits at the base of the canyon walls.

Bedrock conditions at Devil Canyon vary within a limited range due to changes of lithology, but the rock is basically sound and fairly durable. Jointing and shears are frequently quite open at the surface, but there is a general tightening of such openings with depth. The major joint set strikes about North 30° West across the canyon, and may be an indication of shear zones in this direction. WPRS mapped shear zones at this orientation, with 80-90° dips. Two minor sets strike roughly North 60-90° East, with dips of about 50-60° south and 15° south. The orientation of the joints, and particularly the shear zones, is not well defined. Further field mapping in 1981 should clarify this.

6.3.2 - Geotechnical Aspects

The evaluation of the Watana and Devil Canyon dam sites required assessment of geology, rock mechanics, foundation conditions and foundation treatment requirements. In addition, the influence of permafrost and site configuration on construction feasibility were considered and sources of concrete aggregate, impervious core material and embankment fill were investigated. The summary of data from these investigations is discussed by site. A description of the 1980 field investigations and geologic maps to date is presented in Appendix G.

(a) Watana Site

The Watana dam site lies predominantly on sound diorite with some portions of the downstream shell being on andesite. The upper ten to forty feet of rock is weathered. Currently, a high rockfill dam with impervious core is planned at the site. The seismic considerations for the site, as discussed in Section 6.4.3 dictate that the relatively loose alluvium (up to 80 feet in depth) will be removed from underneath the entire dam. In addition, up to 40 feet of rock excavation will be required under the impervious core and the supporting filters to found the dam on sound competent rock. This type of foundation preparation is considered normal for large dams of comparable size. Shear zones and joints within the rock foundation have been located and will require consolidation and curtain grouting, and may necessitate the inclusion of drainge features within the foundation and the abutments. Permafrost is present on the left abutment and may also be present under the river channel. The data indicates that this is a "warm" permafrost and can be economically thawed for grouting.

A deep relict channel exists on the right abutment. The overburden within this relict channel contains a sequence of glacial till and outwash interlayered with silts and clays of glacial origin. The top of rock under the relict channel area will be below the reservoir level. Further investigations will be undertaken to precisely define the characteristics of the channel. However, the data collected to date does not indicate that this relict channel will have any major impact on the feasibility of the site.

The rock conditions in the left abutment, where the underground powerhouse is proposed, are favorable for an underground structure. The powerhouse cavern will require nominal support. The rock condition is expected to be favorable; although, additional investigations will be conducted to determine the exact location and orientation of the features, so as to minimize the impact of joints and any possible unfavorable stress orientation.

Materials for construction of either a rockfill dam or related concrete structures are available within economical distances. Impervious and semi-pervious core and filter materials are available within three miles (4.8 km) upstream (Figure 6.5), and a good source of filter material and concrete aggregate is available at the mouth of Tsusena Creek just downstream of the dam. Rockfill is available immediately adjacent to the dam in the left abutment where rock is removed from the core excavation and excavation for tunnels, the powerhouse, and spillway structures. There is also a possibility of using rounded riverbed material for the shell if adequate quantity is available. Further investigation will be conducted to better define the quantity and characteristics of material in each source area and the relative economics of each borrow location.

(b) Devil Canyon Site

The Devil Canyon dam site lies on argillite and graywacke exhibiting significant jointing and frequent shear zones. The nature of the rock is such that numerous zones of gouge, alteration, and fractured rock were caused during the major tectonic events of the past, in addition to the folding and internal slippage during lithification and metamorphism. Consequently, zones of deep weathering and alteration can be expected in the foundation. Excavation of up to 40 feet of rock will expose sound foundation rock, and consolidation grouting and dental excavation of badly crushed and altered rock will be necessary to provide adequate bearing surfaces for either a rockfill or concrete dam. Overburden within the narrow V-section of the valley is minimal.

The left abutment plateau, which is the location of a saddle dam, has a buried river channel paralleling the river (Figure 6.6). The overburden reaches 90 feet under a small lake in this area, so construction of the saddle dam will require excavation of considerable amounts of fill and lake deposits, or construction of a cutoff extending down to bedrock. Seepage control will be effected by two methods: first, by general contact and consolidation grouting to control flow at the dam foundation contact, and second by a deep grout curtain with corresponding drain hole curtain to limit downstream flow through the foundation. Permafrost has not been detected at the site, but if it does exist, it is not expected to be substantial or widespread. A thawing program can be incorporated with the grout hole installation if necessary.

Construction materials for a concrete dam are available in the large gravel bar immediately upstream of the dam site (Figure 6.7). The materials in this bar are adequate in quantity for all the needs of a concrete dam, or can fill all concrete aggregate and filter requirements for an earthfill dam. The lakebed and till deposits in Cheechako Creek (approximately 0.25 miles upstream), may be sources of a substantial portion of impervious material requirements for an earthfill dam, and are felt to be fully adequate for construction of an earthfill saddle dam in the concrete main dam scheme.

Sufficient local rock for rockfill shell material is available should a rockfill dam be decided on for Devil Canyon. However, testing will be performed to ensure that it is suitable for continuous exposure to water and freeze-thaw cycles. Additional sources of impervious fill material are needed before the feasibility of a rockfill dam at this site can be determined.

6.4 - Seismic Aspects

6.4.1 - Seismic Geology

The Talkeetna Mountains region of south-central Alaska lies within the Talkeetna Terrain. This term is the designation given to the immediate region of south-central Alaska that includes the upper Susitna River basin (as shown on Figure 6.8). The region is bounded on the north by the Denali Fault, and on the west by the Alaska Peninsula features that make up the Central Alaska Range. South of the Talkeetna Mountains, the Talkeetna Terrain is separated from the Chugach Mountains by the Castle Mountain Fault. Susitna Hydroelectric Project dam sites are located in the western half of the Talkeetna Terrain. The eastern half of the region includes the relatively inactive, ancient zone of sediments under the Copper River Basin and is bounded on the east by the Totschunda section of the Denali Fault and the volcanic Wrangell Mountains.

The studies and research conducted to date indicate that the Talkeetna Terrain is a relatively stable section of crust with most of the seismic activity in the area attributed to the Denali and Castle Mountain Faults, which have a record of recent displacements, and to the Benioff Zone.

The Talkeetna Terrain is being underthrust by the Pacific Plate, which is moving in a northwest direction in this area. The Benioff Zone is the contact surface between the crustal (North American) plate and the subducted (Pacific) Plate, and is the source of the most of the large seismic events in Alaska.

Within the Talkeetna Terrain, numerous lineaments and suspected features were investigated by Woodward-Clyde Consultants as part of their 1980 seismic studies. Utilizing available air photos, satellite imagery and airborne remote sensing data, a catalog of reported and observable discontinuities and linear features (lineaments) was compiled. After elimination of those features that were judged to be caused by glaciation, bedding, river processes, or man's impact, the 216 remaining features were screened and those passing the screen were classified as either being features that could positively be identified as faults, or features which could possibly be faults but for which a definitive origin could not be identified.

The following criteria were used in the screening process:

(1) All lineaments or faults that have been defined by the geologic and seismologic communities as having been subjected to recent displacement should be included in assessing the seismic design criteria for the project and are not screened out.

(2) If a lineament exists within 6 miles of a structure site, or if a branch of a more distant lineament is suspected of passing through a structure site, then a more detailed investigation should be made to establish whether the feature is a fault, whether or not it can be considered to have recent displacement, and whether the potential for displacement in the structure foundation exists. It is therefore not screened out.

(3) Investigation of features identified in Item 2 should determine whether these features have experienced displacement in the last 100,000 years. If they have not then they are screened out.

(4) Lineaments more distant than 6 miles from a structure site, and for which deterministic impact on the site may control the design of a structure, should be investigated to determine if the lineament is a fault and if it has moved within the last 100,000 years.

(5) All features identified as faults which have experienced movement in the last 100,000 years should be considered to have had recent displacement. All faults with recent displacement warrant consideration when assigning design criteria for ground motions or for surface displacement at the structure sites.

These guidelines were formulated after review of regulatory requirements of the WPRS, COE, U.S. Nuclear Regulatory Commission, Federal Energy Regulatory Commission, and several state regulations.

To support these studies, a 10-station microseismic network was installed in June of 1980 and operated for three months. The results were integrated with the seismic geology and the historical seismicity data.

As a result of the 1980 field investigations and microseismic network, the resultant group of 48 significant features were identified and analyzed for potential impact to the project even though these features are faults and lineaments for which no recent displacement (which is an index of activity) was found. They were selected as there is no direct evidence showing lack of displacement. This approach is conservative and compatible with the conservative design philosophy used for design of large projects. Of these 48 candidate features, only 13 features were judged to be significant for the design of the project. These thirteen features include four features at the Watana site (including the Talkeetna Fault and the Susitna feature) and nine features at the Devil Canyon site. It is worth noting that no evidence of the Susitna feature was observed during the 1980 studies. These thirteen features will be further investigated during 1981 to establish their impact on the project design.

6.4.2 - Seismology

The regional earthquake activity is closely related to the plate tectonics of Alaska. The Pacific Plate is underthrusting the North American Plate in this region. The major earthquakes of Alaska, including the Good Friday earthquake of 1964, have primarily occurred along the boundary between these plates.

The historical seismicity within the site region is associated with the following sources: the crustal earthquakes within the North American Plate and the shallow and deep earthquakes generated within the Benioff Zone. The historical earthquake records for south-central Alaska and the site region, in particular, were reviewed. The data reveals that the major source of earthquakes in that region is the shallow portion of the Benioff Zone. Several large earthquakes during the twentieth century have been related to this source. The next major source of earthquakes in the site region is in the deep portion of the Benioff Zone, with depths ranging between 24 to 36 miles (40 to 60 km) below the surface. Several moderate size earthquakes have been reported to have been generated at these depths. The crustal seismicity within the Talkeetna Terrain is very low based on historical records. Most of the earthquakes are reported to be related to the Denali-Totschunda Fault or Castle Mountain Fault.

As mentioned previously, a short-term microseismic monitoring network was installed and operated for three months. The objective of this study was to collect microearthquake data in order to evaluate the locations and focal depths of microearthquakes, study the types of faulting and stress orientation within the crust, study the association of microearthquakes with surface faults and lineaments and to understand wave propagation characteristics. A total of 265 earthquakes with sensitivity approaching magnitude zero were recorded. Out of these events, 170 were recorded at shallow depths, the largest being magnitude 2.8 (Richter Scale). Ninety-eight events were related to the Benioff Zone, the largest being magnitude 3.68. None of the microearthquakes recorded at shallow depths were found to be related to any fault or lineament within the Talkeetna Terrain, including the Talkeetna Fault. The depth of the Benioff Zone was distinctly defined by this data as being 36 miles (60 km) under the Devil Canyon site and 39 miles (65 km) under the Watana site.

The subject of Reservoir Induced Seismicity (RIS) was studied on a preliminary basis using a worldwide RIS study and site specific information. The phenomenon of RIS has been noticed in numerous large reservoirs with accepted correlation between seismic tremors under or immediately adjacent to the reservoir and periods of high filling rate. In recent years, this subject has drawn considerable attention within the engineering and seismic community. It is thought that RIS may be caused by the increased weight of the water in the reservoir or by the increased pore pressure migrating through joints in the rock and "lubricating" and acting hydraulically upon highly stressed rock. Studies indicate that for a reservoir system to trigger a significant earthquake, a pre-existing fault with recent displacement must be under or very near to the reservoir. The presence of a fault with recent displacement has not been confirmed at either site. The analysis of previously reported cases indicated a high probability of RIS for the Susitna system on the basis of its depth and volume, if faults with recent displacement exist nearby. Most RIS is felt to be an early release of stored energy in a fault, so in serving as a mechanism for energy release, the resultant earthquakes are likely to be smaller than if full energy buildup occurred. In no case studied has an RIS event exceeded the maximum credible earthquake or any fault[3]. Therefore, RIS of itself does not control the design earthquake determination and is considered only for purposes of estimating recurrence intervals[4].

6.4.3 - Preliminary Evaluation of Design Ground Motion

On the basis of the geologic and seismic studies, three main sources of earthquakes have been identified. These sources include the Denali Fault (39 miles) north of the sites, Castle Mountain Fault less than 60 miles (100 km) south of the site and the Benioff Zone 30 to 36 miles. The thirteen other faults and lineaments considered significant for the project design were not included in assigning earthquakes, as no evidence was found to indicate that these faults and lineaments experienced displacement during recent geologic times. However, further field studies will be conducted on these features due to their proximity to the sites and resultant potential ground rupture considerations.

The Denali Fault has been assigned a preliminary conservative maximum credible earthquake value of magnitude 8.5. This earthquake, when attenuated to the sites, is postulated to generate a mean peak acceleration of 0.21g at the Watana and Devil Canyon sites. The Castle Mountain Fault has been assigned a preliminary conservative value of magnitude 7.4, which will generate a mean peak acceleration of 0.05g to 0.06g range at the sites. The Benioff Zone has been assigned an upper bound conservative value of magnitude 8.5, which will generate a mean peak acceleration of 0.41g at the Watana site and 0.37g at the Devil Canyon site. The duration of strong motion earthquakes for both the Denali and Benioff Zone is estimated to be 45 seconds. It is evident that out of these three potential sources, the Benioff Zone will govern the design. However, further studies will be undertaken to finalize these maximum credible earthquake magnitudes and to evaluate faults and features within the Talkeetna Terrain. Due to their distant locations, none of these faults have any potential for ground rupture at the site.

Large dams have been designed to accommodate ground motions from relatively large earthquakes located close to the dam. In California, dams are routinely designed to withstand ground motions from magnitude 7.5 to 8.5 earthquakes at distances of 12 miles. Dams have also been designed to accommodate up to 20 feet of horizontal displacement and three feet of vertical displacement[2]. All of these conditions are more severe than those anticipated at the Susitna sites. Oroville Dam in central California was designed to high seismic loadings and has been progressively analyzed as new data and methods become available. Current evaluations indicate that the dam, which is comparable size to Watana, can withstand seismic loadings comparable to those postulated for Watana.

6.5 - Susitna Basin Planning Studies

The objective of the planning exercise is to systematically evaluate all alternative plans for developing power from the Susitna Basin upstream from Gold Creek and to select the most promising plans for more detailed study. The process adopted involved several steps which included indentifying potential dam sites within the basin and then proceeding through several screening exercises to eliminate most of the less economic and environmentally less acceptable sites. Finally a more detailed evaluation of the costs and energy benefits of the shortlisted plans was carried out. Throughout this planning process, engineering layout studies were conducted to refine the cost estimates for developing power at specific sites. As it became available this cost data was fed into the screening process to ensure that earlier decisions based on previous data were still valid.

The basic planning steps are listed below and are also illustrated on Figure 6.9:

(a) Site selection
(b) Preliminary screening
(c) Final screening
(d) Refinement of Susitna Basin development options.

Step 1 involved selecting previously identified sites and desk studies aimed at identifying any additional sites. The preliminary screening (Step 2) exercise involved eliminating from further consideration the obviously less attractive sites based on economics and potential environmental impact. This exercise was initially based on published cost and energy data for the sites. As the in-house studies progressed, more up-to-date costs and energy values were incorporated. Final screening (Step 3) involved the application of a computer program to systematically investigate all possible combinations and permutations of dam site, dam height, and installed capacity and the determination of the economic optimum development for specified total power and energy production. The plans, thus identified, were then further refined utilizing a computer model to simulate monthly energy and power production and detailed reservoir operating rule curves. These refined plans were then utilized as input to the generation planning and development selection studies described in Section 7.

30

The planning process is described in more detail in the sections that follow.

6.6 - Site Selection and Preliminary Screening

6.6.1 - Site Selection

In the previous Susitna Basin studies discussed in Section 4, twelve dam sites were identified in the upper portion of the basin; i.e., upstream from Gold Creek (see Figure 6.10). These sites are listed below:

(1) Gold Creek
(2) Olson (alternative name: Susitna II)
(3) Devil Canyon
(4) High Devil Canyon (alternative name: Susitna I)
(5) Devil Creek
(6) Watana
(7) Susitna III
(8) Vee
(9) Maclaren
(10) Denali
(11) Butte Creek
(12) Tyone

Figure 6.11 shows a longitudinal section through the basin and the reservoir levels associated with these sites. Table 6.9 shows which sites are mutually exclusive and which can be grouped to develop the full potential of the basin. Study of these sites indicated that they covered the total basin and there was no evidence of any additional sites. potentially economic.

All relevant data concerning dam type and capital cost, height, power and energy output was assembled and is summarized in Table 6.10. In obtaining the information for these tables, the latest source was used in each case. At the Gold Creek, Devil Creek, Maclaren, Butte Creek and Tyone sites, no engineering or energy studies were undertaken by Acres and only data from previous studies was used. Costs were updated to 1980 levels. The results of the engineering and cost studies performed by Acres at other sites were used to review these costs. For all the other sites Acres developed new conceptual engineering layouts and the capital cost estimates have been revised using calculated quantities and unit rates. For the sake of completeness, Table 6.11 compares the costs developed by Acres with those developed in previous studies.

DEVIL CANYON,

The results in Table 6.10 clearly show that High Devil Canyon and Watan are the most economic large energy producers in the basin. Sites such as Vee and Susitna III are medium energy producers although slightly more costly than these dam sites. Other sites such as ~~Devil Canyon,~~ Olson and Gold Creek are competitive provided they have additional upstream streamflow regulation. Sites such as Denali and Maclaren are expensive compared to other sites.

Preliminary environmental impacts associated with the various dam sites were derived from a review of available information and from the results of field reconnaisance trips. The type of information assembled is general in nature, but does serve to rank the impacts at the various sites.

To facilitate synthesis and presentation of the environmental information, the river is divided into six study reaches starting with reach A at the downstream end and finishing with reach F located upstream of Denali (Figure 6.11). Within each of these reaches, the environmental aspects are assumed constant for the level of study at this stage. The major environmental features for each of these reaches are summarized as follows.

Reach A - Talkeetna to Devil Canyon

Under existing conditions, salmon migrate as far as Devil Canyon, utilizing Portage Creek and Indian River for spawning. The development of any dam downstream of Portage Creek would result in a loss of salmon habitat. The necessary FERC license and permits for such development would probably be difficult to acquire.

Reach B - Devil Canyon to Watana

The concerns associated with development in this section of the river relate mainly to the inundation of Devil Canyon, which is considered a unique scenic and white water reach of the river, and has dam safety aspects associated with the occurrence of major geological faults. In addition, the Nelchina caribou herd has a general migration crossing in the area.

Reach C - Watana to Vee

There are concerns which relate to the loss of some moose habitat in the Watana Creek area and the inundation of sections of Deadman and Lokina Creeks.

Other aspects include the effect on caribou crossing in the Jay Creek area, and the potential for extensive reservoir shoreline erosion and dam safety aspects because of the possibility of geological faults.

Reach D - Vee to Maclaren

The inundation of moose winter range, waterfowl breeding areas, the scenic Vee Canyon and the downstream portions of the Oshetna and Tyone Rivers are all potential environmental impacts associated with this reach of the river. In addition, caribou crossing occurs in the area of the Oshetna River. The area surrounding this section of the river is relatively inaccessible and development would open large areas to hunters.

Reach E - Maclaren to Denali

Environmentally, this area appears to be more sensitive than Reaches B and C. Inundation could affect grizzly bear denning areas, moose habitat, waterfowl breeding areas and most alpine tundra vegetation. Improved access would open wilderness areas to hunters.

Reach F - Upstream of Denali

This area is similar to Reach E with the exception of grizzly bear denning areas. Human access to this area would not impact to the same extent as in Section D and F. However, due to the proximity to the Denali highway, the inflow of people could be greater.

This information was used in Table 6.12 for environmental site ranking. Environmental impacts are divided into three basic categories, i.e. biological (impact on fish and wildlife), social (local and regional impacts) and institutional aspects which include licenses and permitting requirements.

6.6.2 - Preliminary Screening

To reduce the number of sites for further detailed study, several were screened out. The screening criteria used included energy cost and potential environmental impact. One site was automatically screened when alternative sites are located close to each other. This exercise resulted in elimination of the following sites:

Devil Creek - This site is close to the High Devil Canyon site and for planning purposes can be assumed to be an alternative for the latter.

Butte Creek - This site is close to and alternate to the Denali site.

Gold Creek - Severe problems would be encountered in obtaining an FERC license because of the potential environmental impact, particularly on anadromous fisheries.

Olson - As for Gold Creek.

Tyone - Relatively low energy and power potential and anticipated severe environmental impact.

6.7 - Engineering Layout and Cost Studies

In order to develop a more uniform and reliable data base for studying the seven sites remaining after the preliminary screening exercise, it was necessary to develop engineering layouts for these sites and re-evaluate the costs. In addition, it was also necessary to study staged developments at several of the largest dams.

The basic objective of these layout studies was to establish a uniform and consistant cost of development at each site. These layouts are conceptual in nature and do not represent definitive and optimum project arrangements at the sites. Also, because of the lack of geotechnical information at several of the sites, these layouts do not imply that all developments are necessarily technically feasible.

6.7.1 - Design Assumptions

In order to maximize standardization of the layouts a set of basic design assumptions were developed. These assumptions were used as guidelines to determine the size of the various project components and are described below.

(a) Geotechnical Considerations

- Main and Saddle Dams

The geotechnical considerations are summarized in Table 6.13.

- Temporary Cofferdams

It is assumed that all cofferdams are of a fill-type. Since much of the original riverbed material under the main dam shell may have to be excavated, all cofferdams are located outside the upstream and downstream limits of the main dam.

(b) Hydrologic and Hydraulic Considerations

Table 6.14 lists certain key hydrologic parameters. It should be noted that at this conceptual stage spillways were sized for the peak inflow and no benefit of flood peak attenuation due to reservoir storage was taken into account. The spillways were sized for the 10,000 year flood and the energy dissipation in the stilling basins limited to a maximum of 45,000 horsepower per foot width. This maximum limit is based on international experience with other large dams.

Table 6.15 summarizes the normal operating freeboard requirements. In addition to these freeboard requirements checks were undertaken to ensure that the dam was not overtopped during a PMF event and that the spillway design flood could be passed even after a major seismic event had induced a further 1-1/2 percent settlement on a fill dam.

(c) Engineering Layout Considerations

Table 6.16 lists guidelines for determining what components are incorporated in the engineering layouts. The dam crest and full supply levels associated with each site are listed in Table 6.17. It should be noted that two different heights are considered at the Devil Canyon, High Devil Canyon, and Watana sites. In the case of the Watana site, a staged development is considered and the lower dam freeboard has, therefore, been increased by 40 feet for cost estimating purposes. It is assumed that this top layer would have to be stripped before construction of Stage 2 commences.

(d) Mechanical

- Number of Units

In general, a decrease in the number of units will result in a reduction in power plant cost. For these preliminary studies it was assumed that a minimum of two and a maximum of four units would be installed.

- Turbines

Vertical Francis type with steel spiral cases are used. It is assumed that the turbines will be directly connected to vertical synchronous generators.

- Spillway Gates

The spillway gates are fixed wheel vertical lift gates operated by double drum wire rope hoists located in enclosed tower and bridge structures. Maximum gate size for preliminary design are:

- width: 50 ft
- height: 60 ft

A three-foot freeboard is provided for gates over maximum operating water level. The gates will be heated for winter operation.

- Miscellaneous Mechanical Equipment

Cost estimates provide for a full range of power station equipment including cranes, gates, valves, etc.

(e) Electrical Considerations

- Powerhouse

Separate transformer galleries are provided for main and station transformers. Provision is made in the cost estimates for a full range of miscellaneous operating and control equipment including where necessary allowance for remote station operation.

- Switchyard and Transmission Lines

Switchyards are located on the surface and as close to the powerhouse as possible. The size of the yards is approximately 900 by 500 feet. Cost estimates should allow for transmission lines and substations (see Table 6.16).

6.7.2 - Site Layouts

A brief description of the site layouts is given below. Drawings 1 to ___ at the end of this report illustrate the layout details.

(a) Devil Canyon

(Note: At this stage the dam costs incorporated in the generation planning is a rockfill dam. The concrete dam costs will be substituted as soon as they become available and will be incorporated in the final report).

In order to provide a common basis for cost comparisons between the various sites a common rockfill dam type has been assumed for all development except Olson. The dam at Devil Canyon comprises approximately ~~50~~ 28 x 10^6 in yards of rock, gravel, and impervious materials, has a maximum height of approximately 650 feet above foundation level.

Spillway facilities consist of a gated overflow structure, intermediate and downstream stilling basins and concrete line chutes and are located in the right abutment. The power intake structure is also founded deep within this abutment and consists of multi-level intakes serving individual penstocks leading to the underground powerhouse. The powerhouse accommodates 4-100 MW turbine/generator units. The switchyard is situated at the surface fill cofferdam.

Diversion is effected by an upstream rock and earth cofferdams and twin concrete lined tunnels on the right side of the river.

As an alternative to the full power development, a staged alternative has been investigated with the dam completed to its full height, but with an initial installed capacity of 200-300 MW. The complete powerhouse would be excavated together with penstocks and tailrace tunnel for 2-150 MW units. The complete intake would be constructed except for gates and rocks required for the second stage. The second stage installation would include installation of the remaining gates, construction of the corresponding penstocks and tailrace tunnel for the new 2-150 MW units and completion of civil, electrical and mechanical installation within the powerhouse area together with enlargement of the surface switchyard.

(b) Watana

The development is comprised of a 900 ft height rockfill dam with an overall volume of approximately 70 x 10^6 cu. yd. and a crest elevation of 2,225 ft.

The spillway facilities are similar to those at Devil Canyon and are located in the right abutment. The power facilities are located within the left abutment and are similar in concept to Devil Canyon with 4 units giving a total installed capacity of 800MW. The switchyard is on the surface. The diversion consists of an earth/rockfill cofferdam and twin lined tunnels within the right abutment.

As an alternative staged version, a reduced height, broad crested fill dam has been investigated for a 200 ft. lower surface elevation in the reservoir. The first stage powerhouse would be completely excavated and would house three oversized 135 MW units. A low level control structure and twin line tunnels leading into a downstream stilling basin would form the first stage spillway.

For the second stage the dam would be completed in its full height with addtional rockfill being placed on the downstream face and crest. It is assumed that before construction commences on the second stage the top 40 ft. of the first stage crest is removed to prevent any danger of ... deterioration of the impervious core through frost penetration.
Two additional 200 MW units would be installed and corresponding penstock and tailrace tunnels constructed. The runners on the first stage units would be replaced and the turbines upgraded to provide 200 MW each giving a total of 800 MW with the new unit. Rotors on the existing generators could be altered to cater for the new operating speeds by making predetermined connections within their windings.

(c) High Devil Canyon

The development is located between Devil Canyon and Watana and is comprised of an 850 ft high rockfill dam containing 48 x 10^6 cu. yds. of rockfill with a crest elevation of 1775 ft. The left abutment spillway and the right abutment powerhouse facilities are similar in concept to Devil Canyon and Watana. The installed capacity is 800 MW. The left hand diversion is formed by an upstream earth/rockfill cofferdam and twin lined tunnels.

Staging is envisaged as two stages of 400 MW each in the same manner as at Devil Canyon with the dam initially constructed to its full height.

(d) Susitna III

The development is comprised of a rockfill dam approximately 650 ft. high with a volume of approximately 55 x 10^6 cu. yds. and a crest elevation of 2360 ft.

The spillway consists of two-staged spilling basin as for Devil Canyon and Watana, located on the right abutment.

A surface powerhouse of 350 MW capacity is located on the left bank and diversion is through twin tunnels in the right abutment.

(e) Vee

A 650 ft high rockfill dam has been considered with foundations on bedrock. The spillway in the form of a chute and flip bucket is situated within the ridge forming the right abutment.

The power facilities consisting of a 400 MW underground power station are located beyond the left abutment with the intake founded within a low saddle which is filled by a rockfill secondary dam at its low point.

(f) Maclaren

The development consists of a 180 ft high earthfill dam founded on pervious riverbed materials. Crest elevation is 2405 ft. The reservoir is purely for regulating purposes and no generating capacity is included. Flood diversion is via a side chute spillway and stilling basin on the right abutment.

(g) Denali

Denali is similar in concept to Maclaren with a 200 ft high earthfill dam of crest elevation 2555 ft. A combined diversion and spillway facility is formed by twin concrete conduits founded in open cut excavation in the right bank and discharging into a common stilling basin.

Capital Costs

Quantities were determined for items comprising the major works and structures at the sites. Where detail or data was not sufficient for certain work, estimates have been made based on previous experience. In order to determine total capital costs for various structures unit costs have been developed for the items. These have been determined after a review of rates used in previous studies, a review of rates used on similar works in Alaska, and elsewhere with an adjustment factor where applicable based on geography, climate, manpower, accessability, etc. Technical publications have also been reviewed for basic rates and escalation factors.

An overall mobilization cost of 5 percent has been assumed and camp and catering costs have been based on a preliminary review of construction manpower and schedules. An annual construction period of 6 months has been assumed for placement of fill materials and 8 months for all other operations. Night work has been assumed throughout.

A 20 percent allowance for non-predictable contingencies has been added as a lump sum together with 12 percent for engineering and administration.

6.8 - Final Screening

A computer screening model was developed to undertake the next, more detailed screening process. Basically, the model selects a least cost basin development scheme for a given total basin power and energy demand; i.e. it selects the sites, approximate dam heights and installed capacities.

6.8.1 - Screening Model Description

The model incorporates a standard Linear Programming (LP) algorithm for determining the optimum or least cost solution. It is provided with basic hydrologic data, dam volume-cost curves at all the sites, an indication of which sites are mutually exclusive and a total power demand required from the basin. The model then incorporates a time period by time period energy simulation process for individual and groups of sites and systematically searches out the least cost system of reservoirs and selects installed capacities to meet the specified power and energy demand.

A detailed description of the model as well as the input and output data is given in Appendix A. A summary of this information is presented below.

6.8.2 - Input Data

Input data to the model takes the following form:

(a) Streamflow

In order to reduce the complexity of the model, a year is divided into two periods, summer and winter, and flows are specified for each. For the smaller dam sites such as Denali, Maclaren, Vee and Devil Canyon which have little or no overyear storage capability, only two typical years of hydrology are input. These correspond to a dry year (90 percent probability of exceedence) and an average year (50 percent probability of exceedence). For the other larger sites, the full thirty years of historical data are specified.

(b) Site Characteristics

For each site, storage capacity versus cost curves are provided. These curves were developed from the engineering layouts presented in Section 6.7. Utilizing these layouts as a basis the quantities for lower level dam heights were determined and used to estimate the costs associated with these lower levels. Figures 6.__ to 6.__ depict the curves used in the model runs. These curves incorporate the cost of the generating equipment. Interactive computer model runs were required to ensure that the installed capacities calculated by the model are reflected on the reservoir storage capacity versus cost curves fed into the model.

(c) Basin Characteristics

The model is supplied with information on the mutually exclusive sites as outlined in Table 6.10.

(d) Power and Energy Demand

The model must be supplied with a power and energy demand. This is achieved by specifying a total generating capacity required from the river basin and an associated annual plant factor which is then used to calculate the annual energy demand.

6.8.3 - Model Runs and Results

A review of the energy forecasts discussed in Section 5 reveals that between the time a Susitna project could come on line in early 1993 and the end of the planning period, 2010, approximately 2200, 4250, and 9570 Gwh of additional energy would be required for the low, medium, and high energy forecasts, respectively. In terms of capacity, these values represent 400, 780 and 1750 MW. Based on these figures, it was decided to run the screening model for the following total capacity and energy values:

- Run 1: 400 MW - 1750 Gwh
- Run 2: 800 MW - 3500 Gwh
- Run 3: 1200 MW - 5250 Gwh
- Run 4: 1400 MW - 6100 Gwh

The results of these runs are shown in Table 6.18. Because of the simplifying assumptions that are made in the screening model, both the best and second best solutions from an economic point of view are presented. It will be noted that in terms of economics these two solutions are extremely close.

The most important conclusions that can be drawn from the results shown in Table 6.18 are as follows:

(a) For energy requirements of up to 3500 Gwh the High Devil Canyon and Watana sites are the most economic;

(b) Up to energy requirements of 5300 Gwh the combinations of either Watana and Devil Canyon or High Devil Canyon and Vee are the most economic;

(c) The total energy production capability of the Watana/Devil Canyon developments is considerably larger than that of the High Devil Canyon/Vee alternative.

The reasons why this screening process rejected the other sites is as follows.

Susitna III was rejected due to its high capital cost. The marginal cost of the energy production is very high in comparison with Vee, even allowing for the 150 feet of the system head that is lost between the headwaters of High Devil Canyon and the tailwater of Vee. Maclaren has a very small impact on the system's energy and is very expensive.

A scheme involving Denali and Devil Canyon or Denali and Vee giving 400-500 MW are not competitive with Watana or High Devil Canyon for the same installed capacity. Both Watana and High Devil Canyon have enough regulating capacity even at small heads.

6.9 - Susitna Basin Development

6.9.1 - Potential Susitna Schemes

The results of the final screening process indicate that the Watana - Devil Canyon and the High Devil Canyon - Vee plans warrant further, more detailed study. Associated with each of these plans are several options for staging the development. These include staging construction of the dams and/or the power generation facilities. For this more detailed analysis of these two basic plans, a range of different approaches to staging the developments are considered. In order to keep the total options to a reasonable number and also to maintain reasonably large staging steps consistant with the total development size, only staging of the larger two dams, i.e. Watana and High Devil Canyon, is considered. Powerhouse stages are considered in 400 MW blocks. The basic staging concepts adopted for these two large dams involve staging both dam and powerhouse construction or alternatively just staging powerhouse construction.

A total of nine basic plans were developed. These are summarized in Table 6.15 and are briefly described below. Plans 1 to 3 deal with the Watana - Devil Canyon sites and Plans 4 to 6 with the High Devil Canyon - Vee sites.

(a) Plan 1

The first stage involves constructing Watana dam to its full height (2,225 foot crest elevation) and installing 800 MW. Stage 2 involves constructing Devil Canyon Dam (1,470 feet) and installing 600 MW.

(b) Plan 2

For this plan, construction of the Watana Dam is staged from a crest elevation of 2,060 feet to 2,225 feet. The powerhouse is also staged from 400 MW to 800 MW. As for Plan 1, the final stage involves Devil anyon with an installed capacity of 600 MW.

(c) Plan 3

This plan is similar to Plan 2 except that only the powerhouse and not the dam at Watana is staged.

(d) Plan 4

This plan involves constructing the High Devil Canyon Dam first with a crest elevation of 1,775 feet and an installed capacity of 800 MW. The second stage involves constructing the Vee reservoir to a crest elevation of 2,350 feet and installing 400 MW of capacity.

(e) Plan 5

For this plan, the construction of High Devil Canyon dam is staged from a crest elevation of 1,630 to 1,775 feet. The installed capacity is also staged from 400 to 800 MW. As for Plan 4, Vee follows with 400 MW of installed capacity.

(f) Plan 6

This plan is similar to Plan 5 except that only the powerhouse and not the dam at High Devil Canyon is staged.

In addition to these six plans, several additional plans were studied for other specific reasons. These include:

(g) Plan 7

This plan was studied to investigate the feasibility of constructing the Devil Canyon dam first and then the Watana dam. Due to the shorter construction period associated with Devil Canyon dam, this plan can be brought on line approximately 2-3 years before plans involving Watana as a first stage.

The plan involves constructing the Devil Canyon dam to a crest elevation of 1,470 feet and installing 250 MW generating capacity. The second stage involves constructing Watana to a crest level of 2,225 feet with an installed capacity of 800 MW. The final stage involves adding 350 MW capacity to the Devil Canyon dam.

(h) Plan 8

As discussed in more detail in the following Section 6.10, the Devil Canyon dam in Plans 1 to 3 could be replaced by lower re-regulation dam located between the Devil Canyon and Watana site and a tunnel leading from this dam to the currently proposed Devil Canyon dam site.

The plan involves constructing Watana to a crest elevation of 2,225 feet and installing 800 MW of capacity. The next stage is the construction of the downstream re-regulation dam to a crest elevation of 1,500 feet and a 15 mile long tunnel. A total of 300 MW would be installed at the end of the tunnel and a further 30 MW at the re-regulation dam.

(i) Plan 9

This plan was developed in order to assess the economics of developing the two most economic dam sites, Watana and High Devil Canyon jointly. Stage 1 involves constructing Watana to a crest elevation of 2,225 feet with an installed capacity of 800 MW. Stage 2 involves constructing High Devil Canyon to a crest elevation of 1,470 feet. In order to develop the full head between Watana and Portage Creek, a smaller dam is added downstream of High Devil Canyon. It would be located just upstream from Portage Creek so as not to interfer with the anadromous fisheries and would have crest elevation of 1,030 feet and an installed capacity of 150 MW.

Table 6.19 also lists pertinent details such as capital costs, construction periods and energy yields associated with these plans. The cost information was obtained from the engineering layout studies described in Section 6.7. The energy yield information was developed using a multi-reservoir computer model. This model simulates, on a monthly basis, the energy production from a given system of reservoirs for the 30-year period for which streamflow data is available. It incorporates daily peaking operations if these are required to generate the necessary peak capacity. All the model runs incorporate preliminary environmental constraints. Seasonal reservoir drawdowns are limited to 150 feet for the larger and 100 feet for the smaller reservoirs; daily drawdowns for daily peaking operations are limited to 5 feet and minimum discharges from each reservoir are maintained at all times to ensure all river reaches remain watered. These minimum discharges were set approximately equal to the seasonal average natural low flows at the dam sites and are listed in Table 6.__.

The model is driven by an energy demand which follows the seasonal distribution shown in Table 6.20. This distribution corresponds to the seasonal distribution of the total system load as discussed in Section 5.

the model was used to evaluate for each stage of the plans described above the average and firm energy and the installed capacity for a specified plant factor. This usually required a series of iterative runs to ensure that the number of reservoir failures in the 30-year period were limited to one year. The firm power was assumed equal to that delivered during the second lowest annual energy yield in the simulation period and corresponds approximately to the 95 percent level of assurance.

A more detailed description of the model, the model runs and the average monthly energy yields associated with the development plans is given in Appendix B.

The above plans were subjected to economic analysis using the system generation planning model (OGPV) discussed in Section 7. These studies revealed that the staged Watana dam concept (Plan 2) was not as economic as constructing the dam to its full height. The additional capital cost associated with staging the dam is higher than the savings in carrying charges achieved by delaying construction of the second stage within the schedule required to meet load growth.

As a result of these preliminary economic analyses, it became evident that Plans 3 and 6 offered the best economic means of generating power from the Susitna basin.

In the process of evaluating the schemes, it becomes apparent that there would be environmental problems associated with allowing daily peaking operations from the most downstram reservoir in each of the plans described above. In order to avoid these potential problems while still maintaining operational flexibility to peak on a daily basis, re-regulation schemes were incorporated in the basic Plans 3 and 6. Details of these new plans, referred to as 3A and 6A, are listed in Table 6.21.

The brief description of the changes that were made are as follows:

(a) Plan 3A

This plan follows the same basic stages as Plan 3. A low temporary re-regulation dam is constructed downstram from Watana during Stage 1. This dam would regulate the outflows from Watana and allow daily peaking operations. In the final stages only 400 MW of capacity is added to the dam at Devil Canyon. Reservoir operating rules are changed so that Devil Canyon dam acts as the re-regulation dam for Watana. The cost of the re-regulation dam has been estimated at $100 million and is incorporated in the total plan cost.

(b) Plan 6A

This plan is essentially the same as Plan 6 except that a permanent re-regulation dam is located downstream from the High Devil Canyon site. As this re-regulation dam is permanent, it has been developed as a power dam. To obtain the maximum head, it is located as far downstream as possible, i.e. at the Portage Creek site. The crest elevation of this dam is 1,030 feet and it would have a total installed capacity of 150 MW.

6.9.2 - Sensitivity Analysis

A range of sensitivity runs using the multi-reservoir computer model were undertaken to study the effects of the seasonal drawdown constraints on the energy yield from the selected development plans (3A and 6A). The results of these simulation runs are given in Table 6.22 and indicate that drawdown constraints of 50 to 150 feet severely effect firm and average energy production. Relaxing the constraints to 200 foot or more does not yield a significant increase in energy production.

6.10 - Tunnel Alternative to a Dam at Devil Canyon

A long power tunnel could conceivably be used to replace the Devil Canyon dam in the Watana/Devil Canyon Susitna development scheme. It could develop similar head for power generation at costs comparable to the second large dam. Obviously, because of the low winter flows in the river, a tunnel alternative could be conceived only as a second stage to the Watana development.

Conceptually, the tunnel alternatives would comprise the following major components in some combination in addition to a Watana dam reservoir and associated powerhouse:

(a) Power tunnel intake works;
(b) One or two power tunnels of up to forty feet in diameter and up to thirty miles in length;
(c) A surface or underground powerhouse with a capacity of up to 1200 MW;
(d) A re-regulation dam if the intake works are located downstram from Watana;
(e) Arrangements for compensation of the flow in the bypassed river reach.

Four basic alternative schemes were developed and studied. All schemes assume an initial Watana development with full supply level (FSL) at 2200 feet and associated powerhouse with an installed capacity of about 800 MW. Figure 6.__ is a schematic illustration of these schemes. Schemes 1 and 3 involve development of the head available at the Devil Canyon dam site. Scheme 1 considers peaking operation through the tunnels, while Scheme 3 considers base load operation. Schemes 2 and 4 involve development of the full head represented by both the Watana and the Devil Canyon dams. These schemes involve locating the major portion of the generating equipment in the tunnel. As before, Scheme 2 considers peaking operation through the tunnels while Scheme 4 considers base load operation of the tunnel flow.

Scheme 1 comprises a small re-regulation dam about 75 feet high with power tunnels leading to a second powerhouse at the end of the tunnel near Devil Canyon. This power station would operate in series with the one at Watana, since the storage behind the re-regulation dam is small. Essentially the re-regulation dam provides for constant head on the tunnel and deals with surges in operation at Watana. The two powerhouses would operate as peaking stations resulting in flow and level fluctuation downstream from Devil Canyon.

Scheme 2 also provides for peaking operation of the two powerhouses except that the tunnel intake works are located in the Watana reservoir. Initially, the powerhouse at Watana would have 800 MW installed capacity which would then be reduced to some 70 MW after the tunnels are completed. This capacity would take advantage of the required minimum flow from the Watana reservoir. The power flow would be diverted through the tunnels to the powerhouse at Devil Canyon, with an installed capacity of about 1150 MW. Daily fluctuations of water level downstream would be similar to those in Scheme 1 for peaking operations.

Schemes 3 and 4 provide for base load operation at Devil Canyon powerhouse and peaking at Watana. In Scheme 3 the tunnel develops only the Devil Canyon dam head and comprises a 245 foot high re-regulation dam with a capacity to regulate diurnal fluctuations due to peaking operation at Watana. The site for the re-regulation dam was chosen to provide sufficient re-regulation storage and what appears to be a suitable dam site. In Scheme 4, the tunnel intakes are located in the Watana reservoir. The Watana powerhouse remains at the stage-one installed capacity of 800 MW and is used to supply peaking demand. Table 6.23 lists all the pertinent technical information, and Table 6.24 the energy yields and costs associated with these schemes.

In general, development costs are based on the same unit costs as those used in other Susitna developments[9]. Tunnel costs are estimated on the assumption that excavation will be done by conventional drill and blast operations and that the entire length may not have to be lined. Tentative assumptions as to the extent of lining and support are as follows:

(a) 34 percent unlined
(b) 33 percent shotcrete lined
(c) 25 percent concrete lined
(d) 8 percent lined with steel sets

Based on the foregoing economic information, Scheme 3 produces the lowest cost energy.

A review of the relative environmental impacts associated with the four tunnel schemes was undertaken. It revealed that Scheme 3 would have the least impact primarily because it offers the best opportunities for regulating daily flows downstream from the project.

Based on the above review of energy, costs and environmental impact, Scheme 3 was selected as the most appropriate alternative. Consequently, only detailed engineering layout and cost studies were undertaken for Scheme 3 (see Drawings __and __). Energy calculations were undertaken using the same multi-reservoir computer program discussed in Section 6.9.1. A detailed comparison of tunnel Scheme 3 with the Devil Canyon dam scheme is presented in Table 6.25.

A comparison of the costs of the dam scheme versus the tunnel scheme shows that the tunnel scheme is the more costly. However, the tunnel cost estimates are not as reliable as those associated with the dam schemes due to the lack of available geologic information on the tunnel and the inherent lower accuracy associated with estimating tunnel costs.

A comparison of the potential environmental impacts associated with the tunnel and the dam scheme revealed that the tunnel scheme should have the lesser effect. This is determined by the much smaller size of the second dam involved (245 feet versus over 600 feet), producing less flooding of river length and terrestrial habitat, as well as a lower aesthetic impact (see Appendix I).

The tunnel scheme may, in fact, improve anadromous fisheries between the re-regulation dam site and Portage Creek due to the regulation of flows. One negative environment aspect of the tunnel scheme is that of the disposal of tunnel muck. An increase in costs of up to 1 percent may be required to dispose of the excavation material in an environmentally acceptable manner.

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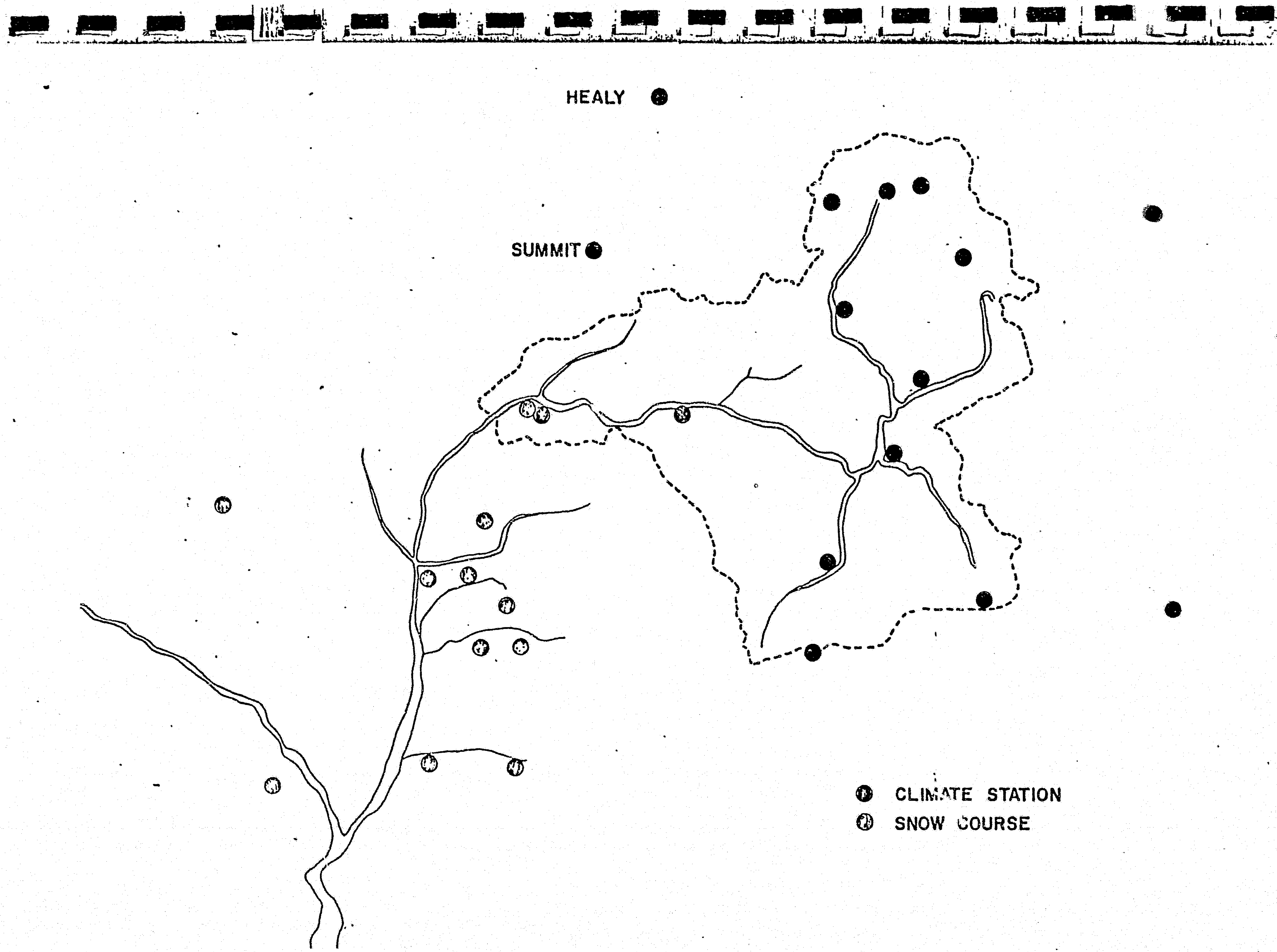
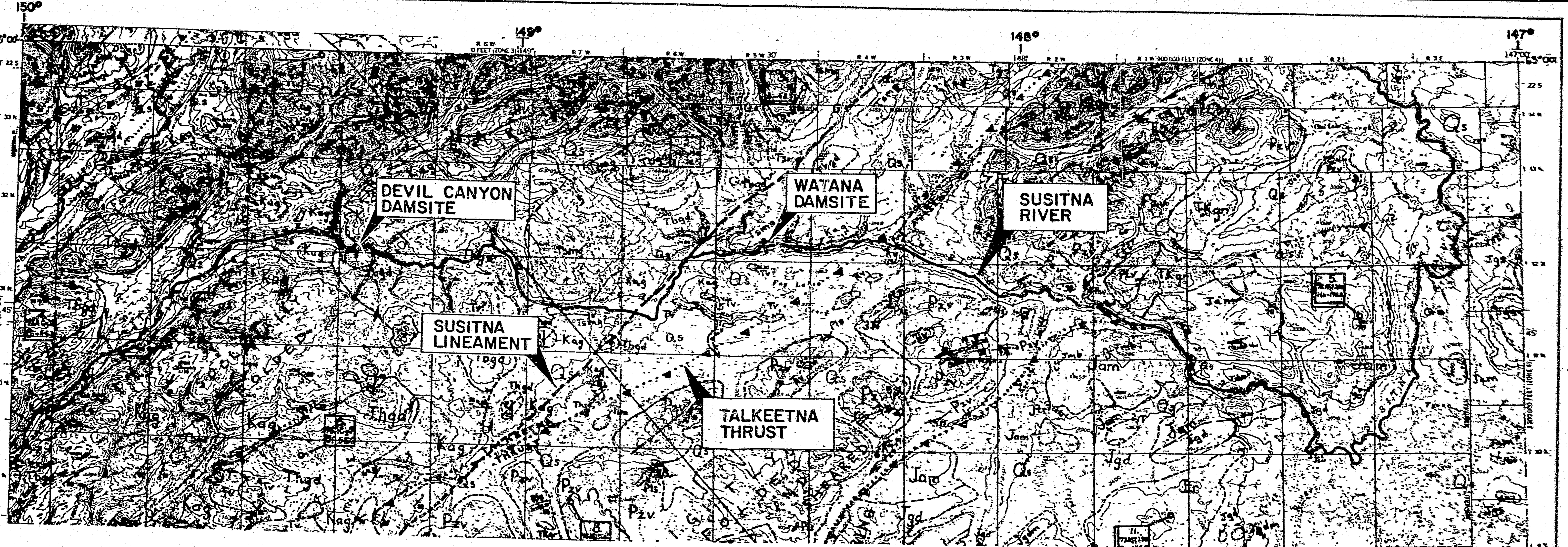
A comparison of the potential environmental impacts associated with the tunnel and the dam scheme revealed that the tunnel scheme should have the lesser effect. This is determined by the much smaller size of the second dam involved (245 feet versus over 600 feet), producing less flooding of river length and terrestrial habitat, as well as a lower aesthetic impact.

The tunnel scheme may, in fact, improve anadromous fisheries between the re-regulation dam site and Portage Creek due to the regulation of flows. One negative environment aspect of the tunnel scheme is that of the disposal of tunnel muck. An increase in costs of up to 1 percent may be required to dispose of the excavation material in an environmentally acceptable manner.

The preliminary assessment of the tunnel scheme indicates that it should not be ruled out as an alternative for hydroelectric development at this stage. It is, therefore, recommended that additional geologic and geotechnical work be done on the tunnel alternative over the next few years to firm the cost estimates and technical feasibility.



CLIMATE AND SNOW COURSE STATIONS



EXPLANATION OF MAP SYMBOLS

Contact, approximately located

Approximate contact of surficial deposits

Fault

Long dashed where approximately located; short dashed where inferred; dotted where concealed. U indicates upthrown side where direction of displacement is known. Arrows indicate relative lateral movement.

Thrust fault

Long dashed where approximately located, short dashed where inferred, dotted where concealed. Teeth indicate upthrown side.

Approximate axis of intense shear zone of variable width, possibly marking a thrust fault

Dotted where concealed; teeth indicate possible upthrown side of postulated thrust.

Anticline, showing crest line ; Syncline, showing trough line

Long dashed where approximately located; arrow indicates plunge.

Location of sample dated by the U.S. Geological Survey using the potassium-argon or the lead-alpha method, showing map number, field number, and the calculated mineral age. Bi - biotite, Hb - hornblende, mu - muscovite, Act - actinolite, Zr - zircon, wr - whole rock.

Location of sample dated by Turner and Smith (1974) using the potassium-argon method, showing map number, field number, and the calculated mineral age. Bi - biotite, Hb - hornblende.

X 4

Fossil locality in units TRv, Pls, and DSls.

Strike and dip of beds

45 Inclined

55 Overturned

Vertical

20 Approximate, estimated from distant observations

Strike and dip of fracture cleavage

80 Inclined

Vertical

Strike and dip of slaty or axial plane cleavage

60 Inclined

Vertical

Strike and dip of shear planes, metamorphic foliation or schistosity

30 Inclined

Vertical

Strike and dip of igneous flow foliation

30 Inclined

Vertical

Bearing and plunge of lineation

30 Inclined

Horizontal

Strike and dip of joints

60 Inclined

Vertical

0 3 6 12

SCALE IN MILES

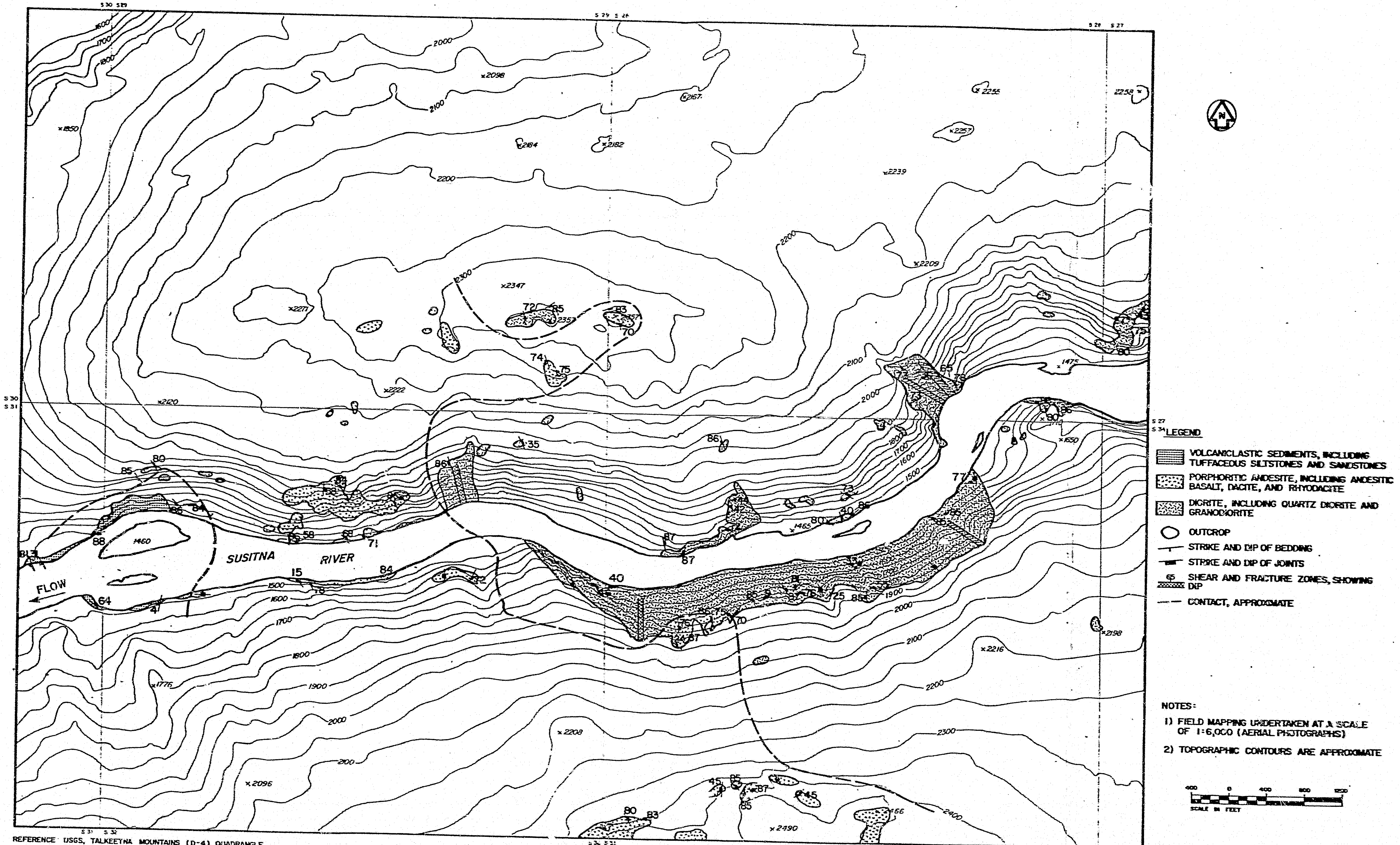
NOTE:

ROCK UNITS ARE LISTED IN FIGURE

REFERENCE: CSEJTEY, B.ET.AL. RECONNAISSANCE GEOLOGIC MAP & GEOCHRONOLOGY, TALKEETNA MOUNTAINS QUADRANGLE, NORTHERN PART OF ANCHORAGE QUADRANGLE, AND SOUTHWEST CORNER OF HEALY QUADRANGLE, ALASKA. U.S.G.S. OPEN FILE REPORT 78-558A. 1978.

REGIONAL GEOLOGY

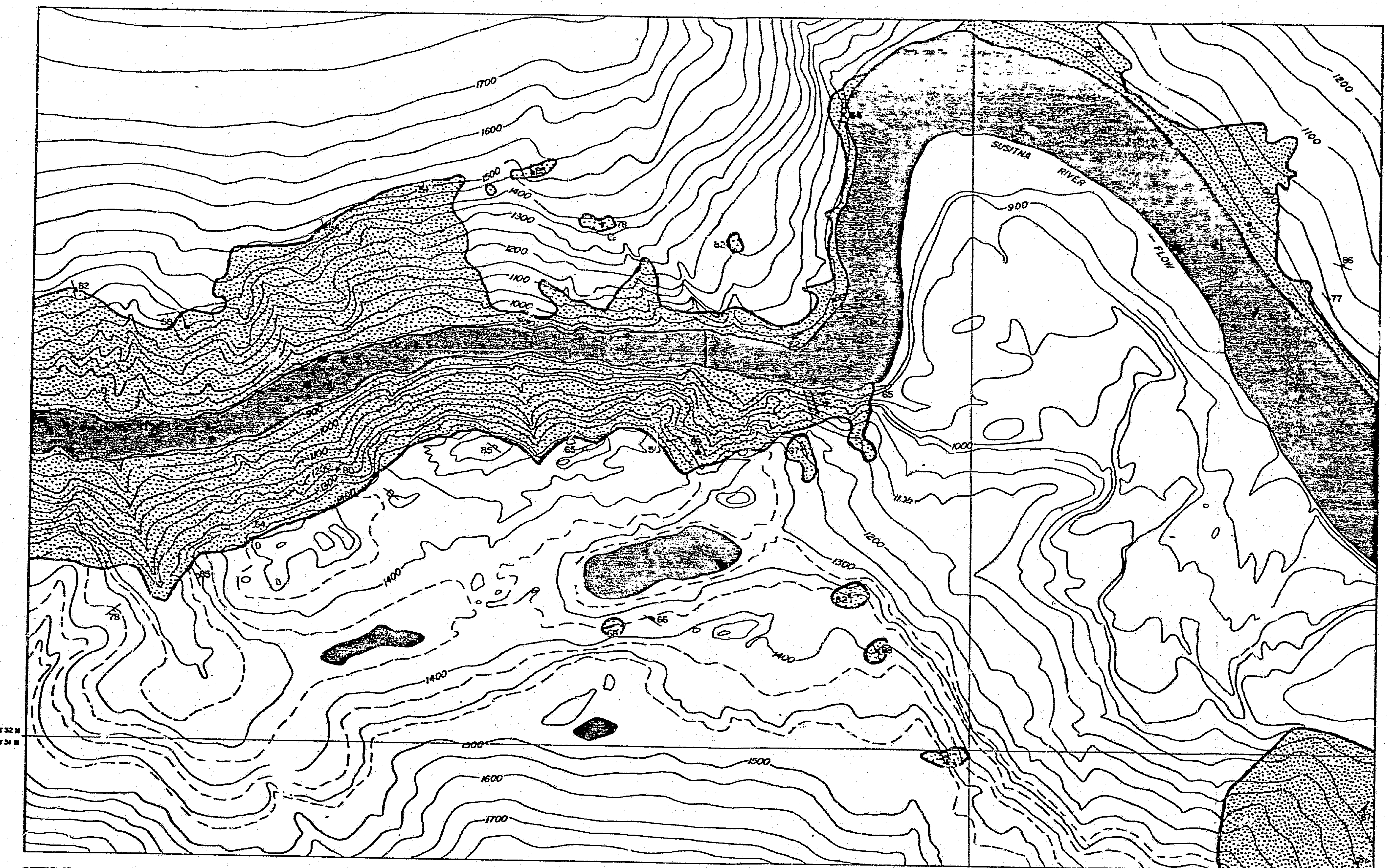
FIGURE 6.2



GEOLOGIC MAP OF WATANA

FIGURE 6.3

ACRES



REFERENCE: USGS, TALKEETNA MOUNTAINS (D-5), ALASKA QUADRANGLE,
SEWARD MERIDIAN: T32N, R1E, S32 AND 33.

S 32 S 33

LEGEND

MAJOR OUTCROPS OF ARGILLITE UNIT
STRIKE AND DIP OF BEDS
STRIKE AND DIP OF JOINTS
STRIKE AND DIP OF OPEN JOINTS
SHEAR AND FRACTURE ZONES

NOTE:

1) GEOLOGIC MAPPING UNDERTAKEN AT THE SCALE OF 1:24,000 (AERIAL PHOTOGRAPHS)
2) TOPOGRAPHIC CONTOURS ARE APPROXIMATE

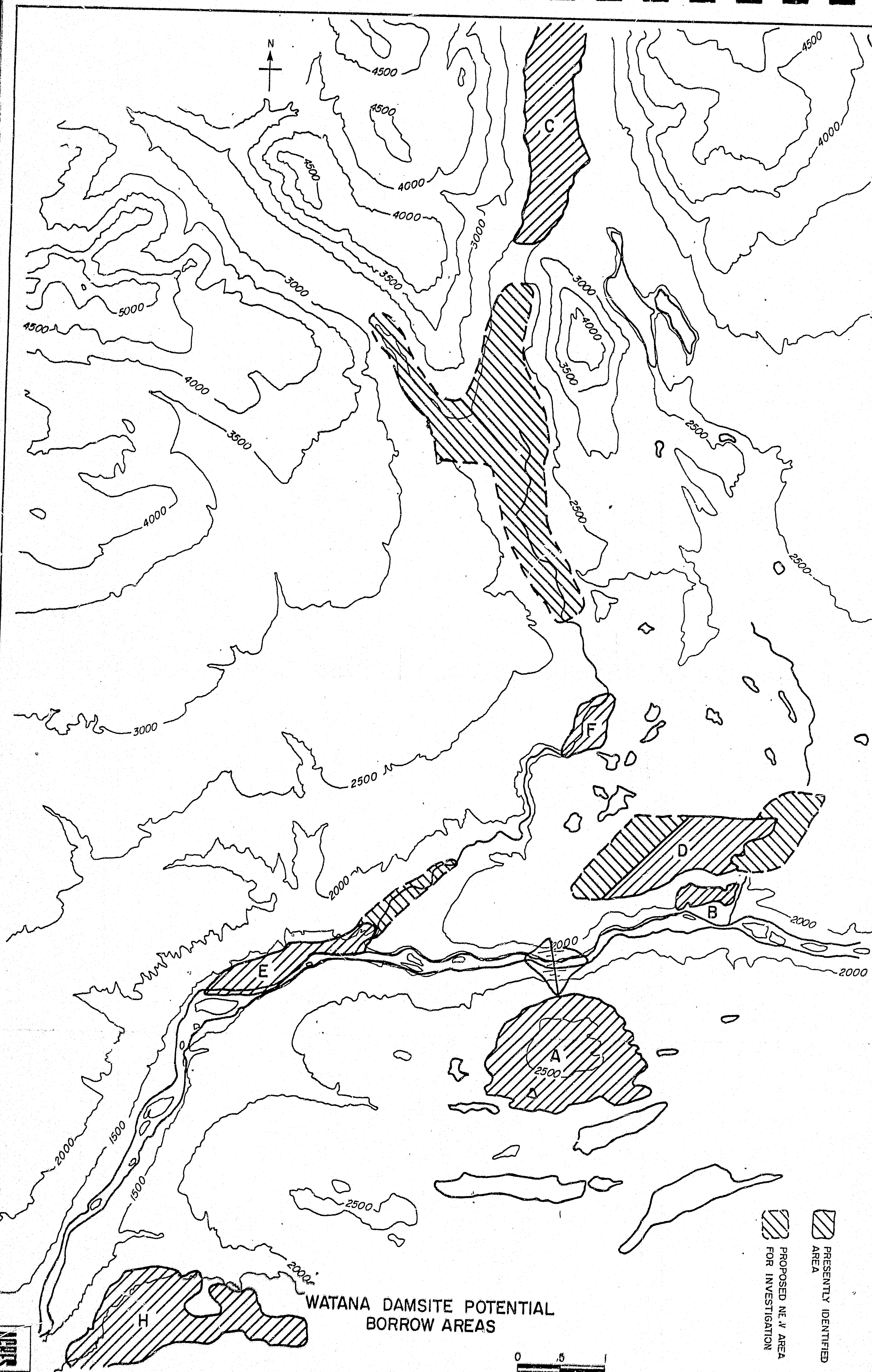
200 0 200 400 600
SCALE IN FEET

CONTOUR INTERVAL 50 FEET
DASHED CONTOUR 25 FEET

GEOLOGIC MAP OF DEVIL CANYON

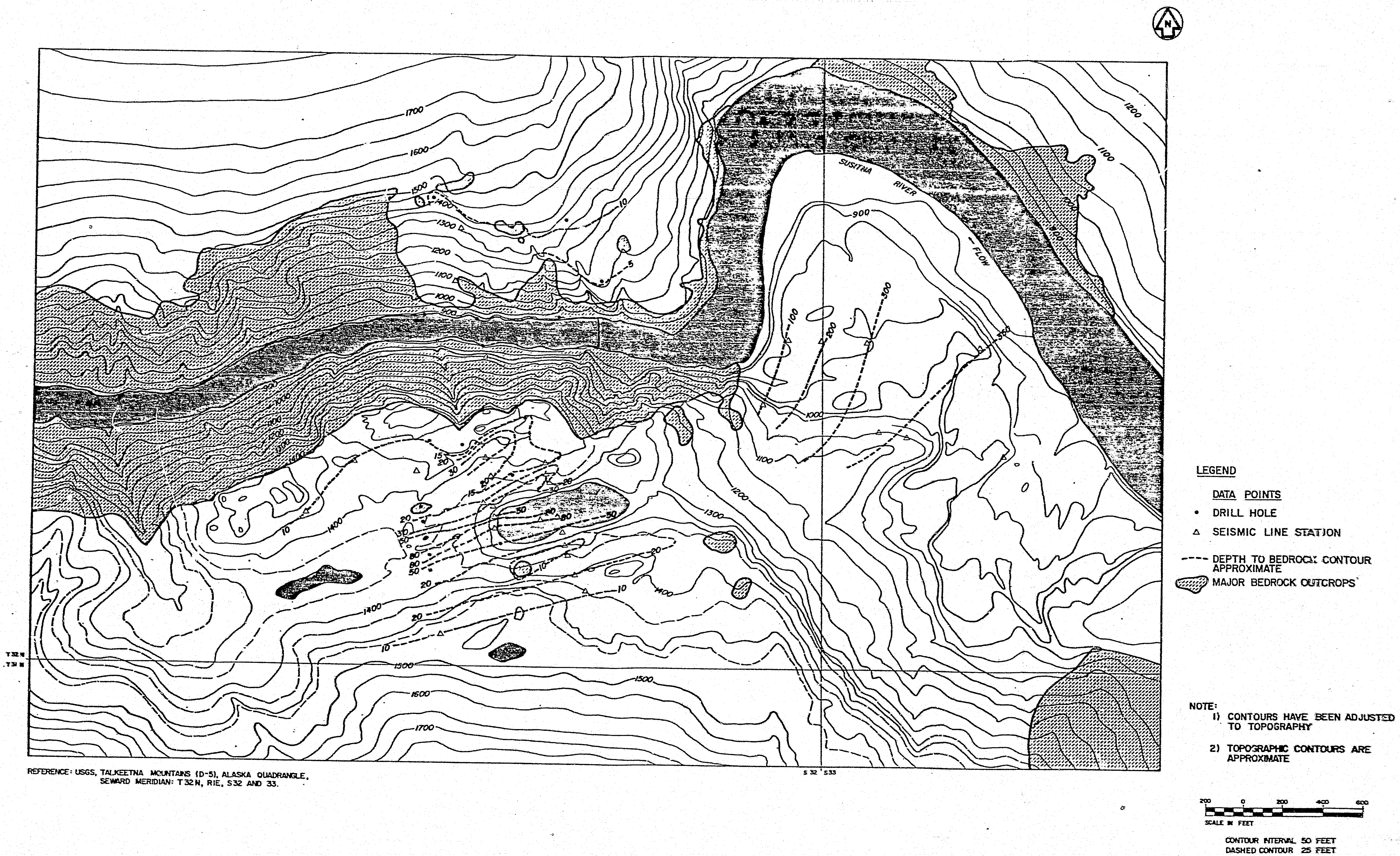
FIGURE 6.4

ACRES



WATANA DAMSITE POTENTIAL BORROW AREAS

FIGURE 6.5

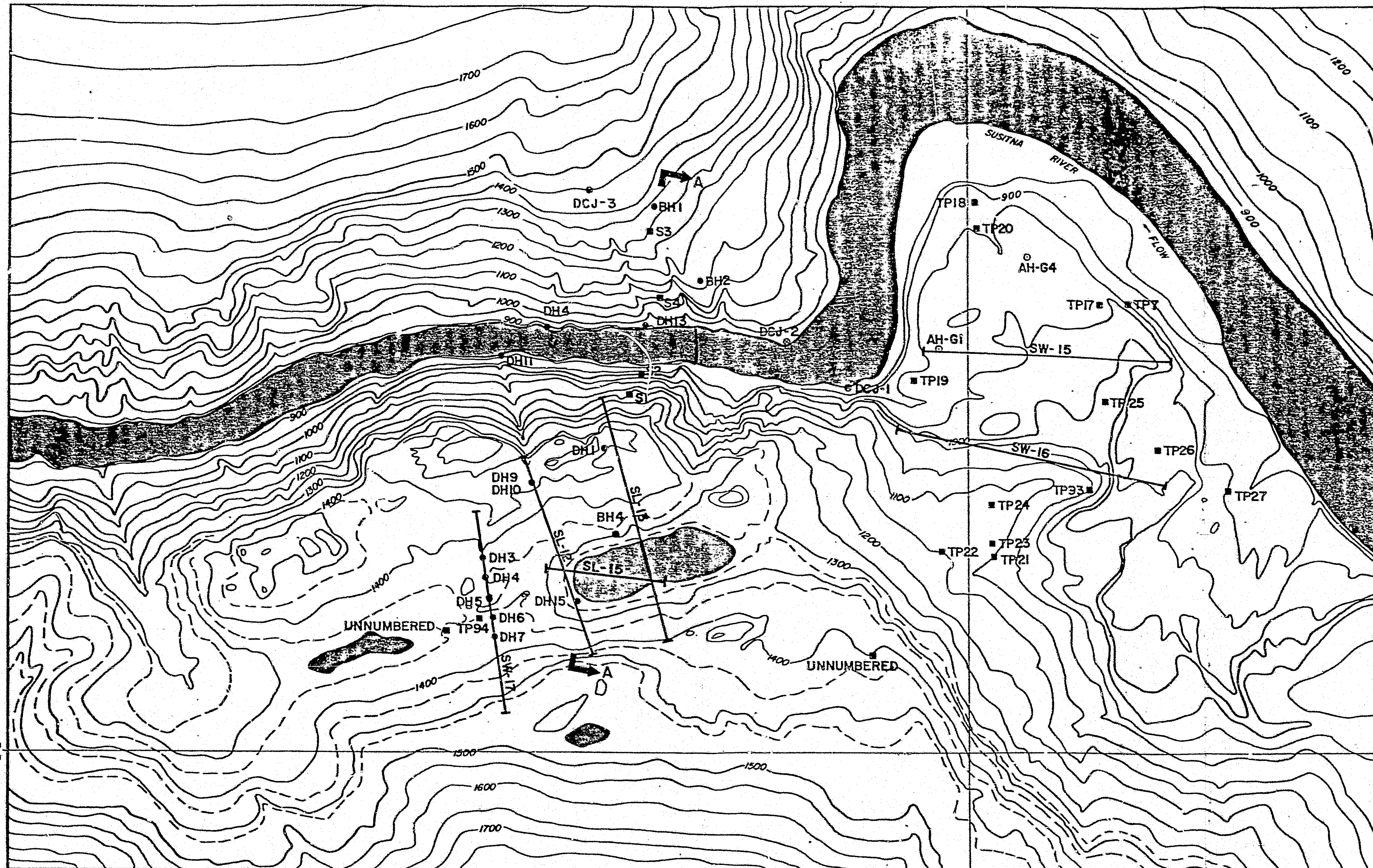


ISOPACH MAP OF OVERBURDEN - DEVIL CANYON

FIGURE 6.6

ACRES

6.22



REFERENCE: USGS, TALKEETNA MOUNTAINS (D-5), ALASKA QUADRANGLE, SEWARD MERIDIAN: T32N, RIE, S32 AND 33.

LEGEND

- DH BOREHOLES-BUREAU OF RECLAMATION, 1960
- BH BOREHOLES-SUMMER 1980 PROGRAM
- TP, S, TEST PITS AND TRENCHES BUREAU OF RECLAMATION, 1960
- AUGER HOLES-SUMMER 1980 PROGRAM
- SW SEISMIC LINES- CORP OF ENGINEERS, 1978
- SL SEISMIC LINES- SUMMER 1980 PROGRAM
- DCJ LOCATION OF JOINT MEASUREMENT
- CROSS SECTION

NOTE:
TOPOGRAPHIC CONTOURS ARE APPROXIMATE
SECTION SHOWN ON FIGURE

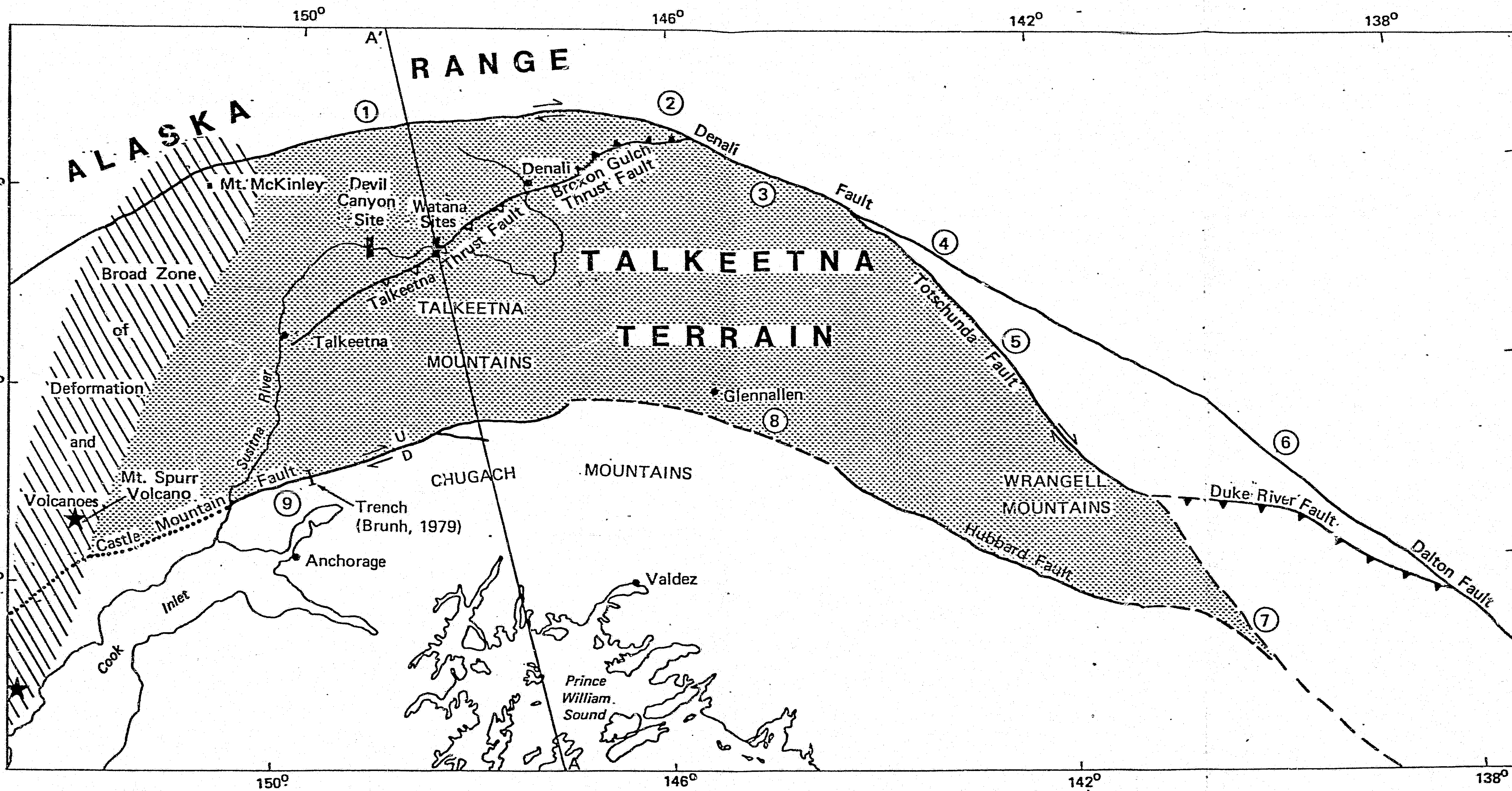
200 0 200 400 600
SCALE IN FEET

CONTOUR INTERVAL 50 FEET
DASHED CONTOUR 25 FEET

DEVIL CANYON LOCATION EXPLORATION MAP

FIGURE 6.7

ACRES



LEGEND

Mapped strike-slip fault with dip slip component

Mapped strike-slip fault, arrows show sense of displacement

Mapped fault, sense of displacement not defined

Inferred strike-slip fault

Mapped thrust fault, teeth indicate upthrown side of block, dashed where inferred

Mapped thrust fault, teeth indicate inferred upthrown side of block

NOTES

1. 0.9 - 2.0 cm/yr Hickman and Campbell, (1973); and Page, (1972).
2. 0.5 - 0.6 cm/yr Stout and others, (1973).
3. 3.5 cm/yr Richter and Matson, (1971).
4. 1.1 cm/yr, no Holocene activity farther east, Richter and Matson, (1971).
5. 0.9 -3.3 cm/yr Richter and Matson, (1971)
6. Inferred connection with Dalton Fault; Plafker and others, (1978).
7. Inferred connection with Fairweather Fault; Lahr and Plafker, (1980).
8. Connection inferred for this report.
9. 0.1 - 1.0 cm/yr Detterman and others (1974).
10. Slip rates cited in notes 1 through 9 are Holocene slip rates.
11. All fault locations and sense of movement obtained from Beikman, (1978).
12. Figure 5-2 presents Section A–A'.

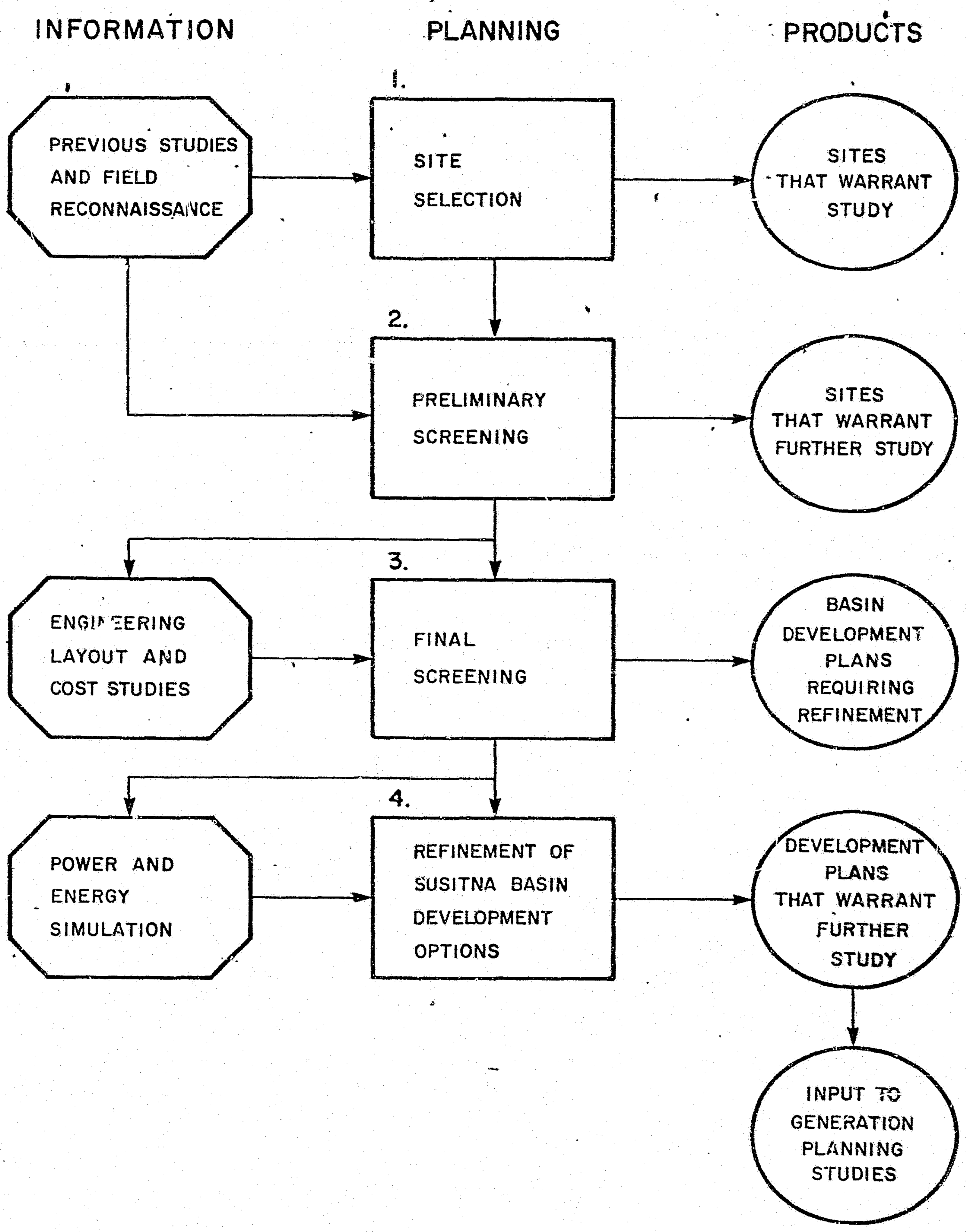
TALKEETNA TERRAIN MODEL

0 25 50 100 Miles

0 25 50 100 Kilometers

PREPARED BY:
WOODWARD-CLYDE CONSULTANTS

FIGURE 6.8



SCHEMATIC REPRESENTATION OF PROCESS USED TO SELECT SUSITNA BASIN DEVELOPMENT OPTIONS

FIGURE 6.9

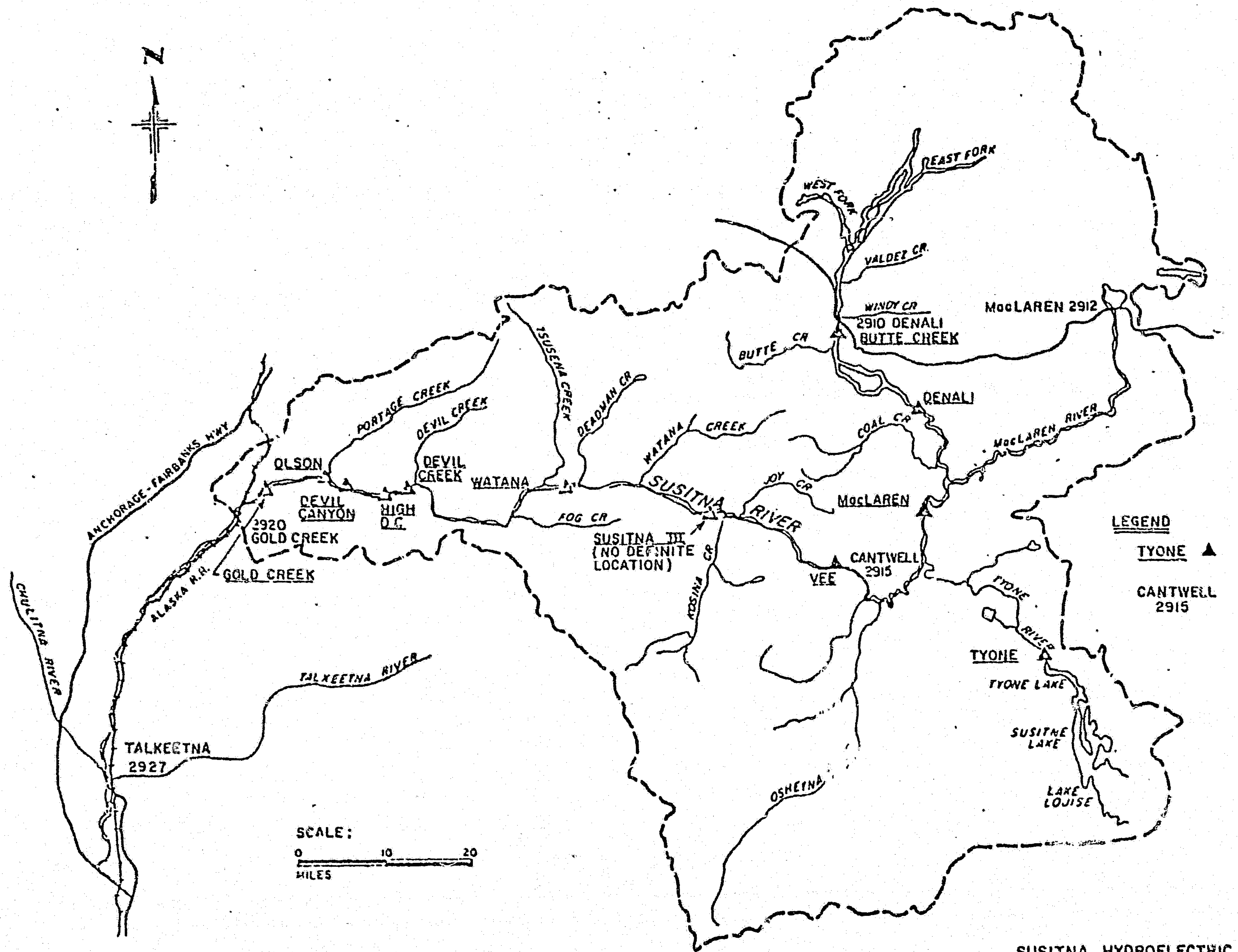


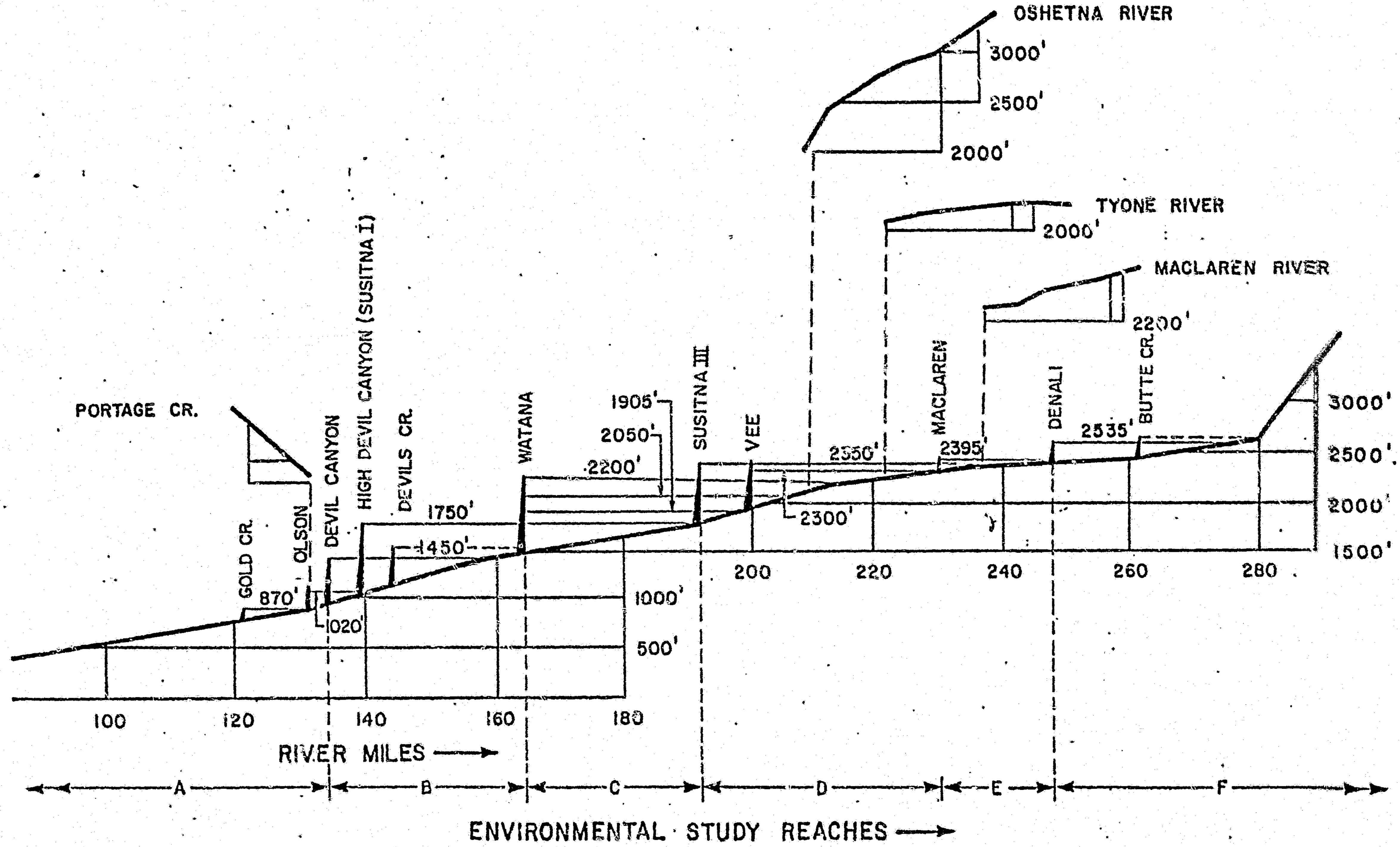
FIG 6.3

~~FIG. 1~~

SUSITNA HYDROELECTRIC PROJECT
DESIGN DEVELOPMENT

LOCATION OF DAMSITES PROPOSED BY OTHERS

~~FIGURE 6.2~~



NOTE: Figure to be changed to incorporate only dam deights previously studied.

FIG 6.4

~~FIG 2~~

SUSITNA HYDROELECTRIC PROJECT
DESIGN DEVELOPMENT

	GOLD CREEK	OLSON	DEVIL CANYON	HIGH DEVIL CANYON	DEVIL CREEK	WATANA	SUSITNA III	VEE	MACLAREN	DENALI	BUTTE CREEK	TYONE
GOLD CREEK												
OLSON			890 (30)									
DEVIL CANYON				1030 (160)	1070 (200)							
HIGH DEVIL CANYON						1465 (44[illegible])						
DEVIL CREEK						1465 (405)						
WATANA							1810 (355)	1925 (470)				
SUSITNA III								1925 (125)	2320 ([illegible]20)			
VEE									2320 (405)			
MACLAREN												
DENALI												
BUTTE CREEK												
TYONE												

LEGEND

COMPATIBLE ALTERNATIVES

MUTUALLY EXCLUSIVE ALTERNATIVES

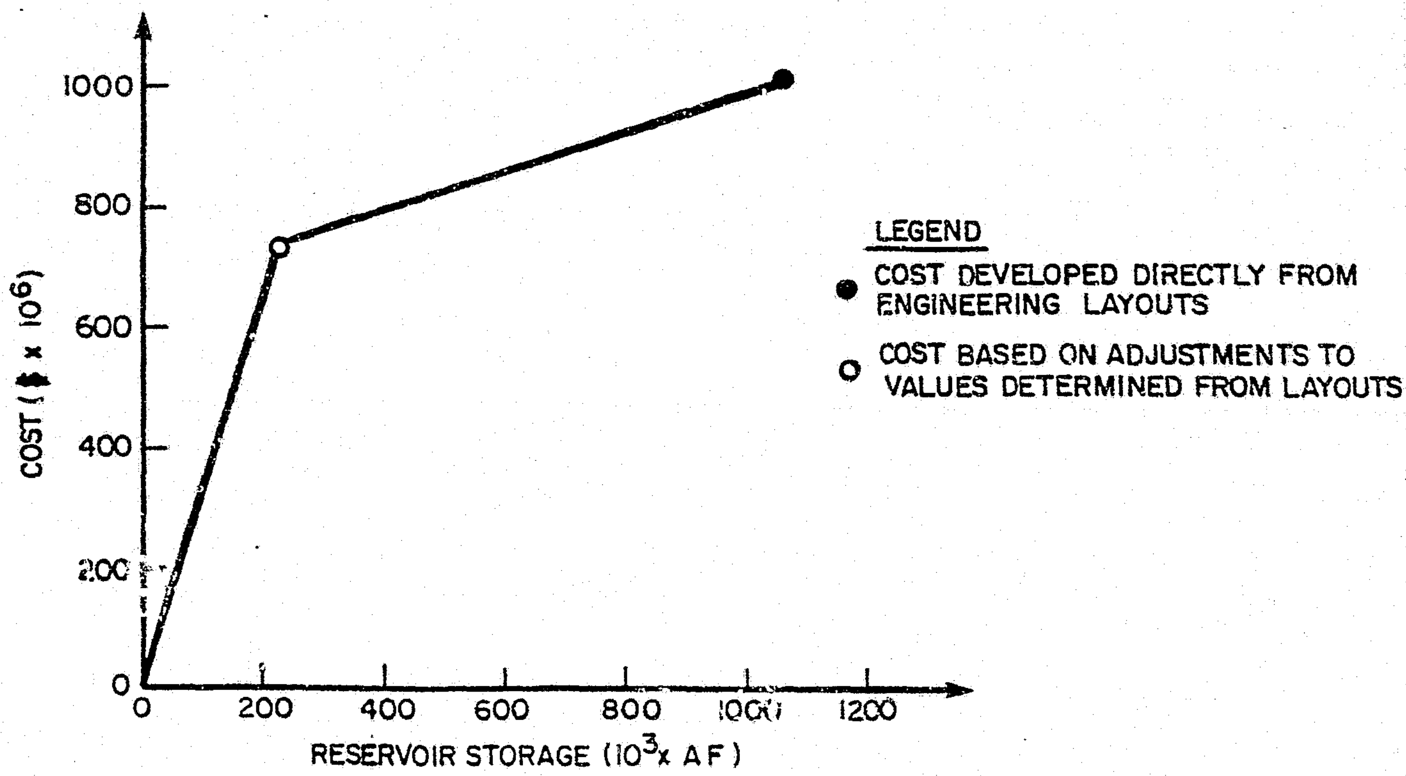
1465 (405) — DAM IN COLUMN IS MUTUALLY EXCLUSIVE IF FULL SUPPLY LEVEL IN DAM IN ROW EXCEEDS THIS VALUE-FT.

VALUE IN BRACKET REFERS TO APPROXIMATE DAM HEIGHT.

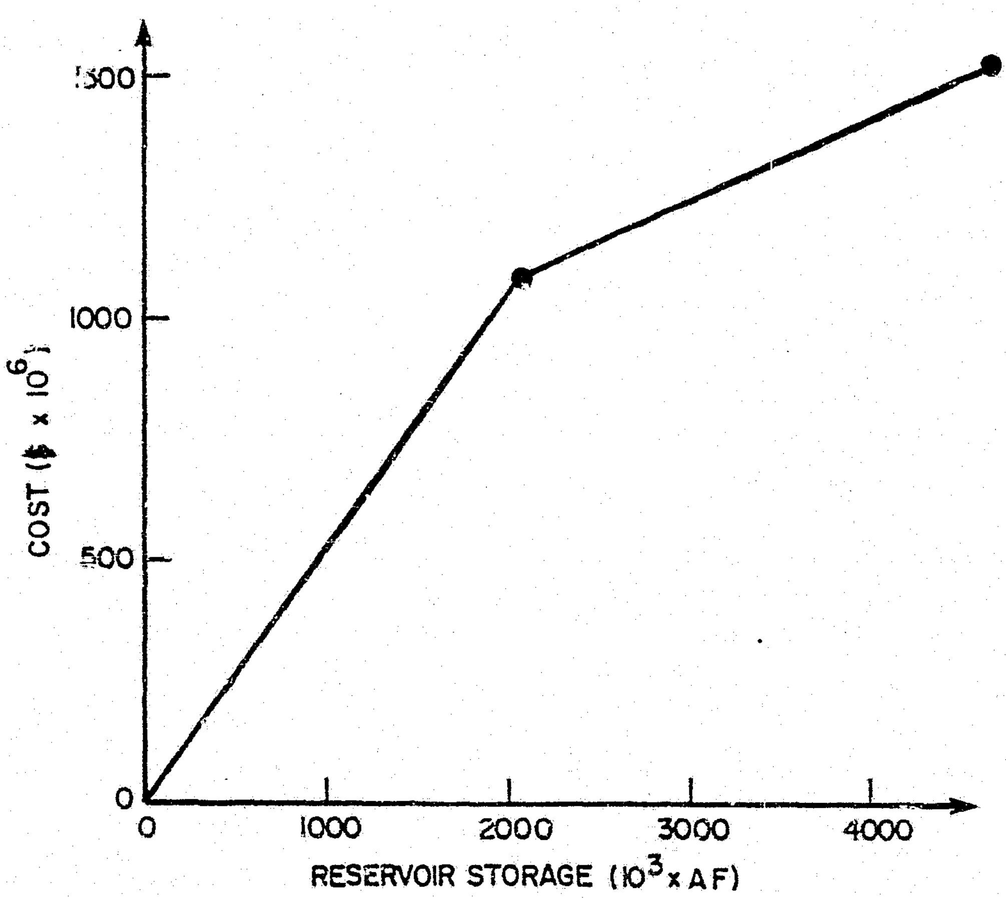
MUTUALLY EXCLUSIVE DEVELOPMENT ALTERNATIVES

FIGURE 6.8

52



DEVIL CANYON

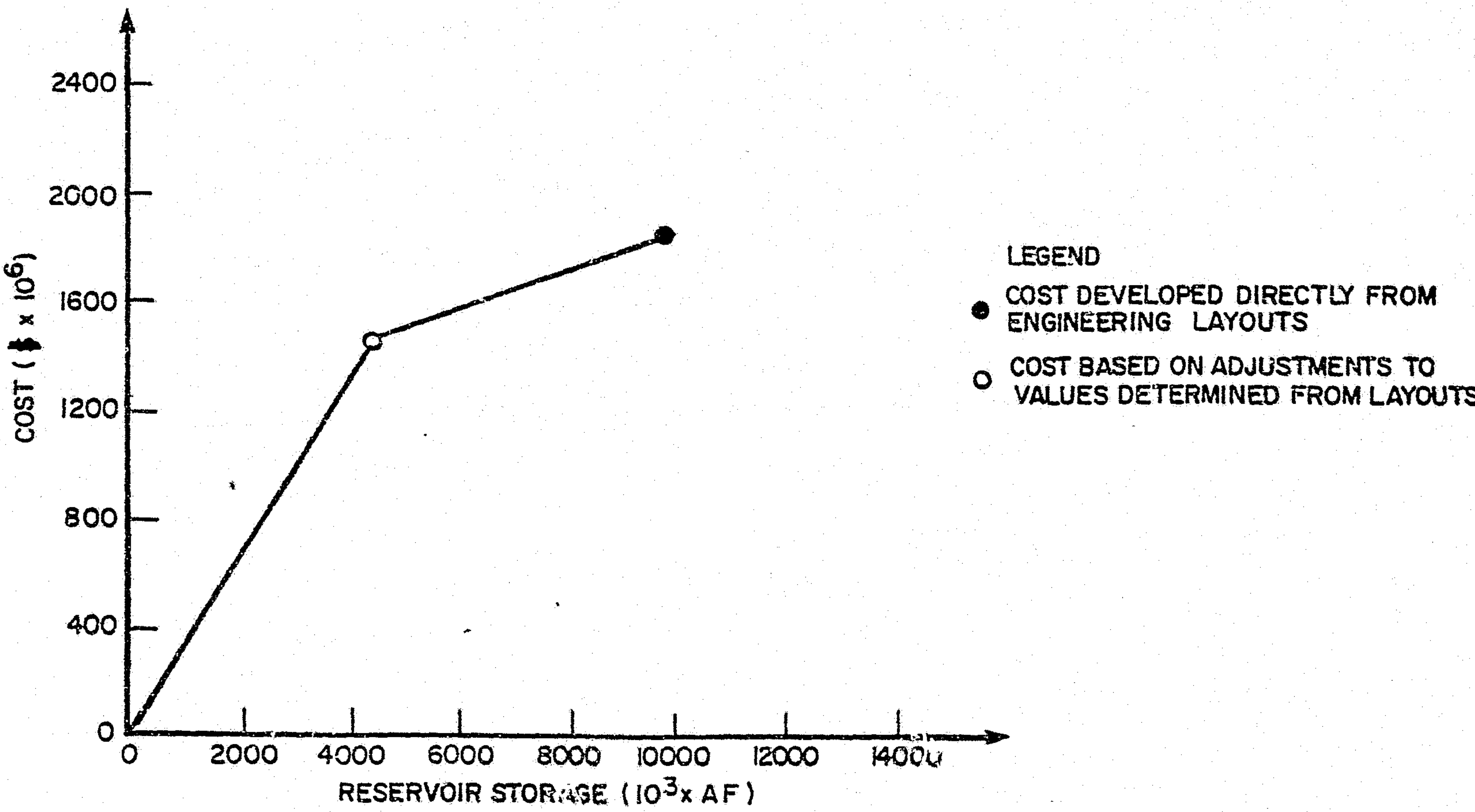


HIGH DEVIL CANYON

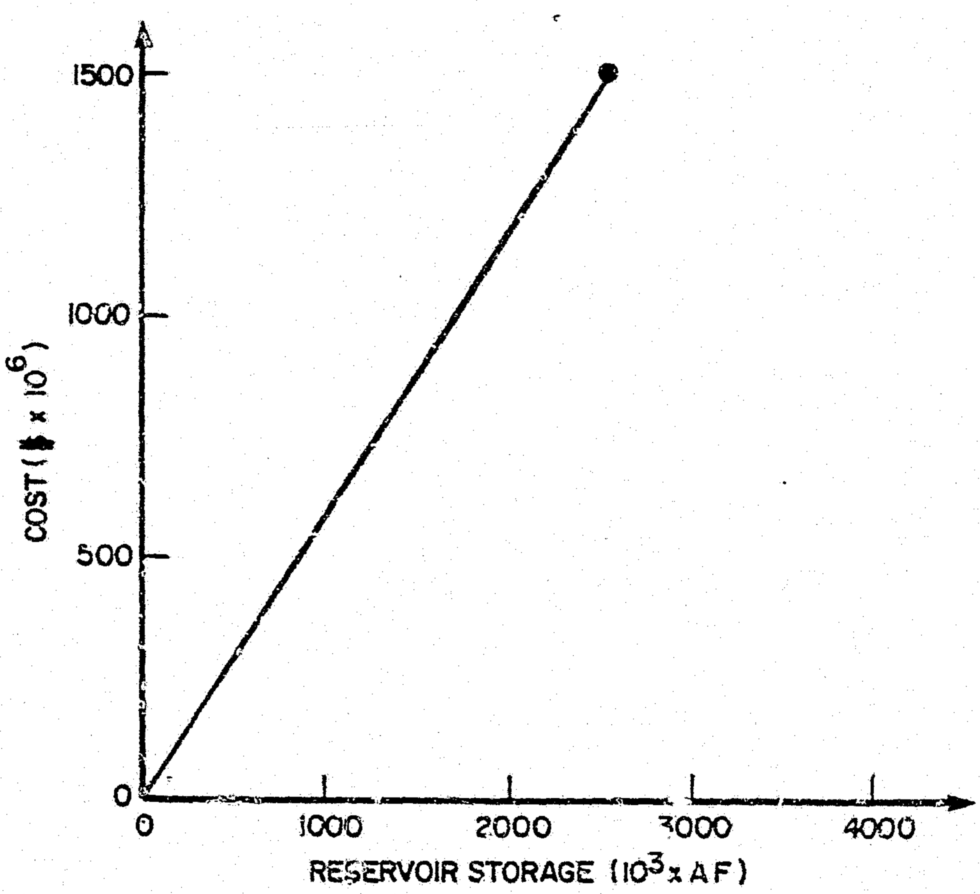
DAMSITE COST VS RESERVOIR STORAGE CURVES

ACRES

FIGURE 6



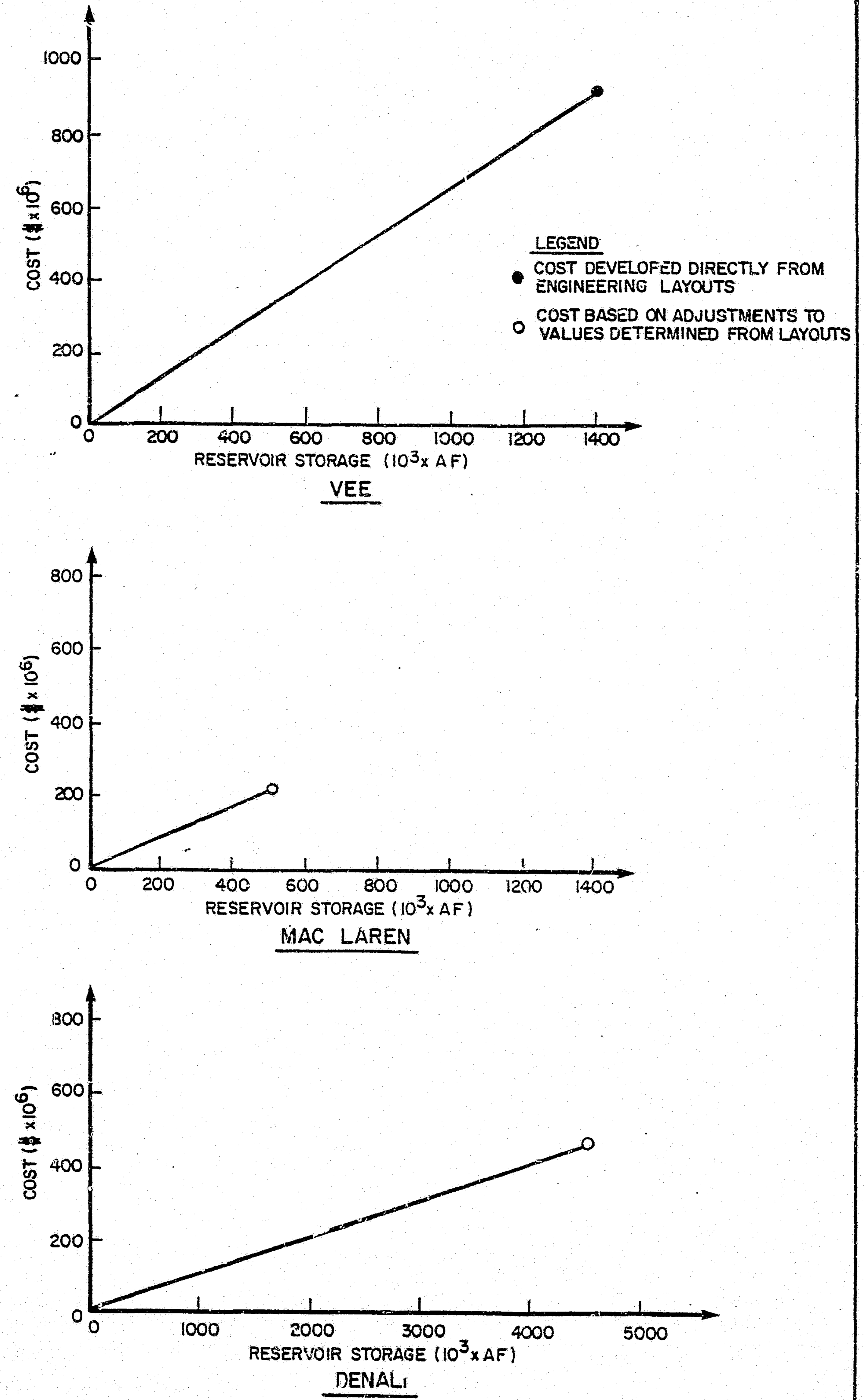
WATANA



SUSITNA III

DAMSITE COST VS RESERVOIR STORAGE CURVES

ACRES



DAMSITE COST VS RESERVOIR STORAGE CURVES

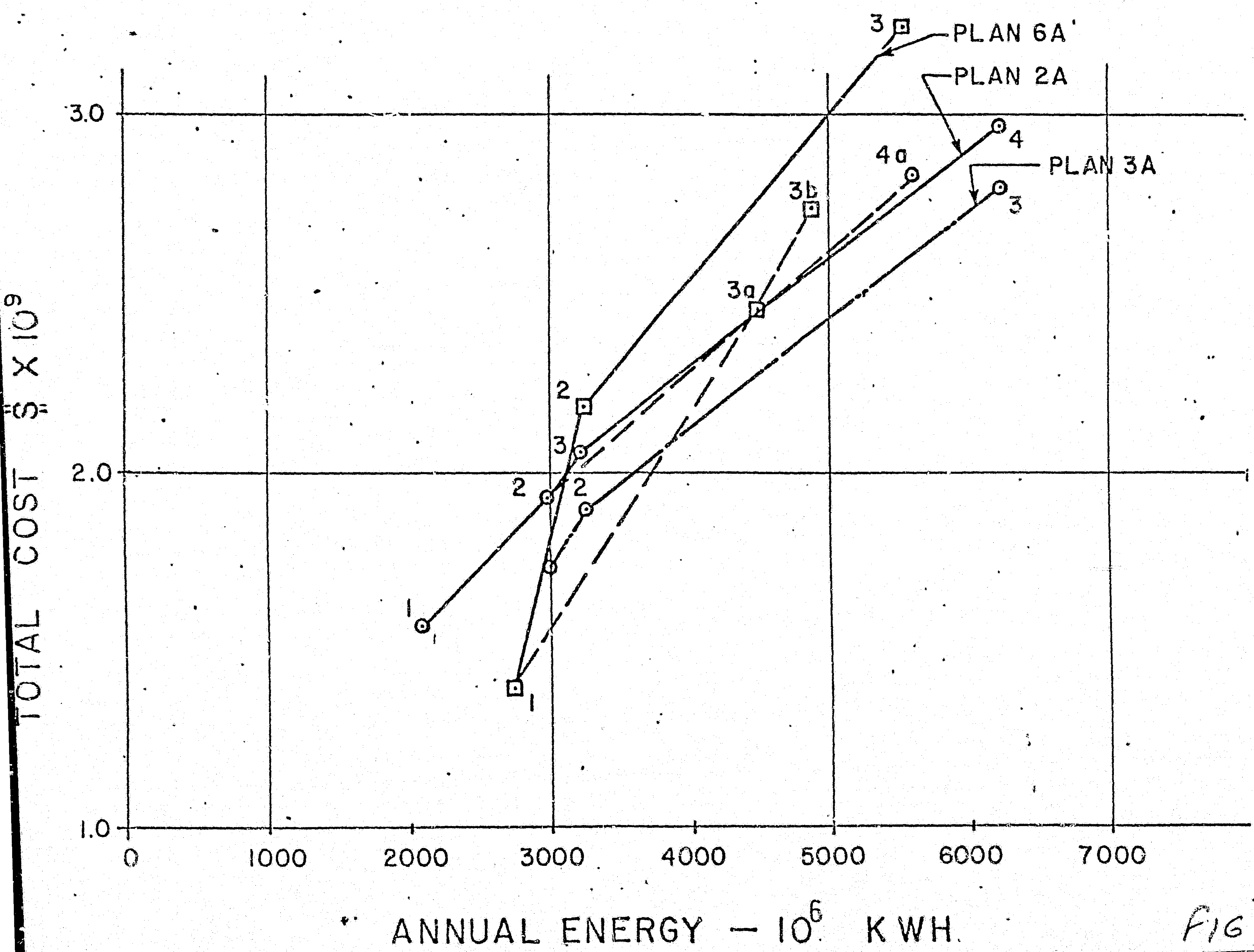
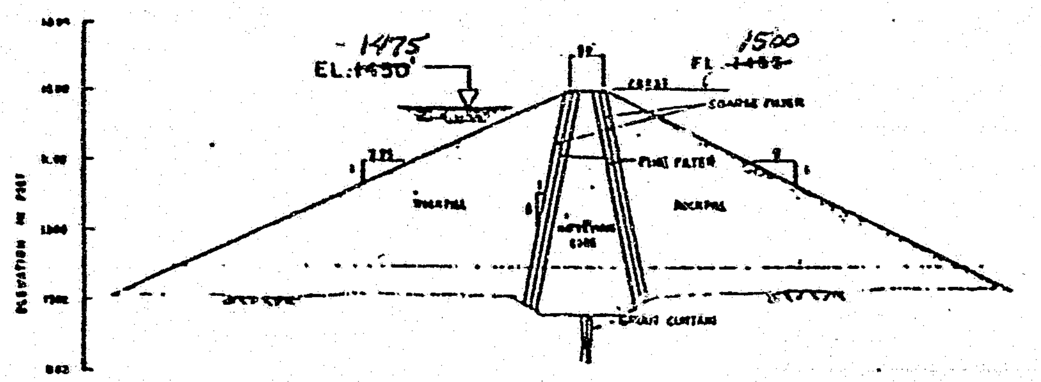
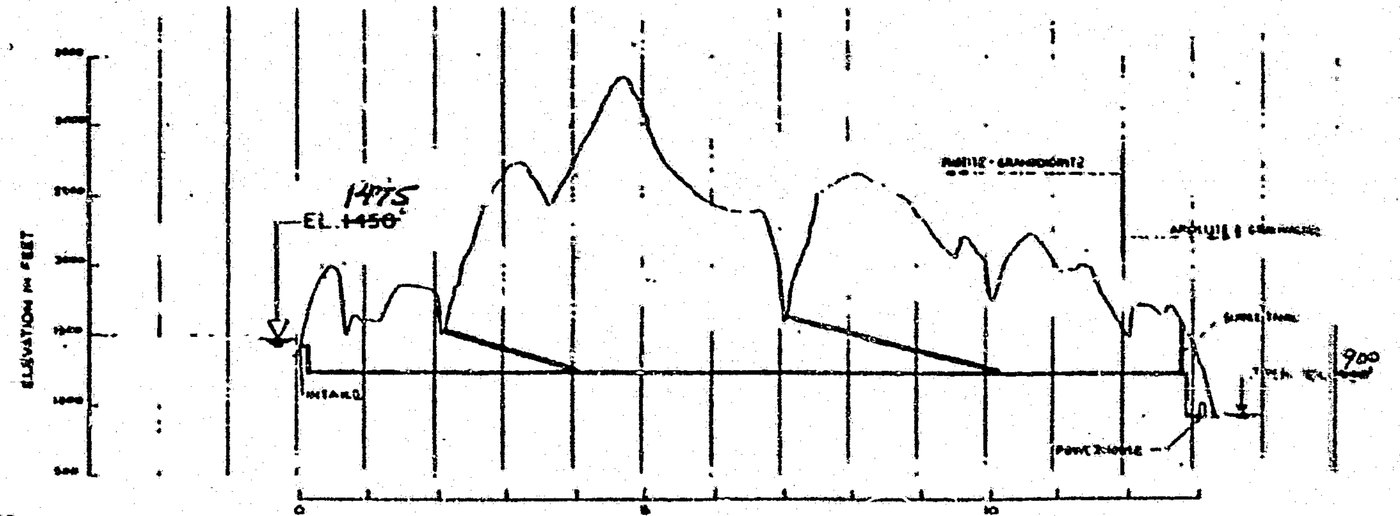

PLAN 6A'
PLAN 2A
PLAN 3A
3
4
4a
3
3b
3a
2
3
2
2
1
1
3.0
2.0
1.0
0
1000
2000
3000
4000
5000
6000
7000
TOTAL COST $ X 10^9
ANNUAL ENERGY — 10^6 KWH.

FIG 7.14

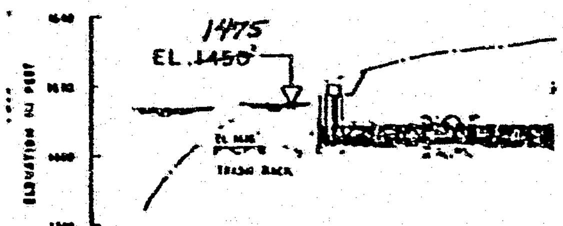
ACRES



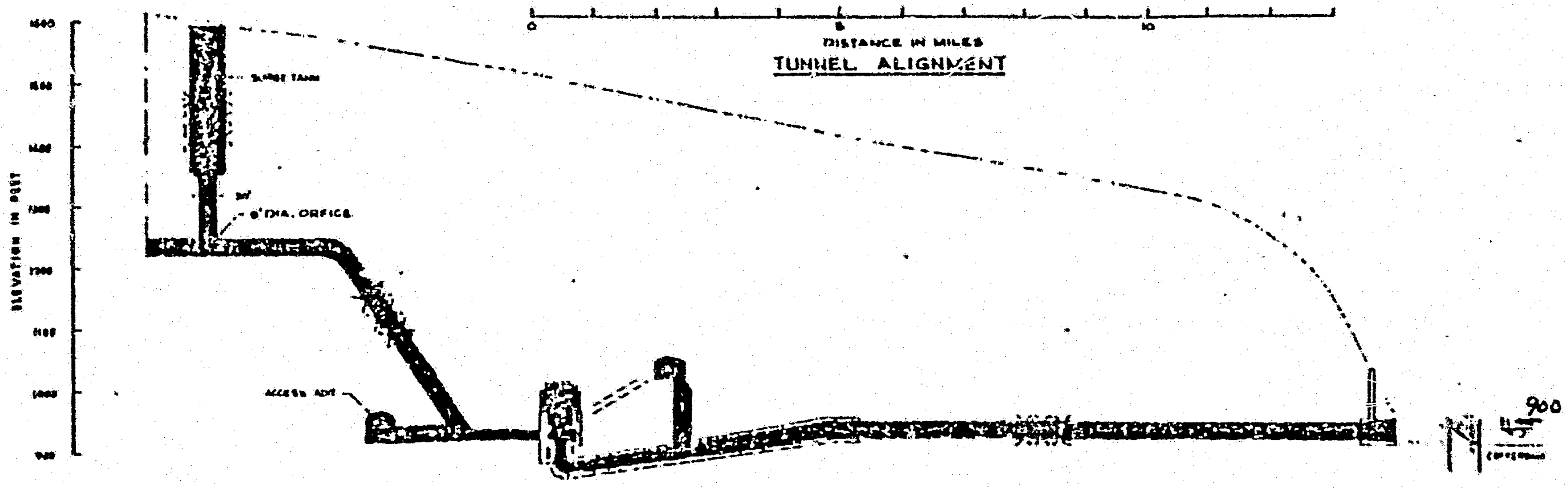
RE-REGULATION DAM TYPICAL SECTION
SCALE



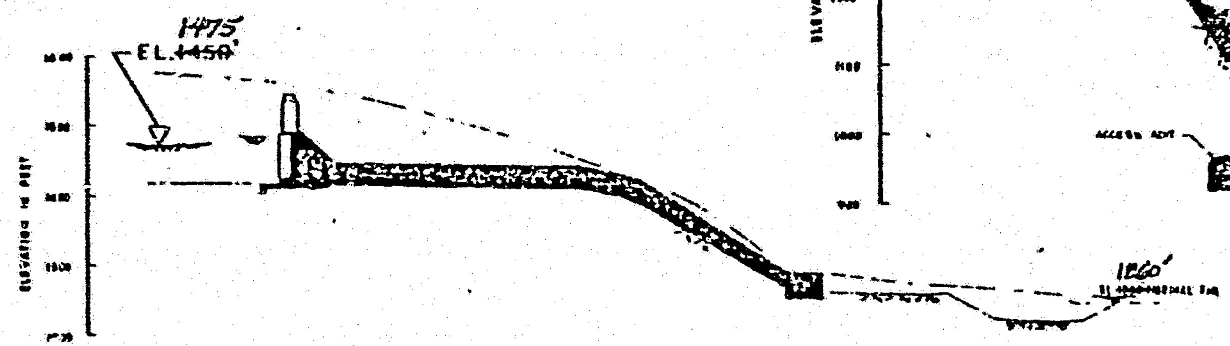
TUNNEL ALIGNMENT



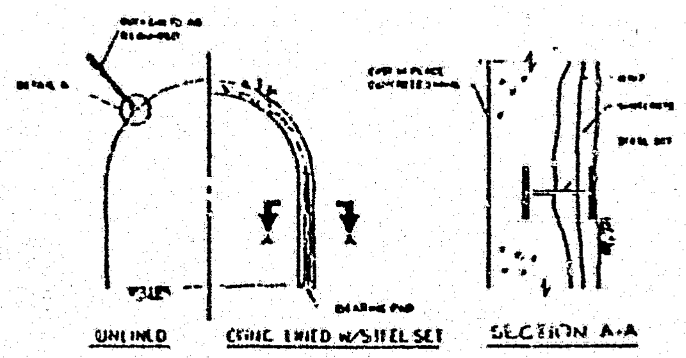
POWER TUNNEL INTAKE SECTION
SCALE A



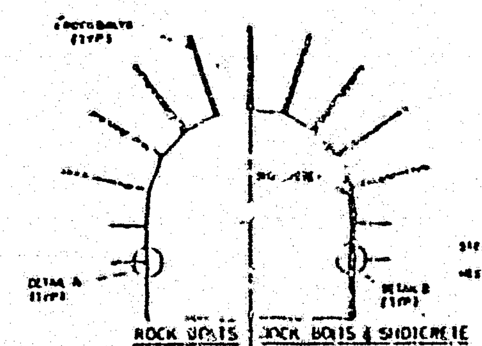
DEVIL CANYON POWER FACILITIES PROFILE
SCALE A



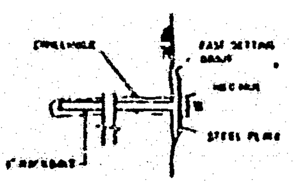
SPILLWAY PROFILE
SCALE A



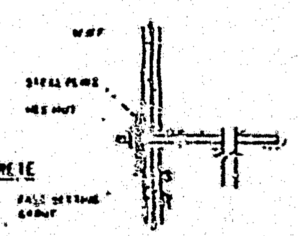
TYPICAL TUNNEL SECTION
NOTE



TYPICAL TUNNEL SECTION
(NOT TO SCALE)



DETAIL A

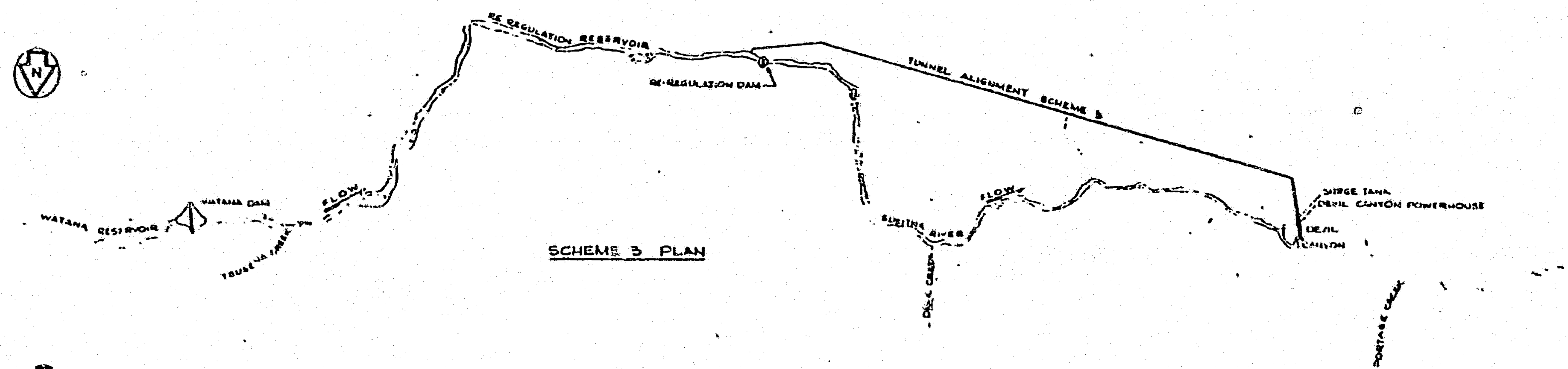


DETAIL B

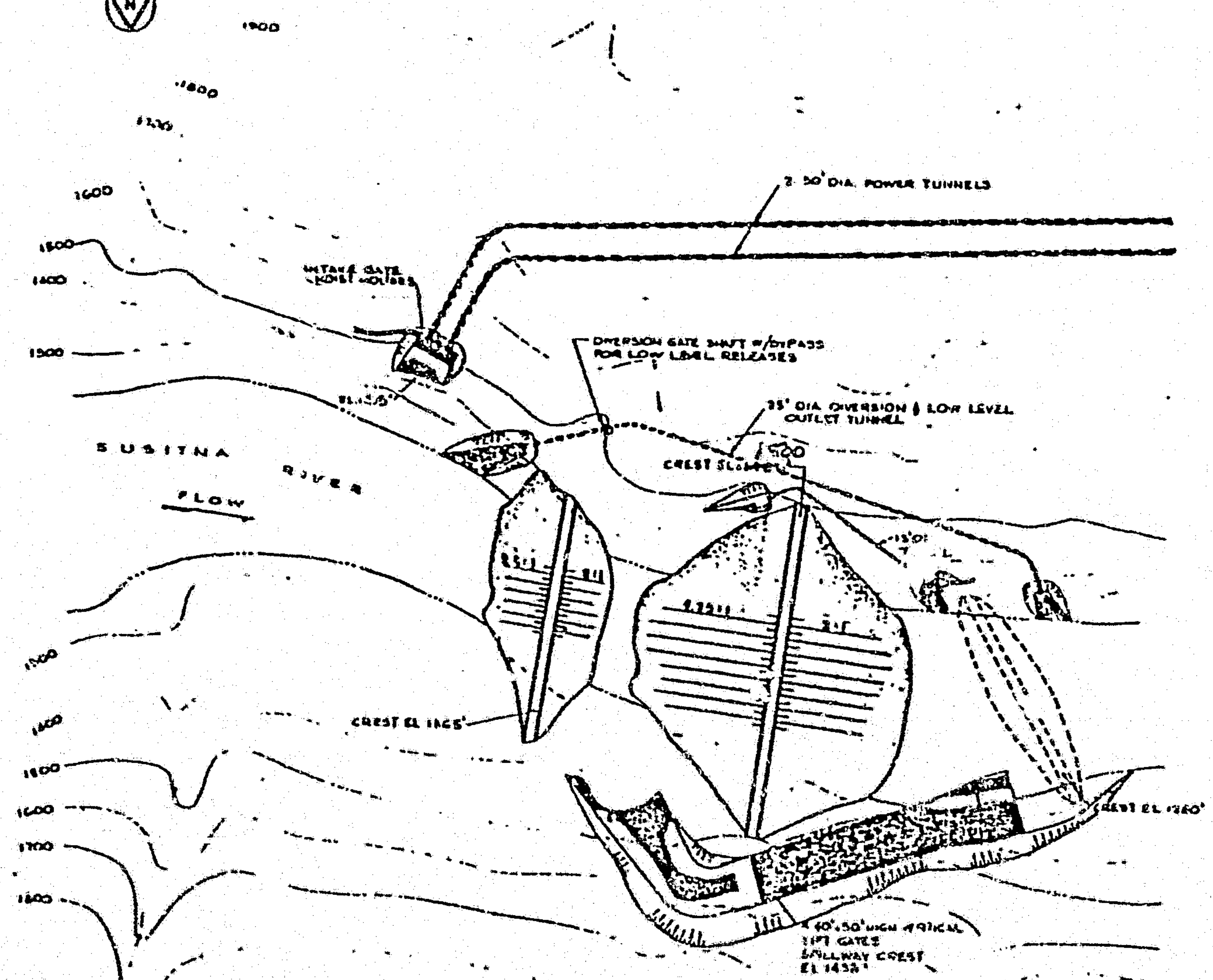
NOTE
ROCKBOLT LENGTH AND SPACING WILL DEPEND ON ACTUAL ROCK CONDITIONS

6.

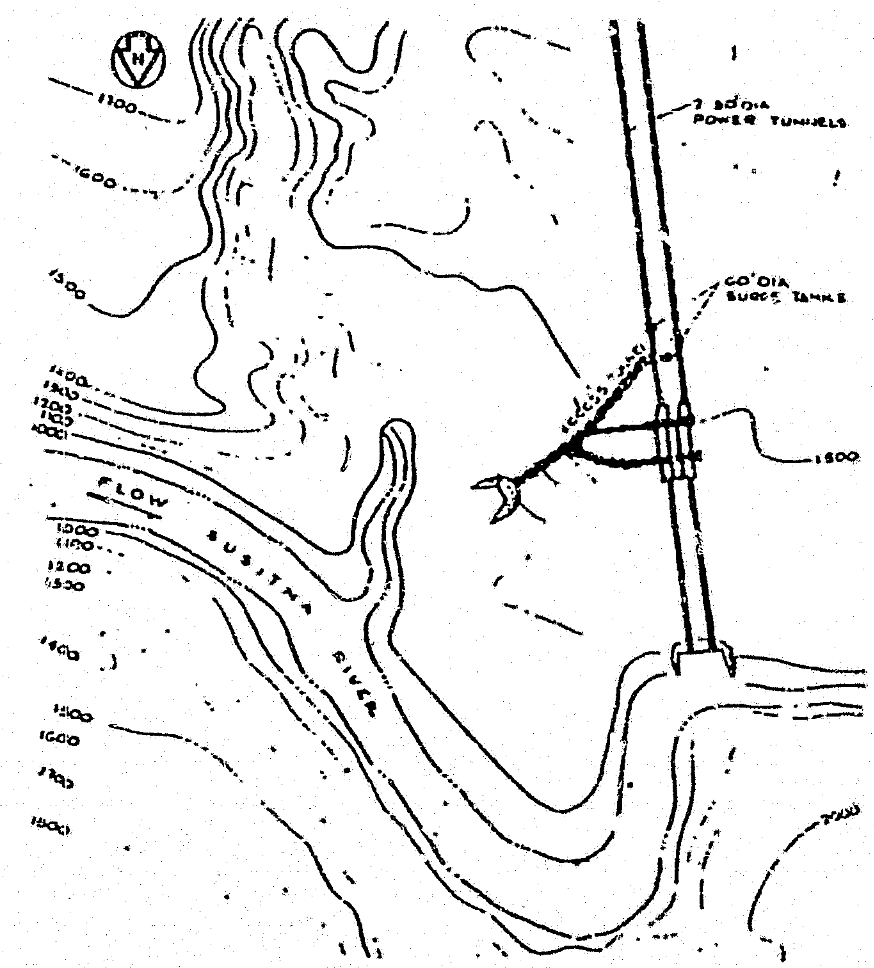
ACRES



SCHEME 3 PLAN



GENERAL ARRANGEMENT
RE-REGULATION DAM



GENERAL ARRANGEMENT
DEVIL CANYON POWERHOUSE

TABLE 6.1 TYPICAL NOAA CLIMATE DATA RECORD

(Source: Ref.)

Meteorological Data For The Current Year

Station: SUMMIT, ALASKA # 26414 SUMMIT AIRPORT Standard time used: ALASKAN Latitude: 63° 20' N Longitude: 149° 08' W Elevation (ground): 2397 feet Year: 1976

Month	Temperature °F Averages Daily maximum	Daily minimum	Monthly	Extremes Highest	Date	Lowest	Date	Degree days Base 65 °F Heating	Cooling	Precipitation in inches Water equivalent Total	Greatest in 24 hrs.	Date	Snow, Ice pellets Total	Greatest in 24 hrs.	Date	Relative humidity, pct. Hour 02 (Local time)	Hour 08	Hour 14	Hour 20
JAN	9.0	-3.8	2.6	34	30	-26	9	1931	0	2.17	1.15	18-19	49.7	31.5	18-19	67	70	73	71
FEB	4.2	-10.4	-3.1	33	5	-28	11	1975	0	1.11	0.50	4	19.6	8.7	5-6		65	65	68
MAR	18.2	2.2	10.2	30	6	-14	15	1696	0	1.65	0.45	3-4	41.1	8.7	3		75	67	
APR	36.9	14.5	25.4	51	30	-3	13	1180	0	0.14	0.08	26	[illegible].8	3.1	26		58		
MAY	43.4	29.4	36.5	54	2	17	7	878	0	2.98	1.90	8	8.7	2.6	8		69		
JUN	60.6	40.9	50.8	74	27	34	8	420	0	0.51	0.30	30	0.0	0.0			69		
JUL	62.1	43.6	52.9	76	23	33	6	368	0	1.05	0.33	23	0.0	0.0			81		
AUG	62.8	41.8	52.3	78	2	31	29	383	0	0.96	0.20	7	0.0	0.0			80		
SEP	49.8	31.7	40.8	59	14	16	30	718	0	1.59	0.48	9	0.4	0.3	20		76		
OCT																			
YEAR																			

Month	Wind Resultant Direction	Resultant Speed m.p.h.	Average speed m.p.h.	Fastest mile Speed m.p.h.	Direction	Date	Percent of possible sunshine	Average sky cover, tenths, sunrise to sunset	Number of days Sunrise to sunset Clear	Partly cloudy	Cloudy	Precipitation .01 inch or more	Snow, Ice pellets 1.0 inch or more	Thunderstorms	Heavy fog, visibility ½ mile or less	Temperature °F Maximum (b) 90° and above	Maximum 32° and below	Minimum 32° and below	Minimum 0° and below	Average station pressure mb Elev. 2405 feet m.s.l.
JAN				28	23	30		6.0	11	4	16	12	7	0	2	0	29	31	20	
FEB				31	07	23		3.9	17	4	8	7	6	0	0	0	27	29	24	
MAR				35	07	17		8.0	4	4	23	11	8	0	0	0	31	31	13	
APR				20	08	14		6.2	5	8	14	3	2	0	0	0	8	30	[illegible]	
MAY				17	24	18		7.5	5	6	20	7	4	0	0	0	0	27	[illegible]	
JUN				18	22	17		6.9	6	8	16	4	0	0	0	3	0	0	[illegible]	
JUL				29	23	27		8.1	3	7	21	14	0	0	1	4	0	0	[illegible]	
AUG				20	26	7						13	0			3	0	1	[illegible]	
SEP				25	25	19		7.[illegible]	3	9	18	13	0	0	2	0	0	17	[illegible]	
OCT				20	08	12														
YEAR																				

Normals, Means, And Extremes – THROUGH 1975#

Month	Temperatures °F Normal Daily maximum	Normal Daily minimum	Normal Monthly	Extremes Record highest	Year	Record lowest	Year	Normal Degree days Base 65 °F Heating	Cooling	Precipitation in inches Water equivalent Normal	Maximum monthly	Year	Minimum monthly	Year	Maximum in 24 hrs. $	Year	Snow, Ice pellets Maximum monthly	Year	Maximum in 24 hrs.	Year
(a)				35		35					35		35		35		34		35	
J	7.9	-4.8	1.6	44	1945	-45	1971	1965	0	0.91	3.38	1948	0.09	1945	0.80	1948	64.8	1948	16.3	1973
F	13.5	-.4	6.6	43	1942	-45	1947	1635	0	1.23	4.31	1951	T	1950	2.79	1951	44.5	1951	28.0	1964
M	19.4	3.0	11.2	49	1961	-35	1971	1668	0	1.04	4.53	1946	0.07	1961	1.67	1946	59.1	1946	18.1	1946
A	32.9	14.1	23.5	57	1956	-30	1944	1245	0	0.67	4.45	1966	0.06	1944	0.97	1963	28.7	1970	9.7	1963
M	45.7	29.1	37.4	76	1960	-14	1945	856	0	0.77	2.66	1966	0.04	1949	0.96	1946	17.4	1958	7.5	1946
J	58.0	39.9	49.0	89	1961	25	1947	480	0	2.19	4.45	1949	0.41	1942	2.22	1967	9.4	1974	8.7	1974
J	60.2	43.8	52.0	81	1961	32	1970	403	0	3.09	5.58	1939	1.17	1955	1.95	1948	9.7	1970	9.7	1970
A	56.0	41.1	48.6	81	1968	20	1955	508	0	3.30	6.33	1955	0.70	1941	2.10	1944	9.0	1955	6.0	1955
S	47.1	32.6	39.9	75	1957	6	1956	753	0	2.81	6.13	1965	0.29	1969	2.07	1944	21.5	1958	14.0	1955
O	30.4	17.5	24.0	59	1969	-15	1975	1271	0	1.62	3.79	1952	0.12	1967	1.24	1963	54.8	1970	12.6	1970
N	15.7	3.7	9.7	44	1962	-29	1948	1659	0	1.23	4.85	1952	0.06	1963	1.30	1964	75.1	1967	21.9	1970
D	9.2	-3.4	2.9	42	1969	-43	1961	1923	0	1.20	4.63	1951	0.24	1945	1.09	1967	50.7	1970	27.4	1970
YR	33.0	18.0	25.5	89	JUN 1961	-45	JAN 1971	14368	0	20.06	6.74	AUG 1944	T	FEB 1950	2.79	FEB 1951	75.1	NOV 1967	28.0	FEB 1964

Month	Relative humidity pct. Hour 02 (Local time)	Hour 08	Hour 14	Hour 20	Wind @ Mean speed m.p.h.	Prevailing direction	Fastest mile Speed m.p.h.	Direction	Year	Pct. of possible sunshine	Mean sky cover, tenths, sunrise to sunset	Mean number of days Sunrise to sunset Clear	Partly cloudy	Cloudy	† Precipitation .01 inch or more	Snow, Ice pellets 1.0 inch or more	Thunderstorms	Heavy fog, visibility ½ mile or less	Temperatures °F Max (b) 90° and above	Max 32° and below	Min. 32° and below	Min. 0° and below	Average station pressure mb. Elev. 2405 feet m.s.l.
(a)	5	7	7	6	8	5	7	7			7	7	7	7	20	8	8	8	34	34	34	34	2
J	68	68	69	68	15.1	NE	44	05	1968		5.2	13	5	13	9	4	0	*	0	30	32	20	921.4
F	76	75	75	76	11.9	NE	46	07	1974		7.0	6	5	17	10	5	0	1	0	26	28	18	918.6
M	76	76	72	73	11.1	NE	48	10	1971		6.2	9	6	16	10	5	0	1	0	27	31	14	917.2
A	80	75	65	75	7.6	NE	33	08	1971		7.2	5	7	18	7	4	0	1	0	13	30	3	922.9
M	83	75	50	67	7.7	W	28	07	1969		7.5	3	9	19	7	2	*	1	*	1	22	*	923.1
J	84	73	57	[illegible]	8.3	SW	29	22	1970		8.2	2	6	22	12	1	2	1	3	0	2	0	924.7
J	89	78	62	72	7.8	SW	30	23	1974		8.2	2	7	22	16	*	2	1	5	0	*	0	929.1
A	86	81	62	76	7.4	SW	31	22	1975		8.3	2	6	23	18	0	*	1	1	0	2	0	930.3
S	85	81	59	75	7.5	NE	32	23	1972		7.4	5	5	20	16	2	*	1	*	1	14	0	924.1
O	85	85	76	81	8.0	NE	35	23	1970		7.6	5	5	21	13	7	0	2	0	18	30	2	916.7
N	79	79	78	79	11.3	NE	39	25	1970		7.1	7	4	19	9	5	0	1	0	27	30	13	921.3
D	76	78	76	77	12.7	NE	44	11	1970		5.5	9	5	17	11	6	0	1	0	30	31	19	914.7
YR	81	76	67	74	9.7	NE	48	10	MAR 1971		7.2	68	70	227	138	41	5	12	9	173	251	86	922.0

NOTE: Due to less than full time operation on a variable schedule, manually recorded elements are from broken sequences in incomplete records. Daily temperature extremes and precipitation totals for portions of the record may be for other than a calendar day. The period of record for some elements is for other than consecutive years.

(a) Length of record, years, through the current year unless otherwise noted, based on January data.
(b) 70° and above at Alaskan stations.
* Less than one half.
T Trace.

NORMALS - Based on record for the 1941-1970 period.
DATE OF AN EXTREME - The most recent in cases of multiple occurrence.
PREVAILING WIND DIRECTION - Record through 1963.
WIND DIRECTION - Numerals indicate tens of degrees clockwise from true north. 00 indicates calm.
FASTEST MILE WIND - Speed is fastest observed 1-minute value when the direction is in tens of degrees.

$ For calendar day prior to 1968.
@ For the period 1950-1956 and January 1968 to date when available for full year.
† For the period 1942-1953 and January 1968 to date when available for full year.

Data for this station not available for archiving nor [illegible]

TABLE 6.2 - Summary of Climatological Data

STATION	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC	ANNUAL
MEAN MONTHLY PRECIPITATION IN INCHES													
Anchorage	0.84	0.56	0.56	0.56	0.59	1.07	2.07	2.32	2.37	1.43	1.02	1.07	
Big Delta	0.36	0.27	0.33	0.31	0.94	2.20	2.49	1.92	1.23	0.56	0.41	0.42	11.44
Fairbanks	0.60	0.53	0.48	0.33	0.65	1.42	1.90	2.19	1.08	0.73	0.66	0.65	11.22
Gulkana	0.58	0.47	0.34	0.22	0.63	1.34	1.84	1.58	1.72	0.88	0.75	0.76	11.11
Matanuska Agr. Exp. Station	0.79	0.63	0.52	0.62	0.75	1.61	2.40	2.62	2.31	1.39	0.93	0.93	15.49
McKinley Park	0.68	0.61	0.60	0.38	0.82	2.51	3.25	2.48	1.43	0.42	0.90	0.96	15.54
Summit WSO	0.89	1.19	0.86	0.72	0.60	2.18	2.97	3.09	2.56	1.57	1.29	1.11	19.03
Talkeetna	1.63	1.79	1.54	1.12	1.46	2.17	3.48	4.89	4.52	2.54	1.79	1.71	28.64
MEAN MONTHLY TEMPERATURES													
Anchorage	11.8	17.8	23.7	35.3	46.2	54.6	57.9	55.9	48.1	34.8	21.1	13.0	
Big Delta	- 4.9	4.3	12.3	29.4	46.3	57.1	59.4	54.8	43.6	15.2	6.9	- 4.2	27.5
Fairbanks	-11.9	- 2.5	9.5	28.9	47.3	59.0	60.7	55.4	44.4	25.2	2.8	-10.4	25.7
Gulkana	- 7.3	3.9	14.5	30.2	43.8	54.2	56.9	53.2	43.6	26.8	6.1	- 5.1	26.8
Matanuska Agr. Exp. Station	9.9	17.8	23.6	36.2	46.8	54.8	57.8	55.3	47.6	33.8	20.3	12.5	34.7
McKinley Park	- 2.7	4.8	11.5	26.4	40.8	51.5	54.2	50.2	40.8	23.0	8.9	- 0.10	25.8
Summit WSO	- 0.6	5.5	9.7	23.5	37.5	48.7	52.1	48.7	39.6	23.0	9.8	3.0	25.0
Talkeetna	9.4	15.3	20.0	32.6	44.7	55.0	57.9	54.6	46.1	32.1	17.5	9.0	32.8

Source: Reference____.

TABLE 6.3 - Recorded Air Temperatures at Talkeetna and Summit in °F

	Talkeetna			Summit		
Month	Daily Max.	Daily Min.	Monthly Average	Daily Max.	Daily Min.	Monthly Average
Jan	19.1	- 0.4	9.4	5.7	- 6.8	- 0.6
Feb	25.8	4.7	15.3	12.5	- 1.4	5.5
Mar	32.8	7.1	20.0	18.0	1.3	9.7
Apr	44.0	21.2	32.6	32.5	14.4	23.5
May	56.1	33.2	44.7	45.6	29.3	37.5
June	65.7	44.3	55.0	52.4	39.8	48.7
Jul	67.5	48.2	57.9	60.2	43.4	52.1
Aug	64.1	45.0	54.6	56.0	41.2	48.7
Sept	55.6	36.6	46.1	46.9	32.2	39.6
Oct	40.6	23.6	32.1	29.4	16.5	23.0
Nov	26.1	8.8	17.5	15.6	4.0	9.8
Dec	18.0	- 0.1	9.0	9.2	- 3.3	3.0
Annual Average			32.8			25.0

TABLE 6.4 - Maximum Recorded Ice Thickness on the Susitna River

Location	Maximum Ice Thickness in Feet
Susitna River at Gold Creek	5.7
Susitna River at Cantwell	5.3
Talkeetna River at Talkeetna	3.3
Chulitna River at Talkeetna	5.3
Maclaren River at Paxson	5.2

TABLE 6.5 - Streamflow Summary

Gage	Drainage Area-mile^2	Average Annual Streamflow - cfs	Maximum Instantaneous Streamflow - cfs	Date	Minimum Instantaneous Streamflow - cfs	Date
Maclaren River near Paxson	280	976	9,260	8-11-71	40	3-1-65
Susitna River near Denali	950	2,695	38,200	8-10-71	34	3-16-59
Susitna River near Cantwell	4,140	6,295	55,000	8-10-71	400	3-16-64
Susitna River near Gold Creek	6,160	9,288	90,700	6-7-64	600	2-18-50

TABLE 6.6 - Monthly Percent of Annual Discharge and Mean Monthly Discharge at Susitna River Stations

MONTH	STATION							
	Susitna River at Gold Creek		Susitna River Near Cantwell		Susitna River Near Denali		Maclaren River Near Paxson	
	%	Mean(cfs)	%	Mean(cfs)	%	Mean(cfs)	%	Mean(cfs)
JANUARY	1	1,438	1	824	1	245	1	90
FEBRUARY	1	1,213	1	722	1	204	1	78
MARCH	1	1,085	1	692	1	187	1	71
APRIL	1	1,339	1	853	1	233	1	82
MAY	12	13,400	10	7,701	6	2,063	7	845
JUNE	24	28,150	26	19,330	23	7,431	25	2,926
JULY	21	23,990	23	16,890	29	9,428	27	3,171
AUGUST	19	21,950	20	14,660	24	7,813	22	2,557
SEPTEMBER	12	13,770	10	7,800	10	3,343	10	1,184
OCTOBER	5	5,580	4	3,033	3	1,138	3	407
NOVEMBER	2	2,435	2	1,449	2	502	1	168
DECEMBER	2	1,748	1	998	1	318	1	111

TABLE 6.7 - Flood Peaks at Selected Locations on the Susitna River

Location	Drainage Area-mile^2	Mean Annual	Flood Peak cfs 1:100 yr	Flood Peak cfs 1:10,000 yr	PMF** Summer (Aug)	PMF** Spring (June)
Gold Creek Gage	6,160	53,000	118,000	185,000	232,000	236,000
Devil Canyon Dam Site	5,810	50,000	103,000	175,000	223,000*	226,000*
Watana Dam Site	5,180	44,600	91,000	155,000	213,000	233,000
Cantwell Gage	4,140	33,700	68,000	118,000	94,000	156,000
Denali Dam Site	950	17,800	43,600	63,000	60,800	61,700

* Incorporating attenuation by the Watana Dam.
** COE estimates for Watana and Gold Creek; others were interpolated based on drainage basin area.

TABLE 6.8 - Suspended Sediment Transport

(Sources: Ref.___)

Station	Sediment Transport (Tons/year)	Initial Unit Weight (Lb/ft^3)
Susitna at Gold Creek	8,734,000	65.3
Susitna near Cantwell	5,129,000	70.6
Susitna near Denali	5,243,000	70.4
Maclaren near Paxson	614,000	68.6

TABLE 6.10 - Potential Hydroelectric Development

Site	Dam: Proposed Type	Dam: Height Ft.	Upstream Regulation	Capital Cost $ x 10^6	Installed Capacity (MW)	Average Annual Energy Gwh	Economic* Cost of Energy $/1000 kWh	Source of Data
Gold Creek	Fill	190	Yes	900	260	1,140	41.9	USBR 1953
Olson (Susitna II)	Concrete	160	Yes	600	200	915	34.6	USBR 1953 KAISER 1974 COE 1975
Devil Canyon	Concrete	660	No Yes	800 1,000	250 600	1,415 2,970	30.6 19.0	This Study "
High Devil Canyon (Susitna I)	Fill	830	No Yes	1,530 1,530	800 800	3,615 3,615	24.6 24.6	" "
Devil Creek	Fill	830	No	-	-	-	-	-
Watana	Fill	860	No	1,860	800	3,250	31.4	"
Susitna III	Fill	665	No	1,500	350	1,730	46.3	"
Vee	Fill	650	No	1,060	400	1,320	37.7	"
Maclaren	Fill	50	No	500	10	45	550.0	"
Denali	Fill	200	No	500	70	370	68.1	"
Butte Creek	Fill	Approx 100	No	-	-	-	-	USBR 1953
Tyone	Fill	35	No	-	-	-	-	USBR 1953

*Includes AFDC, Insurance and Amortization, and Operation & Maintenance Costs.

TABLE 6.11 - Cost Comparisons

Dam		Capital Cost Estimates (1980 $)				
		Acres 1980		Others		
Site	Type	Installed Capacity - MW	Capital Cost $\$ \times 10^6$	Installed Capacity - MW	Capital Cost $\$ \times 10^6$	Source and Date of Data
Gold Creek	Fill	-	-	260	900	USBR 1953
Olson (Susitna II)	Concrete	-	-	200	600	USBR 1953 KAISER 1974 COE 1975
Devil Canyon	Concrete	600	1,000	776	914	COE 1978
High Devil Canyon (Susitna I)	Fill	800	1,500	700	1,846	COE 1975
Devil Creek	Fill	-	-	-	-	-
Watana	Fill	800	1,860	792	1,961	COE 1978
Susitna III	Fill	350	1,500	445	-	-
Vee	Fill	400	1,060	300*	-	-
Maclaren	Fill	10	500	-	-	-
Denali	Fill	70	500	None	496	COE 1975

*Dependable Capacity

6.38

TABLE 6.12 - Environmental Ranking of Sites

River Section	Biological		Social		Institutional	Overall
	Fish	Wildlife	Local	Reg.		
Gold Creek	M	M	M	L	X	M-H
Olson (Susitna II)	M	M	M	L	X	M-H
Devil Canyon	L	L	M-H	M-H	M	M
Devil Canyon (Susitna I)	L	M	M-H	M-H	M	M
Devil Creek	L	M	M-H	M	M	M
Watana	L	M-H	M-H	L-M	M	M
Susitna III	L-M	M-H	M-H	M-H	M-H	M-H
Vee	L-M	M-H	M-H	M	M-H	M-H
Maclaren	L-M	M-H	M	L-M	M-H	M
Denali	L	M-H	M	M	M-H	M
Butte Creek	L	M-H	L-M	L-M	M	M
Tyone	L	M-H	L-M	H	M-H	M-H

Degree of impact:
L - Potential for Low Impact
M - Potential for Moderate Impact
H - Potential for High Impact
X - Potentially Unacceptable

TABLE ~~2~~ ~~6.~~ 6.13

GEOTECHNICAL DESIGN CONSIDERATIONS

GENERAL CONDITIONS	DENALI	MACLAREN	VEE
1. Dam Type	Earth-Rockfill	Earth-Rockfill	Earth-Rockfill
2. U/S Slope	4:1 (H/V)	4:1	2.25:1
3. D/S Slope	4:1	4:1	2:1
4. General Foundation Conditions	All structures would have soil foundations. Depth to bedrock is believed to be 200'+. Interstratified till and alluvium foundation material, local liquefaction potential. 40'+ alluvium in valley.	Assume soil foundations. Depth to bedrock estimated at 200'. Compressible, permeable and liquefiable zones probably exist.	River alluvium 125', drift or talus on abutments is 10-40' thick. Saddle dam located on deep permafrost alluvium.
5. Required Foundation Excavation (in addition to overburden)	Total Excavation Depth: Abutment — Core 30', Shell 10' Channel — Core 70', Shell 50'	Unknown. Assume same as for Denali.	Assume: Core - Remove average of 50' of rock Shell - Remove top 10' of rock
6. Required Foundation Treatment & Grouting	Assume core-grout in five rows of holes to 70% of head up to a maximum of 300'. Probable drain curtain or drain blanket under downstream shell. Foundation surface - no special treatment.	Assume same as for Denali.	Assume grouting same as for Watana. No special treatment under shell. Assume extensive sand drains in saddle dam permafrost area.
7. Seismic Considerations (MCE = Maximum Credible Earthquake)	High exposure, no known site faults. MCE = Richter 8.5 @ 40 miles.	High exposure, no known site faults. MCE = 8.5 @ 40 miles.	High exposure, no known site faults. MCE = 8.5 @ 40 miles.
8. Powerhouse Location	Underground powerhouse unsuitable.	Underground powerhouse unsuitable	Unknown. Assume suitable for underground with substantial rock support.
9. Permafrost	> 100' deep in abutments, probable lenses under river.	Probably > 100'.	> 60' in saddle area, sporadic in abutments.
10. Construction Material Availability	No borrow areas identified. Assume suitable materials are available within a five-mile radius. Processing of impervious material will be required.	Assume same as for Denali.	Assume available 0.5 to 5 mile radius. Impervious will require processing.
11. Remarks	Based on Kachadoorian, 1959.	No report on site. Parameters based on regional geology.	Based on USBR studies.

NOTE: 1) Actual estimates on Watana & Devil Canyon have been taken from overburden contour maps.
2) Data compiled prior to January 1, 1981. Estimates made after this date have used updated excavation criteria.

6.13

TABLE 7 (cont'd)

GEOTECHNICAL DESIGN CONSIDERATIONS

GENERAL CONDITIONS	SUSITNA III	WATANA	HIGH DEVIL CANYON
1. Dam Type	Earth-Rockfill	Earth-Rockfill or concrete arch	Earth-Rockfill
2. U/S Slope	2.25:1	2.25:1 (for earth)	2.25:1
3. D/S Slope	2:1	2:1	2.1
4. General Foundation Conditions	Unknown but rock probably over 50' in depth. Possible permeable compressible and liquefiable strata.	Abutments - assume 15' overburden(OB) Valley bottom - 48-78' alluvium. Assume 70'. Right bank upstream - approximately 475' deep relict channel on right bank, upstream of dam site.	Assume 30-60' overburden and alluvium.
5. Required Foundation Excavation (in addition to overburden)	Assume same as for Watana.	Core: Remove top 40' of rock Shell: Remove top 10' of rock	Core: Remove top 40' of rock Shell: Remove top 15' of rock
6. Required Foundation Treatment & Grouting	Assume grout and drain system full width of dam, dependent on foundation quality. Drain gallery & drain holes.	Extensive grouting to depth = 70% of head but not to exceed 300'. Drain gallery & drain holes.	Assume same as for Watana.
7. Seismic Considerations (MCE = Maximum Credible Earthquake)	High exposure. MCE = 8.5 @ 40 miles. Also near zone of intense shearing.	MCE = Richter 8.5 @ 40 miles <u>or</u> 7.0 @ 10 miles.	Same as for Watana.
8. Powerhouse Location	Unknown. Assume suitable for underground with substantial rock support.	Underground favorable, extensive support may be required.	Probably favorable for underground but assume support needed.
9. Permafrost	Probably sporadic and deep.	> 100 feet on left abutment. More prevalent and deeper on north facing slopes.	Sporadic, possibly 100' ±.
10. Construction Material Availability	Assume available within five miles. Processing similar to that at Watana.	Available within 0-5 miles. Processing required.	No borrow areas defined. Assume available within 5 miles.
11. Remarks	No reports available. Parameters based on regional geology of the area.	Based on Corps studies and 1980 Acres exploration.	No geotechnical data available. Parameters based on regional geology.

TABLE 6.13 (cont'd)

GEOTECHNICAL DESIGN CONSIDERATIONS

GENERAL CONDITIONS	DEVIL CANYON	DEVIL CANYON	PORTAGE CREEK
1. Dam Type	Concrete arch or gravity	Rockfill	Concrete gravity
2. U/S Slope	---	2.25:1	---
3. D/S Slope	---	2:1	---
4. General Foundation Conditions	Assume 35' alluvium in river bottom. Shears and fault zones in both abutments, 35-50' of weathered rock. Saddle dam overburden up to 90' deep. Assume excavation for spillway totals 90' to sound rock on valley walls.		Unknown - assume same as for Devil Canyon.
5. Required Foundation Excavation (in addition to overburden)	Remove 50' of rock. Extensive dental work and shear zone over-excavation will be required. Saddle dam: Excavate 15' into rock	Core: Excavate 40' into rock Shell: Excavate 15' into rock Allow for surface treatment. Saddle dam: Excavate 15' into rock.	Rock type is similar to Devil Canyon, so assume foundation conditions are similar.
6. Required Foundation Treatment & Grouting	Extensive grouting to 70% of head, limited to 300'. Allow for long anchors into rock for thrust blocks. Extensive dental treatment. Deep cutoff under saddle dam, 15' into rock.	Extensive grouting to 70% of head, limited to 300'. Extensive dental treatment under core. Deep cutoff under saddle dam, 15' into rock.	Assume same as Devil Canyon.
7. Seismic Considerations (MCE = Maximum Credible Earthquake)	Same as for Watana.	Same as for Watana.	MCE = Richter 8.5 @ 40 miles or 7.0 at 10 miles.
8. Powerhouse Location	Favorable for underground powerhouse, assume moderate support.	Favorable for underground powerhouse, assume moderate support.	Probably favorable for underground powerhouse, assume moderate support.
9. Permafrost	None expected, but possibly sporadic.	None expected, but possibly sporadic.	None expected, may be local areas on north exposures or in overburden.
10. Construction Material Availability	Concrete aggregate within 0.5 miles, embankment material - assume within 3 miles.	Concrete aggregate within 0.5 miles, embankment material - assume within 3 miles.	Unknown - expect adequate sources 2-5 miles downstream.
11. Remarks	Based on USBR, Corps and 1980 Acres exploration.	Based on USBR, Corps and 1980 Acres exploration.	No previous investigations are available on this site.

TABLE 6.14 - Hydrologic Design Considerations

Parameter	Denali	Maclaren	Vee	Susitna III	Watana	High Devil Canyon	Devil Canyon	Portage Creek	Tunnel Alternative	Remarks
Catchment area-sq.mi^2:	1,269	2,320	4,140	4,225	5,180	5,760	5,810	5,840	--	
Mean annual flow-cfs:	3,290	4,360	6,190	6,350	8,140	9,140	9,230	9,230	--	
Inflow flood peaks* - cfs - 50 year:	43,000	50,000	63,000	65,000	83,000	94,000	94,000	20,000**	20,000**	
Inflow flood peaks* - cfs - 10,000 year:	89,800	106,000	133,000	137,000	175,000	198,000	200,000	200,000	175,000	
Inflow flood peaks* - cfs - PMF:	--	--	189,000	--	235,000	262,000	270,000	270,000	--	
50-year sediment accumulation Acre-ft:	290,000	243,000	162,000	165,000	204,000	248,000	252,000	--	--	assumes no up-stream development

* Not accounting for any reservoir attenuation unless indicated otherwise.
** After upstream dam has been completed

TABLE 6.15 - Freeboard Requirements

		Fill Dam	Concrete Dam
Allowances for:	dry freeboard	3 ft.	3 ft.
	wave runup & wind setup	6 ft.	6 ft.
	spillway design flood surcharge (10,000 year flood)	5 ft.	5 ft.
	post-construction dam settlement	1% dam height	nil
.. Total difference between full supply level and dam cost		14 ft. + 1% dam height	14 ft.

TABLE 6.16 - Engineering Layout Considerations at Single Developments

Components	Denali	Maclaren	Vee	Susitna III	Watana	High Devil Canyon	Devil Canyon	Tunnel Alternatives
Dam	← Conventional earth/rockfill →						Concrete	Earth/rockfill
Spillway	← Service: Gated, open chute with downstream stilling basin →							
	← Emergency: (if required) as above with downstream flip bucket →							
Power Facilities								
Intake:	← Single level →		← Multilevel →					
Power Tunnel:	← Single concrete lined →		← Minimum of two, concrete lined →					Two partially lined tunnels (1/3 conc. lined, 1/3 shotcreted, 1/3 unlined)
Penstocks:	← Steel lining where necessary (near U.G. Powerhouse)(length=1/5 turbine head) →							
Powerhouse:	← Underground if feasible →							
Tailrace Tunnel:	← One lined/unlined →		← Two lined/unlined →					
	← (Lined or unlined - based on cost/energy loss optimization →							
Low Level Outlet Works Intake and Tunnel:	← One or two with gates - use diversion tun[illegible]s) if possible →							
Construction Facilities U/S & D/S Cofferdams:	← Earth or rockfill →						← Fill or cellular →	← Fill →
Diversion Tunnels:	← Minimum of two →							
Access								
Road Access:	← To Denali Highway →		← to Gold Creek →					
Transmission Line	← To Cantwell along Denali Highway →		← to Gold Creek →					
Local	← Roads/tunnels and bridges as required →							

6.

TABLE ~~1~~ (cont'd)

Components	Denali	Maclaren	Vee	Susitna III	Watana	High Devil Canyon	Devil Canyon	Tunnel Alternatives
Compensation Flow Outlet	← Independant intake with control valve discharging through low level outlet works or independent conduit →							
Surge Chamber	← Upstream surge tank required if net head on machines < 1/6 of distance between reservoir and machine →							
	← Downstream surge tank is required if tailrace is pressurized →							
	← Size differential surge chambers for all locations where required →							

NOTE: Portage Creek development will be similar to Maclaren except that access roads and transmission lines will be to Gold Creek.

TABLE 6.17 - Dam Crest and Full Supply Levels

Site	Staged Dam Construction	Full Supply Level - Ft.	Dam Crest Level - Ft.	Average Tailwater Level - ft.
Gold Creek	No	870	880	680
Olson	No	1,020	1,030	810
Portage Creek		1,020	1,030	870
Devil Canyon - intermediate height	No	1,250	1,270	890
Devil Canyon	No	1,450	1,470 (rockfill)	890
			1,460* (concrete)	890
High Devil Canyon	No	1,610	1,630	1,030
	No	1,750	1,775	1,030
Watana	Yes	2,000	2,060	1,465
	Stage 2	2,200	2,225	1,465
Susitna III	No	2,340	2,360	1,810
Vee	No	2,330	2,350	1,925
Maclaren	No	2,395	2,405	2,320
Denali	No	2,540	2,555	2,405

* plus 4 foot hight wave wall.

TABLE 6.18 - Results of the Screening Model

Run	Total Demand Cap MW	Total Demand Ener GWH	Optimal Solution Site Names	Optimal Solution Maximum Water Level-ft	Optimal Solution Inst. Cap. MW	Optimal Solution Total Cost $ x 10^9	First Suboptimal Solution Site Names	First Suboptimal Solution Maximum Water Level-ft	First Suboptimal Solution Inst. Cap. MW	First Suboptimal Solution Total Cost $ x 10^9
1	400	1750	Watana	2060	400	770	High Devil Canyon	1640	400	780
2	800	3500	High Devil Canyon	1750	800	1320	Watana	2200	800	1360
3	1200	5250	watana	2200	800	1360	High Devil Canyon	1750	800	1320
			Devil Canyon	1450	400	850	Vee	2350	400	910
4	1400	6100	Watana	2200	800	1360				
			Devil Canyon	1450	600	1040				

Note: Values on this table are currently being revised to reflect latest cost information.

TABLE 6.19 - Susitna Development Plans

Plan	Stage	Construction	Incremental Capital Cost $ Millions (1980 values)	Construction Period yrs.	Earliest On-line Date	Reservoir Full Supply Level - ft.	Maximum Seasonal Drawdown ft	Annual Energy Production GWH Firm	Avg.	Plant Factor %
1	1	Watana 2225 ft 800MW	1860	9	1993	2200	150	2669	3252	46.4
	2	Devil Canyon 1465 ft 600MW	1000	6-1/2	+1996	1450	150	2640	2975	--
		TOTAL SYSTEM	2860	--	--	--	--	5309	6227	49.9
2	1	Watana 2060 ft 400MW	1570	8	1992	2000	100	1708	2109	60.2
	2	Watana raise to 2225 ft	360	3	--	2200	150	961	881	--
	3	Watana add 400MW capacity	130	2	--	2200	150	0	262	--
	4	Devil Canyon 1465 ft 600MW	900	6-1/2	+1996	1450	150	2640	2975	
		TOTAL SYSTEM 1200MW	2960	--	--	--	--	5309	6227	59.2
3	1	Watana 2225 ft 400MW	1740	9	1993	2200	150	2669	2990	85.3
	2	Watana add 400MW capacity	150	3	--	2200	150	0	262	--
	3	Devil Canyon 1465 ft 600 MW	900	6-1/2	+1996	1450	150	2640	2975	--
		TOTAL SYSTEM 1200MW	2790	--	--	--	--	5309	6227	59.2
4	1	High Devil Canyon 1775 ft 800MW	1500	10	1994	1750	150	2546	3615	51.6
	2	Vee 2350ft 400MW	1060	7	--	1330	150	1323	1292	--
		TOTAL SYSTEM 1200MW	2560	--	--	--	--	3869	4907	46.7

Table 6.19 Susitna Development Plans (continued)

Plan	Stage	Construction	Incremental Capital Cost $ Millions (1980 values)	Construction Period yrs.	Earliest On-line Date	Reservoir Full Supply Level - ft.	Maximum Seasonal Drawdown ft.	Annual Energy Production GWhr Firm	Annual Energy Production GWhr Avg.	Plant Factor %
5	1	High Devil Canyon	1140	7	1992	1610	100	1849	2106	60.1
1630ft 400MW	2	High Devil Canyon add 400MW Capacity raise day m to 1775 ft	500+	3	--	1750	100	697	1509	--
X	3	Vee 2350 ft 400 MW	1060	7	--	2330	150	1323	1292	--
		TOTAL SYSTEM 1200MW	2700	--	--	--	--	3869	4907	46.7
6	1	High Devil Canyon 1775 ft 400MW	1390	8	1992	1750	150	2397	2732	78.6
	2	High Devil Canyon add 400MW capacity	140	5	--	[illegible]	150	534	1276	--
	3	Vee 2350 ft 400MW	1060	7	--	[illegible]	150	1437	1536	--
		TOTAL SYSTEM 1200	3240	--	--	--	--	4428	5544	46.9
7	1	Devil Canyon 1465 ft 250MW	800	6	--	1450	100	1250	1415	64.6
	2	Watana 2225 225 ft 400MW	1740	9	1993	2200	150	2669	2990	85.3
	3	Watana add 400MW	150	3	--	2200	150	--	262	--
	4	Devil Canyon add 350MW	200	3	--	1450	150	2640	1560 ~~2975~~	--
		TOTAL SYSTEM 1400MW	2890					5309	6227	59.2
8	1	Watana 2225 ft 850MW	1900	9	1993	2200	150	2833	3194	--
	2	Tunnel 330MW	1220	--	--	--	--	2052	2241	
		TOTAL SYSTEM 1180MW	3120					4885	5433	52.6
9	1	Watana 2225 ft 800MW	1860	9	1993	2200	150	2669	3252	46.4
	2	High Devil Canyon 1410 ft 400MW			--	--	--	--	--	--
	3	Portage Creek 1030 ft 150MW	650	--	--	--	--	--	--	--
		TOTAL SYSTEM 1350MW	2510							

TABLE 6-20 - Monthly Variation of Peak Power Demand

OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT
.80	0.92	1.00	0.92	0.87	0.78	0.70	0.64	0.62	0.61	0.64	0.70

TABLE 6.21 - Selected Susitna Development Plans

Plan	Stage	Construction	Incremental Capital Cost $ Millions (1980 values)	Reservoir Full Supply Level - ft.	Maximum Seasonal Drawdown ft.	Annual Energy Production GWH Firm	Avg.	Plant Factor %
2A	1	Watana 2060 ft 400MW	1570	2000	150	1708	2109	60.2
	2	Watana Raise to 2225 ft	360	2200	150	961	881	85.3
	3	Watana add 400MW capacity and Re-regulation ~~claim~~ dam	230	2200	150	0	262	46.4
	4	Devil Canyon 1470 ft 400MW	900	1450	150	2640	2975	59.2
		TOTAL SYSTEM 1200MW	3060			5309	6227	
3A	1	Watana 2225 ft 400MW	1740	2200	150	2669	2990	85.3
	2	Watana add 400MW capacity and Re-regulation ~~claim~~ dam	250	2200	150	0	262	46.4
	3	Devil Canyon 1470 ft 400MW	900	--	--	2640	2975	59.2
		TOTAL SYSTEM 1200MW	2890			5309	6227	--
6A	1	High Devil Canyon 1775 ft 400MW	1390	1750	150	2397	2732	78.0
	2A	High Devil Canyon add 400MW capacity	140	1750	~~150~~	534	1276	~~48.2~~
	2B	Portage Creek 1030ft 150MW	+650	1020	150	534	1276	48.25
	3	Vee 2350 ft 400MW	1060	2330	100	1437	1536	46.9
		TOTAL SYSTEM				~~4428~~ 4368	5544	

TABLE 6.22 - Energy Simulation Sensitivity

Development	Installed Capacity MW	Reservoir Full Supply Level FT	Maximum Reservoir Drawdown FT	Annual Energy Gwh Firm	Annual Energy Gwh Average	Plant Factor %
Watana 2225 Ft.	800	2200	100	2350	3260	46.5
	800	2200	150	2670	3250	46.4
	800	2200	2000	2770	3230	46.1
High Devil Canyon 1775 Ft.	800	1760	100	2930	3630	51.8
	800	1760	150	2550	3620	51.7
	800	1760	200	2550	3600	51.4

TABLE 6.23

Information on the Devil Canyon Tunnel Schemes

	Devil Canyon Dam	Tunnel Scheme 1	2	3	4
Reservoir Area (Acres)	7,500	320	0	3,900	0
River Miles Flooded	31.6	2.0	0	15.8	0
Tunnel Length (Miles)	0	27	29	13.5	29
Tunnel Volume (yd^3)	0	11,976,000	12,863,000	3,732,000	5,131,000
Compensating Flow Release From Watana (cfs)	0	1,000	1,000	500[1]	1,000
Downstream[2] Reservoir Volume (Acre-Feet)	1,100,000	9,500	--	350,000	--
Downstream Dam Height (feet)	635	75	--	245	--
Typical Daily Range of Discharge from Devil Canyon Powerhoure (cfs)	6,000 to 13,000	4,000 to 14,000	4,000 to 14,000	8,300 to 8,900	3,900 to 4,200
Approximate Maximum Daily Fluctuations in Downstream Reservoir (feet)	2	15	--	4	--

[1] 1000 cfs compensating flow release from the re-regulation dam.

[2] Downstream from Watana.

TABLE 6.24

Devil Canyon Tunnel Schemes

Costs, Power, Output and Average Annual Energy

	Installed Capacity (MW)		Increase [1] in Installed Capacity (MW)	Devil Canyon Average Annual Energy (GWH)	Increase [1] in Average Annual Energy (GWH)	Tunnel Scheme Total Project Cost ($ x10 ^{3})	Cost [3] of Additional Energy [1] (mills/kWh)
	Watana	Devil Canyon					
Scheme 1	800	550	550	2,050	2,050	1,979,000	42.6
Scheme 2	70	1,150	420	4,750	1,900	2,317,000	52.9
Scheme 3[2]	850	330	380	2,241	2,183	11,221,000	24.8
Scheme 4	800	365	365	2,490	890	1,494,000	73.6

[1] Increase over single Watana (E1.2200) 800MW development with an average annual energy production of 3250 Gwh.

[2] Includes power an energy produced at re-regulation dam.

[3] Energy cost is based on an economic analysis (i.e. using 3% interest rate) as discussed in Section 9.5.

TABLE 6.25

Tunnel Scheme 3

	2-30' Diameter Tunnel	1-40' Diameter Tunnel	Watana-Devil Canyon Dam
Installed Capacity:			
Watana	850MW	850MW	800MW
Devil Canyon	300MW	300MW	400MW
Re-regulation	30MW	30MW	
TOTAL	1,180MW	1,180MW	1,200MW
Average Annual Energy:			
Watana	3,192	3,194	3,250
Devil Canyon	2,053	2,064	2,977
Re-regulation	138	195	
TOTAL	5,433	5,453	6,227
Annual Firm Energy:			
Watana	2,833	2,810	2,669
Devil Canyon	1,925	1,927	2,640
Re-regulation	127	127	
TOTAL	4,885	4,864	5,309

7 - GENERATION EXPANSION PLAN

7 - GENERATION EXPANSION PLAN

7.1 - Introduction

The Susitna Project will provide for the bulk power needs of the Railbelt Region when it is implemented in the 1990's and early twenty-first century. Due to its large size relative to the existing electrical system, proper planning of its capacity and commercial operation date is an important activity toward insuring maximum benefits from the project for the Railbelt. The generation planning effort responds to this need by synthesizing the Railbelt electric system in the 1990's through 2010 dynamically evaluating the benefits of Susitna and other generating resources under various power needs and levels of economic activity in order to establish the best generation expansion plan.

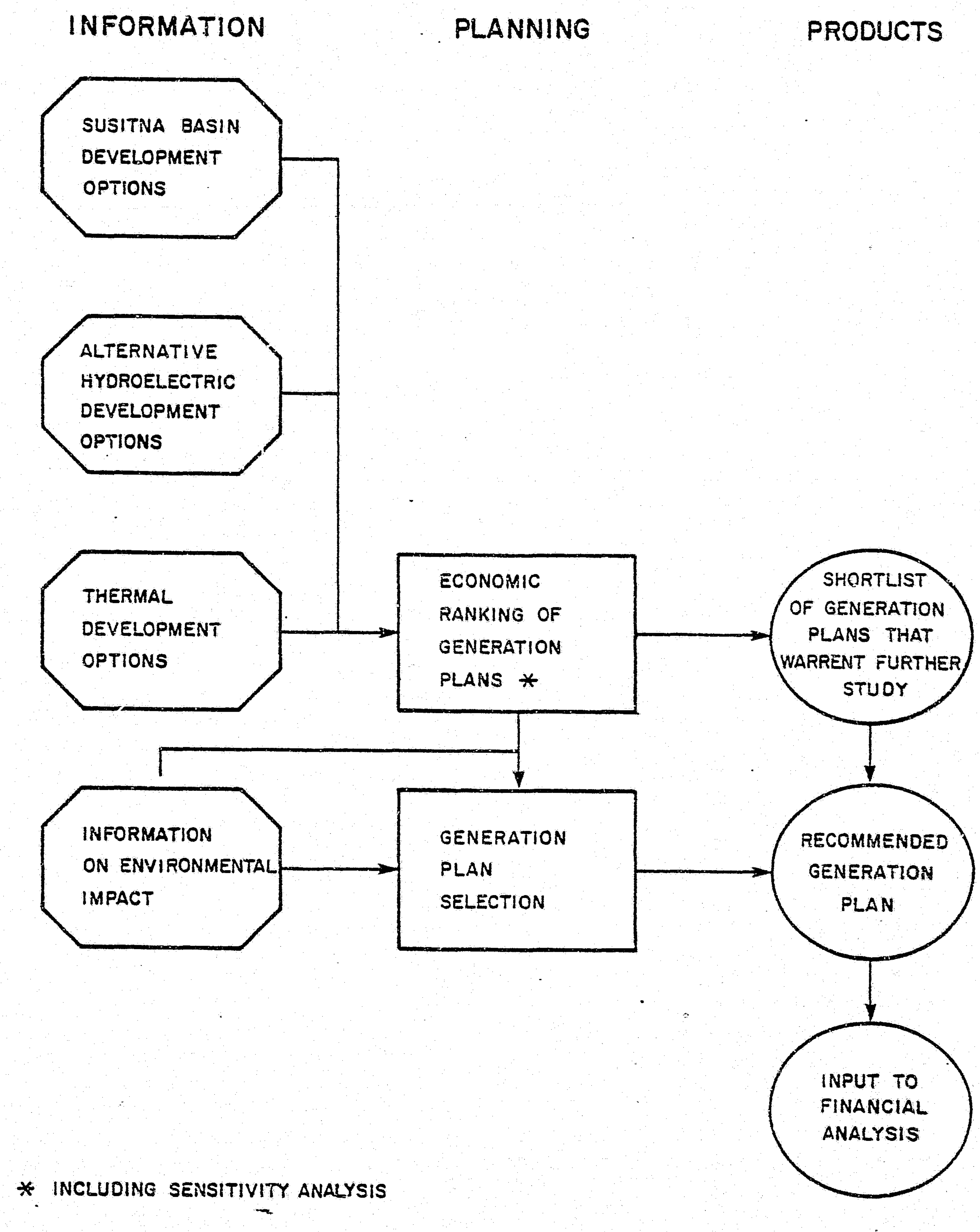
Among the generation options available to the Railbelt, thermal generation based on available Alaska fuels (coal, natural gas and oil) is obviously an important one, since it is currently the primary means of producing electricity and is a conventional method worldwide of providing for new capacity and energy requirements. Other undeveloped hydroelectric sites in addition to Susitna, also provide significant potentials for providing for a diversity of capacity and energy needs.

The generation expansion plan will define the type, capacity and schedules inservice data for generating facilities needed to meet projected loads for the Railbelt electric system between 1980 and 2010 including basically thermal and hydroelectric power projects. Hydroelectric includes Susitna and other smaller projects which may be developed. Thermal includes coal-fired steam, gas-fired combined cycle, and gas or oil-fired gas turbine and diesel electric generating plants. The plan is a result of an extensive effort in simulating the electrical loads (and variable load projections), the existing Railbelt generating facilities, and the optional facilities available for future development. Based upon plant system costs, as well as system reliability (reserve capacity), the generating resources to be included in the expansion plan are screened and selected. However, the selection must be tested to confirm that it does not result in significant adverse system impact if load patterns or economic factors do not follow expected patterns. This is accomplished in the sensitivity analysis phase of the planning effort which precedes selection of the preferred generation plan.

7.2 - Thermal Power

The development of thermal generating facilities would allow consumption of Alaskan nonrenewable resources within the State to benefit the consuming public directly, as compared to resource export which would bring in benefits in the form of state revenue and jobs. Using these nonrenewable resources locally, as compared to exporting them, may or may not be the most economically rewarding option for the State and represents a policy issue which will not be answered here. The selection of future generating facilities within this study is based on economic superiority, resource availability and environmental adequacy.

The thermal types of generation considered within the present study include existing and new generating resources which could fill the full spectrum of load requirements projeted for the future of the Railbelt region. Types of plants include coal-fired steam, oil and natural gas-fired gas turbines and combined



SCHEMATIC REPRESENTATION OF GENERATION PLAN SELECTION PROCESS

FIGURE 7.1

ACRES

cycle plants and diesels. Development of costs for facilities, incremental fuel and operations were required, and performance parameters were established in order that the resources could be evaluated for the future Railbelt system.

Fuel costs were developed based upon a combination of the existing market and the currently expanding export world market. Since the planning effort is aimed at conditions in the period after 1990, it was necessary to define what the possible market costs will be. Based upon the current world energy situation, activity in the Alaska energy market and the extent of fuel reserves, it was necessary to determine whether significant development of the energy exports should raise the market costs to an opportunity cost level during the study period.

7.3- Hydroelectric Power

Previous studies on the Alaskan hydropower potential concluded that in general, developments on Susitna River are among the most economically attractive in the area. A significant number of economic parameters used in hydropower evaluations changed significantly in recent years since the issue of the last studies done by the Corps of Engineers. Consequently, some hydroelectric options to Susitna potentially being among the better sites economically and environmentally were re-estimated based on current price levels. The site's location, allowing specific watershed development, or presenting the advantage of proximity to load centers and/or to the Anchorage-Fairbanks Intertie, were other factors considered in the screening process. Various sizes of hydropower developments were considered to confer a range of options in meeting the needs of a system corresponding to various future demand scenarios.

7.4-Generation Planning

The Railbelt generating resources for the 1990's will consist of existing generating facilities, a proposed transmission intertie between the primary Railbelt load centers of Anchorage and Fairbanks and other new generating facilities to be determined. Based upon scheduling limitations and costs for the various thermal and hydro facilities, and with due consideration to currently planned generation, a base 1990 system is developed.

The economic viability of various thermal and hydroelectric developments in the Railbelt region for the post 1990 period is then tested against future electrical system needs with and without inclusion of a Susitna Project. Further of the various expansion plans are evaluated to determine the overall sensitivity to the range of potential load growth patterns and other variations of financial and economic conditions.

7.5 - Existing System Characteristics

(a) ~~35.1.5.1~~ - System Description

The generation plants considered as existing capacity in the Railbelt for the generation planning studies includes the capacity of all utilities in the region, including the Alaska Power Administration (APAd). To identify the existing generation system for planning purposes, a number of sources were consulted:

TABLE 7.2.1

1980 RAILBELT EXISTING CAPACITY

RAILBELT UTILITY*	Installed Capacity (1980) MW WCC 1980	IECO 1978	DOE 1979	ELEC.WO. 1979	ACRES GM
AMLPD	184.0	130.5	148.0	108.8	215.4
CEA	420.0	411.0	402.2	410.9	411.0
GVEA	211.0	218.6	230.0	211.0	211.0
FMUS	67.0	65.5	68.2	67.4	67.2
CVEA	18.0	--	13.0	--	--
MEA	0.9	0.6	3.0	0.9	0.9
HEA	2.6	9.2	1.7	3.5	2.6
SES	5.5	5.5	5.5	5.5	5.5
APA	--	30.0	30.0	30.0	30.0
TOTAL	909.0	870.9	901.6	838.0	943.6

AMLPD - Anchorage Municipal Light & Power Department
CEA - Chugach Electric Association
GVEA - Golden Valley Electric Association
FMUS - Fairbanks Municipal Utility System
CVEA - Copper Valley Electric Association
HEA - Homer Electric Association
MEA - Matanuska Electric Association
SES - Seward Electric System
APA - Alaska Power Administration

- Woodward Clyde Consultants "Forecasting Peak Electrical Demand for Alaska's Railbelt," September, 1980.

- IECO Transmission Report for the Railbelt, 1978.

- U.S. DOE, "Inventory of Power Plants in the U.S.," April, 1979.

- Electrical World Directory of Public Utilities 1979 - 1980 edition.

- FERC Form 12A for the following utilities:

  Anchorage Municipal Light & Power (AMLP)
  Chugach Electric Association (CEA)
  Homer Electric Association (HEA)
  Fairbanks Municipal Utility System (FMUS)

- Williams Brothers Engineering Company, 1978 Report on FMUS and GVEA (Golden Valley Electric Association) Systems

- Discussions with:

  AMLP - Mr. Hank Nichols
  FMUS - Mr. Larry Colp
  GVEA - Mr. Woody Baker
  APAd - Mr. Don Gotschall

Table 7.2.1 summarizes the information received from these sources. Some discrepancies were apparent especially with respect to AML&P and Copper Valley Electric Association (CVEA). The column: ACRES GM represents the installed capacity used in the OGP-5 Generation Model for Task 6.36 studies. This column represents a resolution of all data sources collected.

The total railbelt installed capacity of 943.6 MW as of 1980 consists of fifty three units. The units are categorized into the following six types of capacity:

No. Units	Type	Capacity (MW)
1	Combined Cycle	140.9
	Hydro	45.0
	NG Gas Turbines (Anchorage)	470.5
8	Oil Gas Turbines (Fairbanks)	168.3
5	Coal-Fired Steam	54.0
21	Small Diesels	64.9
53		943.6

(b)

~~7.6.2~~ - Existing Capacity

Table 7.2.2 lists the complete capacity of the railbelt by unit. The information for each unit is that which has been gathered from the references listed in Section 7.1.

(c)

~~7.6.3~~ - Schedule of Additions and Retirements

In order to establish a retirement policy for Railbelt utilities, several references were consulted including the APA draft feasibility study guidelines, FERC guidelines, experience within the industry, historical records and consultation with utilities, particularly in the Fairbanks area. From consideration of all of these sources, the following retirement policy is proposed for use:

~~(a)~~	Large Steam Turbines (> 100 MW)	=	30 years
(b)	Small Steam Turbines (< 100 MW)	=	35 years
(c)	Oil-Fired Gas Turbines	=	20 years
(d)	Natural Gas-Fired Gas Turbines	=	30 years
(e)	Diesels	=	30 years
(f)	Combined Cycle Units	=	30 years
(g)	Conventional Hydro	=	50 years

These scheduled operating lives and those used for the economic lives of the projects are identical. The impact of these project lives on the existing capacity in the railbelt can be seen by the set retirement dates on Table 7.2.2.

Only two new projects are considered to be committed for the railbelt system. Those will be developed by CEA and the U.S. Army Corps of Engineers (COE).

CEA is in the process of adding 60 MW of gas-fired combined cycle capacity in Anchorage. The plant will be called Beluga No. 8. For study purposes, the plant is assumed to be operating on line in January 1982.

The COE is currently in the post-authorization planning phase for the Bradley Lake project, located on the Kenai peninsula. The project is currently planned to include 94 MW of installed capacity and 420,000 MWh of annual energy, on the average. For study purposes, the project is scheduled to be on line in 1988.

7.6 - Options Available to Meet Future Capacity Requirements

4

This section outlines the basic data on costs and power and energy capability form the range of generating facility outlined above required as input to the generation planning studies.

TABLE 7.2.2
EXISTING 1980 THERMAL CAPACITY

RAILBELT UTILITY	STATION NAME	UNIT #	UNIT TYPE	INSTALLATION YEAR	HEAT RATE BTU/KWH	INSTALLED CAPACITY (MW)	MINIMUM CAPACITY (MW)	MAXIMUM CAPACITY (MW)	FUEL TYPE	FUEL COST $/MBTU	RETIREMENT YEAR*
Anchorage	AMLPD	1	GT	1962	15,000	14	2	15	NG	1.00	1992
Municipal	AMLPD	2	GT	1964	15,000	14	2	15	NG	1.00	1994
Light & Power	AMLPD	3	GT	1968	14,000	18	2	20	NG	1.00	1998
Department	AMLPD	4	GT	1972	12,000	28.5	2	35	NG	1.00	2002
(AMLPD)	G.M.Sullivan	5	GT	1975	12,000	32	NA	NA	NG	1.00	2009
	G.M.Sullivan	6	CC	1979	8,500	33 140.9	NA	NA	NG	1.00	2009
	G.M.Sullivan	7	GT	1975	12,000	73	NA	NA	NG	1.00	2009
Chugach	Beluga	1	GT	1969	13,742	15.1	NA	NA	NG	0.24	1998
Electric	Beluga	2	GT	1968	13,742	15.1	NA	NA	NG	0.24	1998
Association	Beluga	3	GT	1973	13,742	53.5	NA	NA	NG	0.24	2003
(CEA)	Beluga	4	GT	1976	13,742	9.3	NA	NA	NG	0.24	2006
	Beluga	5	GT	1975	13,742	53.5	NA	NA	NG	0.24	2005
	Beluga	6	GT	1976	13,742	67.8	NA	NA	NG	0.24	2006
	Beluga	7	GT	1978	13,742	67.8	NA	NA	NG	0.24	2008
	Bernice Lake	1	GT	1963	23,440	8.2	NA	NA	NG	1.04	1993
		2	GT	1972	23,440	19.6	NA	NA	NG	1.04	2002
		3	GT	1978	23,440	24.0	NA	NA	NG	1.04	2008
	International Station	1	GT	1965	39,973	14.5	NA	NA	NG	1.04	1995
		2	GT	1975	39,973	14.5	NA	NA	NG	1.04	1995
		3	GT	1971	39,973	18.6	NA	NA	NG	1.04	2001
	Knik Arm	1	GT	1952	28,264	14.5	NA	NA	NG	1.04	1985
	Cooper Lake	-	HY	1961	--	15.0	NA	NA	--	1.04	2011
Golden Valley	Healy	1	ST	1967	11,808	25.0	7	27	COAL	1.25	2002
Electric		2	IC	1967	14,000	2.7	[illegible]	3	OIL-2	3.45	1997
Association	North Pole	2	GT	1976	13,500	64.0	5	64	OIL-2	3.45	1996
(GVEA)		2	GT	1977	13,000	64.0	25	64	OIL-2	3.45	1997
	Zehander	1	GT	1971	14,500	17.65	10	20	OIL-2	3.45	1991
		2	GT	1972	14,500	17.65	10	20	OIL-2	3.45	1992
		3	GT	1975	14,900	2.5	1	3	OIL-2	3.45	1995
		4	GT	1975	14,900	2.5	1	3	OIL-2	3.45	1995
		5	IC	1970	14,000	2.5	1	3	OIL-2	3.45	2000
		6	IC	1970	14,000	2.5	1	3	OIL-2	3.45	2000
		7	IC	1970	14,000	2.5	1	3	OIL-2	3.45	2000
		8	IC	1970	14,000	2.5	1	3	OIL-2	3.45	2000
		9	IC	1970	14,000	2.5	1	3	OIL-2	3.45	2000
		10	IC	1970	14,000	2.5	1	3	OIL-2	3.45	2000

TABLE 7.2.2 (Cont'd)

RAILBELT UTILITY	STATION NAME	UNIT #	UNIT TYPE	INSTALLATION YEAR	HEAT RATE BTU/KWH	INSTALLED CAPACITY (MW)	MINIMUM CAPACITY (MW)	MAXIMUM CAPACITY (MW)	FUEL TYPE	FUEL COST $/MBTU	RETIREMENT YEAR
Fairbanks Municipal Utility System (FMUS)	Chena	1	ST	1954	14,000	5.0	2	5	COAL	1.40	1989
		2	ST	1952	14,000	2.5	1	2	COAL	1.40	1987
		3	ST	1952	14,000	1.5	1	1.5	COAL	1.40	1987
		4	IC	1963	16,500	7.0	2	7	OIL-2	4.01	1993
		5	ST	1970	14,500	20.0	5	20	COAL	1.40	2005
		6	IC	1976	12,490	23.1	10	29	OIL-2	4.01	2006
	FMUS	1	IC	1967	11,000	2.7	1	3	OIL-2	4.01	1997
		2	IC	1968	11,000	2.7	1	3	OIL-2	4.01	1998
		3	IC	1968	11,000	2.7	1	3	OIL-2	4.01	1998
Homer Elec. Association (HEA)	Homer-Kenai	1	IC	1979	15,000	0.9	NA	NA	OIL-2	3.50	2009
	Pt. Graham	1	IC	1971	15,000	0.2	NA	NA	OIL-2	3.50	2001
	Seldovia	1	IC	1952	15,000	0.3	NA	NA	OIL-2	3.50	1982
		2	IC	1964	15,000	0.6	NA	NA	OIL-2	3.50	1994
		3	IC	1970	15,000	0.6	NA	NA	OIL-2	3.50	2000
Matanuska Elec. Assoc. (MEA)	Talkeetna	1	IC	1967	15,000	0.9	NA	NA	OIL-2	3.50	1997
Seward Electric System (SES)	SES	1	IC	1965	15,000	1.5	NA	NA	OIL-2	3.50	1995
		2	IC	1965	15,000	1.5	NA	NA	OIL-2	3.50	1995
		3	IC	1965	15,000	2.5	NA	NA	OIL-2	3.50	1995
Alaska Power Administration (APA)	Eklutna	-	HY	1955	--	30.0	NA	NA	--	3.50	2005

GT = Gas turbine
CC = Combined cycle
HY = Conventional hydro
ST = Steam turbine
NA = Not available
NG = Natural gas
MBTU = Million Btu

* Retirement policy:

Large steam turbines >100 MW	30 years
Small steam turbines <100 MW	35 years
Hydro	50 years
Diesels	30 years
Natural gas gas turbines	30 years
Combined cycle	30 years
Oil-fired gas turbines	20 years

(a)

~~7.6.1~~ - Susitna Basin Hydroelectric

Section 6 dexcribes the Susitna Basin studies that lead to the selection of the range of Susitna Basin development options outlined in Tables 6.19 and 6.21.

(b) ~~7.6.2~~ - Oth.. Hydroelectric (Write up to be shortened and simplified in next draft.)

(c) ~~7.6.3~~ - Site Selection and Screening

Previous studies on the Alaskan hydropower potential concluded that in general, development on Susitna River is among the most economically attractive in the area. A significant number of planning parameters changed significantly in recent years since the issue of the last studies done by the Corps of Engineers particulary including lower system electrical growth and capacity needs. Consequently, some hydroelectric options to Susitna, located in adjacent watersheds within the Railbelt and presenting the advantage of proximity to load centers and/or to the Anchorage-Fairbanks Intertie, were re-estimated based on current price levels. Various sizes of hydropower development options were considered to span a range of options to meet the needs of the Railbelt system.

(i) ~~(ii)~~ ~~7.3.2.1~~ Site Selection

In order to select the most suitable sites for development, a multi-step screening and evaluation process was used (See Figure 7.3.1 for a step by step flow diagram of the entire process). Data for the hydroelectric potential in the Railbelt Region were obtained from provious studies issued by federal agencies: U.S. Army Corps of Engineers, "National Hydropower Study" (Form 2, Data Base including physical parameters of the site, cost data and environmental data) and Alaska Power Administration's "Hydroelectric Alternatives for the Alaska Railbelt".

Cost data provided by the Corps of Engineers and by the Alaska Power Administration were updated to estimate the current level of costs and benefits of hydropower development for a total of 91 sites inventoried within the Railbelt Region. Construction costs were developed by standardizing the field costs provided by the Corps and APA, since the two agencies had used different location factors in their estimates to account for higher price levels in Alaska. Contingencies of 20 percent and engineering-administration adjustments of 12 to 14 percent were added to calculate the project cost. Project costs were updated to a January 1, 1980, price level based on the "Handy-Whitman Cost Index for Hydropower Production in the Pacific Northwest".

Using updated project costs as well as a series of plant size-dependent economic factors selected for the rough economic screening (construction periods, annual investment carrying charges and

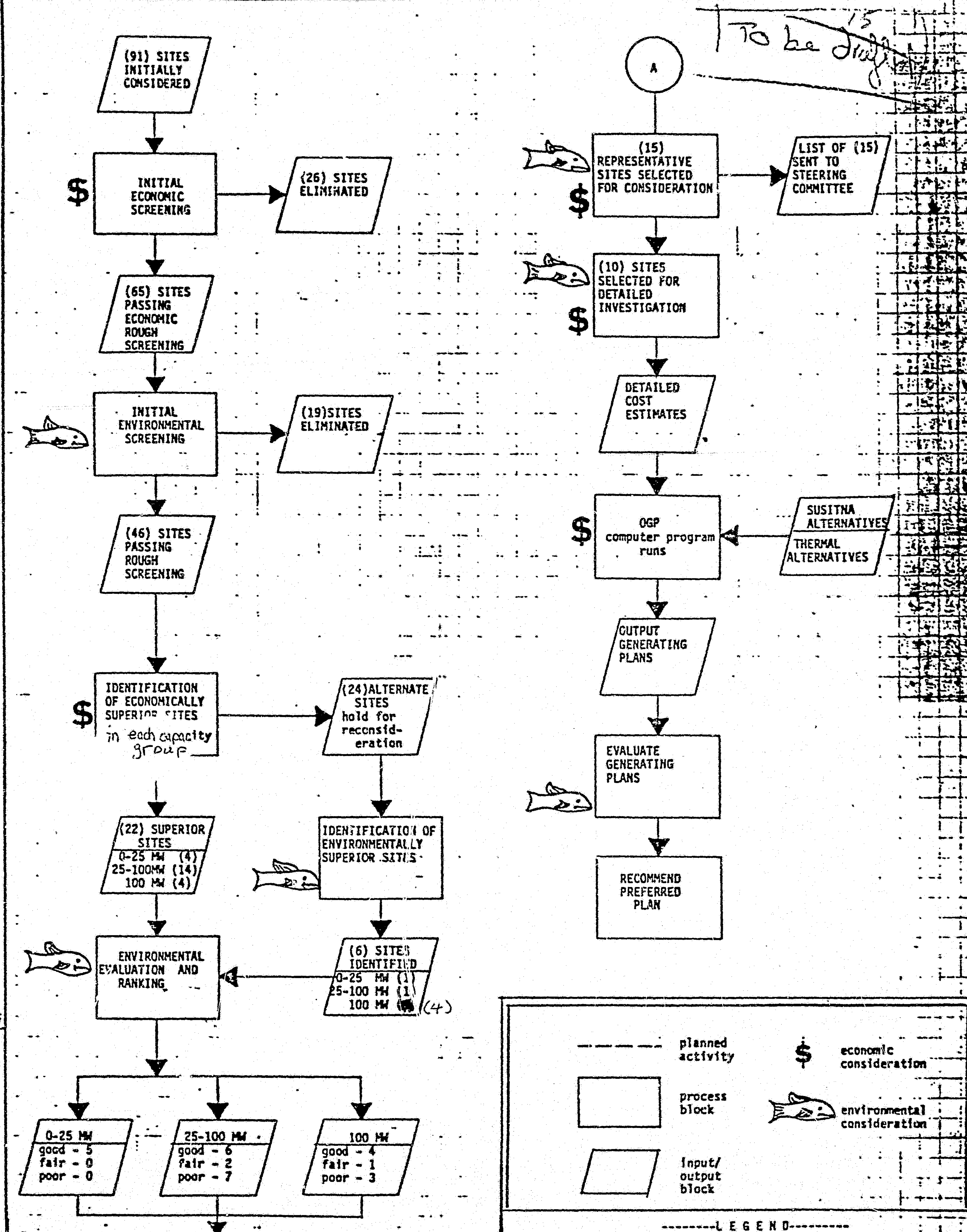


Figure 7.5.1
Flow Diagram Showing Screening and Selection of Hydro Alternatives

ACRES

operation and maintenance expenditures), the average annual production costs in mills/kWh were estimated for the 91 sites using an annually charge of 10.62 percent on the investment cost. Plant capacity factors ranged from 50 to 60 percent, based on source data. A range of average annual production costs were developed for most of the sites, as they were initially estimated by both the Corps and the APA. Site with development costs less than 120 mills/kWh were selected for initial environmental screening (to be changed to economic parameters for consistency).

(11) ~~(b) 7.3.2.~~2 - Initial Screening

Sixty-five sites with production costs less than 120 mills/kWh on either the Corps of Engineers or Alaska Power Administration inventory were exposed to a preliminary environmental evaluation. This initial screening was based on critical environmental restrictions.

Sites were eliminated from further consideration if they:

(1) Produce a significant change within the borders of an existing National Park.

(2) Produce a significant change within an area withdrawn as a National Monument Proclamation.

(3) Are on an anadromous fish river where three or more species are present, the run exceeds 50,000 fish annually and the proposed power development is located downstream of the confluence of any major spawning tributary or in a major fishing area.

Sites excluded by initial environmental screening were:

moved in

Site	Criteria
Healy Carlo Yanert - 2	National Park (Mt. McKinley)
Cleave Wood Canyon	National Monument (Wrangell-St. Elias Nat'l Park) and Major Fishery
Tebay Lake Hanagita Gakona Sanford	National Monument (Wrangell-St. Elias Nat'l Park)
Lake Creek Upper McKinley River Teklanika	National Monument (Denali Nat'l Park)
Crescent Lake	National Monument (Lake Clark Nat'l Park)

Kasilof River	Major Fishery
Vachon Island	
Power Creek	
Million Dollar	
Rampart	
Junction Island	

An additional preliminary analysis was performed to determine the transmission cost impacts on the sites' feasibility. Transmission costs necessary to connect the site to the Anchorage-Fairbanks Intertie were estimated based on a generalized level of expected cost.

Table 7.3.1 is a summary of the results of the initial economic and environmental screening. A total of 46 sites passed the initial screening: 11 sites in the 0-25 MW range, 26 sites in the 25-100 MW range and 9 sites greater than 100 MW.

~~7.3.2.3~~ - Final Selection of Candidate Sites

The 46 sites passing both initial economic and initial environmental screening were divided into three groups in terms of the installed capacity. These groups were (1) 0-25 MW, (2) 25-100 MW, and (3) greater than 100 MW. Within each of the capacity groups, the economically superior sites were identified. This resulted in a list of 22 sites. Based on review of previous environmental studies, six sites were identified as environmentally superior and added to this list, leaving a total of 28 sites. The following table lists the number of sites evaluated in each of the capacity groups.

Site Group	No. of Sites Evaluated
0 - 25 MW	5
25 - 100 MW	15
>100 MW	8
TOTAL	28

The sites were then evaluated numerically by a categorical scoring system as described in ~~7.3.2.5~~ below. They were subsequently listed in ascending order of their scores for each of the size groups and labeled as good, fair, or poor, based on the scores. The same general standards (e.g., cutoff points) were used for all size groups.

For the purpose of evaluating the relative environmental impacts of the 28 selected hydropower developments, a methodology for ranking and evaluation was formulated. A review of the evaluation process was provided to the Susitna Study Steering Committee for their consideration and comment.

TABLE 7.3.15

SUMMARY OF RESULTS OF INITIAL SCREENING

List of 91 sites considered for hydroelectric development.
(*) indicates the list of 65 sites passing economic initial screening.
(___)underline indicates the list of 46 sites passing initial environmental screening.

*	1.	Allison Creek		47.	Kotsina
*	2.	Beluga Lower	*	48.	Lake Creek Lower
*	3.	Beluga Upper	*	49.	Lake Creek Upper
	4.	Big Delta	*	50.	Lane
*	5.	Bradley Lake	*	51.	Lowe
	6.	Bremner R. - Salmon	*	52.	Lower Chulitna
	7.	Bremner R. - S.F.		53.	Lucy
*	8.	Browne	*	54.	McClure Bay
*	9.	Bruskasna	*	55.	McKinley River
*	10.	Cache		56.	McLaren River
	11.	Canyon Creek	*	57.	Million Dollar
	12.	Caribou Creek		58.	Moose Horn
*	13.	Carlo		59.	Nellie Juan River
*	14.	Cathedral Bluffs	*	60.	Nellie Juan R.-Upper
*	15.	Chakachamna	*	61.	Ohio
	16.	Chulitna E.F.	*	62.	Power Creek
*	17	Chulitna Hurricane		63.	Power Creek - 1
	18.	Chulitna W.F.	*	64.	Rampart
*	19.	Cleave	*	65.	Sanford
*	20.	Coal	*	66.	Sheep Creek
*	21.	Coffee		67.	Sheep Creek - 1
*	22.	Crescent Lake	*	68.	Silver Lake
*	23.	Crescent Lake-2	*	69.	Skwentna
	24.	Deadman Creek	*	70.	Snow
	25.	Eagle River	*	71.	Solomon Gulch
	26.	Fox		72.	Stelters Ranch
*	27.	Gakona	*	73.	Strandline Lake
*	28.	Gerstle		74.	Summit Lake
*	29.	Granite Gorge	*	75.	Talachulitna
*	30.	Grant Lake		76.	Talachulitna River
*	31.	Greenstone		77.	Talkeetna R.-Sheep
*	32.	Gulkana River	*	78.	Talkeetna - 2
*	33.	Hanagita	*	79.	Tanana River
*	34.	Healy	*	80.	Tazlina
*	35.	Hicks	*	81.	Tebay Lake
	36.	Jack River	*	82.	Teklanika
*	37.	Johnson		83.	Tiekel River
*	38.	Junction Island	*	84.	Tokichitna
*	39.	Kantishna River		85.	Totatlanika
*	40.	Kasilof River	*	86.	Tustumena
*	41.	Keetna	*	87.	Vachon Island
*	42.	Kenai Lake	*	88.	Whiskers
*	43.	Kenai Lower	*	89.	Wood Canyon
	44.	Killey River	*	90.	Yanert - 2
	45.	King Mtn	*	91.	Yentna
*	46.	Klutina			

(iv) (8) ~~7.3.2.4~~ - Data Survey

A survey of information was performed to locate existing and published sources of environmental data. The 24 reference sources used in preparing the evaluation matrix included publications and maps for which data was collected, prepared and/or adopted by the following agencies:

(a) University of Alaska, Arctic Environmental Information and Data Center
(b) Alaska Department of Fish and Game
(c) Alaska Division of Parks
(d) National Park Service
(e) Bureau of Land Management, U.S. Department of Interior
(f) U.S. Geological Survey
(g) U.S. Army Corps of Engineers, Alaska District
(h) Joint Federal State Land Use Planning Commission.

In addition, representatives of state and federal agencies (including AEIDC, ADNR, ADF&G, ADEC and Alaska Power Administration) were interviewed to provide subjective input to the planning process.

(v) (e) ~~7.3.2.~~5 - Environmental Ranking Methodology

Eight evaluation criteria were used to define the environmental sensitivity of the sites. The criteria and their associated concerns were the following:

Evaluation Criteria	General Concerns
1. Anadromous Fisheries	- Protection of fisheries
2. Big Game	- Protection of wildlife resources - Protection of recreation, commercial, and subsistances resources
3. Waterfowl, Raptors, and Endangered Species	- Protection of wildlife resources
4. Agricultural Potential	- Protection of existing and potential agricultural resources
5. Restricted Land Use	- Consideraiton of legal restrictions to land use
6. Wilderness Consideration	- Protection of wild and unique features
7. Cultural, Recreation, and Scientific Features	- Protection of existing and identified potential features

8. Access - Identification of areas where the greatest change would result from development

The first four criteria were chosen to represent the most valuable and sensitive aspects of the existing natural environment. The remaining criteria were chosen to represent opinions of various legislative and interest groups regarding the use of the land at the site.

Data relating to each of these criteria was compiled separately and recorded for each site, forming a data-base matrix. Based on this collected data, a system of sensitivity scaling was developed to represent the relative sensitivity of each environmental resource (as represented by the criteria) at each site. These scale ratings were defined:

A - Exclusion (used for sites excluded in preliminary screening, not used in final selection)

B - High Sensitivity

C - Moderate Sensitivity

D - Low Sensitivity

A relative weight was assigned to each criteria to represent its relative sensitivity to development. A high value indicates greater importance or sensitivity than a low value.

<u>Relative Weights</u>

Big Game	8
Agricultural Potential	7
Birds	8
Anadromous Fisheries	10
Wilderness Values	4
Cultural and Scientific Features	4
Restricted Land Use	5
Access	4

The weights for the first four criteria were then adjusted down, depending on related technical factors of the development scheme.

Dam height was assumed to be the factor having the greatest impact on anadromous fisheries. All sites were ranked by dam height as follows:

Dam Height	Rank
<150'	+
150' - 350'	++
≥350'	+++

A dam with the lowest height (+) would have least impact, therefore the fisheries weight was adjusted down by two points. Similarly, a dam of height (++) was adjusted down by one point. A dam of height (+++) would have the greatest impact and the weight remained at its maximum value.

The amount of new land flooded by creation of a reservoir was considered to be the factor with greatest impact on agriculture, bird habitat, and big game habitat.

Sites were ranked in terms of their <u>new</u> reservoir area as follows:

Area	Rank
<5,000 ac	+
5,000 - 100,000 ac	++
≥100,000 ac	+++

For developments which utilized an existing lake for storage, the new area flooded was assumed to be minimal (+).

The same numerical adjustments were made for the big game, agricultural potentials, and bird habitat weights as the fisheries. These adjustments are summarized in Table 7.3.2.

TABLE 7.3.2

NUMERICAL ADJUSTMENT VALUES

	Initial Weight	Adjusted Weights					
		Dam Height			Reserv. Area		
		+	++	+++	+	++	+++
Big Game	8				6	7	8
Agric.-Poten.	7				5	6	7
Birds	8				6	7	8
Fisheries	10	8	9	10			

The three scale ratings were given a weighted value as follows:

High Sensitivity = B = 5
Moderate Sensitivity = C = 3
Low Sensitivity = D = 1.

To compute the ranking score, the scale weights were multiplied by the adjusted criteria weights for each criteria and the resulting products were added.

Two scores were computed. The total score is the sum of all eight criteria. The partial score is the sum of the first four criteria only, which gives an indication of the relative importance of the existing natural resources in comparison to the total score.

(4.)

~~7.3.2.5~~ - Analysis

0 - 24 MW

Of the four sites evaluated, all were determined to be acceptable, based on the overall standards. Three of these sites were judged as a group to be better than the fourth which had a higher partial and total score.

25 - 100 MW

A cutoff point of approximately 134 for the total score and approximately 100 for the partial score was used. Sites scoring higher were eliminated. The seven sites scoring lower were re-examined.

The first three, Bruskasna, Bradley Lake, and Snow were the best sites identified.

Of the remaining four, Coffee and Keetna were identified as questionable because of anticipated salmon fisheries problems. Lowe and Cache scored only slightly better, but Lowe has minimal fisheries problems, and the Cache site is farthest upstream on the Talkeetna River, beyond which the salmon migrate only about five miles.

> 100 MW

The same cutoff point for acceptable sites with total and partial scores were used. The result was that only one site, Chakachamna was considered to be acceptable. For this reason, four more sites: Browne, Johnson, Tazlina and Cathedral Bluffs, were included for environmental review. The ranking results are presented in Table 7.3.3.

Fifteen sites were selected for further consideration. Three constraints were used to identify these 15 sites. First, the most economical sites which had passed the environmental rough screening were chosen. Secondly, sites with a very good environmental impact rating which had passed the economic rough screening were chosen. And finally, a representative number of sites in each capacity group were chosen.

TABLE 7.3.3

ENVIRONMENTAL RANKING SCORE BY CAPACITY GROUP

	Partial Score	Total Score
Sites - 0 - 25 MW		
*Strandline Lake	51	85
Upper Nellie Juan	37	96
Tustumena	37	106
Allison Creek	65	82
Silver Lake	65	111
Sites - 25 - 100 MW		
*Hicks	62	79
Bruskasna	71	104
Bradley Lake	71	104
Snow	71	106
Lowe	89	122
Cache	86	127
Coffee	101	126
Keetna	98	131
Whiskers	101	134
Talkeetna-2	98	134
Lower Chulitiua	106	139
Klutina	101	142
Upper Beluga	117	142
Talachultna	126	159
Skwentna	136	169
Sites - > 100 MW		
*Browne	69	94
*Johnson	96	121
*Tazlina	89	124
*Cathedral Bluffs	101	126
Chakachamna	65	134
Lane	106	139
Tokichitna	117	150
Yentna	139	172

---

* Sites selected for evaluation due to superior environmental conditions.

TABLE 7.3.4

SELECTED PROJECTS

Environmental Rating	Capacity 0 - 25 MW	25 - 100 MW	>100 MW
Good	Strandline Lake*	Hicks*	Browne*
	Allison Creek*	Snow*	Johnson
	Tustumena	Cache*	
	Silver Lake	Bruskasna*	
Fair		Keetna*	Chakachamna*
Poor		Talkeetna-2*	Lane
		Lower Chulitna	Tokichitna

This list of 15 sites was provided to the Steering Committee for their evaluation and recommendations. The Committee has also provided a list of alternate sites from which to choose in the event that none of the 15 were acceptable to their review. To date, a response has not been received.

From the list of 15 sites, 10 were selected for detailed development and cost estimates required as input to generation planning. The ten sites chosen are indicated with a (*) on Table 7.3.4 above.

Of the ten sites, Strandline Lake, Hicks, and Browne were identified in the Ch_2M-Hill Report to the Army Corps of Engineers, "Review of Southcentral Alaska Hydropower Potential," as being environmentally very good. These sites were included, even though their associated costs were higher than many of the other sites which had also passed the economic rough screening.

The Chakachamna site had both a very high economic ranking and a good environmental rating in terms of the sensitivity of its natural resources to development. Chakachamna was also identified by the Ch_2M-Hill report as having minimal environmental impacts. One unresolved question that remains with the Chakachamna site is the newly passed Congressional legislation (Public Law 96-487) regarding the Alaskan National Interest Lands would restrict implementation of the project. While the final rulings, resolutions and boundary maps have yet to be published, it appears that the civil works of the project will not affect protected lands. The effects of the lake on protected lands, and the actual status of those protected lands are not clear at this time. Because the Chakachamna Site is so desirable in other respects, it has been kept in consideration as a viable hydropower resource for the future in the Railbelt Region.

Three sites were chosen on the Talkeetna River. These are Cache, Keetna, and Talkeetna-2 which are being studies as an integrated system alternative. Although the identified environmental problems are significant, the system is being studied for several reasons. It is believed that with the system approach, the incremental impacts of building a second or third plant on the same river system would be smaller than the impacts associated with building plants on competely separate rivers. The integrated system not only improves the economic potential of the operating capacity, but also allows for better control over regulation of stream flows as needed by the downstream ecosystems. Secondly, the choice of the Talkeetna River was made over other rivers with potential for development of similar systems, because the environmental sensitivity of the Talkeetna was not as great as that of the Yentna-Skwentna basin, the Chulitna River or the lower Susitna basin, particularly with regards to the presence of anadromous fish or big game. And finally, the Talkeetna River developments were some of the best sites economically, thus providing an economically effective future generating resource.

The remaining sites of the ten studied in detail are Allison Creek, Snow, and Bruskasna. These are sites that where identified by the environmental evaluation as being the best environmentally of the 22 economically superior sites.

(g)
~~7.3.2.6~~ - Power Studies

Determination of the recommended installed capacity for each project was based on analysis of long-term power and energy production. The computer model discussed in Section 6 was used to simulate the reservoir operation under the constraints imposed by a given operating regime.

The power analysis was carried out on a monthly basis using at least 13 years of mean monthly streamflows at each project. This period is considered to be a rather long one for the Alaska streamflow records. In this phase of the formulation studies, monthly flows were used to establish expected power and energy production and, consequently, the installed capacities.

A summary of annual average energy production is given in Table 7.3.5. The monthly energy values are given in Appendix B.

(h)
~~7.3.2.7~~ - Engineering and Cost Studies

The costs of the hydroelectric facilities were estimated at each site. Quantity takeoffs of civil items based on preliminary layouts and unit prices adjusted for Alaska conditions were used to establish costs for specific installations at each site. Recent experience with prices of mechanical and electrical equipment on similar projects was also used. The estimates are at the January 1, 1980 price level and include the land requirements and transmission line costs, as well as contingencies (20 percent) and engineering and administration adjustments (10 percent). The final figures include also an allowance for interest during construction.

Operation and maintenance costs were adopted in line with average experienced costs of existing hydro projects in the Railbelt Region as presented in FERC data. The annual costs are $22 per kilowatt for all plants considered.

The project cost results by major account are presented in Table 7.3.16. The conceptual layouts from which the estimates were developed are presented for each site in Figure 7.3.11, inclusive.

TABLE 7.3.5

OPERATING AND ECONOMIC PARAMETERS

(Ten Selected Hydroelectric Plants, Railbelt, Alaska)

No.	Site	River	Rated Head Ft.	Installed 1/ Capacity MW	Annual 2/ Energy GWh	Capital 3/ Costs $/kW
1	Snow	Snow	640	120	300	2475
2	Bruskasna	Nenana	210	70	114	4460
3	Keetna	Talkeetna	295	110	463	4760
4	Cache	Talkeetna	266	75	180	6750
5	Browne	Nenana	162	210	360	4990
6	Talkeetna-2	Talkeetna	304	83	245	5080
7	Hicks	Matanuska	262	265	246	2700
8	Chakachamna	Chakachatna	793	485	1938	2870
9	Allison	Allison Creek	1,170	7.3	34.7	8050
10	Strandline Lake	Beluga	710	28	85.7	4980

1/ Based on operating the projects for power production.
2/ For capacity factors between 0.11 and 0.55.
3/ Includes interest during Construction.

7.6.4
~~7.3.3~~ - Thermal Generating Resources - Fuels

The purpose of this section is to define the thermal generating resources available to the Railbelt during the 1980-2010 study period. To address thermal resources, it is necessary to review the existing thermal capacity, fuel availability and associated costs future plant capacities and capital costs for development. To develop the parameters necessary for generation planning studies, it is also necessary to assess operation and maintenance costs and planned and forced outages. The contents of this section document the data used in the generation planning study phase described in Section 7.4.

7.6.5 Fuel Availability and Costs

Fuel supplies available in the Railbelt region for future electric generation plants are primarily coal and natural gas resources. Oil and geothermal resources, although not expected to play major roles, are discussed briefly. It is unlikely that oil will be used as the primary fuel for additions to the generation system in the Railbelt due to public policy and high value for other uses. Tables 7.3.6, 7.3.7 and 7.3.8 summarize estimated fuel reserves. Table 7.3.9 lists current (1980) fuel prices in the Railbelt Region while Table 7.3.10 summarizes the developed fuel costs which represent shadow (opportunity) values assuming active international marketing of Alaska fuels.

(a)
~~7.3.3.1~~ - Coal

(1) Coal Availability

Alaskan coal reserves include the following coal producing fields. (Reference 2):

~~(a)~~ Nenana
~~(b)~~ Matanuska
~~(c)~~ Beluga
~~(d)~~ Kenai
~~(e)~~ Bering River
~~(f)~~ Herendeen Bay
~~(g)~~ Chignik Bay

Of these eight regions, only four have potential for Railbelt use. Table 7.3.6 lists pertinent information of these coal reserves.

The Nenana coal field, primarily leased by the Usibelli Coal Mine Incorporated, is located in the vicinity of Fairbanks. The field ranges from less than a mile to more than 30 miles in width for about 80 miles along the north flank of the Alaska Range. Nenana coal is primarily mined by surface methods. An estimated 95 million tons of potetial stripping coal is

TABLE 7.3.6

ALASKAN RAILBELT COAL DATA

(Proximate and Ultimate Analysis)

COAL FIELD	ASTM RANK	APPROXIMATE RESERVES MM TONS	% MOISTURE (RANGE)	% VOLATILE MATTER	% FIXED CARBON	% ASH (RANGE)	HEATING VALUE BTU/LB (RANGE)	% C	% H	% N	% O	% SULFUR (RANGE)
Beluga (Susitna Coal District)		2400	(12-33)	---	---	(3-25)	(7200-8900)	---	---	---	---	(0.2)
Water Fall	Sub Bit C		20.56	36.62	34.68	8.14	8,665	49.9	6.0	0.56	35.2	0.15
Yentna #2 Lwr	Lignite		29.80	38.26	28.[illegible]	3.33	7,943	45.2	6.8	0.53	44.1	0.11
Kenai Cabin	Sub Bit C		23.01	35.63	32.71	8.65	8,028	47.2	6.1	0.62	37.2	0.23
Nenana	Sub Bit	2000	(17-27)	---	---	(3-13)	(7500-9400)	---	---	---	---	(0.1-0.3)
Poker Flat #4	Sub Bit C		25.29	32.51	32.55	9.85	7,779	45.3	6.3	1.10	37.1	0.33
Poker Flat #6 Mid	Sub Bit C		25.23	35.71	31.40	7.66	8,136	46.1	6.3	0.60	39.2	0.12
Moose Seam	Sub Bit C		21.42	36.62	34.88	7.68	8,953	51.7	6.3	0.81	33.3	0.15
Caribou Seam	Sub Bit C		21.93	35.88	32.85	9.34	8,567	49.4	6.1	0.69	34.3	0.13
#2 Seam	Sub Bit C		26.76	33.12	32.25	7.87	7,966	46.4	6.4	0.63	38.5	0.17
Jarvis Creek	Sub Bit C		20.58	36.20	34.16	9.06	8,746	49.8	5.8	0.86	33.4	1.05
Matanuska		100 (limited)	(2 - 9)	---	---	(4-21)	(10,300-14,000)	---	---	---	---	(0.2-1.0)
Castle Mountain	Uv Ab		1.78	28.23	52.20	17.78	12,258	69.3	4.7	1.60	6.3	0.46
Premier	Uv Bb		5.87	35.73	43.96	14.44	11,101	63.6	5.1	1.60	15.3	0.35
Kenai	Sub Bit C	300	(21-30)	---	---	(3-22)	(6500-8500)	---	---	---	---	(0.1-0.4)

References: Alaskan Coal and the Pacific, 1977 Ref (2)
ASME "Burning Coal in Alaska - A Winter Experience", ASME, 1980 Ref (1)

MM = million.

TABLE 7.3.7

ALASKAN GAS FIELDS

LOCATION/FIELD	Remaining Reserves* Gas (BCF)	Product Destination or Field Status
North Slope:		
Prudhoe Bay	29,000	Pipeline construction to lower 48 underway
East Umiat	Unknown	Shut-in
Kavik	Unknown	Shut-in
Kemik	Unknown	Shut-in
South Barrow+	25	Barrow residential & commercial users.
TOTAL	29,025+	
Cook Inlet:		
Albert Kaloa	Unknown	Shut-in
Beaver Creek	240	Local
Beluga	767	Beluga River Power Plant (CEA)
Birch Hill	20	Shut-in
Falls Creek	80	Shut-in
Ivan River	5	Shut-in
Kenai	1313	LNG Plant, Anchorage & Kenai Users
Lewis River	Unknown	Shut-in
McArthur River	78	Local
Moquawkie	None	Field Abandoned
Nicolai Creek	17	Granite Pt. Field
North Cook Inlet	1074	LNG Plant
North Fork	20	Shut-in
North Middle Ground Shoal	125	Shut-in
Sterling	23	Kenai Users
Swanson River	300	Shut-in
West Foreland	120	Shut-in
West Fork	7	Shut-in
TOTAL	4189+	

Reference: (14) From Alaska Oil and Gas Conservation Commission.

+ Producing
* Recoverable reserves estimated to show magnitude of field only.
BCF = billion cubic feet

TABLE 7.3.8

ALASKAN OIL FIELDS

LOCATION/FIELD	Recoverable Reserves* Oil (MMbbl)	Product Destination or Field Status
North Slope:		
Prudhoe Bay+	8375	Pipeline to Valdez
Simpson	Unknown	Shut-in
Ugnu	Unknown	Shut-in
Umiat	Unknown	Shut-in
TOTAL	8375+	
Cook Inlet:		
Beaver Creek	1	Refinery
Granite Point	21	Drift River Terminal
McArthur River	118	Drift River Terminal
Middle Ground Shoal	36	Nikiski Terminal
Redoubt Shoal	None	Field Abandoned
Swanson River	22	Nikiski Terminal
Trading Bay	4	Nikiski Terminal
TOTAL	198	

Reference: (14) From Alaska Oil and Gas Conservation Commission.

+ Producing
* Recoverable reserves estimated to show magnitude of field only.
MMbbl = million barrels

TABLE 7.3.9

EXISTING ALASKAN FUEL PRICES

FUEL	SOURCE/USE	COST $80/MMBTU	REFERENCES
Coal	Healy/Mine-Mouth (GVEA)	1.25	(1) & (14)
	Healy/Fairbanks (FMUS)	1.40	(1) & (14)
	Average Lower 48	1.35	(9) June 1980
	DOE Region 10	1.55	(45) October 1980
	DOE U.S. Average	1.46	(45) October 1980
Natural Gas			
	Kenai-Cook Inlet/ Anchorage Utilities		
	AMLPD	1.00	(31)
	CEA Beluga	0.24	(9) June 1980
	Other	1.04	(9) June 1980
	Average	0.34	(9) June 1980
	Cook Inlet/LNG export to Nikiski	4.50 - 4.65	(46)
	Average Lower 48	1.98	(9) June 1980
	DOE Region 10	4.89	(45) October 1980
	DOE U.S. Average	3.58	(45) October 1980
Oil			
	Prudhoe Bay/Fairbanks Utilities		
	GVEA	3.45	(31)
	FMUS	4.01	(32)
	Average Lower 48	5.44	(9) June 1980
	DOE U.S. Average	4.63 - 4.93	(45) October 1980

Healy Coal = 8,500 Btu/lb
Natural Gas = 1005 Btu/cf

TABLE 7.3.10

SUMMARY OF FUEL PRICE ANALYSES

FUEL	MARKET	VIA	MARKET PRICE $/MMBTU	TRANSPORT COST $/MMBTU	ALASKAN OPPORTUNITY VALUE $/MMBTU
COAL	Pacific NW	barge	1.55	0.50	1.05
	Lower 48	barge	1.46	0.63	0.83
	Japan	barge	N/A	N/A	1.33
	Japan	Placer-Amex	N/A	N/A	1.33*
	Japan	barge	N/A	N/A	1.00-1.30*
	Japan	B-H-W	N/A	N/A	1.00 1.30
NATURAL GAS	Region 10	LNG tanker	4.89	2.50	2.39
	Region 10	Pipeline spur	4.89	1.97	2.92
	Lower 48	LNG-tanker	3.58	2.50	1.08
	Lower 48	Pipeline spur	3.58	1.97	1.61
	Japan	LNG-tanker	4.50-4.65	3.00**	1.50-1.65
OIL	Lower 48	Pipeline-tanker	N/A	N/A	4.00

* from Beluga Coal Studies Reference (16 ,27 and 50)

** estimated

potential stripping coal is available. Underground mining could extract total coal resources in excess of 2 billion tons.

The Matanuska coal fields occupy most of the Matanuska Valley to the east of Anchorage. Although stripping and undergound mining occur; however, stripping is limited due to relatively steep dips and increasingly thick overburden. Reserves are estimated at 50 million tons, and ultimate resource value may be 100 million tons. Local limited usage is possible; however, potential as a Railbelt source in unlikely. (Reference 3)

The Kenai coal field is in the Kenai lowlands, south of Tustumena Lake on the eastern shore of Cook Inlet. Resources are estimated at 300 million tons. However, these coal seams are thin and vertically separated vertically making mining extremely difficult.

The fourth potential coal producing region, the Beluga field, which is part of the larger Susitna Coal District, is located 45 to 60 miles west of Anchorage on the west bank of Cook Inlet, would require the establishment of a mining operation, transportation system and supporting community and infrastructure where none exists. A number of studies have been conducted on the reserves located in the Beluga Coal Fields. It has been estimated that three areas--the Capps, Chuitna and Three Mile field--contain 2.4 billion tons of coal and that in excess of 400 million tons can be stripped without exceeding the coal/overburden ratios for commercial coal extractions.

Current and Potential Coal Use

Limited use of coal in the Railbelt at present is a result of an undeveloped export market and the relatively small local demand for this fuel. Currently, the Usibelli Coal Company mines Nenana coal at a facility located in Healy that produces approximately 0.7 million tons/year. This coal represents the only major commercial coal operation in Alaska. The coal is trucked several miles from the mine site to a 25 MW power plant owned and operated by the Golden Valley Electric Association (GVEA) at Healy, where the delivered cost is $1.25/MMBtu. The Nenana coal is also trucked to a railway spur loading station at Suntana 8-1/2 miles away for transport to Fairbanks (111 miles). The Chena Station (4 units, total capacity 29 MW) is owned by Fairbanks Municipal Utility System (FMUS) and uses this coal at an extra cost of approximately $0.34/MMBtu for transportation costs tarrifs bringing the price for FMUS to $1.40/MMBtu. Healy coal is also used for generation in units at Fort Wainwright Army base and the University of Alaska power plants. Interest in the Nenana coal field for expanded production includes four identified scenarios.

Expansion plans for Healy coal propose to nearly double the production. Options include:

to the Pacific Northwest (Reference 28). Supplying Anchorage with coal via a new railroad tie does not appear to be an option considered in the referenced report for the near future.

The study of the Beluga Coal Field potential at the Bass-Hunt-Wilson (BHW) coal leases in the Chuitna River Field was completed by Bechtel Corporation in April 1980 (Reference 27). This study resulted in a 7.7 MMTPY economic export production rate with no consideration of local coal-fired generating developments.

Coal Price Analysis

Potential export markets for Beluga coal as defined in the previous section include: Lower 48; California and Pacific Northwest markets and Japan. The average market price for coal in the Pacific Northwest and California region, as reported in June, 1980 to the U.S. Department of Energy, ranged from $1.46/MMBtu to $1.55/MMBtu which is slightly higher than the average U.S. price. The costs for transporting a Beluga mined coal to the Pacific Northwest or to California were estimated in a 1977 Report (Reference 2) on "Alaska Coal and the Pacific". These prices were estimated and appear in Table 7.3.10.

A report issued in December 1980 by Battelle Pacific Northwest Laboratory (Reference 50) analyzed marked opportunities for Beluga Coal, with results generally consistent with earlier Bechtel and DOE reports.

The two Beluga Coal studies done for Placer-Amex and the Bass-Hunt-Wilson venture have resulted in opportunity costs for coal of \$1.00 - \$1.33/MMBtu. For purposes of this study the value of \$1.15/MMBtu will be used for future coal generating plants to be constructed in Alaska as seen in Table 7-5.

(b)

~~7.3.3~~.2 - Natural Gas

(1) Natural Gas Availability

Natural gas resources available or potentially available to the Railbelt region include the North Slope (Prudhoe Bay) reserves and the Cook Inlet reserves. Information on these reserves is summarized in Table 7.3.7.

The Prudhoe Bay Field contains the largest accumulation of oil and gas ever discovered on the North American continent. The in-place gas volumes in the field are estimated to be in excess of 40 trillion cubic feet (Tcf). Estimates of the portion of in-place gas that can ultimately be recovered range up to 75 to 80 percent. With losses considered, recoverable gas reserves are estimated at 29 Tcf. Gas can be made available for sale from the Prudhoe Bay Field at a rate of at least 2.0 billion cubic feet per day (Bcfd) and possibly slightly more than 2.5 Bcfd. At this rate, gas deliveries can be sustained for 25 to 35 years, depending on the sales rate and ultimate gas recovery efficiency.

The Cook Inlet Reserves as seen in Table 7.3.7 are relatively small in comparison to the North Slope reserves. Gas reserves are estimated at 4.2 Tcf as compared to 29 Tcf in Prudhoe Bay. Of the 4.2 Tcf, approximately 3.5 Tcf is available for use, the remaining reserves are considered shut-in at this time.

7 Current and Proposed Natural Gas Use

During the mid-seventies, three natural gas transport systems were proposed to market natural gas from the North Slope Fields to the lower 48. Two overland pipeline routes (Alcan and Arctic) and a pipeline/LNG tanker (El Paso) route were considered. The Alcan and Arctic pipeline routes traversed Alaska and Canada for some 4000-5000 miles, transporting natural gas to the central U.S. for distribution east and west. The El Paso proposal involved an overland pipeline route that would generally follow the Alyeska oil pipeline utility corridor for approxmately 800 miles. The liquefaction plant would process approximately 37 million cubic meters of gas per day and the transfer station was proposed at Point Gravinia south of the Valdez termination point. Eleven 165,000 cubic meter cryogenic tankers would transport the LNG to Point Conception in California for regasification.

The results of these studies was the initiation of a 4800-mile, $22 - $40 billion, 2.4 Bcfd, Alaska-Canada Natural Gas pipeline project expected to be operational by 1984-1985. The pipeline project passes approximately 60 miles northeast of Fairbanks.

The gas production capability in the Kenai Peninsula and Cook Inlet region far exceeds demand, as no major transportation system exists to export markets. As a result of this situation, the two Anchorage electric utilities utilize natural gas at a very economical price. Export markets for Cook Inlet natural gas include one operating and one proposed LNG scheme.

(1) The Nikiski terminal owned and operated by Phillips-Marathon on the eastern shore of Cook Inlet transports LNG some 4000 miles to Japan via two Liberian cryogenic tankers. Volume produced is 185 MMCFD with raw natural gas requirements of 70 percent from a platform in Cook Inlet and 30 percent from existing onshore fields.

(2) Pacific Alaska LNG (PALNG) Company (as of 1979) intends to ship LNG to California from another terminal to be constructed at Nikiski on the Kenai Peninsula. The plant will utilimately process up to 430 MMCFD for shipment via two cryogenic tankers

to Little Cojo near Point Conception, California. The Federal Energy Regulatory Commission (FERC) has placed a rider on the project permit, stipulating that in-place and committed gas reserves must total 1.6 Tcf before a license is granted. To date PALNG estimates 1.0 Tcf is in place.

(3) There is also some potential for a gasline spur to be constructed from the Cook Inlet region some 310 miles north to intersect with the Alaska-Canada Natural Gas pipeline project in order to market the Cook Inlet gas. This concept has not been extensively studied but could prove to be a viable alternative.

3) Natural Gas Price Analysis

Markets for Prudhoe Bay gas were not considered in developing a cost for Railbelt fuel alternatives since an existing market and transportation system has been developed with the inception of the Alaska-Canada pipeline project.

Markets for Cook Inlet gas include the lower 48 via two transportation modes; LNG tankers or a pipeline spur constructed from Anchorage to Delta Junction and intersect with the Alaska-Canada pipeline. The regulated ceiling market price for natural gas on the west coast as reported in the Federal Register, Department of Energy, Tuesday October 27, 1980 was $4.89/MMBtu in the Region 10 area (Washington, Oregon, California) and $3.58/MMBtu as the average U.S. price. The LNG tanker scheme as proposed by PALNG was estimated to cost $2.50/MMBtu for transportation and processing. A 310 mile pipeline spur was estimated based on cost data available from the current pipeline project and would be expected to be $1.97/MMBtu which represents the incremental cost of the Alaskan-Canada pipeline and the cost of the tap from Cook Inlet ($1.27/MMBtu plus $0.70/MMBtu respectively).

Table 7.3.10 lists the resulting Alaskan opportunity values under these assumptions for markets in Region 10 and the Lower 48 based on the two transportation routes; LNG-tanker and Pipeline Spur.

The current Japan market price for natural gas from the Nikiski LNG project sales is $4.50 - $4.65/MMBtu per Dr. Charles Logsdan of the State of Alaska Department of Revenue (Reference 46). Based on information collected from Nikiski the transportation/processing costs were estimated to be $3.00/MMBtu which results in an Alaskan opportunity value of $1.50 to $1.65/MMBtu.

The prices developed in this analyses range from $1.08 to $2.92/MMBtu. For purposes of this study $2.00/MMBtu was adopted as the opportunity value of natural gas in Alaska.

c)

~~7.3.5~~.3 - Oil

1) Oil Availability

Both the North Slope and the Cook Inlet Fields have significant quantities of oil resources as seen in Table 7.2.8. North Slope reserves are estimated at 8375 million barrels. Oil reserves in the Cook Inlet region are estimated at 198 million barrels (Reference 14). As of 1979, the bulk of Alaska crude oil production (92.1 percent) came from Prudhoe Bay, with the remainder from Cook Inlet, and net production was increased to 1.4 million barrels per day (Reference 11).

2) Current and Proposed Oil Use

Oil resources from the Prudhoe Bay field are transported via the 800 mile trans-Alaska pipeline at a rate of 1.2 million barrels per day. In excess of 600 ships per year deliver oil from the port of Valdez to the west, Gulf and east coasts of the U.S. Approximately 2 percent (or 10 million barrels) of the Prudhoe Bay crude oil was used in Alaska refineries and along the pipeline route to power the pump stations (Reference 14).

The North Pole Refinery processes 25,000 barrels per day at a plant located 14 miles southeast of Fairbanks connected to the pipeline via a spur. The refinery produces home heating oils, diesel and jet fuel. Much of the installed generating capacity of Fairbanks utilities rely on oil for much of their generation. FMUS has 38.2 MW of oil-fired capacity and GVEA has 186 MW using oil as fuel. Due to the high cost of the oil, these utilities use the coal-fired capacity as much as possible with oil used as standby and for peaking purposes.

Crude oil from Kenai offshore and onshore oil fields is refined at Kenai primarily for use in state. Thermal generating stations in Anchorage have need for standby capacity fired by oil.

7) Oil Price Analysis

Since the installation of the Alyeska oil-pipeline, which has made Alaskan oil marketable the opportunity cost to Alaska has been experienced as the existing price. The contracts for oil to utilities has ranged from \$3.45/MMBtu to \$4.01/MMBtu as reported to FERC. For purposes of the generation expansion study where oil is considered only available for standby units the price adopted for use will be \$4.00/MMBtu as shown in Table 7.3.10.

7.3.3.4 - Geothermal

Of the numerous geothermal sites identified in the state, only a few are located in the South Central Region encompassing the Railbelt (Reference 35). Of these, all but one are low temperature (100-200°F) and therefore feasible only as sources for building or process heating.

The Klawasi site, located east of Glenallen, has been recently investigated for electric power generation potential. A proposal for development was made, but has not been funded. No user of the power to be produced was identified, undoubtedly because no major transmission connection between or near the site to populated areas to the south or west exists. Geothermal energy would be potentially used as suggested in the reference, if the Alaskan pipeline corridor becomes populated, since the geothermal site is near the route of the line.

Based upon available data, a potential site capacity on the order of several hundred MW may exist, although only a 25 MW development is discussed. Unless a transmission loop paralleling Alaskan highway Routes 2/4 or 1 is constructed, the likelihood of a geothermal development at this location supplying any of the Railbelt needs is remote.

7.3.4 - Thermal Generating Resources Engineering, Environmental and Cost Studies

7.3.4.1 - Environmental

The inclusion of air pollution control equipment for thermal generating resources is based on satisfaction of the national New Source Performance Standards (NSPS) and the National Ambient Air Quality Standards (NAAQS)(Reference 36). It is assumed that compliance with NSPS and NAAQS for the final site selection for specific facilities will assure compliance with the Prevention of Significant Deterioration (PSD) aspects of air quality regulation. The State of Alaska has adopted the National Ambient Air Quality Standards, with the addition of a standard for reduced sulfur compounds (Reference 37). The State may also require measures for control of ice fog (Reference 38).

Three New Source Performance Standards cover the plant types under consideration. The NSPS for Electric Utility Steam Generating Units is applicable to coal-fired steam units. Specific standards are set for control of sulfur dioxide, particulate, and nitrogen oxides. For the coal-fired units, the use of available combustion technology is accepted for control of NO_x. Flue gas desulfurization is required

Mt. McKinley National Park is designated as Class I area. A plant located in the vicinity of the Park would be subject to the scrutiny of the effects of its emissions on visibility and air quality within the park. A few other Class II areas are in noncompliance with one or more of ambient air quality standards (Anchorage and Fairbanks - North Pole urban areas are presently the only examples) or are very close to exceeding the PSD increment allowed for the airshed (such as Valdez).

Compliance with stricter regulations in any of these sensitive areas could incur higher pollution control costs, or could effectively result in barring the development of a thermal plant in that area. It is likely that new thermal plants will not be located in these areas if the cost of additional pollution control equipment substantially affects the cost of energy supplied to the consumer. These siting limitations, however, barely touch the number of possible plant locations within the Railbelt. Therefore, the assumption of compliance with NSPS is felt to be satisfactory for air pollution control costs.

The costs for other environmental controls are also included in the cost estimates. These controls are mandated by national and state water discharge standards, solid waste disposal standards, and occupational health and safety standards. These controls will have the greatest relative impact on the cost of coal-fired plants.

7.3.4.2 - Engineering and Cost Studies

The capital costs of four different types of thermal generating plants considered available to the Railbelt region were estimated. Capital cost estimates for coal-fired steam, combined cycle, gas turbines and diesels appear in Tables 7.3.11 to 7.3.17. Table 7.3.18 summarizes other generation parameters necessary for description in the generation planning studies. These tables are located at the end of Section 7.3 due to their length.

Estimating the cost of thermal plants in Alaska is accomplished based on existing lower 48 data and research. Smaller gas turbine and diesel plants are modularized units sold in packages, so capital cost is readily obtainable from manufacturers. Coal-fired steam and combined cycle unit costs have been reported by EPRI which are used as the key reference in this study.

Alaskan Location Adjustment Factors

This study incorporates the use of Alaskan location adjustment factors. These factors represent cost increases to account for Alaskan conditions, which differ from the contiguous 48 states. These conditions are Alaska's adverse weather, remoteness, lack of infrastructure and transportation facilities, limited construction season and high labor premiums. All of these conditions increase the cost in Alaska over a similar facility constructed in the contiguous 48 states. The exact increase (factor) depends on the type of facility and actual location.

Research by several organizations documented in the 1978 Battelle Report (Reference 3) list a range of factors from a low of 1.1 to a high value of 2.8 with a wide variation in values for a single location. Research by the Corps of Engineers (Reference 25) proposed a composite value of 1.5. For purposes of this study three values, 1.6, 1.8 and 2.2, were adopted from the Battelle Report to reflect conditions in Anchorage, Beluga and the Healy/Nenana/Fairbanks regions respectively.

Coal-Fired Steam

As previously reported there are currently at least four coal-fired steam plants in operation. Fairbanks Municipal Utilities System (FMUS) operates the Chena Plant with 29 MW capacity. Another is operated by Golden Valley Electric Association (GVEA) in Healy with a 25 MW capacity. Two more supply Fort Wainwright and the University of Alaska at Fairbanks with heat and electric power.

These plants are small in comparison to the new electric utility units under consideration in the lower 48 so that direct cost comparison is difficult. Another factor that influences the capital costs is that any large, new, coal-fired plant will require extensive emission control equipment to meet EPA emission standards, particularly in the Fairbanks area. This additional equipment as well as a longer construction periods and current high interest and escalation rates, has driven capital costs of new plants in the lower 48 states to much higher levels than previously experienced. These factors are reflected in the costs developed for this study.

Based on the projected plant capacity additions developed in previous studies, three coal-fired unit sizes were adopted for capacity additions; 100, 250 and 500 MW. It is unlikely that a 500 MW plant would be proposed in the Fairbanks region due to the large coal and demand requirements as well as the remote location. Therefore costs for 250 and 100 MW steam facilities only were developed for Fairbanks.

The basic cost of a coal-fired plant was extracted from Coal-Fired Power Plant Capital Cost Estimates, EPRI-AF-342 (Reference 17). EPRI models the cost for a 1000 MW plant situated in a remote, western U.S. site (Reference Plant #4) having maximum emission control devices; flue gas desulfurization (FGD) and a heat rate of 10,500 Btu/kWh. This plant burns Wyoming coal which is very similar in properties to Alaskan coals (Reference 2 and 17). The plant cost was determined by first obtaining the base plant cost for two 500 MW units as seen in Table 7.3.11. The 1976 cost estimates were updated by the use of the Handy-Whitman Indices for the utility industry to represent 1980 dollar estimates. In order to scale the 1000 MW cost estimate down to 100, 250 and 500 MW, two methods were used. The first assumes that the cost for the first 500 MW unit is 54 percent of the total construction cost (Reference 3), therefore the estimate for a 500 MW plant was developed based on 54 percent of the cost of the 1000 MW plant. The scaling exponent was then calculated to be .85 based on the following equation:

$$\begin{bmatrix}\text{Cost of}\\ \text{1000 MW}\\ \text{Plant}\end{bmatrix} \times \left[\frac{\text{(X) MW}}{\text{1000 MW}}\right]^{.85} = \text{Cost of X MW plant}$$

Where X for this study is 100, 250 and 500 MW.

This equation was used to determine the costs of 500, 250 and 100 MW plants on the lower 48. These figures appear in Table 7.3.11. Using the Alaskan location adjustment factors, the total construction costs in the Railbelt area were estimated. To this was added contingency of 16 percent, utilities and other construction costs (10 percent), engineering and administration (12 percent). Interest during construction costs were calculated using symmetric S-shaped cash flow model (Reference 23), 0 percent escalation, a six-year construction period for 500 and 250 MW plants; five-year construction period for

100 MW plants. Total capital costs calculated are shown in Tables 7.3.12, 7.3.13, and 7.3.14). The cost values presented in these tables reflect total capital cost for building a coal-fired steam plant in the different Alaskan locations.

Outages for coal-fired steam plants are reported as planned (scheduled) and forced outages as a percent of time. Edison Electric Institute (EEI) (Reference 41) reports a forced outage of approximately 5.4 percent for large coal-fired plants. The EEI figure of 5.4 percent was rounded to 5 to represent forced outages. Planned outages, as reported by GVEA for their Healy, Alaska plant are in the 5.1 to 16.3 percent range. An average of 11 percent, which correlates with the EEI data, was adopted as the planned outage rate for coal fired plants for this study.

Operation and Maintenance (O&M) costs are divided into two components; fixed costs and variable costs (not including fuel). Fixed O&M is quoted as $/yr/kw in the DOE Steam Plant Construction and Annual Production Expenses (Reference 21) and trends indicated a fixed cost of 0.50, 1.05 and 1.30 for a 500 MW, 250 MW and 100 MW plant respectively. Variable costs are also quoted in the DOE publication. The costs decrease with increasing unit size. The values used in this study are $1.40, $1.80 and to $2.20/yr/kW for a 500 MW, 250 MW and 100 MW plant respectively.

7

Combined Cycle

There are two combined cycle plants in Alaska at present. One is operational and the other is under construction. The operational unit is owned and operated by Anchorage Municipal Light and Power Department (AMLPD). This unit, the George M. Sullivan plant, consists of three units which when operating in tandem produce a net capacity of 140.9 MW. The plant under construction is the Beluga #9 unit owned by Chugach Electric Association (CEA) and will add a 60 MW steam turbine to the system sometime in 1982.

A new combined cycle plant of 250 MW capacity was considered to be representative of future additions in the Anchorage area based on projected designs in the lower 48 states and experience in Alaska. A combined cycle plant in Beluga was not considered. A heat rate of 8500 Btu/kWh was adopted based on Alaskan experience and EPRI AF-610; Combined Cycle Power Plant Capital Cost Estimates (Reference 18).

General Electric Corporation quoted a lower 48 cost for the combined cycle unit which appears in Table 7.3.15. An estimate was made for the costs of foundations and buildings, fuel handling facilities, other mechanical and electrical equipment and a cost of 25 percent for transportation of the basic unit anywhere in the lower 48. These costs were based on prior combined cycle power plant capital cost (EPRI-AF-610) (Reference 18). To this in-place total cost 16 percent contingency, 10 percent for utilities and construction facilities, and 12 percent for engineering and administration was added. Assuming a construction period of three years, 0 percent escalation and 3 percent cost of money and an S-shaped cash flow model, the total capital costs were obtained. Using the location adjustment factors of 1.6 and 2.2, the values were adjusted for a plant located in Anchorage and Fairbanks as seen in Table 7.3.15.

Based on information provided by Anchorage Municipal Light and Power Department (AMLPD) on their G.M. Sullivan units 5-7 combined cycle plant (140 MW), the planned outages are approximately 11 percent. Assuming for a larger plant at 250 MW and correlating with EEI data a 14 percent planned outage was selected. Forced outages of 6 percent were also considered appropriate from the AMLPD and EEI.

Operation and Maintenance (O&M) costs for large combined cycle plants as reported in EPRI AF-610 (Reference 18), is approximately \$2.75/yr/kW fixed O&M and \$0.30/MWh variable O&M.

3 Gas Turbines

Gas turbines are by far the main source of thermal power generating resources in the Railbelt area at present. There are 470.5 MW of installed gas turbines operating on natural gas in the Anchorage area and approximately 168.3 MW of oil-fired gas turbines supplying the

Fairbanks area. Their low initial cost, simplicity of construction and operation as well as currently available low cost fuel (gas) have made them very attractive as a Railbelt generating alternative.

A unit size of 75 MW was considered to be representative of a modern gas turbine plant addition in the Railbelt region. However, the possibility of installing gas turbine units in Beluga was not considered, since the Beluga mine-mouth development is intended for coal. The potential for coal conversion to methanol (synfuel) may be a possibility; however, that consideration is beyond the scope of this study.

The gas turbine plants are assumed to be built over a two year construction period. (Reference 22) The base plant costs are obtained from the Gas Turbine World Handbook (Reference 19), which lists awarded contracts and "turnkey" costs in 1978 dollars in Anchorage, and are quoted in Table 7.3.16 along with the average heat rate of 12,000 Btu/kWh. The costs were escalated using the Handy-Whitman indices to 1980 dollars. A 10 percent increase was included for construction facilities and utilities as well as a 14 percent Engineering and Administration fee and a two year IDC cost. Fairbanks costs are estimated using a factor of 0.6 (2.2 ÷ 1.6) to adjust the Anchorage figures.

Three sources of data were consulted for planned and forced outages of gas turbine units--the EEI report, information from AMLPD and from GVEA. Planned outages are approximately 11 to 12 percent and forced outages estimated at 3.8 percent appear to be valid based upon utility experience.

Operation and Maintenance (O&M) costs are similiar to combined cycle units and are adopted as $2.50/yr/kw and $0.30/MWh for the fixed and variable components. These values reflect intermediate levels of O & M costs in the FMUS/GVEA Net Study (Reference 32).

Diesels

Most diesel plants in operation today are standby units or peaking generation equipment. Nearly all the continuous duty units have been placed on standby service for several years due to the high oil prices which have made them very expensive to operate. The situation in Alaska has required the installation of many small diesel units estimate was made of the auxiliary plant facilities (building, foundations, etc.) as well as fuel facilities and switchyard in Alaska. A transportation charge for bringing the basic unit to Alaska was estimated and included in total construction costs. A construction period of one year was assumed since these plants are modular and quick to assemble. The three site estimates along with contingencies (16 percent), construction facilities and utilities (10 percent), engineering and administration (14 percent) and IDC for the one-year construction period appear in Table 7.3.17. An average cost of $778/kW was developed and used for the entire Railbelt region regardless of location based on the modular and rapid construction techniques associated with these small diesel units.

Diesel units have very low (1 percent) planned outage rate based on EEI utility experience. Forced outages are reported as 4.4-5.0 percent for diesels and 5 percent was adopted for the system planning study.

Diesel Operating and Maintenance (O&M) costs as quoted in the Williams Brothers Report for GVEA and FMUS (Reference 32) are considered typical to the Alaska Region and are used for this study. Fixed cost equal to $0.50/yr/kw and $5.00/MWh variable costs.

TABLE 7.3.11

1000 MW COAL-FIRED STEAM PLANT COST ESTIMATE*
LOWER 48

ACCOUNT/ITEM	1976 $	HANDY-WHITMAN ADJUSTMENT	1980 $
	$ MILLIONS		
10 Concrete	$ 22.40	547/394	31.10
20 Civil/Structural/Architectural			
21,22,24 Structural & Misc. Iron & Steel	23.70	559/397	33.37
25 Architectural & Finish	11.90	500/361	16.76
26 Earthwork	23.70	500/361	32.82
28 Site Improvements	14.80	500/361	20.50
30 Steam Generators	119.70	571/407	167.93
41 Turbine Generators	48.40	413/293	68.22
42 Main Condenser & Auxiliaries	4.20	518/361	6.03
43 Rotating Equipment, Ex. T/G	12.80	518/361	18.36
44 Heaters & Exchangers	3.70	518/361	5.31
45 Tanks, Drums & Vessels	1.50	518/361	2.15
46 Water Treatment/Chemical Feed	2.40	518/361	3.44
47 Coal/Ash/FGD Equipment			
47.1 Coal Unloading Equipment	3.50	461/338	4.77
47.2 Coal Reclaiming Equipment	3.40	461/338	4.63
47.3 Ash Handling Equipment	1.40	461/338	1.90
47.4 Electrostatic Precipitators	61.30	461/338	83.60
47.6 FGD Removal Equipment	87.90	461/338	119.88
47.8 Stack (Lining, Lights, etc.)	5.20	461/338	7.09
48 Other Mechanical Equipment Incl. Insulation & Lagging	9.70	518/361	13.92
49 Heating, Ventilating, Air Conditioning	1.70	518/361	2.43
50 Piping	44.60	629/422	66.47
60 Control & Instrumentation	11.10	461/322	15.41
70 Electrical Equipment (Switchgear/Transformers/MCCs/Fixtures)	11.30	461/332	15.69
80 Electrical Bulk Materials			
81,82,83 Cable Tray & Conduit	11.6 0	173/123	16.31
84,85,86 Wire & Cable	13.40	173/123	18.85
Switchyard	11.30	173/123	15.89
CONSTRUCTION COST TOTAL	$ 566.6		$ 792.82

* Reference 17 EPRI-A-342, Plant #4, p. 8-5.

TABLE 7.3.11 (Cont'd)

$ MILLIONS (1980)	SCALING FACTOR		$ MILLIONS (1980)
$ 792.82	$\left(\frac{500\ MW}{1000\ MW}\right)^{.85}$	=	$ 439.84 for 500 MW plant
$ 792.82	$\left(\frac{250\ MW}{1000\ MW}\right)^{.85}$	=	$ 244.01 for 250 MW plant
$ 792.82	$\left(\frac{100\ MW}{1000\ MW}\right)^{.85}$	=	$ 111.98 for 100 MW plant

TABLE 7.3.12

500 MW COAL-FIRED STEAM COST ESTIMATES

ACCOUNT/ITEM	$ MILLIONS (1980) LOWER 48	ANCHORAGE (1.6)	BELUGA (1.8)
10-20 Civil/Structural/ Architectural	72.66	116.26	130.79
30-46 Mechanical Equipment	146.57	234.51	263.82
47 Coal/Ash/FGD	131.52	210.43	236.73
48-60 Other Mechanical	53.04	84.86	95.47
70-80 Electrical Equipment	36.05	57.68	64.89
Construction Cost Total	439.84	703.74	791.70
Contingency (16 %) Subtotal	510.21	816.33	918.37
Construction/Facilities/ Utilities (10%) Subtotal	561.23	897.97	1010.20
Engineering & Administration (12 %) Subtotal	628.54	1005.73	1131.43
Interest During Construction (6 years)	58.63	93.73	105.45
Total Plant Cost	687.17	1099.46	1236.88
$/kw	1374.00	$ 2199/kw	$ 2473/kw

TABLE 7.3.13

250 MW COAL-FIRED STEAM COST ESTIMATES

ACCOUNT/ITEM	$ MILLIONS (1980) LOWER 48	ANCHORAGE (1.6)	BELUGA (1.8)	FAIRBANKS (2.2)
10-20 Civil/Structural/ Architectural	39.23	62.77	70.61	86.30
30-46 Mechanical Equipment	79.15	126.64	142.47	174.13
47 Coal/Ash/FGD	77.52	124.03	139.53	170.54
48-60 Other Mechanical	28.65	45.84	51.57	63.03
70-80 Electrical Equipment	19.46	31.13	35.02	42.81
Construction Cost Total	244.01	390.41	439.20	536.81
Contingency (16%) Subtotal	283.05	452.87	509.47	622.69
Construction/Facilities/ Utilities (10%) Subtotal	311.35	498.16	560.41	684.96
Engineering & Administration (12%) Subtotal	348.71	557.94	627.65	767.16
Interest During Construction (6 years)	32.51	52.00	58.50	71.50
Total Plant Cost	381.22	609.94	686.15	838.66
$/kw	1524.00	$ 2440/kw	$2744/kw	$3354/kw

TABLE 7.3.14

100 MW COAL-FIRED STEAM COST ESTIMATES

ACCOUNT/ITEM	$ MILLIONS (1980) LOWER 48	ANCHORAGE (1.6)	BELUGA (1.8)	FAIRBANKS (2.2)
10-20 Civil/Structural/ Architectural	21.19	33.90	38.14	46.62
30-46 Mechanical Equipment	42.74	68.38	76.93	94.03
47 Coal/Ash/FGD	22.08	35.21	39.74	48.57
48-60 Other Mechanical	15.47	24.75	27.85	34.03
70-80 Electrical Equipment	10.50	16.80	18.90	23.10
Construction Cost Total	111.98	179.04	201.56	246.35
Contingency (16%) Subtotal	129.89	207.68	233.80	285.76
Construction/Facilities/ Utilities (10%) Subtotal	142.88	228.45	257.19	314.34
Engineering & Administration (12%) Subtotal	160.03	255.86	288.05	352.06
Interest During Construction (5 years)	12.32	19.71	22.18	27.11
Total Plant Cost	172.35	275.57	310.23	379.17
$/kw	723.00	$2755/kw	$3102/kw	$3791/kw

TABLE 7.3.15

250 MW COMBINED-CYCLE PLANT COST ESTIMATES

	$ MILLIONS (1980)		
ACCOUNT/ITEM	LOWER 48	ANCHORAGE (1.6)	FAIRBANKS (2.2)
20 Civil/Structural/Architectural			
21,22,23 Buildings/Struct.	2.83	4.53	6.23
26,28 Foundations Site Work	5.63	9.00	12.39
40 Mechanical			
41-47 Generating Units	37.50	60.00	82.50
45 Fuel Handling	1.40	2.24	3.08
48 Other Mechanical	5.28	18.45	11.62
70/80 Electrical Equipment	11.79	18.86	25.94
100 Transportation	(25%) 9.38	(50%) 18.76	(75%) 28.14
Construction Cost Total	73.81	121.84	169.90
Contingency (16%) Subtotal	85.61	141.34	197.08
Construction/Facilities/ Utilities (10%) Subtotal	94.17	155.47	216.78
Engineering & Administration (12%) Subtotal	105.47	174.13	242.79
Interest During Construction (3 years)	4.79	7.91	11.02
Total Plant Cost	110.26	182.04	253.81
$/kw	$442/kw	$728/kw	$1015/kw

TABLE 7.3.16

75 MW GAS TURBINE PLANT COST ESTIMATES

From Gas Turbine World Handbook (Reference 19)

Turnkey Anchorage Bids 1978 $ x 10^6	MW
13.95	63
18.10	75
18.80	77
14.3	78

$$\$18.10 \times 10^6 \quad \frac{258}{227} = \$20.58 \times 10^6$$

ITEM	$ MILLIONS (1980) ANCHORAGE	FAIRBANKS (2.2 - 1.6)
Turnkey Cost	20.58	32.85
Construction/Facilities/ Utilities (10%)		
Subtotal	22.63	36.13
Engineering & Administration (14%)		
Subtotal	25.80	41.19
Interest During Construction (2 years)	0.52	0.82
Total Plant Cost	26.32	42.01
$/kw	$350/kw	$560/kw

TABLE 7.3.17

10 MW DIESEL PLANT COST ESTIMATES

COMPANY BID REFERENCE ACCOUNT/ITEM	$ MILLIONS (1980)		
	SUPERIOR PRODS. (47)	BELYEA CO. (48)	CUMMINS INT. DIESEL (49)
20 Civil/Structural/Architectural			
21-23 Buildings	$ 0.72	$ 0.72	$ 0.72
28 Foundations	0.72	0.72	0.72
40 Mechanical			
41 Generating Units	5.05	3.00	1.80
45-80 Auxillary Mechanical and Electrical Equipment	0.30	0.30	0.45
100 Transportation	0.50	0.04	0.06
Construction Cost Totals in Alaska	$ 7.29	$ 4.78	$ 3.75
Contingency (16%)			
Subtotal	8.46	5.54	4.35
Construction/Facilities/ Utilities (10%)			
Subtotal	9.31	6.09	4.78
Engineering & Administration (14%)			
Subtotal	10.61	6.94	5.45
Interest During Construction (1 year)	0.16	.10	.08
Total Plant Cost	10.77	7.04	5.53
$/kw	$1077.00/kw	$704.00/kw	$553.00/kw

Average One Cost = $778/kw @ 1.5 Alaska Factor

TABLE 7.3.18

SUMMARY OF THERMAL GENERATING RESOURCE PLANT PARAMETERS

PARAMETER	PLANT TYPE: COAL-FIRED STEAM			COMBINED-CYCLE	GAS-TURBINE	DIESEL
Plant Size Considered:	500 MW	250 MW	100 MW	250 MW	75 MW	10 MW
Heat Rate (Btu/kwh)	10,500	10,500	10,500	8,500	12,000	11,500
O&M Costs						
Fixed O&M ($/yr/kw)	0.50	1.05	1.30	2.75	2.75	0.50
Variable O&M ($/MWH)	1.40	1.80	2.20	0.30	0.30	5.00
Outages						
Planned Outages (%)	11	11	11	14	11	1
Forced Outages (%)	5	5	5	6	3.8	5
Construction Period (yrs)	6	6	5	3	2	1
Start-up Time (years)	6	6	6	4	4	1
Economic Life (years)	30	30	30	30	gas-fired 30 oil-fired 20	30
Capital Cost ($/kw)						
Anchorage	$2199/kw	$2440/kw	$2755/kw	$728/kw	$350/kw	-
Beluga	$2473/kw	$2744/kw	$3102/kw	-	-	-
Fairbanks	-	$3354/kw	$3791/kw	$1015/kw	$560/kw	-
Railbelt	-	-	-	-	-	$778/kw

TABLE 7.3.16 - Cost Estimate Summary, $ Million

Acc. Item	Snow L	Bruskasha	Keetna	Cache	Browne	Talkeetna	Hicks	Chaka	Allison Cr.	Strandline L
Plant Factor	29%	19%	48%	27%	20%	34%	11%	46%	55%	35%
Cap. Installed	120MW	70MW	110MW	75MW	210MW	83MW	265MW	485MW	7.3MW	28MW
Product Cost (mills/kwh)	54.5	164	62.2	169	160	103	160	39.5	119	114
01 Land & Damages	1.095	4.509	1.858	2.125	5.174	0.538	1.967	0.500	0.500	0.500
03 Reservoir	5.236	33.66	15.334	17.578	35.53	4.114	18.7	--	0.0688	--
041 Dam	46.765 (17%)	38.93 (14%)	105.58 (23%)	136.605 (30%)	256.945 (29%)	119.537 (31%)	118.609 (20%)	0.955 --	3.711 (7%)	0.637 --
042 Spillway	26.038	15.70	28.923	26.937	82.958	14.949	23.784	--	1.27	--
043 Diversion +11 Outlet	17.497	34.692	71.583	54.783	32.841	48.449	78.081	--	1.727	--
044 Power Intake	18.300 (6.7%)	11.559 (4.1%)	11.237 (2.4%)	9.679 (2.1%)	25.742 (2.9%)	9.170 (2.4%)	31.88 (5.3%)	487.633 (41%)	8.42 (15.6%)	24.584 (19.6%)
071 Powerhouse - Civil	32.460	24.810	32.387	26.160	60.692	23.835	54.53	115.08	4.308	8.364
072,3,4 Powerhouse Mec & El	35.640	25.640	33.88	27.390	87.108	31.415	77.47	165.92	1.525	7.869
075 Tailrace	1.360	1.373	3.315	2.368	12.173	2.491	6.317	16.009	2.076	4.247
076,7 Switchyard Transmission	4.686	2.075	4.725	3.3	3.875	3.337	4.738	15.488	0.454	6.607
08 Roads, Bridges	4.200	6.800	20.2	17.2	28.0	17.2	15.0	51.8	14.2	36.4
14/19/20/50 Other	13.155	13.224	21.781	21.457	41.775	18.207	28.537	56.494	2.532	5.905
Contingency (20%)	41.268	42.625	70.197	69.118	134.587	58.658	91.887	182.021	8.209	19.087
Engineering (10%)	24.800	25.600	42.100	41.500	80.700	35.200	55.200	109.200	4.9	11.400
Project ($, Million)	272.5	281.2	463.1	456.2	888.1	387.1	606.7	1201.1	53.9	125.6
Cost ($/KW)	2270	4020	4210	6080	4230	4665	2290	2480	7380	4490

7.7 ~~7.4~~ - Planning Procedure

7.7.1 ~~7.4.1~~ - Introduction

The objectives of generation planning are to determine the most suitable size of development and scheduling for the Susitna Basin hydro schemes and to evaluate the sensitivity of these schemes to the assumptions made for the planning studies.

Generation planning analyses was done by making a comparison of alternatives with the aid of a production cost model to address the system cost of power under various developments and the direct comparison of alternatives using standard numerical evaluation techniques.

Since it is recognized that the selection of a generation plan may be sensitive to the underlying assumptions of load projection, interest and escalation rates and fuel costs the planning procedure attempted to deal with these uncertainties. Initially, a set of variables was established for use in identifying base plans in the first phase of stu[illegible]. These plans would consider basin development with and without a hydroelectric development in the Susitna River Basin.

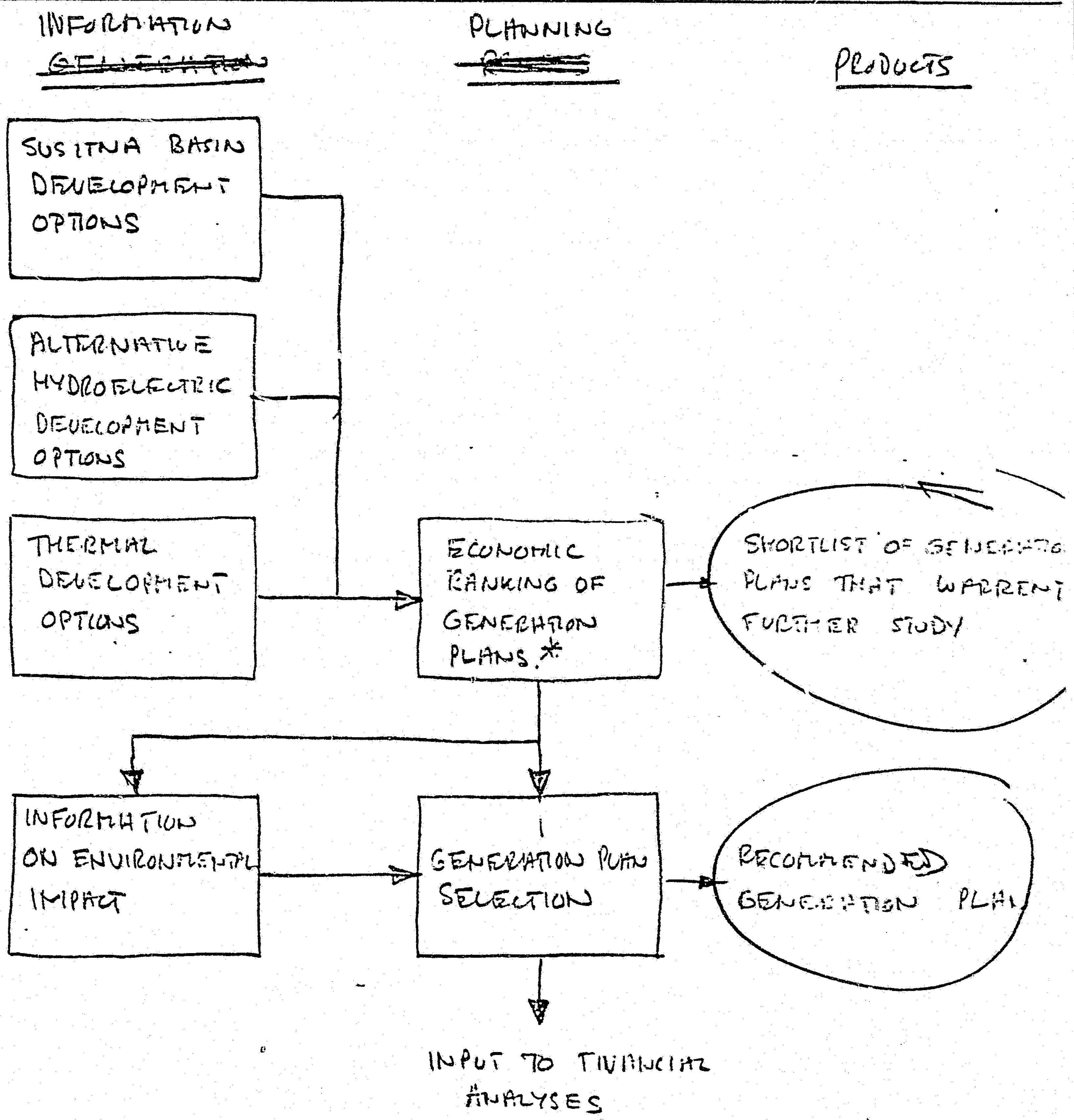
In the first phase of generation planning, the study focused on the mid-load forecast to identify a base plan without the Susitna project and with alternative Susitna developments added to the system.

ACRES

Calculations

SUBJECT:

JOB NUMBER P5700.06
FILE NUMBER
SHEET 2 OF 2
BY BPGH DATE 2/2/81
APP DATE



* INCLUDING SENSITIVITY ANALYSES.

SCHEMATIC REPRESECTION OF GENERATION PLAN SELECTION PROCESS

FIG 7.

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FORM NO. 152 REV. 1

The second phase of planning assessed the impact of varying the load forecast for planning purposes. This was done in two manners. Initially, generation plans with and without the Susitna project were identified for the high and low forecasts. A plan was also made for the low forecast considering an additional load effort at conservation and load management. Under this phase, a plan was developed considering a probablistic forecast.

The third phase of planning assessed the impacts of variable planning parameters including variable fuel escalation. Finally, a sensitivity analysis was performed combining variable forecasts and planning parameters.

7.4.2 - Generation Planning Model

A major tool used in the generation planning study is a computer simulation program for system studies. There are a number of generation planning models available commercially and accepted for use in the utility industry.

These models include the following:

WASP (Wien Automated System Planning)	by Tennessee Valley Authority
GENOP	by Westinghouse
OGP (Optimized Generation Planning)	by General Electric
PROMOD	by Energy Management Associates

The WASP program was not available for use in this study due to limitations on availability to private engineering firms. Therefore, it was not given further consideration for use in generation planning. As of September 30, 1980, this program was made available to the general industry.

Key considerations for use in selection of a model for this study are data processing costs, method of production cost modeling, treatment of system reliability, selection of new capacity, dispatching of hydroelectric capacity to meet load projections and ability of the model to address load uncertainty. Although some of these items are handled differently in each of these programs, common threads of operation exist between the three programs. Some of the salient featues of each model are shown on Table 7.4.1.

One major area of difference in comparing the models is the method of determining forced outages in the production cost algorithm. The three methods used are:

- Deterministic methods which devote unit capacity by a multiplier or by extending planned maintenance schedules.

- Stochastic methods which can be reduced to deterministic methods. Strictly speaking stochastic representations of outages is a random selection of some units in each commitment zone to be put out of service. The load previously served will be transferred to higher cost units.

- Probabilistic methods, which are described by the modified Booth - Baleriaux method of production simulation which allows for probability distribution of generation unit outages.

While the selection of one of these methods may be critical in the use of a model for short-term outage scheduling, it becomes less important for the purposes of this planning study. There would be virtually no difference in planning results over the long term of study for our planning purposes regardless of which method is adopted.

Another consideration of program features is the method of dispatching hydropower resources to meet load demands. The GENOP program dispatches hydroelectric units first with the run-of-river units meeting load demand and the units with storage capability used to shave peak demands.

The OGP program uses a similar method, utilizing hydroelectric energy as much as possible to minimize system operating costs. Hydropower is scheduled first on a monthly basis to account for seasonal conditions. An additional feature of the program is the ability to use dry year or firm energy on a monthly basis to determine system reliability, while using average annnual energy to determine system production costs.

The PROMOD program allows for three levels of annual runoff and associated hydroelectric energy. These energy levels can be entered into the program in a probabilistic manner to be used in determining reliability and production costing. Run-of-river and storage units are dispatched as in the other programs.

Based upon the considerations of the features and availability of the programs, it was decided to use the OGP program for the planning studies. A primary reason for this decision was the efficiency involved in using a program which the study team has previously used and has a working knowledge of.

Although the PROMOD model does have a few advantages over the OGP model, switch-over to it is not warranted due to the level of detail of the study and the inefficiencies involved in starting up and utilizing the program.

There is one other model which warrants consideration. This is the Electric Power Research Institute model, "Over/Under Capacity Planning Model." The EPRI model was developed in 1978 under the objective of providing a framework for evaluating the consequences of over and under capacity in terms of total costs to consumers. The model calculates long-term total costs of alternative planning reserve margins from an end point energy cost view.

The fundamental purpose of the EPRI model is to measure total cost to consumers of different planning reserve margins. The model is not intended to provide a detailed analysis of technology mix, load forecasting, production costing or corporate finance although many outputs are summaries of these kinds of data.

It was concluded that although the EPRI model could provide useful information in terms of the levels of capacity needed for meeting uncertain demand and the consequences of over and under building, the model did not meet the overall needs of the study.

The primary tool used for the generation planning studies was the mathematical model developed by the General Electric-Electric Utility Systems Engineering Department, called Optimized Generation Planning (OGP). The following information is paraphrased from GE literature on the program.

The OGP program was developed over ten years ago to combine the three main elements of generation expansion planning (system reliability, operating and investment costs) and automate generation addition decision analysis. OGP will automatically develop optimum generation expansion patterns in terms of economics, reliability and operation. Many utilities use OGP to study load management, unit size, capital and fuel costs, energy storage, forced outage rates and forecast uncertainty.

The OGP program requires an extensive system of specific and generalized data to perform its planning function. In developing an optimal plan, the program considers the existing and committed (planned and under construction) units available to the system and the characteristics of these units including age, heat rate, size, and outage rates as the base generation plan. The program [illegible] considers the given load forecast and system design and operation criteria to determine the need for additional

TABLE 7.4.1

SALIENT FEATURES OF GENERATION PLANNING PROGRAMS

Program/ Developer	Load Modeling	Generation Modeling	Optimization Available	Reliability Criterion	Production Simulation	Availability and Cost/Run
GENOP/ Westinghouse	Done by two external programs	Done by one external program	yes	LOLP or % reserve	Deterministic or Modified Booth - Baleriaux	$500.00 to validate Learning Curve Cost $300 - $800/run
PROMOD/EMA	Done by one external program	Done by one external program	no	LOLP or % reserve	Modified Booth - Baleriaux	$2,500.00 to validate on TYMSHARE Learning Curve Costs $300 - $500/run
OGP/GE	Done by one external program	Done by one external program	yes	LOLP or % reserve	Deterministic or Stochastic	AAI validated Columbia & Buffalo Experienced Personnel $50 - $800/run

system capacity based on given reliability criteria. If a need exists during any monthly iteration, the program will consider additions from a list of alternatives and select the available unit fitting the system needs in the optimal fashion. Unit selection is made by computing production costs for the system with each alternative included and comparing the results.

The first calculation in selecting the generation capacity to install in a future year is the reliability evaluation, using input corresponding to the desired system characteristics. This will answer the questions of "how much" capacity to add and "when" it should be installed. A production costing simulation is also done to determine the operating costs for the generation system with given unit additions. Finally, an investment cost analysis of the capital costs help to answer the question of "what kind" of generation to add to the system.

The model is further used then to compare alternative plans for meeting variable electrical demands, based on system reliability and production costs for the study period.

~~7.4.3~~ 7.7.3 - Load Representation

Besides generation unit data and system reliability criteria, the program uses a model of the system load including month to year peak load ratios, typical daily load shapes for days and weekends, and projected growth for the period of study in terms of demand and energy supply.

Load forecasts used for generation planning are represented in detail in Section 5.

The forecasts to be used for generation planning is based on Acres' analysis of the ISER energy forecast. The energy forecast used by Acres for establishing the "base" generation plan is the mid-range forecast. Sensitivity analyses will be carried out using variable loads developed using the ISER scenarios of high and low levels of both economic activity and government spending.

The energy and load forecasts developed by ISER and Woodward Clyde Consultants include energy projections from self-supplied industrial and military generation sectors. It is foreseeable that these markets will be unavailable for the future electrical suppliers to a large extent. By the same token, the capacity owned by these sectors will not be available as a supply by the general market.

A review of the industrial self suppliers indicates that they are primarily offshore operations, drilling operations and others which would not likely add nor draw power from the system. Thus, those amounts have been deleted from the ISER totals.

Additionally, although it is considered likely that the military would purchase available cost effective power from a general market, much of their capacity resource is tied to district heating systems, and thus would be expected to continue operation. For these reasons only one-third of the military generation total will be considered as a load on the total system. This amount is about 4 percent of total energy in 1980 and decreases to 2.5 percent in 1990. This method of accounting for these loads has no real effect on total capacity additions needed to meet projected loads after 1985. Table 7.4.2 illustrates the load and energy forecasts at five year intervals throughout the planning period.

TABLE 7.4.2

LOAD AND ENERGY FORECASTS* ALASKA RAILBELT AREA

	Low Forecast		Mid Forecast		High Forecast	
YEAR	MW	GWh	MW	GWh	MW	GWh
1980 BASE	514	2,789	514	2,789	514	2,789
1985	578	3,158	650	3,565	695	3,859
1990	641	3,503	735	4,032	920	5,085
1995	797	4,351	944	5,171	1,294	7,119
2000	952	5,198	1,173	6,413	1,669	9,153
2005	1,047	5,707	1,379	7,526	2,287	12,543
2010	1,141	6,215	1,635	8,938	2,209	15,933

* Derived from the Woodward-Clyde Consultants submittal of September 23, 1980, adjusted to eliminate industrial self-supplied and two-thirds of the military sector.

~~7.4.4~~ 7.7.4 - Impact of Load Uncertainty

Obviously, the load forecast used to develop a generation plan will have a significant bearing on the nature of the plan. In order to identify the impact of the uncertain loads, two methods will be used.

The first will be to develop plans using the high and low forecasts on their own. This will identify the upper and lower bounds of development which will be needed in the railbelt.

In order to incorporate the variable forecasts and uncertainty of the load forecasts into planning, a probability based load model feature of the OGP program will be used. A brief description of this feature follows.

The middle level forecast or most likely forecast, is introduced into the program in detail. This would include daily load shapes, monthly variability and annual growth of peaks and energy. Additional variables are added which introduce forecast uncertainty in terms of higher and lower levels of peak demand and the probability of the occurrence of these forecasts. For example: in year 1985 the middle level demand forecast entered is 1000 MW. Variable forecasts are entered for 850, 900, 1100 and 1150 MW, with associated probabilities of occurrence of .10, .20, .20 and .10, leaving the middle level as .40.

The OGP program will use this variable forecast in generating system reliability calculation only. A loss of load probability will be calculated for each projected demand level as compared to the available capacity and a weighted average will be taken. This loss of load probability will then be used for capacity addition decisions. After capacity decisions are made, the program uses the middle level forecast detail for operating the production cost model.

This method of dealing with uncertainty is directly applicable to the data available for 6.36 studies. There are five forecasts which could be plugged in to the reliability calculations, the three by ISER and the two extremes calculated by Acres represented in Table 7.4.2. Subjectivity is reduced to the decision of placing probabilities on the load forecasts.

Two alternative probabilities will be introduced. The initial set will be the same as those introduced in the example. This is based on the assumption that each outside forecast is half as likely to happen as the adjacent forecast towards the middle. As an alternative, the system will be analyzed under the assumption that all forecasts have an equal chance of happening. The loads and probabilities will be analyzed as:

FORECAST	Probability Set 1	Probability Set 2
LES-LG*	.10	.20
LES-MG	.20	.20
MES-MG	.40	.20
HES-MG	.20	.20
HES-HG	.10	.20

* ES - Economic activity
G - Government
L, M, H - Low, Medium, High

An inquiry has been made to ISER to gain their opinions of these probability sets and invite a probability set of their own.

~~7.4.5~~ 7.7.5 - Target Generation Plant Reliability

In order to perform this system study, a criterion for generating plant and system reliability is necessary. This criterion is important to determine the adequacy of the available generating capacity as well as the sizing and timing of additional units. Plant reliability is expressed in the form of forced and planned outage rates which have been presented within the individual resource description in Section 7.3. System reliability is expressed as the "loss of load probability" (LOLP).

A LOLP for a system is calculated probability based on the characteristics of capacity, forced and scheduled outage and cycling ability of individual units in the generating system. The probability defines the likelihood of not meeting the full demand within a one year period. For example, a LOLP of 1 relates to the probability of not meeting demand one day in one year; a LOLP of 0.1 is one day in ten years. For this study, LOLP of 0.1 will be adopted. This value is widely used by utility planners in the country as a target for independent systems. This target value will be used both for the base plan and for sensitivity analyses dealing with the effects of over/under capacity availability.

~~7.4.6~~ 7.7.6 - Interconnection Capability

Early in the study process, it was determined that some judgement was needed to determine whether it would be appropriate to assume the existence of an interconnected system or isolated load center. Initially, it was determined that a 138 kV line would connect the Anchorage and Fairbanks load centers and would provide the capability of transferring 50 MW of capacity at any point in time.

The next logical consideration was, in further capacity addition studies, whether to assume a full flow interconnection or to limit the interconnection to the 138 kV line. In order to address this question, a simplified analysis was performed, comparing the costs of thermal expansion in each load center with the costs of adding intertie capability as needed and generation capability in the least expensive manner. Thus, one scenario was developed with the 138 kV line in place in 1984 and additional transmission added if needed with expansion in the most economic area. A second scenario was developed allowing only the 138 kV line in 1984 and individual load center capacity additions past that point in time. The ISER mid-level load forecast was used.

Under the intertie scenario, it was found necessary to add a 230 kV uprate of the 138 kV line in 1986 and the currently committed capacity additions of CEA and Bradley Lake. No other capacity additions were needed until 1993 when additional capacity was needed.

Under the limited intertie scenario, capacity was necessary to ensure reliability in both systems in the 1986-1988 timeframe, in addition to that capacity already committed. Capacity would again be needed in 1993 in both Anchorage and Fairbanks systems. Assumptions for the assessment were considered to be conservative on the side of the non-intertied system. These assumptions and additional detail on the assessment are included in Appendix C.

It was clearly seen from this brief study, that an intertied system is the most cost effective position for both Fairbanks and Anchorage, by an overall cost ratio of greater than 10 to 1, (non-intertie to intertie).

From the assessment, it was considered that the best way to proceed with the initial generation planning analysis was to assure up to 230 kV of intertie line as existing in the system in 1986. Any additional generating facilities which would be needed to carry power to either load center would be included in the cost of the alternative.

7.7.7

~~7.4.7~~ - Economic and Financial Parameters

As a public investment, it was determined that the Susitna project should be evaluated initially from a public or economic perspective, using economic parameters. Initial analysis and screening of Susitna candidates employed a numerical economic analysis and the general aid of the OGP generation planning model. A financial or cost of power study will then be undertaken for those alternative candidates that were judged most favorable from the economic evaluation. That is the economically viable proposals will be simulated using the same generation planning model to determine the cost of power with and without Susitna proposal.

The differences between economic and financial perspectives pertain to the following parameters.

- Project Life

In economic evaluations, an economic life is used without regard to the terms (repayment period) of debt capital employed to finance the project. Cost of power (or financial) perspective uses an amortization period that is tied to the terms of financing. Retirement period (policy) should be equivalent to project life in economic evaluations; cost of power analysis may use a retirement period that differs from project life.

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~~5.3~~ – Denomination of Cash Flows and Discount Rates

The economic evaluation will use real dollars and real discount rates that exclude the effects of general price inflation with the exception of fuel escalation. Cost of power analysis is in nominal or escalated dollar terms; that is, it uses escalated cash flows and nominal interest rates.

~~5.4~~ – Taxes and Subsidies

These intra-state transfer payments are excluded from the economic analyses and considering the current status of taxation needs in Alaska, taxes will be considered as zero for the cost of power analysis.

~~(5.5)~~ – Market or Shadow Prices

Whenever market and shadow prices diverge, economic evaluations use shadow prices (opportunity costs or values). Cost of power analysis uses market prices projected as applicable based on Subtask 6.32 output.

It is important to note that application of the various parameters contained herein will not necessarily provide an accurate reflection of the true life cycle cost of any single generating resource of the system.

From the public (State of Alaska) perspective, the relevant project costs are based on opportunity values and exclude transfer payments such as taxes and subsidies. This comparative analysis of project economics and state net economic benefits will be addressed under Task 11.

(a) ~~7.4.7.1~~ - Interest Rates and Annual Carrying Charges

Generation planning based on economic parameters and criteria will use a 3 percent real discount rate in the base case analysis. This figure corresponds to the historical and expected real cost of debt capital. Sensitivity analysis will examine in 1981 the effects of low and high real discount rates, using a range of 1.5 percent (recent real return on Alaska Permanent Fund investments) to 5 percent. The issue of tax-exempt financing does not impinge on these economic evaluations.

Financial or cost of power analyses requires a nominal or market rate of interest for discounted cash flow analysis. This rate will depend on, among others, general price inflation, capital structure (debt-equity ratios) and tax-exempt status. In the base case, a general rate of price inflation of 7 percent is assumed for the period 1980 to 2010. Given a 100 percent debt capitalization and a 3 percent real discount rate, the appropriate nominal interest rate is approximately 10 percent in the base case.[1/]

1/ The nominal interest rate is computed as (1 + inflation rate) x (1 + real interest rate), or 1.07 x 1.03.

To calculate annual carrying charges, the following assumptions were made regarding the economic life of various power projects, for consistency, these lives were also used as the plant lives.

(1) Large steam plant	- 30 years
(2) Small steam plant	- 35 years
(3) Hydroelectric project	- 50 years
(4) Gas turbine, oil-fired	- 20 years
(5) Gas turbine, gas-fired	- 30 years
(6) Diesel	- 30 years

It should be noted that the 50-year life for hydro projects was selected as a conservative estimate and does not include replacement investment expenditures. The factors for insurance costs (0.10 percent for hydro projects and 0.25 percent for all others) are based on FERC guidelines.[2/] State and federal taxes were assumed to be zero for all types of power projects. This assumption is valid for planning based on economic criteria since all intra-state taxes should be excluded as transfer payments from Alaska's perspective. The subsequent financial analyses may relax this assumption if non-zero state and/or local taxes or payments in lieu are identified. Table 7.4.3 summarizes the annual fixed carrying charges relevant to the generation planning analysis based on economic and financial parameters.

2/ Federal Energy Regulatory Commission, Hydroelectric Power Evaluation, Washington, August 1979.

(b) ~~7.4.7.2~~ - Cost Escalation Rates

In the initial set of generation planning parameters, it is assumed that all cost items except energy escalate at the rate of general price escalation (7 percent per year). This results in real growth rates of zero percent for non-energy costs in the set of economic parameters used in real dollar generation planning and nominal growth rates of 7 percent for the subsequent escalated dollar cost of power (financial) analysis.

Base period (January 1980) energy prices will be estimated based on both market and shadow (opportunity) values. The initial set of generation planning parameters will use base period costs (market and shadow prices) of $\$1.15/10^6$ Btu and $\$4.00/10^6$ Btu for coal and distillate respectively. For natural gas, the current actual market price is about $\$1.05/10^6$ Btu and the shadow price is estimated to be $\$2.00/10^6$ Btu. The shadow price for gas represents the expected market value assuming an export market were developed. This assumption and value is to be used for both the economic and cost of power analysis.

Real growth rates in energy costs (excluding general price inflation) are shown in Table 7.4.4. These are based on fuel escalation rates from the Department of Energy (DOE) mid-term Energy Forecasting System for DOE Region 10 (including the States of Alaska, Washington, Oregon and Idaho).[3/] Price escalators pertaining to the industrial sector were selected over those available for the commercial and residential sectors to reflect utilities' bulk purchasing advantage. A composite escalation rate has been computed for the period 1980 to 1995 reflecting average compound growth rate per year. As DOE has suggested that the forecasts to 1995 may be extended to 2005, the composite escalation rates are assumed to prevail in the period 1996 to 2005. Beyond 2005, zero real growth in energy prices is assumed.

For cost of power analyses, the nominal (inflation-inclusive) rates of energy price escalation will be used. These are defined as (1 + general price inflation rate) x (1 + energy price escalator). For example, using 7 percent and 3 percent values for the rates of general price inflation and fuel prices, the nominal escalator for fuel would be 1.07 x 1.03 = 1.102, or 10.2 percent.

Table 7.4.5 summarizes the sets of economic and financial parameters for generation planning.

3/ Department of Energy, Office of Conservation and Solar Energy, Methodology and Procedures for Life Cycle Cost Analysis, Federal Register, October 7, 1980.

TABLE 7.4.3

ANNUAL FIXED CARRYING CHARGES
USED IN GENERATION PLANNING MODEL

	Project Life/Type			
	30-Year Thermal (%)	35-Year Thermal (%)	50-Year Hydro (%)	20-Year Thermal (%)
ECONOMIC PARAMETERS				
Cost of Money	3.00	3.00	3.00	3.00
Amortization	2.10	1.65	0.89	3.72
Insurance	0.25	0.25	0.10	0.25
TOTALS	5.35	4.90	3.99	6.97
FINANCIAL PARAMETERS				
Non-exempt				
Cost of Money	10.00	10.00	10.00	10.00
Amortization	0.61	0.37	0.09	1.75
Insurance	0.25	0.25	0.10	0.25
TOTALS	10.86	10.62	10.19	12.00
Tax-exempt				
Cost of Money	8.00	8.00	8.00	8.00
Amortization	0.88	0.58	0.17	2.19
Insurance	0.25	0.25	0.10	0.25
TOTALS	9.13	8.83	8.27	10.44

TABLE 7.4.4

FUEL PRICES AND ESCALATION RATES

	Natural Gas	Coal	Distillate
Base Period (January 1980) Prices ($/million Btu)			
Market Prices	$1.05	$1.15	$4.00
Shadow (Opportunity) Values	2.00	1.15	4.00
Real Escalation Rates (Percentage Change Compounded Annually)			
1980 - 1985	1.79%	9.56%	3.38%
1986 - 1990	6.20	2.39	3.09
1991 - 1995	3.99	-2.87	4.27
Composite (average) 1980 - 1995	3.98	2.93	3.58
1996 - 2005	3.98	2.93	3.58
2006 - 2010	0	0	0

TABLE 7.4.5

SUMMARY OF ECONOMIC AND FINANCIAL PARAMETERS FOR GENERATION PLANNING

	Generation Planning Analysis	
	Economic*	Financial*
1 - Base Period (January 1980) Energy Prices ($/million Btu)		
1.1 - Natural Gas	2.00	2.00
1.2 - Coal	1.15	1.15
1.3 - Distillate	4.00	4.00
2 - General Price Inflation Per Year (%)	not applicable	7
3 - Discount & Interest Rates Per Year (%)		
3.1 - Real Discount Rate	3	not applicable
3.2 - Nominal Interest Rate (Non-exempt Case)	not applicable	10
3.3 - Nominal Interest Rate (Tax-exempt Case)	not applicable	8
4 - Non-energy Cost Escalation Per Year (%)	0	7
5 - Energy Price Escalation Per Year (%)		
5.1 - Natural Gas		
1980 - 2005	3.98	11.26
2006 - 2010	0	7.00
5.2 - Coal		
1980 - 2005	2.93	10.14
2006 - 2010	0	7.00
5.3 - Distillate		
1980 - 2005	3.58	10.83
2006 - 2010	0	7.00
6 - Economic Life		
6.1 - Large Steam Turbine	30	not applicable
6.2 - Small Steam Turbine	35	not applicable
6.3 - Hydro	50	not applicable
6.4 - Diesel and Gas Turbine (Gas-fired)	30	not applicable
6.5 - Gas Turbine (Oil-fired)	20	not applicable
7 - Amortization Period		
7.1 - Steam	not applicable	30
7.2 - Hydro	not applicable	50
7.3 - Diesel and Gas Turbine (Gas-fired)	not applicable	30
7.4 - Gas Turbine (Oil-fired)	not applicable	20

* Note that economic and financial parameters apply to real dollar and escalated dollar analyses respectively.

7.5 - Base Generation Plan - Mid Level Load Forecast

This section describes the efforts conducted under the first phase of the generation planning procedure described in Section 7.4.1, which concentrates on the mid level load forecast and the economic parameters. Three subsections describe the all thermal generation plan (with input from Section 7.3.3), the thermal and competitive hydro plan (with input from Section 7.3.2) and the Susitna Alternative schemes (input from Section 6). The OGP-5 program is the main engineering tool used throughout this generation plan analysis. Appendices A and B contain the summary outputs of selected runs as well as a description of "How to Interpret An OGP-5 Summary Output". It should be noted that the maximum number of years that can be analysed in our OGP-5 run is 20 and since our study period is thirty years (1980-2010), a ten-year run representing the 1980 to 1990 time frame was made and is common to all mid level forecast generation planning sequences. This ten year model is summarized in Table 7.5.1, which shows the 1982 and 1988 committed units and retirements that occur during this period. The results of this 10 year run are transferred to the 1990-2010 runs in order to get the 30 year representation of system characteristics. A summary of all runs completed in this phase is presented in Table 7.5.2.

7.5.1 - Thermal Generation Plan

Two all-thermal generating futures were considered; one which allowed the renewal of existing natural gas gas turbines which are due to be retired during the study period and one which merely retired the units at the end of their economic lives. The purpose for the renewal policy follows from the Fuel Use Act limitations on new electric generating stations using natural gas and on the potential exemption allowed for renewed units. This case appears to be the closest to the real life simulation of operating natural gas turbines in Alaska in the future. Of the 943 MW of existing capacity, 734 MW were due to retire in the next 20 years. Of these 456 MW were natural gas gas turbines. These units were input at 100% of the capital cost in the year they were to retire and allowed to continue operating. The non-renewed scenario would represent the extreme case for natural gas gas turbines operating only in the peaking condition and therefore was used in comparisons. In both cases, base-loaded natural gas combined cycle units were not considered due to the limitations of the Fuel Use Act. Table 7.5.2 summarizes the results of these two all-thermal runs.

The Thermal Plans are similar in composition, adding 900 MW of coal units in 100 MW increments) and similar amounts of diesel capacity (40 MW in the renew case and 50 MW in the no renew case). The natural gas gas turbines are almost exactly matched with new gas turbines in the selected no renew case adding 600 MW to the system. The addition of these units represents approximately an $11 million PW variation between the renew and no renew case.

7.5.2 - Thermal and Competitive Hydropower Generation Plan

Based on the results of the competitive hydropower screening described in Section 7.3.2, three of the ten sites were chosen to be the most economically sound projects, compared to their thermal alternatives and were applied to the generation planning procedure. These sites were chaka-chamna, Keetna and Snow and were assumed to be installed during 1993, 1997 and 2002. The results of this generation plan are presented in Table 7.5.2 and graphically depicted in Figure 7.5.1 as compared to the all thermal case.

7.5.3 - Susitna Generation Plans

Essentially five Susitna "alternatives" evolved from the Sustitna Basir Studies described in Section 6. These five Susitna plans were tested in the OGP-5 model and compared to the three runs described in the previous sections. Table 7.5.2 summarizes the results of all eight runs.

The five simplified Susitna plans are as follows:

Plan	Stage	Description	ON-LINE Month/Year	TOTAL COST Million 1980$	Installed Capacity	December Firm Capacity
2A	1	Watana Low Dam	1/92	1774	400 MW	206 MW
	2	Raise Watana Dam	1/95	376		194 MW
	3	Add Capacity	1/97	136	400 MW	400 MW
	4	Devil Canyon Dam	1/02	999	400 MW	352 MW
					TOTAL 1200 MW	1152 MW
3AE	1	High Watana Dam	6/93	1984	400 MW	400 MW
	2	Add powerhouse capacity	1/96	157	400 MW	400 MW
	3	Devil Canyon Dam	1/00	999	400 MW	352 MW
					TOTAL 1200 MW	1152 MW
3A2	1	Watana High Dam	6/93	1984	400 MW	400 MW
	2	Devil Canyon Dam	1/00	999	400 MW	337 MW
					TOTAL 800 MW	737 MW
6A	1	High Devil Canyon Dam	1/94	1570	400 MW	351 MW
	2	Vee Dam	1/00	1177	400 MW	315 MW
					TOTAL 800 MW	666 MW
7A	1	Watana High Dam	6/93	1984	400 MW	400 MW
	2	Add powerhouse capacity	1/96	157	400 MW	400 MW
	3	Add tunnel capacity	1/00	1314	380 MW	179 MW
					TOTAL 1180 MW	979 MW

Despite the short term competitiveness of the 3A2 alternative, the 3AE plan was selected as the proposed Susitna alternative to complete the Phase II and Phase III generation planning procedures.

TABLE 7.5.1 TEN YEAR BASE GENERATION PLAN
MID LOAD FORECAST

YEAR	MW Committed	MW Retired	SYSTEM (MW) COAL	NG GT	OIL GT	OIL DIESEL	CC	HY	TOTAL CAPABILITY (MW)
1980	-	-	54	470	168	65	141	49	947*
1981	-	-	54	470	168	65	141	49	947
1982	60 CC^{+}	-	54	470	168	65	201	49	1007
1983	-	-	54	470	168	65	201	49	1007
1984	-	-	54	470	168	65	201	49	1007
1985	-	14 (NGGT)	54	456	168	65	201	49	993
1986	-	-	50	456	168	65	201	49	993
1987	-	4 (Coal)	50	456	168	65	201	49	989
1988	95 HY^{+}	-	50	456	168	65	201	144	1084
1989	-	5 (Coal)	45	456	168	65	201	144	1079
1990	-	-	45	456	168	65	201	144	1079

*This figures varies slightly from the 943.6 MW reported due to internal computer rounding.

TABLE 7.5.2 SUMMARY OF BASE GENERATION PLANS - MID LOAD FORECAST

	ALL THERMAL		THERMAL	SUSITNA ALTERNATIVES				
	THERMAL +RENEWS	THERMAL NO RENEWS	AND OTHER HYDRO	STAGED W 2A	HW / DC 3AEE	W400/DC400 3A2	HDC/VEE 6A	W/ TUNNEL 7
JOB # I.D.	LME3	LME1		L5Y9	L8J9	LCK5	LB25	LAZ7
1990 MW	1079	1079 MW		1079 MW	1079 MW	1079 MW	1079 MW	1079 MW
1990-2010 THERMAL ADDS:	456 RN							
Coal (MW)	900	900		200	300	200	400	400
NGGT (MW)	150	600		300	225	525	450	300
Diesels (MW)	40	50		0	0	50	60	10
TOTAL	1546 MW	1550 MW		500 MW	525 MW	755 MW	910 MW	710 MW
TOTAL RETIREMENTS	(734)	(734 MW)		(734 MW)	(734 MW)	(734 MW)	(734 MW)	(734 MW)
HYDRO ADDS: M/Y NAME MW				1/92 W400 1/95 + Dam 1/97 N400 1/02 DC400	6/93 W400 1/96 W400 1/00 DC400	6/93 W400 1/00 DC400	1/94 HDC 400 1/00 VEE 400	6/93 W400 1/96 W400 1/00 T380
TOTAL FIRM* MW 2010	1891 MW	1895MW		1997 MW	2023 MW	1858 MW	1921 MW	1689 MW
$ x 10 ^{6} (80$)								
10 Year PW	873.7	873.7		873.7	873.7	873.7	873.7	873.7
20 Year PW	3308.3	3319.4		2509.4	2360.6	2349.6	2624.5	2584.6
TOTAL	4182.0	4193.1		3382.1	3234.3	3222.3	3497.2	3458.3
PROJECT LIFE PW								

* In Peak Month (December)

7.6 - Generation Planning - Load Sensitivity

As discussed in Secion 5, the many uncertainties of load forecasting provide a wide range of possibilities for future generation planning. This section provides a detailed look at the generation planning procedure as applied to varying load situations. The four load models evaluated in this sensitivity are shown graphically in Figure 7.6.1. They are the High Government-High Economic Scenario HG-HES, the Low Government-Low Economic Scenario LG-LES, the Load Management and Conservation Scenario (LMLCS), and the Probabilistic Scenario (PS). Also shown on this figure is the Medium Government-Medium Economic Scenario (MG-MES) used in the previous analysis and the ISER high and low forecasts (MG-HES and MG-LES). Planning under the four previously mentioned load forecasts is described below.

7.6.1 - High Government - High Economic Scenario (HG-HES)

A similar methodology was applied to the high load forecast as the medium load analysis described in Section 7.5. This analysis involved a common 1980-1990 ten year run, two 20 year 1990-2010 all thermal runs (with and without renewed gas turbines) and a 20-year 1990-2010 Suistna alternative run. For this analysis, the Susitna alternative 3AE was chosen as the only high load model alternative which installs Watana High Dam (800 MW) and Devil Canyon Dam (400 MW) during the study period. Table 7.6.1

summarizes the results of this analysis. Figure 7.6.1 depicts the all thermal generation plan and the Susitna generation plan 3AE. Of particular note in the high forecast is the installation of a 100 MW coal unit in 1990 to meet demand until Susitna comes on line. It can be seen that the total difference in 1980 present worth is of the two systems is in excess of $200 million in 1980 dollars indicating the benefit of planning under the high load forecast with the Susitna plan.

7.9.2 ~~7.6.2~~ - Low Government - Low Economic Scenario

The low range load forecast poses a different situation with respect to the generation planning procedure. The installation of Susitna 3AE would be staged as Watana 400 MW in June of 1993 and Devil Canyon 400 MW delayed to 2002. This configuration results in almost a $700 million (1980 dollars) difference between the all-thermal case for the low load forecast. These results are summarized in Table 7.6.2 and Figure 7.6.3.

7.9.3 ~~7.6.3~~ - Load Management and Conservation Scenario

(To be written)

7.9.4 ~~7.6.4~~ - Probabilistic Generation Planning

(To be written)

7.9.5 ~~7.6.5~~ - Summary of Load Sensitivity Analysis

(To be written)

TABLE 7.6.1 SUMMARY OF GENERATION PLANS - HIGH LOAD FORECAST

PARAMETER/JOB I.D.#	ALL THERMAL RENEWS L2E9	ALL THERMAL NO RENEWS L7F7	SUSITNA ALTERNATIVES 3AE LA73
1990 MW (+100 MW COAL)	1179	1179	1179
1990-2010 Thermal adds	456		
Coal (MW)	1900	1900	900
NGGT (MW)	375	975	750
Diesels (MW)	130	50	0
TOTAL	2861 MW	2925 MW	1650MW
(RETIREMENTS) MW	(734)	(734)	(734)
HYDO Month/Year Name MW	-	-	6/93 W400 1/96 W400 1/00 DC400
2010 TOTAL FIRM* CAPACITY MW	3306MW	3370MW	3248MW
$ x 10^6 (80$)			
10 year PW	$1060.5	$1060.5	$1060.5
20 year PW	5306.8	5307.4	4094.6
TOTAL	$6367.3	$6367.9	$6155.1

* In peak month - December

TABLE 7.6.2 SUMMARY OF GENERATION PLANS - LOW LOAD FORECAST

PARAMETER/JOB I.D.#	ALL THERMAL RENEWS L2C7	ALL THERMAL NO RENEWS L7E1	SUSITNA ALTERNATIVES 3A2 LC07
1990 MW	1079	1079	1079
1990-2010 Thermal adds	456		
Coal (MW)	600	700	-
NGGT (MW)	-	300	150
Diesels (MW)	30	40	40
TOTAL	1086 MW	1040 MW	290 MW
(RETIREMENTS) MW	(734)	(734)	(734)
HYDO Month/Year Name MW	-	-	6/93 W400 1/02 D400
2010 TOTAL FIRM* CAPACITY	1431MW	1385MW	1272MW
$ x 10^6 (80$)			
10 year PW	$ 744.1	$ 744.1	$ 744.1
20 year PW	2502.2	2519.8	1835.8
TOTAL	$3246.3	$3263.9	$2579.9

* In peak month - December

7.7 - Variable Parameters and Sensitivity Analysis

This section describes the Phase III work accomplished to assess the impact of variable parameters and sensitivity of the parameters on the results of the program. As the work described in the previous section performed a sensitivity analysis of load forecasts, this section provides a sensitivity analysis of thermal and Susitna costs, cost of money (i.e., interest rates), fuel cost and differential fuel cost escalation. and plant be sensitivity. All these analyses are based or the mid level load forecast and the Susitna alternative 3AE.

7.7.1 - Range of Capital Cost Estimates

Thermal Capital Cost

(to be written)

Susitna Costs

(to be written)

Susitna Capital Costs

The primary concern with respect to Susitna costs is the variability due to seismic design which could significantly increase the cost of the project. In order to assess this concern, three runs of the OGP5 model varying only the cost of the Susitna alternatives were made. The range of costs were as follows:

Base Case	Sensitivity

7.7.2 or .3 - Range of Interest Rates

Another concern with respect to the economics of the study is the impact of a variable cost of money. Holding all other parameters constant as was done in the 0 percent inflation - 3 percent cost of money runs, a range of interest rates were looked at from 3 to 9 percent. under both the thermal and Susitna cases. The results of these runs are shown in Figure 7.7.2.

7.7.4 - Sensitivity of the Cost of Money Parameter

(to be completed)

7.7.5 - Range of Fuel Costs and Fuel Cost Escalation

Variable Fuel Costs

The base run made using the developed opportunity fuel costs and DOE fuel cost escalation parameters for both thermal and Susitna options were tested using a 20 percent less base cost and allowed to escalate at the DOE rates these parameters are presented in Table 7.7.2.

Variable Fuel Cost Escalation

The DOE escalation rates of 3.98% for coal, 2.93% for natural gas and 3.58% for oil were used in the base case runs. A run was made using a constant 0% escalation rate for all fuels and the base case fuel cost. These parameters were used in both the thermal and Susitna option

7.7.6 - Sensitivity of Fuel Cost and Differential Fuel Escalation Rates

(to be written)

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8 - ENGINEERING STUDIES

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(NOTE: The material presented here is a preliminary sketch of what is to appear in the final version of the report. It will be expanded as current office work is completed. More text will be added as well as sets of engineering drawings of project layouts and figures showing results of concrete dam stress and cost summary tables).

As the project planning studies outlined in Sections 6 and 7 were completed, a start was made with more detailed engineering studies for the selected Watana and Devil Canyon sites. The major thrust of these studies is twofold:

(a) To select the appropriate dam type for the two sites;
(b) To undertake some preliminary design of the selected dam types.

This section briefly outlines the results of the studies to date.

8.1 - Devil Canyon Site

8.1.1 - Dam Type Studies

A major cost advantage of an arch dam relative to a comparable rock/earth-fill dam is in the generally reduced cost of the auxiliary structures and hence in order to study the relative economics of different dam types it was necessary to develop complete general arrangements. A representative layout has been studied for each of three dam types at the Devil Canyon site:

(a) A thick concrete arch dam;
(b) A thin concrete arch dam; and
(c) A rockfill dam.

None of these layouts are intended as the final site arrangement, but each will be sufficiently representative of the preferred scheme for each dam type as to provide an adequate basis for technical and economic comparison. All dams are located just downstream of where the river enters Devil Canyon close to its narrowest point and the optimum location for all types of dam.

(a) Thick Arch Dam

As shown on Drawing No. _______, the main concrete dam is a single center arched structure with a vertical clyindrical upstream face and a sloping downstream face inclined at 1V:0.4H. The maximum height of the dam is 635 feet with a uniform crest width of 30 feet, a crest length of approximately 1,400 feet and a maximum foundation width of 225 feet. The crest elevation is 1,460 feet. The center portion of the dam is founded on a massive mass concrete pad constructed in the excavated river bed. This central section incorporates a service spillway with gated orifice spillways discharging down the steeply inclined downstream face of the dam into a single large dissipating basin set below river level and spanning the valley with sidewalls anchored into the solid bedrock.

The main dam terminates in thrust blocks high on the abutments. The left abutment thrust block incorporates an emergency gated central structure which discharges into a rock channel running well downstream and terminating at a high level in the river valley.

Beyond the control structure and thrust block is a rockfill dike sitting on a low lying saddle and founded on bedrock. The powerhouse houses 4 x 150 MW units and is located underground within the right abutment. The multi-level intake is constructed integral to the dam and connected by vertical steel-lined penstocks.

The service spillway is designed to pass approximately the 1:500 year routed flood with larger floods discharged downstream via the emergency spillway.

(b) Thin Arch Dam

As shown on Drawing No. ____ the main dam is a two center double curved arch structure of similar height to the thick arch dam, but with a 20 foot uniform crest width and a maximum base width of 90 feet. The crest elevation is 1455 feet. The center section is founded on a concrete pad and the extreme upper portion of the dam terminates in concrete thrust blocks located on the abutments.

The main service spillway is located on the right abutment and consists of a conventional gated control structure discharging down a concrete-lined chute terminating in a flip bucket. The bucket discharges into an unlined plunge pool excavated in the riverbed aluvium and located sufficiently far downstream to prevent undermining of the dam and associated structures.

The main spillway is supplemented by orifice type spillways located high in the center portion of the dam and discharging into a concrete-lined plunge pool immediately downstream of the dam. An emergency spillway consisting of either a fuse plug or a simple gated structure discharging into an unlined rock chute, terminating well downstream is located beyond the saddle dam on the left abutment.

The concrete dam terminates in massive thrust blocks and is continued on the left abutment by the already vertical saddle dam.

The right bank and supplementary central spillways will discharge the 1:10,000 year flood and excess flows for storms with a reduced frequency will be discharged through the emergency left abutment spillway.

(c) Rockfill Dam

As shown on Drawing No. _____, the rockfill dam is approximately 670 feet high. It has a crest width of 50 feet, upstream and downstream slopes of 1:2.25 and 1:2, respectively and contains approximately 20 x 10^6 cubic yards of material. The central impervious core is supported by a downstream semi-pervious zone and these two zones are protected upstream and downstream by filter and transition materials.

The shell sections are constructed from blasted rock and the whole of the dam is founded on sound bedrock. External cofferdams are founded on the riverbed aluvium. A single spillway consisting of a gated control structure, chute and downstream unlined plunge pool is located on the right abutment. This is designed for the 1:10,000 year routed flood with excess capacity to allow discharge of the probable maximum flood with no damage to the main dam.

8.1.2 - Construction Materials

Sand and gravel for concrete aggregates are found in sufficient quantities immediately upstream in the Cheechako fan and terraces. The gravel and sands are formed from the granitic and metamorphic rocks of the area, and at this time it is anticipated that they will be suitable for the production of aggregates after a moderate amount of screening and washing.

Material for the rockfill dam shell would be blasted rock, some of it coming from the site excavations.

It is anticipated that some impervious material for the core is available from the till deposits forming the flat elevated areas on the left abutment and that other suitable borrow materials will be available in high lying areas within the three mile upstream reach of the river, however, none of these deposits have yet been proven.

8.1.3 - Remarks

The geology of the site is as discussed in Section 6.3 and it appears at this stage that there are no geological or geotechnical aspects that would preclude any of the dam types from consideration. A rockfill dam would be more adaptable than a concrete arch dam to poorer foundation conditions, although at present, foundation and abutment loadings from the arch dams appear well within acceptable limits.

The thick arch dam allows for the incorporation of a main service spillway within the crown of the dam and discharging straight down the river. For the thin arch and rockfill alternatives the equivalent discharge capacity has to be provided at additional cost through the abutments.

Under hydrostatic temperature and seismic loadings, stresses within the thick arch dam are generally lower than for the thin arch alternative. Where, at a particular section, the surface stresses approach the maximum allowable, the remaining understressed area of concrete is greater for the thick arch and the factor of safety for the dam is correspondingly higher. The thin arch is, however, a more efficient design and better utilizes the inherent properties of the concrete. It is designed around acceptable perdetermined factors of safety and requires a smaller volume of concrete for the actual dam structure.

The costs of the alternative dam layouts including all associated structures and transmission to Gold Creek are as given below:

Capital Cost in $ 1980 x 1000*

Thick Arch	Thin Arch	Rockfill

* Costs include all engineering and administrative costs and contingencies but not escalation or AFDC.

8.1.4 - Preliminary Arch Dam Design

Both thin and thick arch dam designs were originally analyzed by means of a finite element computer program. Results from these analyses indicated substantially lower stresses for the thick arch under hydrostatic and temperature loadings as would be anticipated with extremely high tensile stresses for both types of dams under high seismic loading.

Stresses close to the foundations and abutments were distorted because of the coarse mesh spacing of the selected nodes. In accordance with current American practice, to reduce the cost of computer time and in order to produce results which could more readily be interpreted, it was decided to use the trial load method and the associated program Arch Dam Stress Analysis System (ADSAS) developed by the USBR. A thin two center arch dam is located approximately normal to the valley. There is a gradual thickening of the dam towards the abutments, but the two center configuration produces similar thickness and contact pressures at equivalent rock/concrete contact elevations and a symmetrical distribution of pressures across the dam. Under hydrostatic loads no tension is evident at the dam faces. Under extreme temperature distribution as determined by the USBR program HEATFLOW, for full reservoir conditions there are low tension stresses on both faces across the crest of the dam. These approach the allowable tensile stress of 150 psi.

Although analysis has still to be completed for seismic loadings, indications are that the concrete thin arch dam at Devil Canyon will be structurally feasible.

8.2 - Watana Site

8.2.1 - Dam Type Studies

A rockfill dam layout has been studied at Watana with the dam sited between the northwest trending shear zones of the "Fins" and the "Fingerbuster". The dam is close to the alignment proposed by the Corps of Engineers and is skewed slightly to the valley in a north-northwest direction. The approximate height of the dam is 900 feet, and the volume is approximately 62×10^6 in yards. The crest elevation of the dam is 2,225 feet.

The spillway discharges down the right abutment with an intermediate stilling basin and a downstream stilling basin below river level. An 800 MW underground power station is located on the left abutment.

8.2.2 - Construction Materials

At this time it is assumed that some of the shell material for the dam will be obtained from site excavations and the remainder, which will be the large majority, will consist of blasted rock from borrow areas. Gravels for filler zones is available from alluvial deposits in Tsusena Creek. Core material is available from glacial tills located approximately three miles upstream above the right side of the river valley. This material will require very little processing.

8.2.3 - Remarks

As an alternative to the rockfill dam, a three center concrete thin arch has been considered, and layouts are shown on Drawings ____ and ____. The cost of the conrete for such a dam is prohibitive when compared to a rockfill and no further consideration has been given to this alternative. The tentative cost of a rockfill dam scheme at Watana is $\$1,860 \times 10^3$ including all engineering and administrative costs and contingencies but not escalation or AFDC.

8.2.4 - Preliminary Dam Design

A section has been tentatively established for a rockfill dam with a near vertical impervious core. At this time, no stability analyses have been conducted on the dam, but the section is based on Acres past experience and on general experience throughout the world on similar sizes of dam and locations of similar seismic activity.

The crest width of the dam is 50 feet, the upstream slope is 1V:2.25H and the downstream slope is 1V:2H.

The core is composed of materials from the fine till deposits and the shell is presently considered to be constructed from blasted rock from site excavations and from borrow.

9 - SUSITNA HYDROELECTRIC DEVELOPMENT

9 - SUSITNA HYDROELECTRIC DEVELOPMENT

9.1 - Introduction

It is anticipated at this stage that the final scheme will be a Watana rockfill dam development in conjunction with a thin concrete dam development downstream.

The heights of the dams will be approximately 900 feet at Watana and 635 feet at Devil Canyon developing maximum heads of 760 feet and 585 feet respectively at the turbines producing maximum outputs of 800 and 400 MW. The total storage at each of the Watana and Devil Canyon reservoirs will be 10 x 10^6 and 1.1 x 10^6 acre feet respectively with live storage of 4.6 x 10^6 and 0.75 x 10^6 acre feet.

Project configurations are conceptual and the upcoming stages of the study in 1981 will determine more accurately the layouts, dam heights, and installed capacities.

9.2 - Project Description

When completed the two sites will be operated in conjunction with one another with routed flows from Watana supplying the much smaller capacity Devil Canyon reservoir. The large storage at Watana and associated high degree of regulation substantially raises th firm energy potential of both Watana and Devil Canyon. For this reason, together with the resulting reduced floods during construction and lower design floods at Devil Canyon, it is economic to construct Watana as the initial development. Watana would be staged with an initial capacity of 400 MW and an additional 400 MW added later. After complete development at the site, Devil Canyon would be brought on line to meet increased system demand.

9.2.1 - Watana Development

Tentative development of this site will be as described in Section 8. Initially, the dam will be constructed to its full height with a reduced power installation. Excavation of penstock and tailrace tunnels associated with additional future generating units will be completed at the time of installation of these units.

9.2.2 - Devil Canyon Development

The development of this site will be as described in Section 8. The dam will be constructed to its full height and the full capacity of 400 MW will be installed.

9.2.3 - Construction Schedules

At this stage of the study a preliminary assessment of the construction schedules for the Watana and Devil Canyon dams have been made. The main objective being to provide a reasonable estimate of on-line dates for the generating planning studies described in Chapter 7. More detailed construction schedules will be developed during the 1981 studies.

In developing these preliminary schedules, roughly 70 major construction activities were identified and the applicable quantities such as excavation and borrow volumes and volume of concrete were determined. Construction durations were then estimated using historical records as backup and the expertise of senior scheduler-planners, estimators and design staff. A critical path logic diagram (CPM) was then developed from those activities and the project duration was manually determined. The critical or near critical activity durations were further reviewed and refined as needed. These construction logic diagrams are coded so that they may be incorporated into a computerized system for the more detailed studies to be conducted during 1981.

The schedules developed are as follows:

(a) Watana Rockfill Dam

As shown in Figure ___, it is expected to take approximately 11 years to complete construction of the Watana dam from the start of an access road at Highway 3 to the testing and commissioning of all the generating units. Principal components of the schedule include approximately 2-1/2 years for site and local access, 1-1/2 years for river diversion and most of the remaining time for foundation preparation and embankment placement. This period compares to the 10 years estimated in the COE 1979 report.

Only about six months per year can be used for fill placement due to snow and temperature conditions. Fill placement is estimated at approximately 2.3 million cubic yards per month with a total volume placement of 61 million cubic yards. This is in general agreement with the 1979 COE report which estimates approximately 2.4 million cubic yards per month placement over a five month annual placement period. It is expected that the river can be impounded as construction proceeds so as to minimize the time lag between the completion of the dam embankment and the testing and commissioning of the first power unit.

The schedule shows the date of earliest power production from Watana would be in 1993. This is based on starting construction of the access road in 1983 with start of construction at the site early in 1985 as soon as the FERC license is received.

Should it not be possible to start construction of the access road prior to receipt of the FERC license, alternate methods of site access could be developed. One such method would be to bring in equipment required for initial site access and diversion tunnel construction overland from the Denali highway during the winter months. An alternative method would involve constructing an airstrip and flying the necessary equipment and camp facilities in. This would allow paralleling the permanent access road construction period with the initial on-site construction and, although more costly, could reduce the total construction period by up to 2-1/2 years.

(b) Devil Canyon Gravity Arch Dam

As shown in Figure 9.4, it will take approximately 6-1/2 years to complete the dam from the time of access to the site to the testing and commissioning of the power units. This is slightly shorter than the schedule in the COE 1979 Rep which indicates an eight year schedule. The key elements in determining the entire project duration are the construction of diversion tunnels, cofferdams, the excavation and preparation of the foundation and the placement of the concrete dam. For purposes of estimating activity durations, it is assumed that embankment and curtain grouting will be done through vertical access shafts on each embankment with several horizontal tunnels being provided through the dam.

It is assumed that access to the Devil Canyon site can easily be made available due to the proximity of the road to the Watana site. If this were the case, at least 15 months would be added to the front end of the Devil Canyon schedule in order to construct a road from Highway 3.

The attached figures represent an "early start" schedule and the majority of effort was expended in determining the "critical path" which controls project duration. The "non-critical" items should be scheduled not merely to minimize construction period, but also to take into account resource availability and financial and climatic aspects. The "optimization" of the schedule will be performed during 1981.

It is expected that the project schedules will be refined as the following aspects are developed:

(a) Reconcilation and refinement of major construction activity quantities;

(b) Detailing and refinement of foundation preparation and grouting requirements;

(c) Refinement of reservoir filling rates;

(d) Detailing of major structural components;

(e) Incorporation of additional information based upon ongoing field studies and development of client and project requirements.

9.2.4 - Cost Estimates

Cost estimates for Devil Canyon and Watana are presently based on costs as established for the comparison of alternative site developments and as described under Section 6.6.

A preliminary contractor's type estimate is presently being prepared and this will provide a more accurate level of costing, fitting to comparison of schemes at a particular site and selection of an optimum site development.

Costs will be based on the assembly of a typical construction fleet and labor force and the determination of applicable plant, material and labor costs.

Escalation and interest during construction will be based on a typical curve representative of the pattern of annual expenditures as experienced on previous similar projects.

REFERENCES

DRAWINGS

APPENDICES

B - HYDROPOWER SIMULATION MODEL RESULTS

3-1

TABLE 1

MONTH	STAGE 1 Watana (2200) 800 MW		STAGE 2 Devil Canyon (1450) (Total 1400 MW) + 600 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	264	263	523	519
FEBRUARY	250	249	496	494
MARCH	224	224	443	442
APRIL	201	201	381	392
MAY	186	186	406	392
JUNE	187	183	424	371
JULY	285	183	474	361
AUGUST	499	190	738	381
SEPTEMBER	370	204	671	407
OCTOBER	233	233	472	462
NOVEMBER	266	266	526	522
DECEMBER	287	287	571	566
TOTAL ANNUAL	3252	2669	6125	5309

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 2

MONTH	STAGE 1 Watana (2200) 400 MW		STAGE 2 Add 400 MW to Watana		STAGE 3 ~~Add~~ Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	138	137	264	263	523	519
FEBRUARY	130	129	250	249	496	494
MARCH	117	116	224	224	443	442
APRIL	103	56.6	201	201	381	392
MAY	100	100	186	186	406	392
JUNE	154	102	187	183	424	371
JULY	322	103	285	183	474	361
AUGUST	355	365	499	190	738	381
SEPTEMBER	269	188	370	204	671	407
OCTOBER	131	123	233	233	472	462
NOVEMBER	140	139	266	266	526	522
DECEMBER	150	149	287	287	571	566
TOTAL ANNUAL	2109	1708	3252	2669	6125	5309

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 3

MONTH	STAGE 1 Watana (2200) 400 MW		STAGE 2 Add 400 MW to Watana		STAGE 3 ~~Add~~ Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	263	263	264	263	523	519
FEBRUARY	250	249	250	249	496	494
MARCH	224	224	224	224	443	442
APRIL	201	201	201	201	381	392
MAY	186	186	186	186	406	392
JUNE	187	184	187	183	424	371
JULY	245	183	285	183	474	361
AUGUST	333	190	499	190	738	381
SEPTEMBER	315	204	370	204	671	407
OCTOBER	233	233	233	233	472	462
NOVEMBER	266	265	266	266	526	522
DECEMBER	287	287	287	287	571	566
TOTAL ANNUAL	2990	2669	3252	2669	6125	5309

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 3A

MONTH	STAGE 1 Watana (2200) 400 MW		STAGE 2 Add 400 MW to Watana		STAGE 3 ~~Add~~ Devil Canyon (1450) 400 MW	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	263	263	264	263	523	519
FEBRUARY	250	249	250	249	496	494
MARCH	224	224	224	224	443	442
APRIL	201	201	201	201	381	392
MAY	186	186	186	186	431	392
JUNE	187	184	187	183	458	371
JULY	245	183	285	183	576	361
AUGUST	333	190	499	190	688	381
SEPTEMBER	315	204	370	204	636	407
OCTOBER	233	233	233	233	498	462
NOVEMBER	266	265	266	266	526	511
DECEMBER	287	287	287	287	571	567
TOTAL ANNUAL	2990	2669	3252	2669	6227	5310

EA: Average Monthly Energy
EF: Monthly Firm Energy

B-5

TABLE 4

MONTH	STAGE 1 High Devil Canyon (1750) 800 MW		STAGE 2 Vee (2355) (Total 1200 MW) ~~+ 400 MW~~	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	250	249	368	368
FEBRUARY	232	234	349	350
MARCH	205	210	303	313
APRIL	184	189	268	276
MAY	180	179	254	258
JUNE	218	182	290	247
JULY	497	171	526	319
AUGUST	643	186	752	298
SEPTEMBER	446	197	575	280
OCTOBER	230	223	394	366
NOVEMBER	255	253	404	395
DECEMBER	273	272	425	401
TOTAL ANNUAL	3613	2545	4908	3871

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 5

MONTH	STAGE 1 HIGH DEVIL CANYON (1610) 400 MW ~~Watana (2200) 400 MW~~		STAGE 2 HIGH DEVIL CANYON (1750) ADD 400 MW ~~Add 400 MW to Watana~~		STAGE 3 VEE (2355) 400 MW TOTAL 1200 MW ~~Add Devil Canyon (1450) 400 MW~~	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	114	113	250	249	368	368
FEBRUARY	107	106	232	234	349	350
MARCH	96	791	205	210	303	313
APRIL	79	252	184	189	268	276
MAY	92	857	180	179	254	258
JUNE	300	215	218	182	290	247
JULY	319	319	497	171	526	319
AUGUST	317	319	643	186	752	298
SEPTEMBER	289	245	446	197	575	280
OCTOBER	152	102	230	223	394	366
NOVEMBER	117	116	255	253	404	395
DECEMBER	125	124	273	272	425	401
TOTAL ANNUAL	2107	3559	2107	2545	4908	3871

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 6

HIGH DEVIL CANYON (1750) 400 MW | HIGH DEVIL CANYON (1750) ADD 400 MW | VEE ([illegible]) 400 MW (TOTAL 1200 MW)

MONTH	STAGE 1 ~~Watana (2200) 400 MW~~		STAGE 2 ~~Add 400 MW to Watana~~		STAGE 3 Add ~~Devil Canyon (1450) 400 MW~~	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	234	232	250	249	368	368
FEBRUARY	217	219	232	234	349	350
MARCH	192	197	205	210	303	313
APRIL	173	177	184	189	268	276
MAY	169	168	180	179	254	258
JUNE	196	171	218	182	290	247
JULY	266	171	497	171	526	319
AUGUST	288	175	643	186	752	298
SEPTEMBER	284	185	446	197	575	280
OCTOBER	218	209	230	223	394	366
NOVEMBER	239	238	255	253	404	395
DECEMBER	256	255	273	272	425	401
TOTAL ANNUAL	2732	2397	2107	2545	4908	3871

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 6A

HIGH [illegible] CANYON (1750) 400 MW

HIGH DEVIL CANYON (1750) ADD 400 MW PORTAGE CREEK 15 MW.

VEE (2350) 400 MW (TOTAL [illegible] MW)

MONTH	STAGE 1 ~~Watana (2200)~~ ~~400 MW~~		STAGE 2 ~~Add 400 MW to Watana~~		STAGE 3 Add ~~Devil Canyon (1450) 400 MW~~	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	234	232	167	167	432	435
FEBRUARY	217	219	158	158	411	415
MARCH	192	197	142	142	360	372
APRIL	173	177	125	125	318	328
MAY	169	168	133	117	287	290
JUNE	196	171	476	251	321	277
JULY	266	171	493	494	564	349
AUGUST	288	175	515	522	820	332
SEPTEMBER	284	185	461	349	646	315
OCTOBER	218	209	222	145	447	415
NOVEMBER	239	238	167	167	457	446
DECEMBER	256	255	182	182	480	456
TOTAL ANNUAL	2732	2397	3241	2819	5543	4430

EA: Average Monthly Energy
EF: Monthly Firm Energy

TABLE 7

MONTH	STAGE 1 HIGH DEVIL CANYON (1750) 800 MW Watana (2200) ~~400 MW~~		STAGE 2 PORTAGE CREEK 150 MW ~~Add 400 MW to Watana~~		STAGE 3 VEE (2350) 400 MW (TOTAL [illegible] MW) ~~Add Devil Canyon (1450) 400 MW~~	
	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)	EA (GWH)	EF (GWH)
JANUARY	250	249	167	167	432	435
FEBRUARY	232	234	158	158	411	415
MARCH	205	210	142	142	360	372
APRIL	184	189	125	125	318	328
MAY	180	179	133	117	287	290
JUNE	218	182	476	251	321	277
JULY	497	171	493	494	564	349
AUGUST	643	186	515	522	820	332
SEPTEMBER	446	197	461	349	646	315
OCTOBER	230	223	222	145	447	415
NOVEMBER	255	253	167	167	457	446
DECEMBER	273	272	182	182	480	456
TOTAL ANNUAL	2107	2545	3241	2819	5543	4430

EA: Average Monthly Energy
EF: Monthly Firm Energy

C - GENERATION PLANNING MODEL RESULTS

APP-C1

APPENDIX ~~A~~ C

HOW TO INTERPRET AN OGP-5 GENERATION PLANNING PROGRAM SUMMARY OUTPUT

The General Electric OGP-5 program ~~is~~ used in the Generation planning study provides the operator with a large quantity of useful system characteristics including fuel consumption by type and by year, hourly dispatch of operating units, production costs for each unit type by year and decision making calculations for years when additions are contemplated by the system. This output, which also includes detailed description of the input parameters, was used in the study to recommend the various plans and analyse the results. An abbreviated summary of the salient output results is also printed by the program for those who are interested in the results of a variety of program runs. Included in ~~this~~ Appendix B are the summary outputs of the key runs made during the generation planning procedure. The following describes the type of output received in these pages and how to interpret the results in a manner consistent with the generation planning results discussed in Sections 7.5 to 7.8.

Each summary has three (3) pages:

- Generation System
- Yearly Cost and Cumulative Present Worth
- Yearly $/MWh

Some information is repeated on the summaries (i.e., load, total capabilities and yearly cost) but essentially each table contains a particular set of information useful to the generation planner.

Refer to Page 1 - Generation System

small LC

1. JOB NUMBER REFERS TO THE ID CODE FOR EACH RUN AND ACTS AS A CROSS REFERENCE IN THE TEXT.

2. The types of generation available to the Alaska Railbelt include coal, natural gas, gas turbines, NGASGT), oil gas turbines (OIL GT), diesels, combined cycle units (COMCYC) and Hydro (Types 7-10 on the summary). NUKE referring to Nuclear units is not available to the Railbelt however is required input to the program.

3. Since the OGP-5 program can only be run in 20 year intervals and the study period was 30 years, it was necessary to make a 10 year run and carry the results forward to the 20 year (1990-2010) run. This line summarizes the 1990 system by the number of MW per unit type.

4. This matrix indicates the year and number of each type of unit added to the operating system based on need or committed (flagged by an asterick *) Hydro MW additions are somewhat misleading. The program rates the Hydro station based on the MW capacity available in the peak month of demand (i.e., December) rather than the total installed capacity of the units. This does not affect the production costing routine since the energy is computed over a year of generation.

5. The bottom portion of the matrix indicated the total amount of additions and retirements during the 20 year period and the percentage mix totals for the last year of the study and for all automatic additions.

Referring to page 2 of the summary - Yearly Cost and Cumulative Present Worth:

1. Load and MW capability are used to compute the percent reserve available by year.

2. The Loss of Load Probability (described in Section 7.4.5) is listed in days per year which is the planning criteria outlined as 1 day in 10 years = 0.01. You can also plan for LOLP in hours/year however this option was not exercised.

3. Yearly cost refers to the total yearly cost (in millions of that year's dollars) for operating the system.

4. Correspondingly the Cumulative Present Worth Total column brings this yearly cost back by the cost of money (3% in our study) to 1980 dollars (our base). The cumulative present worth figure does not include pre-1980 sunk costs of the existing system.

Referring to page 3 of the summary, the yearly $/MWh table:

1. peak demand and annual energy (GWh) is listed as input from the load model

2. The total costs are broken up into investment costs, fuel costs and O&M costs (N.I. refers to nuclear inventory costs which are not a part of this study). The costs are quoted in $/MWh (=mills/KWh) in the year they occur. The total $/MWh is not a representation of the cost paid by consumers for electricity. It is a production cost for an operating system neglecting metering, distribution losses and most importantly the sunk investment costs of the existing 1980 system. It is, however, a tool to judge the various thermal alternative hydro and Susitna projects since the logic is the same for all cases.

APP

APPENDIX B

SELECTED OGP-5

GENERATION PLANNING SUMMARY OUTPUTS

JOB NUMBER I.D.	LOAD MODEL	DESCRIPTION
LME3	MID	(1990-2010) all thermal with renews
LME1	MID	(1990-2010) all thermal without renews
---	MID	(1990-2010) thermal and competitive hydropower
L5Y9	MID	(1990-2010) Susitna 2A staged Watana dam/DC
L8J9	MID	(1990-2010) Susitna 3AE-High Watana/DC
LCK5	MID	(1990-2010) Susitna 3A2 - Watana 400/DC 400
LB25	MID	(1990-2010) Susitna 6A - High Devil Canyon/Vee
LAZ7	MID	(1990-2010) Susitna 7A- Watana 800 + Tunnel
L2E9	HIGH	(1990-2010) all thermal with renews
L7F7	HIGH	(1990-2010) all thermal without renews
LA73	HIGH	(1990-2010) Susitna 3AE
L2C7	LOW	(1990-2010) all thermal with renews
L7E1	LOW	(1990-2010) all thermal without renews
LC07	LOW	(1990-2010) Susitna 3A2

D - TASK 2 - STATUS REPORT

D. 1 COMPLETION REPORT SUMMARY

LAND STATUS RESEARCH

SUBTASK 2.04

INTRODUCTION

The purpose of this report is to provide an overview of the results obtained through the identification of the general land ownership status within the Upper Susitna River Basin and the Anchorage-Fairbanks Intertie Corridor (Figure 1).

SIGNIFICANT LAND POLICIES AFFECTING THE STUDY AREA

The Federal government remains the largest land owner in Alaska. However, this domination of ownership has been eroded with the passage of the Alaska Statehood Act in 1959 and the Alaska Native Claims Settlement Act in 1971. These Acts have placed in question the ultimate land ownership patterns of the State with competition for the land divided among the Federal government, the State of Alaska, and private Native regional and village corporations.

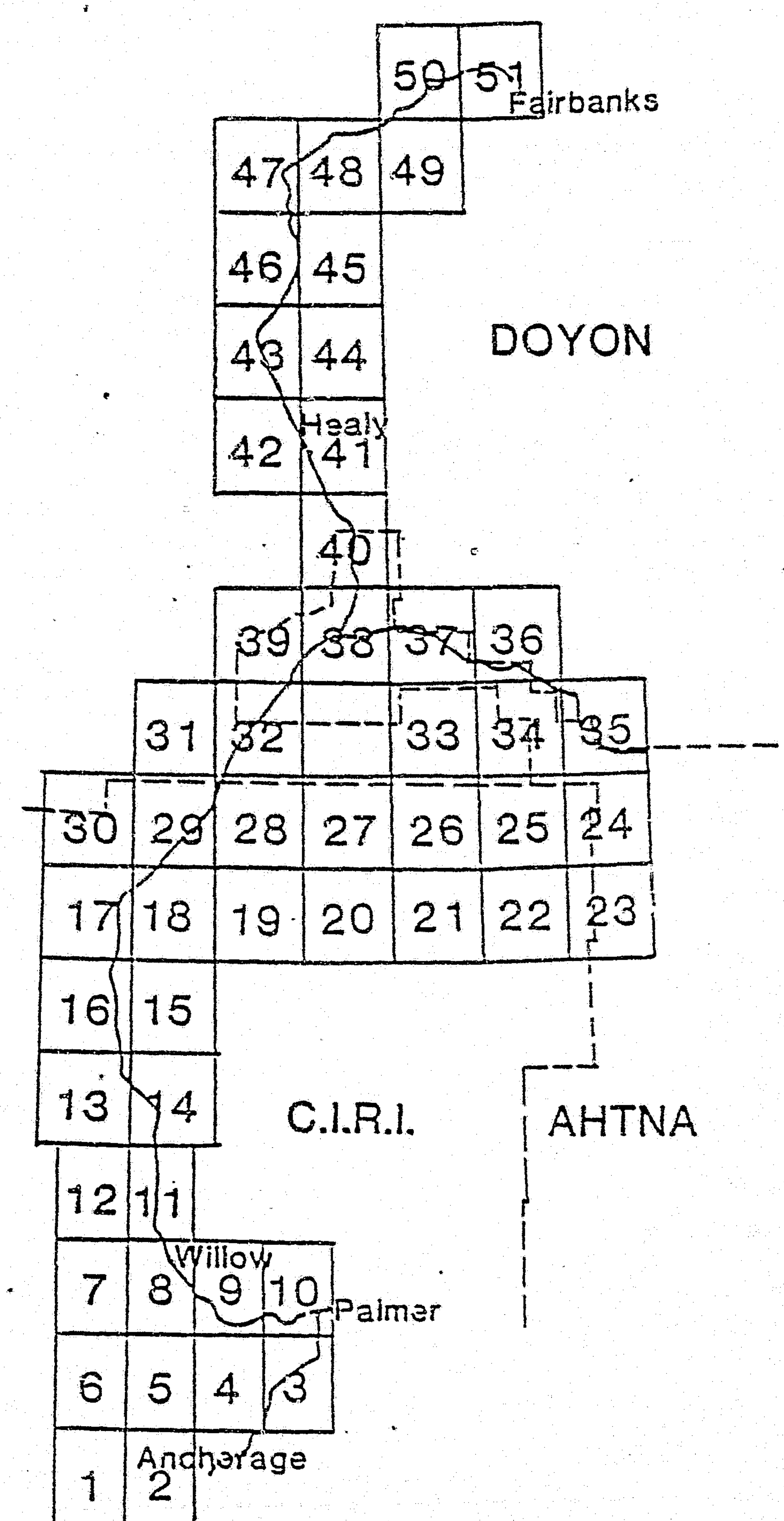
With the enactment of the Statehood Act, the State of Alaska became entitled to a total of 104.5 million acres. Section 6(b) of the Act included 102.5 million acres of general grant lands to be used at the discretion of the State. In addition, certain federal lands were to be held in trust for both public schools and for the University of Alaska. Public Law 84-830, passed in 1956, provided for one million acres of mental health grant lands.

In 1978, the State legislature passed a law designed to convert the 1.2 million acres of land held as special trusts for funding public schools, mental health programs, and the University of Alaska into general grant lands to be treated in the same manner as other State-held land. The plan was to replace the land with an annual income, a percentage of the total receipts from the management of State land, including oil royalties. However, the University of Alaska exercised its option and turned down this trust fund and retains management over the lands it holds title to.

The State of Alaska has granted land entitlements to the organized Boroughs and Municipalities. As a result of this entitlement, both the Matanuska-Susitna and North Star Boroughs have extensive land holdings. The Municipality of Anchorage has received its entitlement, which is considerably less than that received by the boroughs.

In response to increasing public pressure and changing laws, the State legislature passed HB66 in 1979, charging the Department of Natural Resources with the responsibility of disposing 100,000 acres of land annually to private ownership.

Map Index



LAND STATUS RESEARCH STUDY AREA

ANCHORAGE – FAIRBANKS TRANSMISSION CORRIDOR

& UPPER SUSITNA RIVER BASIN

FIGURE 1

This land is disposed through four methods: direct sale, homesites, remote parcels, and agricultural rights. It is apparent from recent discussions between the Alaska Power Authority and the State Division of Lands that the State Division of Lands is severely encumbered by its requirement to annually dispose of 100,000 acres of land to the public. Consequently, necessary regional and site considerations, e.g. proposed Intertie Corridor, relating to the disposal of these lands are frequently omitted from the State's land disposal selection process.

With the passage of the Alaska Native Claims Settlement Act (ANCSA) in 1971, the State of Alaska was no longer the sole entity selecting federal lands. Under the Act, private Native regional and village corporations were entitled to select lands from the Federal government holdings and from those lands previously selected, but not patented to the State of Alaska. To date, neither the State nor the Native Corporations has received its full entitlement under the Statehood Act and the Alaska Native Claims Settlement Act.

PRESENT LAND OWNERSHIP TRENDS

Anchorage-Willow

This section contains a complex mixture of land ownership with the extensive private ownership interspersed with large blocks of State and Borough lands. The State has reserved several areas for public recreational use (Nancy Lake State Recreation area, Goose Bay and Susitna Flats Game Refuge, and Chugach State Park). The only large State land disposal within this area is the Pt. MacKenzie Agricultural Project scheduled for spring 1981. The holdings by the Federal government are dominated by military reserves in the Anchorage area.

Willow-Talkeetna

Thia area is characterized by numerous private holdings along the Parks Highway. Large blocks of State, Native, and Borough lands dominate the remainder of the land in this area. Numerous State land disposals have taken place and are projected for this area.

Talkeetna-Fairbanks

This section represents an area of large blocks of State owned land. Numerous private holdings are concentrated in scattered communities located along the Parks Highway. The most notable of these are Cantwell, Healy, Clear and Nenana. Cantwell and Nenana are both surrounded by large blocks of Native lands.

Both the Denali State Park and the Mt. McKinley National Park are located in this section.

Upper Susitna River Basin

The land status in this area is relatively simple, due to the large amount of public land managed by the Bureau of Land Management. There are large blocks of private Native Village corporation lands along the Susitna River. Other private holdings consist of widely scattered remote parcels. The State has selected much of the Federal land in this area and is expected to receive patent.

LAND STATUS METHODOLOGY

The CIRI Land Department utilized the following sources to identify the ownership and other interests within the Anchorage-Fairbanks Transmission Line Corridor and Upper Susitna River Basin:

Alaska Department of Natural Resources
Alaska Department of Transportation
Bureau of Land Management
Cook Inlet Region, Inc., Land Records
Matanuska-Susitna Borough Tax Assessor Records
Municipality of Anchorage Tax Assessor Records
North Star Borough Land Management Records

Land information compiled from the above agencies was transcribed onto diazo worksheets. Mylars were made from these worksheets and used to prodice finished maps and additional diazo reproducibles.

D.2 AERIAL PHOTOGRAPHY AND PHOTOGRAMMETRIC MAPPING

Prior to 1980, the only low level aerial photography that was available covering the study area consisted of photos obtained for the Army Corps of Engineers in the Vicinity of the Proposed Devils Canyon and Watana Damsites. This photography was of mapping quality at the photo scale of 1" = 2,000' and was photographed in black and white format. The attached map delineates the limits of this photography.

Some fragmentary low level photography existed along portions of the alternative transmission corridors. These photographs were obtained by several agencies and were produced at various photo scales.

High altitude photography obtained in past years existed over the entire project area. The National Aeronautical and Space Administration (N.A.S.A.) obtained both black and white, and color infrared photography from an altitude of approximately 60,000 feet. LANDSAT satellite photography existed prior to 1980 and was photographed from several hundred miles altitude.

Subsequent to commencement of the 1980 field season, the following areas have been aerial photographed:

- Area I, Devils Canyon Reservoir

  Scale; 1" = 2,000'
  Format; Focal Length = 6", Color 9" x 9"

- Area II, Watana Reservoir

  Scale; 1" = 2000'
  Format; Focal Length = 6", Color 9" x 9"

- Area 3, Lower Susitna River from Cook Inlet to Devils Canyon

  Scale; 1" = 4,000'
  Format; Focal Length = 6", Black & White 9" x 9"

- Area 4, Alternative Access Corridors including "Block"

  Scale; 1" = 2,000'
  Format; Focal Length = 6", Color 9" x 9"

- Area 5, Alternative Transmission Corridors (Partial)

  Scale; 1" = 2,000'
  Format; Focal Length = 6", Color 9" x 9"

The limits of the above listed photography are shown on the attached map.

The photography coverage in Areas I and II were pre-marked with flight panels (white crosses) on the ground which have been field surveyed and will serve as mapping control for future contour mapping of both Devils Canyon and Watana Reservoirs.

D.3 CONTROL NETWORK SURVEYS

R&M has completed the horizontal and vertical control field surveys and is currently involved in the data reductions and network adjustments. Preliminary horizontal and vertical coordinates have been generated, and the full final network adjustment will be completed by February 2, 1981.

The horizontal control is broken into three schemes:

1. Primary control: Second order, Class I Stations. Relative positional accuracy exceeds 1 in 50,000.

2. Secondary Control: Second Order, Class II Stations. Relative positional accuracy exceeds 1 in 20,000.

3. Additional Control: Third Order, Class I Stations. Relative positional accuracy exceeds 1 in 10,000.

The actual horizontal field closures analyzed have been well above these minimums. A full positional analysis for each station will accompany the final documentation.

The vertical control consists of a first order level line running through the project area. This line was tied to the horizontal network. The result is first order benchmarks at periodic spacing and third order elevations throughout the horizontal network.

The attached map shows the horizontal and vertical control station positions and the horizontal network configuration. The final data will be stored at R&M Consultants' Anchorage office.

D.4 ACCESS ROAD

Subtask 2.10 of the plan of study is the location study necessary to determine the most desirable location for an access route and the most ecomonmical transportation mode or modal split. There are three general corridors being analyzed for access to potential damsites, tunnel sites, and other ancilliary features of the proposed project. In addition consideration is given to using road, railroad or a combination of both to serve the project.

The work to date has been held to definition of well defined general corridors and which still satisfy the requirements of the plan of study with regard to location. Alignment design criteria being utilized for this study consists of the following:

APPROVED ROADWAY DESIGN PARAMETERS

Design Speed	60 mph
Maximum Grade	6%
Maximum Curvature	5°
Design Loading (Construction Period)	80 Kip Axle & 200 Kip total
Design Loading (After Construction)	HS-20

APPROVED RAILROAD DESIGN PARAMETERS

Maximum Grade	2.5%
Maximum Curvature	10°
Loading	E-50

This criteria was applied to a number of possible alignments and each alignment was sketched on one-inch to the mile contour maps. All alternatives were designed to serve both the Devils Canyon and the Watana Damsites. Other potential dam sites could be served with only minor changes if other sites should prove to be desirable. All alternatives were compared and the three routes showing the most advantageous grade, alignment and length characteristics were recommended for photography. As an additional check the three most promising corridors were flown by helicopter to provide the project team with a close look at actual ground conditions.

The three most promising corridors shown in Exhibit ______, allow consideration of a number of transportation alternative plans including certain attractive stage construction and modal split options. These options will be examined in detail during later phases of the access study. The proposed railroad alignment is nearly coincident with the proposed road alignment on the south side of the Susitna River and must be considered as a viable alternative at this time.

D.5 AIRSTRIP LOCATION STUDY

An airstrip location study and site survey was done under Subtask 2.03 in September and October of 1980. The work was undertaken persuant to specific instructions from Acres American, Inc.

Wind data from the weather recording station at Watana Camp was used to generate a Wind Rose for use in determining the preferred orientation of the runway. Two possible runway locations were laid out on large scale contour mapping pursuant to FAA criteria for general transport class facility. The two alignments were reviewed in the field and the more suitable alignment was surveyed and reviewed by the archeological team. The proposed runway lay adjacent to an identified borrow area that was identified as having sufficient material for construction. A peat probe was used to determine the amount of unsuitable material on the surface.

The proposed alignment was laid out such that initial construction of 2500 feet was possible without encroaching on areas requiring drainage structures. This alignment is expandable to serve C-130 aircraft. Cost estimates were prepared and a location study report submitted.

D.6 HYDROGRAPHIC SURVEYS

Hydrographic surveys extend from Portage Creek confluence downstream to the village of Talkeetna; a distance of about 60 miles. During September and October of 1980, there were 62 cross sections of the Susitna River floodplain surveyed and a longitudinal profile of the rivers thalweg sounded.

Hydrographic survey data will be used for hydraulic modeling, ice process modeling, sedimentation studies, river morphology studies, instream flow studies and fisheries studies. River cross sections define the floodplain geometry for the determination of the pre and post project flow regime; formation, stability and decay of an ice cover; river morphological characteristics and will provide input for riverene aquatic habitat definition.

In addition to horizontal and vertical coordinates, each cross section documents vegetation limits and types, bed and bank materials, unique morphological features such as scour, erosion, deposition, ice scars, bar formation and flow regime at the time of survey. Cross sections are plotted on air photo mosaics (scale 1 inch = 500 ft.) which enables tying each cross section together longitudinally along the river. Key cultural and environmental features can also be identified on the mosaics allowing positive location for special attention during the above listed analyses.

Each cross section has a benchmark established in the field with a vertical and horizontal datum so that they can be resurveyed in the future to determine changes with time in floodplain geometry.

The vertical and horizontal coordinates are entered on the computer in HEC-2 format and are available in computer listing or punched card form. A report including pictures with descriptions of morphological features will be utilized by the office analyzer to ensure proper interpretation of field data.

E - TASK 3 - STATUS REPORT

APPENDIX E

E.1 Field Data Collection and Processing

The objective of the Field Data Index and Distribution System is to establish a formal system of conveying information concerning hydrologic and climatologic data availability to each member of the study team. The project data base consists of (a) Historical recorded data up to January 1, 1980; (b) 1980 data collected by government agencies and study team members.

Historical files have been researched and available data are documented in the Field Data Indexes prepared by R & M Consultants and updated every six months. Records which could be retrieved or copied exist in R&M Consultants files. Records which are unavailable at this time, are identified as to location of files, data type, and period of record.

There are 15 major data categories assigned to the Susitna Basin. With each major category, each data station is assigned a unique number which identifies the index file containing the data. A convention of upstream to downstream order is used to number each data station. For example, if it is desired to review hydrological data availability in the Susitna River at Gold Creek, the following index numbers would be referenced:

0140	Streamflow Continuous Gaging
0340	Water Quality
0440	Water Temperature
0540	Sediment Discharge

All new data collected by R&M Consultants or other organizations will be added to the index system. Typical log of field observation carried out by R&M Consultants is presented in Table E.1.

Hard copy of the data will be stored in the R&M Consultants and Acres American offices. The data is made available to project team members and other concerned parties.

E.2 - Water Resources Studies

E.2.1 - Streamflow Extension

Historical streamflow data is available for several gaging stations on the Susitna River and its tributaries. The longest period of record is available for the station at Gold Creek (30 years from September 1949). At other stations, the record length varies from 6 to 23 years.

The Acres FILLIN computer program has been used for filling in the incomplete streamflow data sets. It is based on the program developed by the Texas Water Development Board (December 1970)(1). The procedure adopted is a multisite regression technique which analyzes monthly time series data (streamflow, rainfall or evaporation data) and fills in missing portions in the incomplete records. The program evaluates statistical parameters which characterizes the data set (i.e. seasonal means, seasonal standard deviations, lag-one autocorrelation coefficients and multisite spatial correlation coefficients) and creates a filled-in data set in which these statistical parameters are preserved.

A brief description of the steps involved in the program is presented in the following sections.

E.2.2 - Program Description

The fill in procedure comprises the following steps:

1. The data sets pertaining to individual sites are arranged in descending order of the length of record in each set.

2. Sample skewness is removed by a Gaussian transformation. The procedure chosen is a logastitimic transformation of each data item.

3. The mean and standard deviation of the transformed data sets are computed.

4. Each value of the transformed data is normalized by subtracting the monthly mean and dividing the remainder by the monthly standard deviation. This transformation renders the time series data stationary to the second order.

5. The linear predictor equations for each site are estimated. The dependent variable at time step i at site s is a function of time step i, and variables at several other sites.

The general form of the predictor equation i is:

$$y_{s,i} = \sum_{K=1}^{s} a_{S,K} \; y_{K,i+1} + \sum_{k=1}^{s-i} b_{s,k} \; y_{k,i} + e_{s,i}$$

where as,k and bs,k are the regression coefficients and es,i is a random Gaussian process with the covariance function equal to the multiple correlation coefficient matrix.

6. The predictor equations are used to synthesize data for the gaps. The voids are filled in a reverse direction going from the denser to the sparser data.

7. The synthesized values are adjusted in order to avoid abrupt transitions which sometimes occur at the interfaces of the synthesized and available data. This smoothing procedure uses the left-hand edge of the gap to set up a linear corrector which introduces it into the analysis as a maximum probable upper (or lower) bound of the process.

8. The inverse transforms are carried out on the data to convert it back to the original units.

The fill-in procedure preserves the statistical parameters of the original time series: mean, variance, autocorrelation and cross correltion coefficients.

E.2.3 - Data and Computer Runs

Mean monthly flow data obtained from the USGS was used as input. A subroutine which interfaces the FILLIN program with the USGS data format was set up by Acres. Table E2 shows the available historical data at the gaging stations. Tables E.3 to E.9 summarize the input data. All the missing data are identified as -1 for computation reason.

Records of all seven gaging sites were used in the first model run. Lack of overlapping data between Cantwell, Chulitna and Susitna stations resulted in a zero correlation which aborted the fill-in procedure. The extension of data for the Susitna station was therefore, carried out without the Cantwell and Chulitna station records.

The mean and standard deviation of the filled data sets (Table E.10) are within the limits of the confidence interval of 5%. The lag-one correlation coefficients show similar limits (Table E.11) for the un-filled data sets.

The spatial correlation matrix shows a good correspondence of the values in winter and fall and a fair correspondence in spring and summer. Spatial correlation coefficients for utilized and filled data sets are given in Tables E.12 and E.13, respectively. Filled-in data sets for the seven gaging sites are presented in Tables E-14 to E-20.

The fill-in procedure used appears superior to other existing regression procedures which have difficulties in preserving autocorrelation and spatial correlation. Probably the smoothing procedure used in this program has an important contribution to the fitness of the model.

E.2.3 Estimate of Streamflow at Dam Sites

Estimate of mean monthly flows at the sites was made adopting a linear drainage area relationship between the gaging stations and the dam sites. For Denali site, such a relation could not be used due to lower unit run off from the Lake Louise area. Since the local area at the dam site is similar to that below Cantwell station, the streamflow was directly related to the unit flows measured at Gold Creek, Cantwell and Denali gages. The following relationships were used to calculate streamflows at the dam sites:

1. $Q_{DC} = 0.827\ (Q_g - Q_c) + Q_c$

2. $Q_{HDC} = 0.802\ (Q_g - Q_c) + Q_c$

3. $Q_W = 0.515\ (Q_g - Q_c) + Q_c$

4. $Q_{SIII} = 0.042\ (Q_g - Q_c) + Q_c$

5. $Q_V = 0_c$

6. $Q_D = 0.153\ (Q_g - Q_c) + Q_d$

7. $O_M = 0.429\ (Q_c - Q_d) + Q$

Where Q = Streamflow in ft^3/sec

A = Drainage area in mi^2

Subscript DC, HDC, W, SIII, V, D and M stand for dam sites at Devil Canyon, High Devil Canyon, Watana, Susitna III, Vee, Denali and MacLaren respectively.

Subscripts g, c, and d stand for gaging stations at Gold Creek, Cantwell and Denali respectively.

The computed mean monthly flows for the 30 year period at each dam site are given in Tables E.21 to E.27.

E-3 - Flood and PMF Studies

E.3.1 - Flood Studies

Historical flood records of stations along the Susitna River and its tributaries indicated that the majority of flood peaks occur in the months of June and August, Figure E1. Generally, the annual flood peak is a result of snowmelt or a combination of snowmelt and rainfall over an extensive area of the basin. To date, 55 percent of the annual maximum flood peaks of the Susitna River recorded at Gold Creek have occurred in June. The summer flood peaks generally occur in August and are a result of heavy widespread rain augumented by significant snowmelt from higher elevations and glaciers. The largest flood peaks observed and the mean annual peak at the stations on the Susitna River and its tributaries are given in Table E.28.

TABLE E.28 - Largest Observed Peak Discharges

Station	USGS Gage No.	Drainage Area-Mile^2	Mean Annual Flood Near cfs	Maximum Observed Flood Near cfs	Date Maximum Peak Observed
Maclaren River near Paxson	(15291200)	280	6,000	9,260	8-11-71
Susitna River near Denali	(15291000)	950	17,000	38,200	8-10-71
Susitna River near Cantwell	(15291500)	4,140	33,700	55,000	8-10-71
Susitna River at Gold Creek	(15292000)	6,160	53,000	90,700	6-7-64

R&M Consultants have conducted frequency analyses of streamflow to determine up to the 1:10,000 year flood peak in the basin. In addition, they have performed other statistical analyses to determine relationships between the twenty (Q_{20}) and two year (Q_2) flood peaks for a check of the homogeneity of floods at the stations selected for inclusion into a regional flood frequency analysis. The statistical frequency distribution found to give the best fit to available data was the three parameter log normal distribution in the basin.

The ratio Q_{20}/Q_2 was developed for both the annual and October - May peak discharges. The ratios for these two series are given in Tables E.29 and E.30 and indicate that the stations selected in both cases for the regional flood peak frequency analysis are homogenous at the 95 percent confidence level.

The Multiple Linear Regression analysis conducted by R&M Consultants related mean annual instantaneous peak flow to basin characteristics. Twelve watershed parameters were considered, including: drainage area, main channel slope, stream length, mean basin levation, area of lakes and ponds, area of forests, area of glaciers, mean annual precipitation, precipitation intensity, mean annual snowfall, and mean minimum January temperature. A forward stepping multiple linear regression computer program was utilized for this analysis. It was found that drainage area, stream length, area of glaciers, mean annual precipitation and mean annual snowfall were the most influential parameters in predicting mean annual instantaneous peak flow. For October - May instantaneous peak flows, drainage area and stream length were found to be the most influential. The equations developed from the linear regression analysis are:

(1) Mean Annual Instantaneous Peak

$$Q = 7.06(DA) + 46.36(L) + 697.14(G) + 200.15(MAP) - 49.55(MAS) - 2594.44$$

(2) Mean October - May Instantaneous Peak

$$Q = 1.56(DA) + 143.35(L) - 2893.83$$

where

Q = Peak Flows, stet
DA = Drainage Area, mi^2
L = Main Channel Length, mi
MAP = Mean Annual Precipitation, in
MAS = Mean Annual Snowfall, in
G = Area of Glaciers, percent

mean October - May peak are 0.99 and 0.97, respectively. The standard error of the estimates are 1464.9 cfs and 3081.1 cfs, respectively. Continuing studies include using log transforms of flows and basin parameters to determine if better regression equations can be obtained.

Dimensionless flood frequency curves have been developed for both the annual instantaneous peak and the October - May instantaneous peak for the basin and are shown in Figures E2 and E3. The curves relate the ratio of a flood peak with a given return period to the two year flood peak. The two year flood peak can be represented by the mean annual instantaneous flood peak given by the regression equations above. Therefore, a flood peak for a given return period in engaged areas can be obtained from Figure E2 or E3 if watershed characteristics are given.

E.3.2 - Probable Maximum Flood Studies

Probable maximum flood (PMF) determination is being carried out by using the SSARR computer program developed by the Corps of Engineers for mathematical hydrological simulations, operational river forecasting, and river management activities. The SSARR program now being used is the same as used by the Corps of Engineers in the previous (1975) PMF studies. Present studies consist of a review of previous PMF studies on the Susitna River.

The acceptability of the SSARR computer program for streamflow forecasting has been demonstrated on numerous occasions. Therefore, present analysis consist of only sensitivity runs to determine the changes to peak flows due to variations in critical parameters. Basically, the preliminary sensitivity runs will attempt to show the change in peak flow estimates due to changes in input parameters such as temperature and precipitation rather than the physical parameters which describe the response of the watershed.

The first sensitivity run consisted of delaying spring melt by inputting a cool temperature sequency in May followed by a sharp temperature rise in early June, with the maximum temperature occurring on the first day of the recommended probable maximum precipitation (PMP) storm. The temperature sequence ensures that very limited melt occurs within the watershed prior to the PMP resulting in large quantities of snowpack available for melting in late May and early June. The aim is to try and ensure that the snowmelt peak flow occurs within a reasonable time of the rainfall peak. The temperature sequence assumed, 32^{0}, is not below the minimum monthly mean temperature for May that has been recorded at the representative station. The result of this run is an increase in the spring PMF peak inflow to Watana Reservoir from 233,000 cfs to 243,000 cfs, an increase of four percent.

Other sensitivity runs will consist of precipitation increases in amounts of snow on ground at the start of simulations and rainfall amounts, particularly for storms antecedent to the PMF storm. Final runs will refine basin parameters to attempt to model the watershed more accurately, provided that the sensitivity of the model to increases in precipitation and manipulation of temperature sequences prove significant.

Runs made: increase snowpack 4% change
full PMP storm 47% change
temperature sequence increase 9% F

E.4 - Climate Studies for Transmission Lines

The objective of the studies is to provide climatological criteria for ice and wind loadings for of transmission line design.

E.4.1 - Wind Loads

Historical records of wind data collected by the National Oceanic Atmospheric Administration (NOAA - formerly National Weather Service) for the stations at Anchorage, Fairbanks, Talkeetna, Summit, Big Delta and Gulkana were obtained and reviewed. Data for the Healy Power Station sites were obtained from the Artic Environmental Information and Data Center (AEIDC). The length of record varies from over 25 years at Fairbanks to less than two years at Healy. The records provide the fastest mile wind which is the fastest observed 1-minute value. Gust speed are not reported by NOAA. Discussions were held with the Corps of Engineers on the design criteria used for the Snettisham transmission lines. It was, however, apparent that the conditions in the Susitna tranmission corridors will be far less severe than the Snettisham values. Further discussions with the utilities in the Susitna area are in progress.

For preliminary design, the data collected from the stations listed above were analyzed. A summary of the peak wind speeds are presented in Table E.32. The highest wind speed of 74 mph was observed at Big Delta. Since the Healy record is short, hourly reported wind speeds were examined for occurrence of speeds over 50 mph. In addition to the 70 mph wind recorded in January 1979, speeds of 50 to 60 mph were recorded several times in 1979. During the first half of 1980, a peak value of 65 mph was recorded.

Based on the above and experience on other projects in northern climates, conservative estimates of 100 mph for the highest wind speed (1 minute duration) and a 150 mph for a few second gust have been made for preliminary designs. These represent approximately 1:30 year events.

TABLE E.32

Station	Period of Record Years	Maximum Observed Wind Speed mph
Anchorage	24	61
Big Delta	23	74
Fairbanks	26	40
Gulkana	15	52
Healy	1-1/2	70
Summit	15	48
Talkeetna	10	38

E.4.2 - Ice Loads

Ice loads on transmission lines usually result from freezing precipitation and/or in-cloud icing.

(a) Freezing Precipitation

Long term data on freezing precipitation is available only for Anchorage and Fairbanks stations (10 years). For Gulkana, Big Delta, and Talkeetna only 3 years (1969 - 72) record could be obtained. Three hourly data obtained from the NOAA were analyzed and a plot of occurrence frequency for Anchorage and Fairbanks has been prepared, Figure E.4.1. This indicates that a potential 2" ice accumulation has an occurrence frequency of 1 in 30 years.

(b) In-cloud Icing

With the available information on cloud cover, temperature and wind, it has not been possible to estimate in-cloud icing. Field observations of actual ice-accretions during individual in-cloud icing events are being made during the winter of 1980. With this and other climatic data collected it is proposed to calibrate an Acres mathematical model that calculates in-cloud ice accretion as a function of super cooling, cloud drop size distribution (cloud type) and wind speed and estimate potential ice accretion for design conditions.

E.4.3 - Combined Wind/Ice Loads

For design of the transmission lines a combination of wind and one of the two types of ice loads is expected to be critical. In the absence of estimates for in-cloud icing loads, it is proposed that preliminary designs be based on wind loads due to 100 mph sustained wind and/or 150 mph gusts in combination with 2" ice accumulation due to freezing rain since this ice may remain on the lines for some time after its accumulation. A detailed evaluation of the combined ice/wind loads is proposed to be made after this winter field data is analyzed taking account of the economic impact of the design loads on tower designs.

SUSITNA HYDROELECTRIC PROJECT
Table E.1 - Hydrology Field Observation Log

Parameter Measured		Station Location	Type of Instrument Used	Date of Installation (1980)	Observation Frequency	Date of Observation (1980)	Type of Observation
(1)	River Stage	Susitna River near Watana Dam site	Scientific Instr. Co. Manometer Stevens Water Level Recorder	6/20	Continuous	7/10 P	Scheduled
(2)	River Discharge	Susitna River near Watana Dam site	Teledyne-Gurley Price Current Meter	N/A	Unscheduled	8/20 8/21 9/3 9/18 10/20	Event Event Event Event Event
(3)	River Crest Stage (Susitna River)	(a) Susitna-Chulitna Confluence	Crest-stage recorder	6/26	Unscheduled	7/31	Event
		(b) Chase	Crest-stage recorder	7/31	Unscheduled	-	Event
		(c) Curry	Crest-stage recorder	6/26	Unscheduled	7/31	Event
		(d) Section 25	Crest-stage recorder	6/26	Unscheduled	7/31	Event
		(e) Sherman	Crest-stage recorder	6/26	Unscheduled	7/31	Event
		(f) Portage Creek	Crest-stage recorder	6/25	Unscheduled	-	Event
		(g) Devil Canyon Upper	Crest-stage recorder	6/25	Unscheduled	7/31	Event
		(h) Watana Dam	Crest-stage recorder	7/30 10/1	Unscheduled	-	Event

SUSITNA HYDROELECTRIC PROJECT

Table E.1 - Hydrology Field Observation Log (Cont'd)

Parameter Measured	Station Location	Type of Instrument Used	Date of Installation (1980)	Observation Frequency	Date of Observation (1980)	Type of Observation
	(i) Deadman Creek	Crest-stage recorder	7/30	Unscheduled	-	Event
(4) River Stage (Susitna River)	(a) Devil Canyon	Staff Gage	4/81	Unscheduled	-	Event
(5) Water Quality(1,2)	(a) Susitna River near Watana Dam site	Martek Water Quality Data Logger	10/23	Continuous	-	Scheduled
	(b) Susitna River near Cantwell	VWR pH Meter YSI DO Meter	N/A	Sum: monthly Win: 2-3 months	6/19 8/8	Scheduled Scheduled
	(Vee Canyon Site)	YSI S-C-T Meter			9/5	Scheduled
		Van Dorn Sampler Imhoff Cones			9/17 10/17	Sched/Event Scheduled
	(c) Susitna River Gold Creek	Same as at Vee Canyon	N/A	Sum: monthly Win: 2-3 months	8/8 10/14	Scheduled Scheduled
(6) Sediment	(a) Susitna River near Cantwell (Vee Canyon Site)	Point-integrating Suspended Sediment Sampler	N/A	Sum: monthly Win: 2-3 months	9/5 9/17 10/18	Scheduled Sched/Event Scheduled
	(b) Susitna River at Gold Creek	Same as at Vee Canyon	N/A	Sum: monthly	- 10/16	- Scheduled

SUSITNA HYDROELECTRIC PROJECT

Table E.1 - Hydrology Field Observation Log (Cont'd)

Parameter Measured	Station Location	Type of Instrument Used	Date of Installation (1980)	Observation Frequency	Date of Observation (1980)	Type of Observation
(7) Climate (3)	(a) Watana Camp	MRI Weather Wizard (WW)	3/13	Continuous	4/8 - 6/10 6/19 - 7/30 8/14 - 10/2 10/17 P	Scheduled
	(b) Devil Canyon	MRI Weather Wizard	7/17	Continuous	7/17 - 8/28 10/16 - P	Scheduled
	(c) Kosina Creek	MRI Weather Wizard	8/25	Continuous	8/25 - P	Scheduled
	(d) Tyone River	MRI Weather Wizard	8/27	Continuous	8/27 - 8/30 10/17 - 12/1	Scheduled
	(e) Denali (Susitna Lodge)	MRI Weather Wizard	7/18	Continuous	7/18 - 8/28 8/28 - ?	Scheduled
	(f) Susitna Glacier	MRI Weather Wizard	7/20	Continuous	7/20 - 8/7 8/7 - 8/14 8/28 - P	Scheduled
(8) Snow Density and Depth	(a) West Fork Glacier Snow Course	Carpenter Machine Works Snow Sampling Kit Aerial Snow Markers	8/26 (4)	Win: monthly	1/1/81	Scheduled
	(b) Susitna Glacier Snow Course	Same as at West Fork	8/28 9/4 (4)	Win: monthly	1/1/81	Scheduled

SUSITNA HYDROELECTRIC PROJECT
Table E.1 - Hydrology Field Observation Log (Cont'd)

Parameter Measured	Station Location	Type of Instrument Used	Date of Installation (1980)	Observation Frequency	Date of Observation (1980)	Type of Observation
	(c) East Forst Glacier Snow Course	Same as at West Fork	9/4 (4)	Win: monthly	1/1/81	Scheduled
	(d) Butte Creek Pass Snow Course	Same as at West Fork	9/11 (4)	Win: monthly	1/1/81	Scheduled
(9) Ice Buildup During Precipitation	(a) Watana Camp	Steel Plate	11/12	Unscheduled	-	Event
	(b) Denali (Susitna Lodge)	Steel Plate	11/12	Unscheduled	-	Event
	(c) Healy	Steel Plate	11/81 (proposed)	Unscheduled	-	Event
(10) In-cloud Icing (ice buildup on transmission line)	(a) Watana Camp	Short Section of Transmission Line	9/10 10/16	Unscheduled	-	Event
	(b) Denali (Susitna Lodge)	Short Section of Transmission Line	9/11 10/20	Unscheduled	-	Event
	(c) Healy	Short Section of Transmission Line	1981 (proposed)	Unscheduled	-	Event
(11) Snow Creep	(a) Watana Camp		12/80 (proposed)	Win: monthly	1/1/81	Scheduled
	(b) Devil Canyon		12/80 (proposed)	Win: monthly	1/1/81	Scheduled

SUSITNA HYDROELECTRIC PROJECT

Table E.1 - Hydrology Field Observation Log (Cont'd)

Parameter Measured	Station Location	Type of Instrument Used	Date of Installation (1980)	Observation Frequency	Date of Observation (1980)	Type of Observation
	(c) Healy		12/80 (proposed)	Win: monthly	1/1/81	Scheduled
(12) Ice Thickness and Competence	Susitna River and Tributaries (5)	Ice Auger Measuring Tape Ice Penetrometer	N/A	Win: monthly	12/1	Scheduled
(13) Extent of Ice Cover, Locations of Ice Jams	Susitna River	SLR Camera Survey Equipment	N/A	Daily or weekly During Freeze-up & Break-up	10/80, 11/80, 12/80 4/81, 5/81	Event
(14) Glacial Composition and Movement	Susitna Glacier	Survey Equipment SLR Camera Aerial Photography	6/81 (proposed)	Monthly or Bimonthly		Scheduled

SUSITNA HYDROELECTRIC PROJECT

Table E.1 - Hydrology Field Observation Log (Cont'd)

NOTES:

(1) WQ parameters measured by the continuous water quality monitor: water temperature, dissolved oxygen, conductivity, pH, and oxidation - reduction potential.

(2) WQ parameters measured in the field: dissolved oxygen, water temperature, conductivity, pH, alkalinity, settleable solids, and free carbon dioxide.

(3) Climate parameters measured at each station: air temperature, average wind speed, wind direction, peak wind gust, relative humidity, precipitation, and solar radiation. Snowfall amounts will be measured in heated precipitation bucket at Wanata only. Data are recorded at thirty (30) minute intervals at the Susitna Glacier station and at fifteen (15) minute intervals at all the other stations.

(4) Dates refer to dates of installation of aerial snow survey markers. The actual snow courses are located at one of the markers at each of the three glaciers.

(5) Several sites along the main stem of the Susitna and a few sites on the larger tributaries are to be observed.

TABLE E.2 - Available Mean Monthly Streamflow Data

Sites (USGS Gage No.)		Years						
		1950	1955	1960	1965	1970	1975	1979
Gold Creek	(15292000)	1950						1979
Denali	(15291000)		1957					1979
Maclaren	(15291200)			1958				1979
Skwentna	(15294300)			1960				1979
Talkeetna	(15292800)				1964			1979
Cantwell	(15291500)			1961		1972		
Chulitna	(15292400)			1958		1972		
Susitna	(15294350)						1973	1979

TABLE E.3 MACLAREN UNFILLED DATA SET

SITE NO. 1 MC LAREN

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1950
2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1951
3	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1952
4	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1953
5	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1954
6	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1955
7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1956
8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1957
9	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	3532.0	3525.0	2699.0	784.0	1958
10	378.0	115.0	123.0	129.0	95.4	62.5	77.5	587.0	2879.0	2680.0	2083.0	856.0	1959
11	549.0	250.0	190.0	150.0	110.0	94.3	91.5	1742.0	2124.0	3359.0	3048.0	2439.0	1960
12	687.0	195.0	149.0	110.0	93.9	96.0	145.0	1237.0	2678.0	3369.0	3299.0	1168.0	1961
13	381.0	210.0	170.0	120.0	100.0	92.0	120.0	632.0	2916.0	3265.0	2927.0	1127.0	1962
14	383.0	210.0	130.0	100.0	91.0	80.0	83.0	2131.0	3110.0	4649.0	3136.0	1213.0	1963
15	416.0	140.0	98.0	85.0	88.0	71.0	72.0	386.0	4297.0	2764.0	2224.0	871.0	1964
16	379.0	147.0	49.3	44.0	42.0	41.0	62.0	984.0	2268.0	3223.0	2409.0	2098.0	1965
17	522.0	180.0	55.0	45.0	45.0	43.0	50.0	265.0	2990.0	2505.0	2095.0	954.0	1966
18	369.0	95.0	70.0	65.0	60.0	55.0	53.3	1023.0	3634.0	3255.0	3605.0	1416.0	1967
19	417.0	130.0	100.0	97.4	95.0	95.0	95.0	208.0	3245.0	3427.0	2129.0	680.0	1968
20	265.0	121.0	68.5	58.2	55.0	57.6	95.3	849.0	2613.0	2692.0	974.0	470.0	1969
21	249.0	117.0	73.2	59.4	50.4	52.7	69.2	746.0	1751.0	2441.0	2367.0	77[illegible].0	1970
22	301.0	192.0	131.0	83.4	60.4	55.0	66.0	365.0	3414.0	3528.0	3659.0	1165.0	1971
23	375.0	156.0	123.0	115.0	107.0	97.4	98.5	1218.0	3069.0	3255.0	2676.0	1366.0	1972
24	550.0	243.0	136.0	87.4	65.2	53.4	51.2	576.0	2906.0	2856.0	2271.0	821.0	1973
25	307.0	123.0	82.6	68.5	61.8	56.6	56.7	649.0	2069.0	2634.0	2439.0	1543.0	1974
26	305.0	232.0	140.0	115.0	110.0	100.0	103.0	758.0	3178.0	3649.0	1982.0	1574.0	1975
27	553.0	235.0	139.0	106.0	94.1	90.0	105.0	781.0	2870.0	2810.0	2604.0	600.0	1976
28	302.0	168.0	119.0	97.3	92.0	90.0	92.9	366.0	3942.0	3834.0	3394.0	1297.0	1977
29	512.0	265.0	186.0	162.0	140.0	121.0	134.0	709.0	2317.0	3196.0	2356.0	924.0	1978
30	307.0	192.0	142.0	122.0	110.0	100.0	111.0	634.0	2430.0	3056.0	2223.0	1137.0	1979

TABLE E.4 CANTWELL UNFILLED DATA SET

SITE NO. 2 CANTWELL

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1950
2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1951
3	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1952
4	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1953
5	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1954
6	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1955
7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1956
8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1957
9	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1958
10	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1959
11	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1960
12	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	9688.0	15710.0	14820.0	16700.0	6725.0	1961
13	3281.0	1800.0	1400.0	1300.0	1000.0	940.0	1200.0	10000.0	28320.0	20890.0	16000.0	9410.0	1962
14	4326.0	2200.0	1400.0	1000.0	830.0	760.0	720.0	11340.0	15000.0	22790.0	18190.0	9187.0	1963
15	3848.0	1300.0	877.0	644.0	586.0	429.0	465.0	2806.0	34630.0	17040.0	11510.0	5352.0	1964
16	3134.0	1911.0	921.0	760.0	680.0	709.0	1097.0	8818.0	16430.0	18350.0	13440.0	12910.0	1965
17	3116.0	1000.0	750.0	700.0	650.0	650.0	875.0	4387.0	18500.0	12220.0	12680.0	6523.0	1966
18	2322.0	780.0	720.0	680.0	640.0	560.0	513.0	9452.0	19620.0	16880.0	19190.0	10280.0	1967
19	3084.0	1490.0	1332.0	1232.0	1200.0	1200.0	1223.0	9268.0	19500.0	17480.0	10940.0	5410.0	1968
20	2406.0	1063.0	618.0	508.0	485.0	548.0	998.0	7471.0	12330.0	13510.0	6597.0	3376.0	1969
21	1638.0	815.0	543.0	437.0	426.0	463.0	887.0	7580.0	9909.0	13900.0	12320.0	5211.0	1970
22	2155.0	1530.0	1048.0	731.0	503.0	470.0	529.0	1915.0	21970.0	18130.0	22710.0	9800.0	1971
23	4058.0	2050.0	1371.0	1068.0	922.0	881.0	876.0	9694.0	20000.0	16690.0	15620.0	9423.0	1972
24	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1973
25	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1974
26	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1975
27	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1976
28	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1977
29	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1978
30	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1979

TABLE E.5 GOLD CREEK UNFILLED DATA SET

SITE NO. 3 GOLD CREEK

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	6335.0	2583.0	1439.0	1027.0	788.0	726.0	870.0	11510.0	19600.0	22600.0	19880.0	8301.0	1950
2	3848.0	1300.0	1100.0	960.0	820.0	740.0	1617.0	14090.0	20790.0	22570.0	19670.0	21240.0	1951
3	5571.0	2744.0	1900.0	1600.0	1000.0	880.0	920.0	5419.0	32370.0	26390.0	20920.0	14480.0	1952
4	8202.0	3497.0	1700.0	1100.0	820.0	820.0	1615.0	19270.0	27320.0	20200.0	20610.0	15270.0	1953
5	5604.0	2100.0	1500.0	1300.0	1000.0	780.0	1235.0	17280.0	25250.0	20360.0	26100.0	12920.0	1954
6	5370.0	2760.0	2045.0	1794.0	1400.0	1100.0	1200.0	9319.0	29860.0	27560.0	25750.0	14290.0	1955
7	4951.0	1900.0	1300.0	980.0	970.0	940.0	950.0	17660.0	33340.0	31090.0	24530.0	18330.0	1956
8	5806.0	3050.0	2142.0	1700.0	1500.0	1200.0	1200.0	13750.0	30160.0	23310.0	20540.0	19800.0	1957
9	8212.0	3954.0	3264.0	1965.0	1307.0	1148.0	1533.0	12900.0	25700.0	22880.0	22540.0	7550.0	1958
10	4811.0	2150.0	1513.0	1448.0	1307.0	980.0	1250.0	15990.0	23320.0	25000.0	31180.0	16920.0	1959
11	6558.0	2850.0	2200.0	1845.0	1452.0	1197.0	1300.0	15780.0	15530.0	22980.0	23590.0	20510.0	1960
12	7794.0	3000.0	2694.0	2452.0	1754.0	1810.0	2650.0	17360.0	29450.0	24570.0	22100.0	13370.0	1961
13	5916.0	2700.0	2100.0	1900.0	1500.0	1400.0	1700.0	12590.0	43270.0	25850.0	23550.0	15890.0	1962
14	6723.0	2800.0	2000.0	1600.0	1500.0	1000.0	830.0	19030.0	26000.0	34400.0	23670.0	12320.0	1963
15	6449.0	2250.0	1494.0	1048.0	966.0	713.0	745.0	4307.0	50580.0	22950.0	16440.0	9571.0	1964
16	6291.0	2799.0	1211.0	960.0	860.0	900.0	1360.0	12990.0	25720.0	27840.0	21120.0	19350.0	1965
17	7205.0	2098.0	1631.0	1400.0	1300.0	1300.0	1775.0	9645.0	32950.0	19860.0	21830.0	11750.0	1966
18	4163.0	1600.0	1500.0	1500.0	1400.0	1200.0	1167.0	15480.0	29310.0	26800.0	32620.0	16870.0	1967
19	4900.0	2353.0	2055.0	1981.0	1900.0	1900.0	1910.0	16180.0	31550.0	26420.0	17170.0	8816.0	1968
20	3822.0	1630.0	882.0	724.0	723.0	816.0	1510.0	11050.0	15500.0	16100.0	8879.0	5093.0	1969
21	3124.0	1215.0	866.0	824.0	768.0	776.0	1080.0	11380.0	18630.0	22660.0	19980.0	9121.0	1970
22	5288.0	3407.0	2290.0	1442.0	1036.0	950.0	1082.0	3745.0	32930.0	23950.0	31910.0	14440.0	1971
23	5847.0	3093.0	2510.0	2239.0	2028.0	1823.0	1710.0	21890.0	34430.0	22770.0	19290.0	12400.0	1972
24	4826.0	2253.0	1465.0	1200.0	1200.0	1000.0	1027.0	8235.0	27800.0	18250.0	20290.0	9074.0	1973
25	3733.0	1523.0	1034.0	874.0	777.0	724.0	992.0	16180.0	17870.0	18800.0	16220.0	12250.0	1974
26	3739.0	1700.0	1603.0	1516.0	1471.0	1400.0	1593.0	15350.0	32310.0	27720.0	18090.0	16310.0	1975
27	7739.0	1993.0	1081.0	974.0	950.0	900.0	1373.0	12620.0	24380.0	18940.0	19800.0	6881.0	1976
28	3874.0	2650.0	2403.0	1829.0	1618.0	1500.0	1680.0	12680.0	37970.0	22870.0	19240.0	12640.0	1977
29	7571.0	3525.0	2589.0	2029.0	1668.0	1605.0	1702.0	11950.0	19050.0	21020.0	16390.0	8607.0	1978
30	4907.0	2535.0	1681.0	1397.0	1296.0	1200.0	1450.0	13870.0	24690.0	28880.0	20460.0	10770.0	1979

TABLE E.6 CHULITNA UNFILLED DATA SET

SITE NO. 4 CHULITNA

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1950
2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1951
3	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1952
4	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1953
5	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1954
6	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1955
7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1956
8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1957
9	-1.0	-1.0	-1.0	-1.0	1044.0	948.0	1220.0	10460.0	23170.0	25010.0	20760.0	8000.0	1958
10	4197.0	1883.0	1262.0	1097.0	1049.0	738.0	890.0	7413.0	23660.0	25650.0	22100.0	9957.0	1959
11	4723.0	2283.0	1700.0	1448.0	1103.0	933.0	1000.0	13890.0	17390.0	23650.0	19320.0	12420.0	1960
12	5135.0	1950.0	1745.0	1452.0	1100.0	1079.0	1600.0	10100.0	20490.0	27420.0	24580.0	16030.0	1961
13	5777.0	2400.0	1500.0	1300.0	1000.0	930.0	1170.0	7743.0	20620.0	27220.0	21980.0	13490.0	1962
14	3506.0	1500.0	1552.0	1600.0	1300.0	846.0	700.0	11060.0	17750.0	28950.0	18390.0	11330.0	1963
15	8062.0	2300.0	1000.0	1007.0	820.0	770.0	1133.0	2355.0	40330.0	24430.0	20250.0	9235.0	1964
16	5642.0	2900.0	2100.0	1600.0	1400.0	1300.0	1400.0	7452.0	20070.0	23230.0	22550.0	22260.0	1965
17	6071.0	1620.0	1350.0	1200.0	1100.0	1100.0	1300.0	3971.0	21740.0	23750.0	27720.0	12200.0	1966
18	4682.0	1680.0	1500.0	1458.0	1257.0	1045.0	972.0	12400.0	25520.0	35570.0	33670.0	12510.0	1967
19	3483.0	1660.0	1397.0	1235.0	1200.0	1148.0	1347.0	10940.0	29000.0	30140.0	20710.0	7375.0	1968
20	2898.0	1480.0	1139.0	974.0	900.0	824.0	1333.0	6001.0	18560.0	20820.0	11300.0	6704.0	1969
21	4578.0	1887.0	1316.0	1200.0	1154.0	1100.0	1437.0	9643.0	19670.0	26100.0	24660.0	11330.0	1970
22	3826.0	2210.0	1403.0	1113.0	950.0	934.0	982.0	4468.0	22180.0	27280.0	23810.0	11080.0	1971
23	5439.0	2157.0	1432.0	1174.0	1041.0	939.0	893.0	9765.0	17900.0	25770.0	20970.0	12120.0	1972
24	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1973
25	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1974
26	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1975
27	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1976
28	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1977
29	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1978
30	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1979

TABLE E.7 TALKEETNA UNFILLED DATA SET

SITE NO. 5 TALKEETNA

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1950
2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1951
3	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1952
4	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1953
5	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1954
6	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1955
7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1956
8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1957
9	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1958
10	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1959
11	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1960
12	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1961
13	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1962
14	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1963
15	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	17080.0	9820.0	8396.0	3815.0	1964
16	3115.0	1568.0	1100.0	720.0	620.0	540.0	580.0	3474.0	11090.0	12180.0	11150.0	10610.0	1965
17	4438.0	1460.0	876.0	711.0	526.0	395.0	422.0	2410.0	12970.0	10100.0	10730.0	5370.0	1966
18	2388.0	897.0	[illegible]	637.0	546.0	471.0	427.0	4112.0	9286.0	12600.0	14160.0	6971.0	1967
19	2029.0	1253.0	987.0	851.0	777.0	743.0	983.0	8840.0	14100.0	11230.0	7546.0	4120.0	1968
20	1637.0	827.0	556.0	459.0	401.0	380.0	519.0	3869.0	5207.0	7080.0	3787.0	2070.0	1969
21	1450.0	765.0	587.0	504.0	458.0	440.0	545.0	3950.0	7979.0	10320.0	8752.0	5993.0	1970
22	2817.0	1647.0	1103.0	679.0	459.0	402.0	503.0	2145.0	19040.0	11760.0	16770.0	5990.0	1971
23	2632.0	1310.0	845.0	727.0	628.0	481.0	519.0	3516.0	12700.0	12030.0	9576.0	8709.0	1972
24	3630.0	1373.0	889.0	748.0	654.0	574.0	577.0	3860.0	12210.0	7676.0	9927.0	3861.0	1973
25	1807.0	960.0	745.0	645.0	559.0	482.0	535.0	5678.0	8030.0	7755.0	7704.0	4763.0	1974
26	1967.0	1002.0	774.0	694.0	586.0	508.0	522.0	4084.0	13180.0	12070.0	8487.0	7960.0	1975
27	2884.0	773.0	558.0	524.0	480.0	470.0	613.0	3439.0	10580.0	9026.0	8088.0	3205.0	1976
28	1857.0	1105.0	1069.0	700.0	549.0	506.0	548.0	4244.0	18280.0	9344.0	8005.0	5826.0	1977
29	3268.0	1121.0	860.0	746.0	576.0	485.0	534.0	2950.0	7429.0	10790.0	7001.0	3567.0	1978
30	1660.0	1138.0	932.0	762.0	652.0	577.0	710.0	7790.0	12010.0	14440.0	8274.0	4039.0	1979

TABLE E.8 SKWENTNA UNFILLED DATA SET

SITE NO. 6 SKWENTNA

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1950
2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1951
3	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1952
4	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1953
5	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1954
6	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1955
7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1956
8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1957
9	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1958
10	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1959
11	3532.0	1850.0	1400.0	1097.0	961.0	843.0	835.0	10480.0	13440.0	16690.0	15990.0	9171.0	1960
12	3889.0	1600.0	1597.0	1403.0	1154.0	1155.0	1700.0	11210.0	20570.0	16480.0	13910.0	12020.0	1961
13	4605.0	2200.0	1400.0	1200.0	860.0	760.0	1000.0	6613.0	15630.0	14930.0	12080.0	6723.0	1962
14	2801.0	1250.0	1100.0	1000.0	810.0	700.0	650.0	7765.0	14050.0	20430.0	12020.0	7180.0	1963
15	5355.0	1550.0	840.0	970.0	750.0	600.0	840.0	1635.0	27250.0	16480.0	12680.0	6224.0	1964
16	4425.0	1790.0	1300.0	920.0	800.0	740.0	770.0	4810.0	17160.0	19370.0	14010.0	13090.0	1965
17	4122.0	1575.0	1150.0	1100.0	1100.0	1100.0	1300.0	4502.0	19550.0	14180.0	17320.0	9812.0	1966
18	5576.0	1400.0	900.0	720.0	650.0	650.0	780.0	1794.0	14430.0	14740.0	15760.0	9517.0	1967
19	3832.0	1560.0	1181.0	1023.0	1000.0	950.0	1293.0	13460.0	20770.0	17480.0	10560.0	3855.0	1968
20	1929.0	678.0	624.0	600.0	600.0	626.0	1487.0	11070.0	19580.0	13650.0	7471.0	3783.0	1969
21	5654.0	1607.0	832.0	766.0	700.0	650.0	728.0	11710.0	22880.0	21120.0	13030.0	6665.0	1970
22	2919.0	2023.0	1184.0	865.0	721.0	613.0	607.0	5963.0	25400.0	20600.0	15920.0	6024.0	1971
23	3020.0	1327.0	1103.0	989.0	898.0	811.0	742.0	8045.0	15330.0	16840.0	13370.0	9256.0	1972
24	4551.0	2340.0	1316.0	910.0	702.0	606.0	727.0	6349.0	15200.0	13850.0	9874.0	6164.0	1973
25	3540.0	1700.0	1265.0	1023.0	902.0	811.0	1005.0	6765.0	10650.0	11670.0	10480.0	11800.0	1974
26	4557.0	2328.0	919.0	800.0	750.0	750.0	767.0	7852.0	19060.0	19520.0	11710.0	8471.0	1975
27	4704.0	1973.0	1258.0	971.0	897.0	800.0	1270.0	8806.0	15120.0	14580.0	11120.0	8165.0	1976
28	6196.0	2880.0	2871.0	2829.0	1821.0	1200.0	1200.0	8906.0	36670.0	25270.0	20160.0	10290.0	1977
29	5799.0	2373.0	1548.0	1213.0	944.0	841.0	1023.0	9006.0	13840.0	18100.0	13740.0	7335.0	1978
30	4936.0	1580.0	1555.0	1165.0	1036.0	981.0	1597.0	11660.0	14980.0	15830.0	16210.0	7448.0	1979

TABLE E.9 DENALI UNFILLED DATA SET

SITE NO. 7 DENALI

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	CALYR
1	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1950
2	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1951
3	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1952
4	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1953
5	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1954
6	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1955
7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	1956
8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	12210.0	11170.0	9769.0	4017.0	1957
9	1277.0	610.0	288.0	219.0	150.0	120.0	210.0	1163.0	8367.0	9150.0	6536.0	1879.0	1958
10	939.0	390.0	170.0	119.0	81.0	41.7	43.0	1782.0	8891.0	8333.0	7882.0	2498.0	1959
11	1577.0	760.0	575.0	444.0	321.0	275.0	265.0	3349.0	5237.0	9039.0	7910.0	4817.0	1960
12	1781.0	660.0	483.0	331.0	271.0	281.0	415.0	2959.0	6412.0	8078.0	7253.0	2695.0	1961
13	1290.0	680.0	440.0	280.0	240.0	220.0	280.0	2197.0	9087.0	10220.0	9454.0	3649.0	1962
14	1079.0	510.0	310.0	250.0	230.0	200.0	210.0	3253.0	6763.0	10500.0	10210.0	3949.0	1963
15	925.0	290.0	185.0	140.0	140.0	110.0	130.0	910.0	11630.0	7577.0	6552.0	2633.0	1964
16	1468.0	702.0	279.0	220.0	200.0	208.0	320.0	2464.0	4647.0	6756.0	5764.0	6955.0	1965
17	920.0	300.0	240.0	210.0	200.0	200.0	280.0	1629.0	6850.0	8287.0	6432.0	3200.0	1966
18	920.0	300.0	240.0	210.0	200.0	200.0	280.0	1629.0	6850.0	8287.0	6432.0	3200.0	1967
19	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	11840.0	9825.0	2192.0	1968
20	700.0	304.0	172.0	145.0	140.0	145.0	229.0	1768.0	8146.0	9445.0	3919.0	2213.0	1969
21	1002.0	501.0	339.0	265.0	221.0	193.0	319.0	2210.0	5013.0	8454.0	6216.0	1946.0	1970
22	528.0	395.0	276.0	170.0	125.0	120.0	135.0	629.0	8099.0	10410.0	10400.0	3288.0	1971
23	1039.0	478.0	380.0	339.0	307.0	286.0	270.0	3468.0	6542.0	10450.0	8664.0	2778.0	1972
24	667.0	323.0	211.0	178.0	164.0	153.0	153.0	1042.0	5741.0	8346.0	7268.0	2445.0	1973
25	876.0	462.0	366.0	310.0	271.0	235.0	262.0	2541.0	5642.0	9547.0	9292.0	5452.0	1974
26	2135.0	673.0	381.0	300.0	200.0	200.0	200.0	1640.0	7040.0	12110.0	7295.0	3571.0	1975
27	1539.0	375.0	169.0	112.0	97.0	90.0	123.0	1805.0	5939.0	8558.0	10080.0	1822.0	1976
28	894.0	467.0	331.0	266.0	240.0	231.0	246.0	1498.0	8253.0	10010.0	10180.0	3707.0	1977
29	1148.0	652.0	439.0	348.0	300.0	246.0	263.0	2031.0	5250.0	8993.0	8644.0	3622.0	1978
30	865.0	463.0	312.0	263.0	229.0	203.0	250.0	2791.0	7650.0	9504.0	9178.0	4512.0	1979

TABLE E.10 Mean and Standard Deviation Before and After Filling-in

Site (No.of Data)	Statistical Parameter	Before or After	MONTH 10	11	12	1	2	3	4	5	6	7	8	9
Gold Creek (360)	Mean	B	31,250	13,246	9,070	8,204	7,409	6,262	7,213	60,822	122,506	130,980	109,362	68,060
		A	30,054	12,658	8,214	7,905	7,037	6,320	6,978	60,462	123,697	131,931	110,840	65,963
	SD	B	6,611	3,091	2,375	1,300	1,125	621	809	13,086	25,167	12,247	14,740	13,458
		A	8,302	3,645	2,796	1,668	1,472	955	1,031	15,009	30,175	14,056	17,360	17,258
Denali (259)	Mean	B	1,122	490	313	243	206	188	232	2,036	7,285	9,350	8,050	3,349
		A	1,106	475	308	252	210	187	237	2,072	7,195	9,277	7,798	3,180
	SD	B	384	149	107	83	66	63	80	790	1,930	1,311	1,716	1,216
		A	340	149	107	112	79	69	73	834	1,797	1,219	1,749	1,132
Maclaren (256)	Mean	B	409	177	118	96	84	76	87	802	2,912	3,180	2,572	1,148
		A	409	173	110	93	82	72	85	824	2,893	3,179	2,806	1,194
	SD	B	110	50	40	31	26	22	26	462	611	496	609	460
		A	106	48	39	30	25	22	24	488	562	437	581	474
Skwentna (240)	Mean	B	4,297	1,779	1,267	1,078	903	809	1,016	7,920	18,578	17,090	13,370	8,149
		A	4,237	1,731	1,195	1,057	861	787	1,004	8,651	19,860	17,277	13,566	7,997
	SD	B	1,110	477	447	441	256	179	321	3,139	5,854	3,147	2,871	2,452
		A	1,084	586	442	437	241	174	288	3,460	7,261	3,332	2,976	2,564
Talkeetna (184)	Mean	B	2,505	1,146	842	674	565	497	569	4,290	11,498	10,513	9,272	5,429
		A	2,698	1,195	851	673	560	480	551	4,071	11,572	10,751	10,405	6,015
	SD	B	825	273	176	102	92	87	129	1,776	3,801	1,954	2,879	2,180
		A	726	308	191	114	104	81	121	1,489	3,643	1,741	3,015	2,004
Cantwell (137)	Mean	B	3,033	1,449	998	823	722	691	853	7,701	19,326	16,891	14,658	7,800
		A	3,073	1,438	981	822	703	657	828	7,165	17,642	16,446	16,037	7,729
	SD	B	802	476	314	272	230	228	257	2,911	6,462	2,906	4,126	2,668
		A	776	430	263	219	193	225	275	2,798	5,397	2,662	3,163	2,673
Chulitna (176)	Mean	B	4,858	1,993	1,456	1,275	1,094	975	1,158	8,510	22,536	26,332	22,184	11,736
		A	5,282	2,094	1,493	1,311	1,089	973	1,184	9,658	23,267	26,982	22,444	11,876
	SD	B	1,276	389	261	198	147	147	249	3,159	5,648	3,362	4,674	3,671
		A	1,351	471	290	194	133	129	195	4,257	5,383	3,636	4,388	3,666

B - Before
A - After

TABLE E.11

Lag-One Correlation Coefficients

	Before Filling	After Filling
Gold Creek	.61	.61
Denali	.56	.559
Maclaren	.59	.575
Skwentna	.60	.608
Talkeetna	.66	.628
Cantwell	.64	.628
Chulitna	.41	.499
Susitna	.574	.715

TABLE E.12 SPATIAL CORRELATION MATRIX UNFILLED DATE SET

Gold Creek	i	1.0	.588	.628	.480	.346	.530	.525	.552	.395	.456	.257	.166	.233	.333
Denali	i		1.0	.728	.415	.732	.583	.863	.198	.611	.443	.211	.442	.242	.529
MacLaren	i			1.0	.482	.592	.308	.730	.377	.524	.694	.346	.367	.154	.499
Skwentna	i				1.0	.368	.384	.673	.191	.248	.346	.544	.157	.213	.277
Talkeetna	i					1.0	.480	.724	.019	.386	.402	.172	.586	.112	.408
Cantwell	i						1.0	.488	.154	.280	.113	.033	.166	.392	.204
Chulitna	i							1.0	.208	.558	.479	.276	.492	.225	.666
Gold Creek	i								1.0	.553	.615	.452	.290	.486	.490
Denali	i-1									1.0	.730	.399	.722	.550	.853
McLaren	i-1										1.0	.478	.593	.276	.721
Skwentna	i-1											1.0	.350	.351	.453
Talkeetna	i-1												1.0	.429	.706
Cantwell	i-1													1.0	.453
Chulitna	i-1														1.0

TABLE E.13 SPATIAL CORRELATION MATRIX FILLED DATE SET

Gold Creek	i	1.000	0.487	0.554	0.527	0.322	0.513	0.489	0.502	0.257	0.328	0.296	0.116	0.277	0.243
Denali	i		1.000	0.710	0.379	0.664	0.557	0.833	0.171	0.628	0.408	0.194	0.375	0.308	0.490
MacLaren	i			1.000	0.441	0.474	0.350	0.742	0.313	0.463	0.629	0.282	0.269	0.233	0.461
Skwentna	i				1.000	0.422	0.448	0.454	0.276	0.277	0.290	0.607	0.231	0.307	0.279
Talkeetna	i					1.000	0.485	0.645	0.066	0.373	0.270	0.220	0.574	0.221	0.356
Cantwell	i						1.000	0.468	0.238	0.325	0.185	0.246	0.253	0.559	0.246
Chulitna	i							1.000	0.187	0.514	0.437	0.231	0.386	0.243	0.611
Gold Creek	i								1.000	0.483	0.550	0.532	0.319	0.512	0.489
Denali	i-1									1.000	0.707	0.381	0.663	0.555	0.834
MacLaren	i-1										1.000	0.443	0.471	0.345	0.742
Skwentna	i-1											1.000	0.423	0.477	0.455
Talkeetna	i-1												1.000	0.483	0.644
Cantwell	i-1													1.000	0.464
Chulitna	i-1														1.000

TABLE E.14 GOLD CREEK FILLED DATA SET

SITE NO.= 1 RUNF GOLD CREEK

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	SUMYR	CALYR
1	6335.0	2583.0	1439.0	1027.0	788.0	726.0	870.0	11510.0	19600.0	22600.0	19880.0	8301.0	95659.1	1950
2	3848.0	1300.0	1100.0	960.0	820.0	740.0	1617.0	14090.0	20790.0	22570.0	19670.0	21240.0	108745.1	1951
3	5571.0	2744.0	1900.0	1600.0	1000.0	880.0	920.0	5419.0	32370.1	26390.0	20920.0	14480.0	114194.1	1952
4	8202.0	3497.0	1700.0	1100.0	820.0	820.0	1615.0	19270.0	27320.1	20200.0	20610.0	15270.0	120424.1	1953
5	5604.0	2100.0	1500.0	1300.0	1000.0	780.0	1235.0	17280.0	25250.0	20360.0	26100.0	12920.0	115429.1	1954
6	5370.0	2760.0	2045.0	1794.0	1400.0	1100.0	1200.0	9319.0	29860.0	27560.0	25750.0	14290.0	122448.1	1955
7	4951.0	1900.0	1300.0	980.0	970.0	940.0	950.0	17660.0	33340.0	31090.1	24530.0	18330.0	136941.2	1956
8	5806.0	3050.0	2142.0	1700.0	1500.0	1200.0	1200.0	13750.0	30160.0	23310.0	20540.0	19800.0	124158.1	1957
9	8212.0	3954.0	3264.0	1965.0	1307.0	1148.0	1533.0	12900.0	25700.0	22880.0	22540.0	7550.0	112953.1	1958
10	4811.0	2150.0	1513.0	1448.0	1307.0	980.0	1250.0	15990.0	23320.0	25000.0	31180.0	16920.0	125869.1	1959
11	6558.0	2850.0	2200.0	1845.0	1452.0	1197.0	1300.0	15780.0	15530.0	22980.0	23590.0	20510.0	115792.1	1960
12	7794.0	3000.0	2694.0	2452.0	1754.0	1810.0	2650.0	17360.0	29450.0	24570.0	22100.0	13370.0	129004.1	1961
13	5916.0	2700.0	2100.0	1900.0	1500.0	1400.0	1700.0	12590.0	43270.0	25850.0	23550.0	15890.0	138366.0	1962
14	6723.0	2800.0	2000.0	1600.0	1500.0	1000.0	830.0	19030.0	26000.0	34400.0	23670.0	12320.0	131873.0	1963
15	6449.0	2250.0	1494.0	1048.0	966.0	713.0	745.0	4307.0	50580.0	22950.0	16440.0	9571.0	117513.1	1964
16	6291.0	2799.0	1211.0	960.0	860.0	900.0	1360.0	12990.0	25720.0	27840.0	21120.0	19350.0	121401.1	1965
17	7205.0	2098.0	1631.0	1400.0	1300.0	1300.0	1775.0	9645.0	32950.0	19860.0	21830.0	11750.0	112744.1	1966
18	4163.0	1600.0	1500.0	1500.0	1400.0	1200.0	1167.0	15480.0	29510.0	26800.0	32620.0	16870.0	133810.1	1967
19	4900.0	2353.0	2055.0	1981.0	1900.0	1900.0	1910.0	16180.0	31550.0	26420.0	17170.0	8816.0	117135.1	1968
20	3822.0	1630.0	882.0	724.0	723.0	816.0	1510.0	11050.0	15500.0	16100.0	8879.0	5093.0	66729.0	1969
21	3124.0	1215.0	866.0	824.0	768.0	776.0	1080.0	11380.0	18630.0	22660.0	19980.0	9121.0	90424.1	1970
22	5288.0	3407.0	2290.0	1442.0	1036.0	950.0	1082.0	3745.0	32930.0	23950.0	31910.0	14440.0	122470.1	1971
23	5847.0	3093.0	2510.0	2239.0	2028.0	1823.0	1710.0	21890.0	34430.0	22770.0	19290.0	12400.0	130030.1	1972
24	4826.0	2253.0	1465.0	1200.0	1200.0	1000.0	1027.0	8235.0	27800.0	18250.0	20290.0	9074.0	96620.1	1973
25	3733.0	1523.0	1034.0	874.0	777.0	724.0	992.0	16180.0	17870.0	18800.0	16220.0	12250.0	90977.1	1974
26	3739.0	1700.0	1603.0	1516.0	1471.0	1400.0	1593.0	15350.0	32310.0	27720.0	18090.0	16310.0	122802.1	1975
27	7739.0	1993.0	1081.0	974.0	950.0	900.0	1373.0	12620.0	24380.0	18940.0	19800.0	6881.0	97631.1	1976
28	3874.0	2650.0	2403.0	1829.0	1618.0	1500.0	1680.0	12680.0	37970.0	22870.0	19240.0	12640.0	120954.1	1977
29	7571.0	3525.0	2589.0	2029.0	1668.0	1605.0	1702.0	11950.0	19050.0	21020.0	16390.0	8607.0	97706.1	1978
30	4907.0	2535.0	1681.0	1397.0	1286.0	1200.0	1450.0	13870.0	24690.0	28880.1	20460.0	10770.0	113126.1	1979

TABLE E.15 DENALI FILLED DATA SET

SITE NO.= 2 RUNF DENALI

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	SUMYR	CALYR
1	1272.9	591.5	321.0	382.5	251.2	230.7	258.8	2152.1	6977.0	9185.2	7934.9	1794.5	31352.3	1950
2	711.1	242.1	152.4	122.9	113.9	101.8	315.8	1560.0	6155.5	8022.1	5167.0	2860.2	25524.6	1951
3	1084.4	549.7	336.5	297.5	198.9	170.9	178.4	1367.4	8032.3	9411.0	7715.6	3092.5	32435.7	1952
4	1028.2	391.1	232.2	238.7	134.7	77.9	216.0	1601.3	6270.8	8950.7	6349.5	2255.9	27747.2	1953
5	914.7	192.2	145.5	84.8	64.3	88.7	217.3	2593.9	5077.0	7864.5	6286.8	2287.0	25816.8	1954
6	1120.6	546.8	450.0	299.3	229.1	146.6	164.2	1380.0	7192.5	10378.4	10047.8	2831.5	34786.8	1955
7	1455.2	373.7	247.4	196.5	300.4	275.0	249.3	4259.3	9754.7	9449.4	5306.8	3242.2	35109.9	1956
8	1057.7	475.1	439.7	650.9	422.4	287.1	291.9	3017.3	12210.0	11170.0	9769.0	4017.0	43808.1	1957
9	1277.0	610.0	288.0	219.0	150.0	120.0	210.0	1163.0	8367.0	9150.0	6536.0	1879.0	29969.0	1958
10	939.0	390.0	170.0	119.0	81.0	41.7	43.0	1782.0	8891.0	8333.0	7882.0	2498.0	31169.7	1959
11	1577.0	760.0	575.0	444.0	321.0	275.0	265.0	3349.0	5237.0	9039.0	7910.0	4817.0	34569.0	1960
12	1781.0	660.0	483.0	331.0	271.0	281.0	415.0	2959.0	6412.0	8078.0	7253.0	2695.0	31619.0	1961
13	1290.0	680.0	440.0	280.0	240.0	220.0	280.0	2197.0	9087.0	10220.0	9454.0	3649.0	38037.0	1962
14	1079.0	510.0	310.0	250.0	230.0	200.0	210.0	3253.0	6763.0	10500.0	10210.0	3949.0	37464.0	1963
15	925.0	290.0	185.0	140.0	140.0	110.0	130.0	910.0	11630.0	7577.0	6552.0	2633.0	31222.0	1964
16	1468.0	702.0	279.0	220.0	200.0	208.0	320.0	2464.0	4647.0	6756.0	5764.0	6955.0	29983.0	1965
17	920.0	300.0	240.0	210.0	200.0	200.0	280.0	1629.0	6850.0	8287.0	6432.0	3200.0	28748.0	1966
18	920.0	300.0	240.0	210.0	200.0	200.0	280.0	1629.0	6850.0	8287.0	6432.0	3200.0	28748.0	1967
19	973.5	616.9	323.6	189.0	266.9	266.7	325.0	1495.3	6138.2	11840.0	9825.0	2192.0	34452.1	1968
20	700.0	304.0	172.0	145.0	140.0	145.0	229.0	1768.0	8146.0	9445.0	3919.0	2213.0	27326.0	1969
21	1002.0	501.0	339.0	265.0	221.0	193.0	319.0	2210.0	5013.0	8454.0	6216.0	1946.0	26679.0	1970
22	528.0	395.0	276.0	170.0	125.0	120.0	135.0	629.0	8099.0	10410.0	10400.0	3288.0	34575.0	1971
23	1039.0	478.0	380.0	339.0	307.0	286.0	270.0	3468.0	6562.0	10450.0	8664.0	2778.0	35021.0	1972
24	667.0	323.0	211.0	178.0	164.0	153.0	153.0	1042.0	5741.0	8346.0	7268.0	2445.0	26691.0	1973
25	876.0	462.0	366.0	310.0	271.0	235.0	262.0	2541.0	5642.0	9547.0	9292.0	5452.0	35256.0	1974
26	2135.0	673.0	381.0	300.0	200.0	200.0	200.0	1640.0	7040.0	12110.0	7295.0	3571.0	35745.0	1975
27	1539.0	375.0	169.0	112.0	97.0	90.0	123.0	1805.0	5939.0	8558.0	10080.0	1822.0	30709.0	1976
28	894.0	467.0	331.0	266.0	240.0	231.0	246.0	1498.0	8253.0	10010.0	10180.0	3707.0	36323.0	1977
29	1148.0	652.0	439.0	348.0	300.0	246.0	263.0	2031.0	5250.0	8993.0	8644.0	3622.0	31936.0	1978
30	865.0	463.0	312.0	263.0	229.0	203.0	250.0	2791.0	7650.0	9504.0	9178.0	4512.0	36220.0	1979

TABLE E.16 MACLAREN FILLED DATA SET

SITE NO.= 3 RUNF MC LAREN

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	SUMYR	CALYR
1	503.2	195.6	96.7	90.2	110.8	65.7	63.4	705.9	2345.7	3029.7	2394.7	555.6	10157.2	1950
2	286.9	97.8	50.9	48.3	50.7	35.8	96.3	783.1	2380.2	2966.1	2530.5	2085.4	11412.0	1951
3	381.7	160.9	115.3	99.6	66.8	50.7	51.6	322.9	2752.2	3533.1	3092.9	1692.7	12320.5	1952
4	449.3	156.6	69.7	61.6	46.0	50.8	82.8	520.6	2403.9	2924.6	2601.9	979.1	10346.8	1953
5	370.7	131.4	85.7	100.3	56.3	45.8	68.7	2083.7	3332.7	3132.4	2797.8	885.9	13091.4	1954
6	368.2	159.9	102.9	97.3	107.0	73.0	72.8	397.9	2889.5	3137.6	3741.1	1748.4	12895.7	1955
7	604.3	246.2	102.6	66.5	105.2	83.4	103.3	1549.8	3303.3	3415.6	2178.4	1080.7	12839.4	1956
8	287.5	125.8	96.1	88.4	70.5	92.4	71.5	682.8	3158.5	3271.5	2246.0	1528.9	11719.8	1957
9	430.3	171.1	118.6	108.7	80.8	64.0	118.1	828.0	3532.0	3525.0	2699.0	784.0	12459.8	1958
10	378.0	115.0	123.0	129.0	95.4	62.5	77.5	587.0	2879.0	2680.0	2083.0	856.0	10065.4	1959
11	549.0	250.0	190.0	150.0	110.0	94.3	91.5	1742.0	2124.0	3359.0	3048.0	2439.0	14146.8	1960
12	687.0	195.0	149.0	110.0	93.9	96.0	145.0	1237.0	2678.0	3369.0	3299.0	1168.0	13226.9	1961
13	381.0	210.0	170.0	120.0	100.0	92.0	120.0	632.0	2916.0	3265.0	2927.0	1127.0	12060.0	1962
14	383.0	210.0	130.0	100.0	91.0	80.0	83.0	2131.0	3110.0	4649.0	3136.0	1213.0	15316.0	1963
15	416.0	140.0	98.0	85.0	88.0	71.0	72.0	386.0	4297.0	2764.0	2224.0	871.0	11512.0	1964
16	379.0	147.0	49.3	44.0	42.0	41.0	62.0	984.0	2268.0	3223.0	2409.0	2098.0	11746.3	1965
17	522.0	180.0	55.0	45.0	45.0	43.0	50.0	265.0	2990.0	2505.0	2095.0	954.0	9749.0	1966
18	369.0	95.0	70.0	65.0	60.0	55.0	53.3	1023.0	3634.0	3255.0	3605.0	1416.0	13700.3	1967
19	417.0	130.0	100.0	97.4	95.0	95.0	95.0	208.0	3245.0	3427.0	2129.0	680.0	10718.4	1968
20	265.0	121.0	68.5	58.2	55.0	57.6	95.3	849.0	2613.0	2692.0	974.0	470.0	8318.6	1969
21	249.0	117.0	73.2	59.4	50.4	52.7	69.2	746.0	1751.0	2441.0	2367.0	773.0	8748.9	1970
22	301.0	192.0	131.0	83.4	60.4	55.0	66.0	365.0	3414.0	3528.0	3659.0	1165.0	13019.8	1971
23	375.0	156.0	123.0	115.0	107.0	97.4	98.5	1218.0	3069.0	3255.0	2676.0	1366.0	12655.9	1972
24	550.0	243.0	136.0	87.4	65.2	53.4	51.2	576.0	2906.0	2856.0	2271.0	821.0	10616.2	1973
25	307.0	123.0	82.6	68.5	61.8	56.6	56.7	649.0	2069.0	2634.0	2439.0	1543.0	10090.2	1974
26	385.0	232.0	140.0	115.0	110.0	100.0	103.0	768.0	3178.0	3649.0	1982.0	1574.0	12336.0	1975
27	553.0	235.0	139.0	106.0	94.1	90.0	105.0	781.0	2870.0	2810.0	2604.0	600.0	10987.1	1976
28	302.0	168.0	119.0	97.3	92.0	90.0	92.9	366.0	3942.0	3834.0	3394.0	1297.0	13794.2	1977
29	512.0	265.0	186.0	162.0	140.0	121.0	134.0	709.0	2317.0	3196.0	2356.0	924.0	11022.0	1978
30	307.0	192.0	142.0	122.0	110.0	100.0	111.0	634.0	2430.0	3056.0	2223.0	1137.0	10564.0	1979

TABLE E.17 SKWENTNA FILLED DATA SET

SITE NO.= 4 RUNF SKWENTNA

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	SUMYR	CALYR
1	3914.4	1208.1	1012.1	720.8	695.3	753.7	932.7	10833.8	16583.8	16325.4	12895.4	5176.6	71052.2	1950
2	2741.5	747.5	628.3	733.7	891.9	768.4	1460.6	10775.6	13874.9	15583.3	11340.5	7822.1	67368.3	1951
3	3116.0	1552.9	924.2	1074.9	822.8	696.0	864.9	8077.6	22948.5	17793.5	11668.3	5492.4	75032.1	1952
4	4024.5	1106.4	824.1	1013.5	828.6	775.4	1018.4	8743.6	13573.8	14073.4	9533.7	4786.8	60302.1	1953
5	2723.1	1228.7	698.8	687.2	490.2	562.7	766.2	11172.8	19246.9	12761.3	17702.9	10650.8	78691.7	1954
6	4211.4	1223.2	1202.3	1191.9	686.6	732.0	911.7	11900.3	40356.0	24816.5	20590.6	9652.0	117474.5	1955
7	5923.6	2831.9	1506.0	854.4	996.2	707.1	943.5	17845.3	34533.9	23137.7	14854.5	13371.3	117505.5	1956
8	4936.3	3094.2	1989.7	2165.8	1130.2	1144.0	900.7	5015.3	29642.6	19122.7	13917.9	8835.0	91894.4	1957
9	5544.7	2174.4	976.2	600.4	613.5	761.4	1253.5	12067.6	19677.0	17800.6	15359.6	6205.8	83034.6	1958
10	4038.4	1184.7	761.1	1091.1	629.9	522.0	759.8	4698.4	13830.5	15086.5	11729.1	4937.1	59268.6	1959
11	3532.0	1850.0	1400.0	1097.0	961.0	843.0	835.0	10480.0	13440.0	16690.0	15990.0	9171.0	76289.0	1960
12	3889.0	1600.0	1597.0	1403.0	1154.0	1155.0	1700.0	11210.0	20570.0	16480.0	13910.0	12020.0	86688.0	1961
13	4605.0	2200.0	1400.0	1200.0	860.0	760.0	1000.0	6613.0	15630.0	14930.0	12080.0	6723.0	68001.0	1962
14	2801.0	1250.0	1100.0	1000.0	810.0	700.0	650.0	7765.0	14050.0	20430.0	12020.0	7180.0	69756.1	1963
15	5355.0	1550.0	840.0	970.0	750.0	600.0	840.0	1635.0	27250.0	16480.0	12680.0	6224.0	75174.1	1964
16	4425.0	1790.0	1300.0	920.0	800.0	740.0	770.0	4810.0	17160.0	19370.0	14010.0	13090.0	79185.1	1965
17	4122.0	1575.0	1150.0	1100.0	1100.0	1100.0	1300.0	4502.0	19550.0	14180.0	17320.0	9812.0	76811.1	1966
18	5576.0	1400.0	900.0	720.0	650.0	650.0	780.0	1794.0	14430.0	14740.0	15760.0	9517.0	66917.0	1967
19	3832.0	1560.0	1181.0	1023.0	1000.0	950.0	1293.0	13460.0	20770.0	17480.0	10560.0	3855.0	76964.1	1968
20	1929.0	678.0	624.0	600.0	600.0	626.0	1487.0	11070.0	19580.0	13650.0	7471.0	3783.0	62098.1	1969
21	5654.0	1607.0	832.0	766.0	700.0	650.0	728.0	11710.0	22880.0	21120.0	13030.0	6665.0	86342.1	1970
22	2919.0	2023.0	1184.0	865.0	721.0	613.0	607.0	5963.0	25400.0	20600.0	15920.0	6024.0	82839.1	1971
23	3020.0	1327.0	1103.0	989.0	898.0	811.0	742.0	8045.0	15330.0	16840.0	13370.0	9256.0	71731.0	1972
24	4551.0	2340.0	1316.0	910.0	702.0	606.0	727.0	6349.0	15200.0	13850.0	9874.0	6164.0	62589.0	1973
25	3540.0	1700.0	1265.0	1023.0	902.0	811.0	1005.0	6765.0	10650.0	11670.0	10480.0	11800.0	61611.0	1974
26	4557.0	2328.0	919.0	800.0	750.0	750.0	767.0	7852.0	19060.0	19520.0	11710.0	8471.0	77484.1	1975
27	4704.0	1973.0	1258.0	971.0	897.0	800.0	1270.0	8806.0	15120.0	14580.0	11120.0	8165.0	69664.0	1976
28	6196.0	2880.0	2871.0	2829.0	1821.0	1200.0	1200.0	8906.0	36670.0	25270.0	20160.0	10290.0	120293.1	1977
29	5799.0	2373.0	1548.0	1213.0	944.0	841.0	1023.0	9006.0	13840.0	18100.0	13740.0	7335.0	75762.0	1978
30	4936.0	1580.0	1555.0	1165.0	1036.0	981.0	1597.0	11660.0	14980.0	15830.0	16210.0	7448.0	78978.0	1979

TABLE E.18 TALKEETNA FILLED DATA SET

SITE NO.= 5 RUNF TALKEETNA

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	SUMYR	CALYR
1	3895.8	1576.9	1026.9	614.5	468.3	396.8	384.3	4318.5	8918.1	11734.6	10605.3	5210.8	49150.8	1950
2	2319.4	770.3	514.5	536.3	402.6	378.6	607.0	3155.9	7542.5	10122.6	9355.4	8464.7	44169.7	1951
3	2387.8	1094.8	779.8	582.5	466.5	412.8	489.3	2638.3	11368.8	9476.0	8289.7	7047.8	45034.1	1952
4	3188.0	1554.7	931.0	635.0	470.4	453.2	652.5	4946.2	9867.9	9499.4	8028.7	5615.6	45842.6	1953
5	2023.6	1134.0	693.2	648.8	472.1	386.2	429.2	3563.7	9554.8	10044.6	18033.2	6924.8	53908.1	1954
6	2426.0	926.2	632.4	594.4	522.0	444.2	450.1	2529.8	10206.6	12340.6	14206.1	6302.3	51580.8	1955
7	2290.7	1033.4	789.1	629.9	628.2	502.4	497.1	6414.7	14813.5	11720.6	12931.5	8179.4	60430.4	1956
8	3017.4	1786.3	1034.0	707.3	605.6	501.6	524.4	4355.4	12778.8	10847.8	11373.2	9326.5	56858.4	1957
9	3662.4	1688.5	1014.7	822.1	609.3	515.3	705.2	4462.7	16038.6	13653.5	12199.7	4513.8	59885.9	1958
10	2424.2	820.8	614.8	578.9	526.5	436.2	568.5	4173.6	7498.7	10509.2	13065.2	7053.4	48270.0	1959
11	2946.6	932.5	802.8	623.0	478.5	411.7	496.4	3826.2	5317.8	9181.2	12318.5	7648.0	44983.2	1960
12	3264.0	1485.1	1239.1	1001.4	804.9	621.0	741.9	4106.8	15161.4	12515.9	14030.1	7879.3	62850.7	1961
13	3095.2	1554.6	1033.9	814.9	734.5	569.1	648.2	3259.9	16992.5	9664.8	9289.7	5663.1	53320.4	1962
14	3576.4	1377.5	1107.3	776.7	700.4	537.3	454.8	4327.7	9949.3	13023.0	10087.2	3777.5	49695.1	1963
15	2839.9	916.2	693.0	528.9	440.3	383.6	371.2	1694.3	17080.0	9820.0	8396.0	3815.0	46978.4	1964
16	3115.0	1568.0	1100.0	720.0	620.0	540.0	580.0	3474.0	11090.0	12180.0	11150.0	10610.0	56747.0	1965
17	4438.0	1460.0	876.0	711.0	526.0	395.0	422.0	2410.0	12970.0	10100.0	10730.0	5370.0	50408.0	1966
18	2308.0	897.0	750.0	637.0	546.0	471.0	427.0	4112.0	9286.0	12600.0	14160.0	6971.0	53245.0	1967
19	2029.0	1253.0	987.0	851.0	777.0	743.0	983.0	8840.0	14100.0	11230.0	7546.0	4120.0	53459.0	1968
20	1637.0	827.0	556.0	459.0	401.0	380.0	519.0	3869.0	5207.0	7080.0	3787.0	2070.0	26792.0	1969
21	1450.0	765.0	587.0	504.0	458.0	440.0	545.0	3950.0	7979.0	10320.0	8752.0	5993.0	41743.0	1970
22	2817.0	1647.0	1103.0	679.0	459.0	402.0	503.0	2145.0	19040.0	11760.0	16770.0	5990.0	63315.0	1971
23	2632.0	1310.0	845.0	727.0	628.0	481.0	519.0	3516.0	12700.0	12030.0	9576.0	8709.0	53673.0	1972
24	3630.0	1373.0	889.0	748.0	654.0	574.0	577.0	3860.0	12210.0	7676.0	9927.0	3861.0	45979.0	1973
25	1807.0	960.0	745.0	645.0	559.0	482.0	535.0	5678.0	8030.0	7755.0	7704.0	4763.0	39663.0	1974
26	1967.0	1002.0	774.0	694.0	586.0	508.0	522.0	4084.0	13180.0	12070.0	8487.0	7960.0	51834.0	1975
27	2884.0	773.0	558.0	524.0	480.0	470.0	613.0	3439.0	10580.0	9026.0	8088.0	3205.0	40640.0	1976
28	1857.0	1105.0	1069.0	700.0	549.0	506.0	548.0	4244.0	18280.0	9344.0	8005.0	5826.0	52033.0	1977
29	3268.0	1121.0	860.0	746.0	576.0	485.0	534.0	2950.0	7429.0	10790.0	7001.0	3567.0	39327.0	1978
30	1660.0	1138.0	932.0	762.0	652.0	577.0	710.0	7790.0	12010.0	14440.0	8274.0	4039.0	52984.0	1979

TABLE E.19 CANTWELL FILLED DATA SET

SITE NO.= 6 RUNF CANTWELL

YEAR	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	SUMYR	CALYR
1	4218.3	1824.1	924.6	828.3	662.6	562.7	618.3	7827.5	15670.4	16690.4	13901.9	5631.6	69360.7	1950
2	2710.0	889.0	710.7	556.2	494.8	409.5	999.4	6194.6	12003.0	14652.4	11642.8	11693.5	62955.8	1951
3	3255.8	1575.1	956.5	740.4	492.3	560.5	639.3	2642.7	16465.7	17394.7	13705.1	8185.0	66613.1	1952
4	3431.2	1668.6	932.4	731.2	511.6	476.7	833.7	5960.2	13671.0	13140.8	11158.3	5876.8	58392.4	1953
5	2334.1	916.8	794.1	708.4	482.6	443.3	638.4	7852.1	16795.4	16371.9	19033.7	9832.6	76203.3	1954
6	3293.4	1784.7	1105.3	930.6	797.6	491.0	563.2	3014.7	14675.8	16621.7	12900.7	6064.7	62243.4	1955
7	2465.1	1075.3	855.2	684.3	727.2	614.7	569.2	8231.9	20082.3	18916.4	14164.8	8487.2	76873.6	1956
8	2547.4	1279.1	902.1	888.4	843.4	851.3	802.6	8230.5	19438.8	16361.0	13422.6	8899.4	74466.8	1957
9	3410.4	2051.9	1096.8	876.9	592.2	454.1	689.9	3004.9	13973.2	15743.3	12723.2	4464.4	59081.3	1958
10	2690.1	969.6	733.6	661.7	644.9	501.2	671.2	7894.5	16362.3	15620.2	16790.6	8063.5	71603.4	1959
11	3711.0	1718.7	1187.7	1042.0	826.4	695.6	785.6	13750.5	11108.1	16291.3	17056.1	12704.7	80877.7	1960
12	4625.6	2012.7	1534.8	1207.4	984.7	1056.1	1701.7	9688.0	15710.0	14820.0	16700.0	6725.0	76766.0	1961
13	3281.0	1800.0	1400.0	1300.0	1000.0	940.0	1200.0	10000.0	28320.1	20890.0	16000.0	9410.0	95541.1	1962
14	4326.0	2200.0	1400.0	1000.0	850.0	760.0	720.0	11340.0	15000.0	22790.0	18190.0	9187.0	87763.1	1963
15	3848.0	1300.0	877.0	644.0	586.0	429.0	465.0	2806.0	34630.0	17040.0	11510.0	5352.0	79487.0	1964
16	3134.0	1911.0	921.0	760.0	680.0	709.0	1097.0	8818.0	16430.0	18350.0	13440.0	12910.0	79160.1	1965
17	3116.0	1000.0	750.0	700.0	650.0	650.0	875.0	4387.0	18500.0	12220.0	12680.0	6523.0	62051.0	1966
18	2322.0	780.0	720.0	680.0	640.0	560.0	513.0	9452.0	19620.0	16880.0	19190.0	10280.0	81637.1	1967
19	3084.0	1490.0	1332.0	1232.0	1200.0	1200.0	1223.0	9268.0	19500.0	17480.0	10940.0	5410.0	73359.1	1968
20	2406.0	1063.0	618.0	508.0	485.0	548.0	998.0	7471.0	12330.0	13510.0	6597.0	3376.0	49910.0	1969
21	1638.0	815.0	543.0	437.0	426.0	463.0	887.0	7580.0	9909.0	13900.0	12320.0	5211.0	54129.0	1970
22	2155.0	1530.0	1048.0	731.0	503.0	470.0	529.0	1915.0	21970.0	18130.0	22710.0	9800.0	81491.1	1971
23	4058.0	2050.0	1371.0	1068.0	922.0	881.0	876.0	9694.0	20000.0	16690.0	15620.0	9423.0	82653.0	1972
24	3619.2	1962.0	1138.5	895.6	778.9	638.9	723.2	4763.6	16762.6	12619.1	12379.8	5037.5	61318.9	1973
25	2037.4	929.4	651.2	583.7	467.7	407.8	553.0	9163.1	12544.9	13434.2	11833.3	7888.1	60493.8	1974
26	2108.9	1191.4	929.8	812.5	779.6	669.5	807.2	5583.5	19277.4	20812.1	14871.9	10648.4	78492.2	1975
27	3879.3	1052.1	564.4	549.6	529.7	496.4	628.4	4788.3	16571.4	14057.3	14468.0	4585.6	62170.6	1976
28	2198.5	1195.9	1150.1	848.6	689.9	777.8	996.2	9619.2	30705.6	16666.4	13242.6	7420.0	84510.7	1977
29	3968.8	1833.7	1263.7	1192.1	1034.4	1272.7	1368.8	7819.4	15655.3	16812.8	10181.5	5488.6	67891.8	1978
30	2345.0	1288.6	1032.3	878.5	808.3	746.7	870.6	6209.9	15598.4	18493.7	12750.7	7320.9	68343.7	1979

TABLE E.21 COMPUTED STREAMFLOW AT DEVIL CANYON

~~5758.2~~	~~2404.7~~	~~1342.5~~	~~951.3~~	~~735.7~~	~~670.0~~	~~802.2~~	~~10490.7~~	~~18468.6~~	~~21383.4~~	~~18820.6~~	~~7950.8~~
3652.0	1231.2	1030.8	905.7	767.5	697.1	1504.6	13218.5	19978.5	21575.9	18530.0	19799.1
5221.7	2539.0	1757.5	1483.7	943.2	828.2	878.5	4989.5	30014.2	24861.7	19647.2	13441.1
~~7517.6~~	~~3232.6~~	~~1550.4~~	~~999.6~~	~~745.6~~	~~766.7~~	~~1531.8~~	~~17758.3~~	~~25230.7~~	~~19184.0~~	~~19207.0~~	~~13928.4~~
5109.3	1921.3	1387.1	1224.2	929.7	729.4	1130.6	15286.0	23188.1	19154.1	24071.6	11579.1
4830.4	2506.8	1868.0	1649.1	1275.2	1023.6	1107.4	8390.1	28081.9	26212.8	24959.6	13989.2
~~4647.9~~	~~1788.6~~	~~1206.6~~	~~921.7~~	~~893.1~~	~~852.3~~	~~867.3~~	~~15979.0~~	~~31137.1~~	~~29212.0~~	~~22609.8~~	~~16495.8~~
5235.3	2773.8	1986.6	1583.2	1388.9	1105.4	1109.0	12473.6	28415.4	22109.6	19389.2	18029.0
7434.5	3590.4	2904.9	1792.0	1212.2	1085.7	1437.4	11849.2	24413.5	21763.1	21219.8	6988.8
~~4402.8~~	~~1999.8~~	~~1370.9~~	~~1316.9~~	~~1179.1~~	~~877.9~~	~~1119.9~~	~~13900.9~~	~~21537.7~~	~~23390.4~~	~~28594.4~~	~~15329.6~~
6060.7	2622.7	2011.5	1686.2	1340.2	1112.8	1217.8	14802.9	14709.8	21739.3	22066.1	18929.9
7170.9	2759.9	2436.6	2212.0	1593.6	1638.9	2405.4	16030.7	27069.3	22880.6	21164.4	12218.6
~~5459.4~~	~~2544.1~~	~~1978.7~~	~~1796.0~~	~~1413.4~~	~~1320.3~~	~~1613.4~~	~~12141.2~~	~~40679.7~~	~~24990.6~~	~~22241.8~~	~~14767.2~~
6307.7	2696.0	1896.0	1496.0	1387.4	938.4	810.9	17697.6	24094.1	32388.4	22720.5	11777.2
5998.3	2085.4	1387.1	978.0	900.2	663.8	696.5	4046.9	47816.4	21926.0	15585.8	8840.0
~~5744.0~~	~~2645.1~~	~~1160.8~~	~~925.3~~	~~828.8~~	~~866.9~~	~~1314.4~~	~~12267.1~~	~~24110.3~~	~~26195.7~~	~~19789.3~~	~~18234.2~~
6496.5	1907.8	1478.4	1278.7	1187.4	1187.4	1619.1	8734.0	30446.3	18536.2	20244.6	10844.3
3844.0	1457.9	1364.9	1357.9	1268.3	1089.1	1053.7	14435.5	27796.4	25081.2	30293.0	15728.2
~~4585.3~~	~~2203.5~~	~~1929.7~~	~~1851.2~~	~~1778.7~~	~~1778.7~~	~~1791.0~~	~~14982.4~~	~~29462.1~~	~~24871.0~~	~~16090.5~~	~~8225.9~~
3576.7	1531.8	836.3	686.6	681.8	769.6	1421.3	10429.9	14950.7	15651.2	8483.6	4795.5
2866.5	1145.7	810.0	756.9	708.7	721.8	1046.6	10721.6	17118.9	21142.2	18652.8	8443.5
~~4745.2~~	~~3081.8~~	~~2074.8~~	~~1318.8~~	~~943.6~~	~~866.8~~	~~986.2~~	~~3427.9~~	~~31031.0~~	~~22941.6~~	~~30315.9~~	~~13636.0~~
5537.0	2912.3	2312.6	2036.1	1836.4	1659.8	1565.5	19776.8	31929.8	21716.5	18654.1	11884.2
4638.6	2154.8	1387.0	1139.8	1128.6	955.0	986.7	7896.4	26392.6	17571.8	19478.1	8726.0
~~3491.4~~	~~1462.9~~	~~997.4~~	~~842.7~~	~~745.9~~	~~689.5~~	~~949.1~~	~~15004.6~~	~~16766.7~~	~~17790.0~~	~~15257.0~~	~~11370.1~~
3506.8	1619.4	1486.5	1408.8	1342.2	1271.9	1456.7	14036.5	30302.6	26188.0	17031.6	15154.7
7003.3	1853.0	1007.9	896.8	876.2	825.2	1261.2	11305.3	22813.6	18252.6	19297.7	6463.3
~~3552.4~~	~~2391.7~~	~~2147.5~~	~~1657.4~~	~~1469.7~~	~~1361.0~~	~~1509.8~~	~~11211.9~~	~~35606.7~~	~~21740.5~~	~~18371.2~~	~~11916.1~~
6936.3	3210.8	2371.4	1867.9	1525.0	1480.6	1597.1	11693.4	18416.8	20079.0	15326.5	8080.4
4502.3	2324.3	1549.4	1304.1	1203.6	1164.7	1402.8	13334.0	24052.4	27462.8	19106.7	10172.4

TABLE E.22 COMPUTED STREAMFLOW AT HIGH DEVIL CANYON

5675.8	2379.2	1328.8	940.5	728.3	662.0	792.5	10345.1	18307.0	21209.6	18669.2	7900.8
3624.0	1221.3	1020.9	898.0	760.0	691.0	1488.5	13094.0	19862.6	21433.9	18367.1	19593.3
5171.8	2509.7	1737.1	1467.1	935.1	820.8	872.6	4928.2	29677.6	24643.4	19465.4	13292.7
7419.8	3194.9	1529.1	985.3	735.0	759.1	1519.9	17542.3	24932.2	19038.9	19006.6	13736.7
5038.7	1895.7	1371.0	1213.4	919.6	722.1	1115.7	15001.1	22893.5	18981.9	23781.9	11387.6
4753.3	2470.7	1842.8	1628.4	1257.3	1012.7	1094.2	8257.4	27827.9	26020.4	24846.7	13946.2
4604.6	1772.7	1193.3	913.4	882.2	839.8	855.4	15738.9	30822.4	28943.6	22335.5	16233.8
5153.7	2734.3	1964.4	1566.5	1373.0	1091.8	1096.0	12291.3	28166.1	21938.1	19224.8	17776.0
7323.4	3538.4	2853.6	1767.3	1198.7	1076.8	1423.8	11699.1	24229.7	21603.5	21031.2	6908.6
4344.5	1978.4	1350.6	1298.2	1160.9	863.3	1101.3	13602.5	21283.1	23160.5	28225.1	15102.4
5989.6	2590.2	1984.6	1663.5	1324.2	1100.7	1206.1	14663.4	14592.6	21562.1	21848.4	18704.1
7081.9	2725.6	2399.8	2177.7	1570.7	1614.5	2370.4	15840.8	26729.2	22639.3	21030.7	12054.2
5394.2	2521.8	1961.4	1781.2	1401.0	1308.9	1601.0	12077.1	40309.6	24867.8	22055.0	14406.8
6248.3	2681.2	1881.2	1481.2	1371.3	952.5	808.2	17507.2	23821.8	32101.0	22584.9	11699.6
5934.0	2041.9	1371.8	968.0	890.8	656.8	689.6	4009.8	47421.6	21779.7	15463.8	8735.6
5665.9	2623.2	1153.6	920.4	824.4	862.2	1307.9	12163.9	23880.4	25960.8	19599.2	18074.8
6395.3	1880.6	1456.5	1261.4	1171.3	1171.3	1596.8	8603.8	30088.6	18347.1	20018.1	10715.0
3798.4	1437.6	1345.5	1337.6	1249.5	1073.3	1037.5	14286.3	27551.6	24835.6	29960.6	15565.0
4540.4	2182.1	1911.8	1832.7	1761.4	1761.4	1774.0	14811.3	29163.9	24649.7	15936.3	8141.5
3541.6	1517.7	829.7	681.2	675.9	762.9	1408.6	10341.3	14872.3	15587.1	8427.1	4753.0
2829.7	1135.8	802.0	747.4	700.3	714.0	1041.8	10627.5	16903.1	20925.3	18463.2	8346.7
4667.6	3035.3	2044.1	1301.2	930.5	855.0	972.5	3382.6	30759.7	22797.5	30088.2	13521.2
5492.7	2886.5	2284.5	2007.1	1809.0	1636.5	1544.9	19475.0	31572.6	21566.0	18563.3	11810.5
4611.8	2140.7	1375.8	1131.2	1118.5	948.5	980.9	7848.1	26191.5	17475.0	19362.1	8676.3
3456.9	1454.3	992.2	838.3	741.5	684.5	943.0	14836.7	16609.0	17645.7	15119.5	11244.4
3473.6	1607.9	1469.8	1393.5	1323.8	1253.6	1437.2	13848.9	30015.8	25969.1	16880.4	14989.7
6898.2	1833.0	997.4	885.8	865.6	814.6	1245.2	11117.5	22589.8	18154.4	19225.9	6403.7
3506.4	2354.8	2111.0	1632.9	1448.6	1341.1	1485.5	11002.2	35269.1	21579.1	18247.1	11812.7
6845.7	3165.9	2340.3	1844.9	1504.6	1462.8	1582.2	11636.8	18326.4	19944.6	15174.5	8005.2
4444.5	2294.1	1530.6	1290.8	1191.9	1159.7	1396.1	13257.5	23961.3	27260.3	18913.3	10087.0

TABLE E.23 COMPUTED STREAMFLOW AT WATANA

4719.9	2083.6	1168.9	815.1	641.7	569.1	680.1	8655.9	16432.1	19193.4	16913.6	7320.4
~~3299.1~~	~~1107.3~~	~~906.2~~	~~808.0~~	~~673.0~~	~~619.8~~	~~1302.2~~	~~11647.8~~	~~18517.9~~	~~19786.6~~	~~16478.0~~	~~17205.5~~
4592.9	2170.1	1501.0	1274.5	841.0	735.0	803.9	4216.5	25773.4	22110.9	17356.3	11571.0
6285.7	2756.8	1281.2	818.9	611.7	670.7	1382.0	15037.2	21469.8	17355.3	16681.6	11513.5
~~4218.9~~	~~1599.6~~	~~1183.8~~	~~1087.8~~	~~803.1~~	~~638.2~~	~~942.6~~	~~11696.8~~	~~19476.7~~	~~16983.6~~	~~20420.6~~	~~9165.5~~
3859.2	2051.1	1549.5	1388.3	1050.5	886.1	940.8	6718.1	24881.4	23787.9	23537.0	13447.8
4102.3	1588.1	1038.6	816.9	754.8	694.4	718.3	12953.3	27171.8	25831.3	19153.4	13194.4
~~4208.0~~	~~2276.6~~	~~1707.0~~	~~1373.0~~	~~1189.0~~	~~935.0~~	~~945.1~~	~~10176.2~~	~~25275.0~~	~~19948.9~~	~~17317.7~~	~~14841.1~~
6034.9	2935.9	2258.5	1480.6	1041.7	973.5	1265.4	9957.8	22097.8	19752.7	18843.4	5978.7
3668.0	1729.5	1115.1	1081.0	949.0	694.0	885.7	10140.6	18329.6	20493.1	23940.4	12466.9
~~5165.5~~	~~2213.5~~	~~1672.3~~	~~1400.4~~	~~1138.9~~	~~961.1~~	~~1069.9~~	~~13044.2~~	~~13233.4~~	~~19506.1~~	~~19323.1~~	~~16085.6~~
6049.3	2327.8	1973.2	1779.9	1304.8	1331.0	1965.0	13637.9	22784.1	19839.8	19480.2	10146.2
4637.6	2263.4	1760.4	1608.9	1257.4	1176.8	1457.4	11333.5	36017.1	23443.7	19887.1	12746.2
~~5560.1~~	~~2508.9~~	~~1708.9~~	~~1308.9~~	~~1184.7~~	~~883.6~~	~~776.6~~	~~15299.2~~	~~20663.4~~	~~28767.4~~	~~21011.4~~	~~10800.0~~
5187.1	1789.1	1194.7	852.0	781.6	575.2	609.2	3578.8	42841.9	20082.8	14048.2	7524.2
4759.4	2368.2	1070.3	863.0	772.7	807.3	1232.4	10966.0	21213.0	23235.9	17394.1	16225.6
~~5221.2~~	~~1565.3~~	~~1203.6~~	~~1060.4~~	~~984.7~~	~~984.7~~	~~1338.4~~	~~7094.1~~	~~25939.6~~	~~16153.5~~	~~17390.9~~	~~9214.1~~
3269.8	1202.2	1121.6	1102.2	1031.3	889.5	849.7	12535.5	24711.9	21987.3	26104.5	13672.9
4019.0	1934.3	1704.2	1617.6	1560.4	1560.4	1576.7	12826.7	25704.0	22082.8	14147.5	7163.6
~~3135.0~~	~~1354.9~~	~~753.9~~	~~619.2~~	~~607.5~~	~~686.0~~	~~1261.6~~	~~9313.7~~	~~13962.1~~	~~14843.5~~	~~7771.9~~	~~4260.0~~
2403.1	1020.9	709.3	636.2	602.1	624.1	986.4	9536.4	14399.0	18410.1	16263.8	7224.1
3768.0	2496.4	1687.4	1097.1	777.4	717.1	813.7	2857.2	27612.8	21126.4	27446.6	12188.9
~~4979.1~~	~~2587.0~~	~~1957.4~~	~~1670.9~~	~~1491.4~~	~~1366.0~~	~~1305.4~~	~~15973.1~~	~~27429.3~~	~~19820.3~~	~~17509.5~~	~~10955.7~~
4301.2	1977.9	1246.5	1031.5	1000.2	873.9	914.1	7287.0	23859.3	16351.1	18016.7	8099.7
3056.5	1354.7	931.6	786.4	689.9	627.3	871.9	12889.0	14780.6	15971.9	13523.7	9786.2
~~3088.8~~	~~1474.4~~	~~1276.7~~	~~1215.8~~	~~1110.3~~	~~1041.4~~	~~1211.2~~	~~11672.2~~	~~26689.2~~	~~23430.4~~	~~15126.6~~	~~13075.3~~
5679.1	1601.1	876.2	757.8	743.2	690.7	1059.8	8938.8	19994.0	17015.3	18393.5	5711.5
2973.5	1926.7	1687.5	1348.7	1202.9	1110.8	1203.4	8569.4	31352.8	19707.3	16807.3	10613.1
~~5793.9~~	~~2645.3~~	~~1979.7~~	~~1577.9~~	~~1267.7~~	~~1256.7~~	~~1408.4~~	~~11231.5~~	~~17277.2~~	~~18385.2~~	~~13412.1~~	~~7132.6~~
3773.9	1944.9	1312.6	1136.8	1055.4	1101.2	1317.9	12369.3	22904.8	24911.7	16670.7	9096.7

TABLE E.24 COMPUTED STREAMFLOW AT SUSITNA 3

SUSITNA 3

~~3137.7~~	~~1594.5~~	~~904.3~~	~~607.5~~	~~498.3~~	~~415.4~~	~~494.0~~	~~5860.1~~	~~13328.9~~	~~15856.4~~	~~14007.7~~	~~6359.8~~
2761.4	918.5	716.3	659.1	529.0	502.1	993.8	9259.4	16292.1	17060.0	13351.1	13253.3
3634.8	1607.9	1110.2	955.6	685.2	592.9	690.2	3038.5	19311.4	17919.1	13865.3	8721.4
~~4408.5~~	~~2031.6~~	~~871.0~~	~~543.5~~	~~407.6~~	~~524.5~~	~~1153.8~~	~~10890.7~~	~~15739.0~~	~~14568.7~~	~~12833.3~~	~~7833.7~~
2862.1	1109.4	874.1	880.0	610.2	499.4	656.3	6227.6	13821.2	13676.0	14857.0	5487.7
2379.1	1356.7	1064.1	990.8	708.1	676.6	686.9	4170.3	20004.4	20092.8	21369.2	12622.8
~~3270.9~~	~~1282.7~~	~~782.5~~	~~657.1~~	~~544.0~~	~~453.8~~	~~491.4~~	~~8342.6~~	~~21129.4~~	~~20679.8~~	~~13886.5~~	~~8163.5~~
2642.6	1519.0	1280.8	1032.6	884.3	675.4	695.4	6675.3	20489.7	16656.5	14161.2	9983.4
3902.2	1938.5	1273.5	1006.0	781.8	802.6	1003.3	7075.7	18569.2	16689.2	15222.2	4439.4
~~2548.4~~	~~1317.5~~	~~725.3~~	~~721.5~~	~~598.2~~	~~413.8~~	~~528.8~~	~~4410.5~~	~~13441.0~~	~~16078.2~~	~~16848.6~~	~~8104.7~~
3801.4	1590.0	1155.3	964.9	832.2	730.1	844.6	10364.3	10983.7	16103.2	15143.3	11751.6
4340.1	1669.3	1267.0	1121.5	864.9	861.8	1294.0	9991.8	16254.2	15206.1	16913.9	6988.2
~~3385.4~~	~~1835.6~~	~~1427.7~~	~~1323.8~~	~~1019.8~~	~~958.2~~	~~1219.8~~	~~10102.6~~	~~28912.2~~	~~21086.4~~	~~16299.0~~	~~9666.6~~
4420.9	2223.8	1423.8	1023.8	875.7	769.5	724.4	11644.6	15435.6	23249.8	18407.0	9311.1
3951.0	1337.6	901.4	660.0	601.0	440.2	476.1	2865.4	35261.7	17274.1	11705.2	5519.1
~~3259.0~~	~~1946.2~~	~~932.5~~	~~767.9~~	~~687.1~~	~~716.6~~	~~1107.4~~	~~8983.2~~	~~16797.9~~	~~18725.8~~	~~13744.2~~	~~13165.0~~
3277.9	1043.5	784.9	727.7	675.7	675.7	910.6	4595.2	19072.3	12522.6	13042.4	6730.0
2394.9	812.5	750.9	712.5	670.1	585.3	538.9	9690.7	20011.7	17272.9	19721.9	10541.0
~~3155.9~~	~~1524.2~~	~~1360.6~~	~~1261.7~~	~~1227.7~~	~~1227.7~~	~~1250.2~~	~~9541.7~~	~~19977.2~~	~~17834.1~~	~~11186.7~~	~~5544.9~~
2462.1	1085.5	628.5	516.6	494.4	558.6	1018.3	7612.7	12455.5	13612.6	6687.4	3444.0
1696.9	830.8	555.8	432.3	439.5	475.4	894.6	7730.5	10254.4	14246.9	12623.4	5365.9
~~2279.1~~	~~1604.3~~	~~1097.2~~	~~759.2~~	~~524.1~~	~~489.0~~	~~550.9~~	~~1987.5~~	~~22404.1~~	~~18360.5~~	~~23074.4~~	~~9983.8~~
4128.9	2091.3	1416.1	1114.4	965.8	918.3	909.0	10177.0	20571.5	16930.8	15765.3	9540.9
3787.1	1708.5	1032.4	866.4	804.5	750.4	803.5	6358.4	19999.0	14491.0	15789.9	7145.3
~~2393.7~~	~~1189.7~~	~~831.4~~	~~700.6~~	~~604.6~~	~~532.6~~	~~754.3~~	~~9665.2~~	~~11754.3~~	~~13201.5~~	~~10882.5~~	~~7372.7~~
2451.8	1253.4	957.1	921.8	757.0	690.1	837.3	8069.4	21183.0	19228.4	12223.6	9906.6
3661.3	1217.2	675.6	546.0	540.7	485.6	733.1	5332.7	15697.4	15129.9	17015.6	4566.0
~~2091.3~~	~~1218.1~~	~~986.6~~	~~878.1~~	~~796.2~~	~~729.6~~	~~736.6~~	~~4542.7~~	~~24870.7~~	~~16609.2~~	~~14424.3~~	~~8627.7~~
4053.2	1783.5	1382.8	1135.9	875.5	915.4	1120.8	10527.7	15540.5	15804.2	10494.9	5688.4
2664.0	1366.9	951.8	881.8	829.4	1004.4	1188.5	10899.3	21155.9	21024.3	12958.6	7457.5

TABLE E.25 COMPUTED STREAMFLOW AT VEE

3005.9	1553.7	882.3	590.2	486.4	402.6	478.5	5627.1	13070.3	15578.3	13765.5	6279.8
2716.6	902.8	700.5	646.7	517.0	492.3	968.1	9060.2	16106.6	16832.8	13090.5	12924.0
3555.0	1561.0	1077.6	929.0	672.2	581.1	680.7	2940.3	18772.9	17569.8	13574.4	8483.9
4252.1	1971.2	836.8	520.6	390.6	512.3	1134.8	10545.2	15261.4	14336.5	12512.6	7527.0
2749.0	1068.5	848.3	862.7	594.1	487.8	632.4	5771.8	13349.9	13400.4	14393.4	5181.2
2255.8	1298.8	1023.7	957.7	679.6	659.1	665.7	3958.0	19598.0	19784.9	21188.5	12554.0
3201.6	1257.2	761.2	643.8	526.4	433.8	472.5	7958.4	20625.9	20250.5	13447.6	7744.3
2512.1	1455.9	1245.3	1025.9	858.9	653.8	674.6	6383.6	20090.9	16382.1	13898.2	9578.6
3724.5	1855.4	1191.4	966.5	760.1	788.4	981.5	6835.5	18275.1	16433.9	14920.4	4311.1
2455.1	1283.2	692.8	691.5	569.0	390.5	499.1	3933.0	13033.6	15710.3	16257.6	7741.2
3687.7	1538.0	1112.2	928.6	806.6	710.8	825.8	10141.0	10796.2	15819.6	14795.0	11390.4
4197.7	1614.4	1208.2	1066.6	828.2	822.7	1230.1	9688.0	15710.0	14820.0	16700.0	6725.0
3281.0	1800.0	1400.0	1300.0	1000.0	940.0	1200.0	10000.0	28320.1	20890.0	16000.0	9410.0
4326.0	2200.0	1400.0	1000.0	850.0	760.0	720.0	11340.0	15000.0	22790.0	18190.0	9187.0
3848.0	1300.0	877.0	644.0	586.0	429.0	465.0	2806.0	34630.0	17040.0	11510.0	5352.0
3134.0	1911.0	921.0	760.0	680.0	709.0	1097.0	8818.0	16430.0	18350.0	13440.0	12910.0
3116.0	1000.0	750.0	700.0	650.0	650.0	875.0	4387.0	18500.0	12220.0	12680.0	6523.0
2322.0	780.0	720.0	680.0	640.0	560.0	513.0	9452.0	19620.0	16880.0	19190.0	10280.0
3084.0	1490.0	1332.0	1232.0	1200.0	1200.0	1223.0	9268.0	19500.0	17480.0	10940.0	5410.0
2406.0	1063.0	618.0	508.0	485.0	548.0	998.0	7471.0	12330.0	13510.0	6597.0	3376.0
1638.0	815.0	543.0	437.0	426.0	463.0	887.0	7580.0	9909.0	13900.0	12320.0	5211.0
2155.0	1530.0	1048.0	731.0	503.0	470.0	529.0	1915.0	21970.0	18130.0	22710.0	9800.0
4058.0	2050.0	1371.0	1068.0	922.0	881.0	876.0	9694.0	20000.0	16690.0	15620.0	9423.0
3744.3	1686.0	1014.6	852.6	788.2	740.1	794.3	6281.0	19677.3	14336.0	15604.3	7065.0
2338.5	1176.0	823.0	693.5	597.5	524.7	744.5	9396.5	11502.1	12970.6	10662.4	7171.6
2398.7	1235.0	930.5	897.3	727.6	660.8	806.1	7769.2	20724.2	18878.2	11981.7	9642.5
3493.1	1185.2	658.9	528.4	523.8	468.5	727.5	5032.2	15339.4	14972.8	16900.8	4470.5
2017.8	1159.1	928.2	838.9	762.3	697.8	697.7	4207.1	24330.5	16351.0	14225.7	8462.2
3908.1	1711.7	1333.1	1099.1	842.8	887.0	1096.8	10469.1	15395.8	15589.1	10251.8	5568.0
2571.5	1318.7	921.7	860.6	810.6	996.3	1177.7	10776.8	21010.2	20700.3	12649.3	7320.9

TABLE E.26 COMPUTED STREAMFLOW AT MACLAREN

1684.5	870.7	494.4	330.7	272.6	225.6	268.1	3153.4	7324.4	8729.9	7714.0	3519.1
~~1522.3~~	~~505.9~~	~~392.6~~	~~362.4~~	~~289.7~~	~~275.9~~	~~542.5~~	~~5077.2~~	~~9025.9~~	~~9432.9~~	~~7335.7~~	~~7242.4~~
1992.2	874.8	603.9	520.6	376.7	325.6	381.5	1647.7	10520.1	9845.9	7606.9	4754.3
2382.8	1104.6	468.9	291.7	218.9	287.1	635.9	5909.4	8552.3	8034.0	7011.9	4218.0
~~1540.5~~	~~598.8~~	~~475.4~~	~~483.4~~	~~332.9~~	~~273.4~~	~~354.4~~	~~3234.4~~	~~7481.1~~	~~7509.4~~	~~8065.9~~	~~2903.5~~
1264.1	727.8	573.7	536.7	380.8	369.4	373.0	2218.0	10982.5	11087.2	11873.7	7035.1
1794.1	704.5	426.6	360.8	295.0	243.1	264.8	4459.8	11558.5	11348.1	7535.9	4339.8
~~1407.7~~	~~815.9~~	~~697.8~~	~~574.9~~	~~481.3~~	~~366.4~~	~~378.0~~	~~3577.3~~	~~11258.7~~	~~9180.3~~	~~7788.4~~	~~5367.7~~
2087.2	1039.7	667.6	541.6	425.9	441.8	550.0	3830.5	10241.1	9209.3	8361.2	2415.9
1375.8	719.1	388.2	387.5	318.9	218.8	279.7	2204.0	7303.9	8803.8	9110.5	4338.1
~~2066.5~~	~~861.9~~	~~623.3~~	~~520.4~~	~~452.0~~	~~398.3~~	~~462.8~~	~~5682.9~~	~~6050.0~~	~~8865.1~~	~~8290.9~~	~~6383.0~~
2352.3	904.7	677.1	597.7	464.1	461.0	693.8	5429.0	8803.7	8304.9	9358.5	3768.6
1838.6	1008.7	784.5	728.5	560.4	526.8	672.5	5603.9	15870.2	11706.5	8966.2	5273.2
~~2424.2~~	~~1232.9~~	~~784.5~~	~~560.4~~	~~476.3~~	~~425.9~~	~~403.5~~	~~6354.8~~	~~8405.8~~	~~12771.2~~	~~10193.4~~	~~5148.3~~
2156.4	728.5	491.5	360.9	328.4	240.4	260.6	1572.4	19406.2	9549.0	6450.0	2999.2
1756.3	1070.9	516.1	425.9	381.1	397.3	614.7	4941.5	9207.1	10283.1	7531.6	7234.6
~~1746.2~~	~~560.4~~	~~420.3~~	~~392.3~~	~~364.3~~	~~364.3~~	~~490.3~~	~~2458.4~~	~~10367.1~~	~~6847.9~~	~~7105.7~~	~~3655.4~~
1301.2	437.1	403.5	381.1	358.6	313.8	287.5	5296.8	10994.8	9459.3	10753.8	5760.8
1728.2	835.0	746.4	690.4	672.5	672.5	685.4	5193.7	10927.5	9795.6	6130.6	3031.7
~~1348.3~~	~~595.7~~	~~346.3~~	~~284.7~~	~~271.8~~	~~307.1~~	~~559.3~~	~~4186.6~~	~~6909.6~~	~~7570.8~~	~~3696.9~~	~~1891.9~~
917.9	456.7	304.3	244.9	238.7	259.5	497.1	4247.7	5552.9	7789.4	6904.0	2920.2
1207.6	857.4	587.3	409.6	281.9	263.4	296.4	1073.1	12311.7	10159.8	12726.4	5491.8
~~2274.0~~	~~1148.8~~	~~768.3~~	~~598.5~~	~~516.7~~	~~493.7~~	~~490.9~~	~~5432.4~~	~~11207.7~~	~~9352.9~~	~~8753.2~~	~~5280.5~~
2098.3	944.8	568.6	477.8	441.7	414.7	445.1	3519.8	11026.9	8033.7	8744.4	3959.6
1310.5	659.0	461.2	388.6	334.8	294.0	417.2	5265.7	6445.6	7268.5	5975.1	4018.9
~~1344.2~~	~~692.1~~	~~521.4~~	~~502.8~~	~~407.7~~	~~370.3~~	~~451.7~~	~~4353.8~~	~~11613.6~~	~~10579.1~~	~~6714.4~~	~~5403.5~~
1957.5	664.2	369.2	296.1	293.5	262.5	407.7	2820.0	8596.0	8390.6	9471.0	2505.2
1130.7	649.5	520.2	470.1	427.2	391.0	391.0	2357.6	13634.5	9162.9	7971.9	4742.1
~~2190.0~~	~~959.2~~	~~747.1~~	~~615.9~~	~~472.3~~	~~497.1~~	~~614.6~~	~~5866.7~~	~~8627.6~~	~~8735.9~~	~~5745.0~~	~~3120.2~~
1441.0	739.0	516.5	482.3	454.2	558.3	660.0	6039.2	11773.8	11600.2	7088.5	4102.5

TABLE E.27 COMPUTED STREAMFLOW AT DENALI

~~1305.2~~	~~612.0~~	~~415.1~~	~~202.4~~	~~230.8~~	~~132.8~~	~~210.8~~	~~2164.3~~	~~6941.5~~	~~11941.7~~	~~9389.7~~	~~2877.6~~
962.8	330.8	251.6	166.1	134.6	151.1	350.7	3563.4	8584.7	12566.8	9947.5	6108.6
1204.3	407.2	282.2	340.1	343.6	314.6	346.8	2236.4	10195.3	13320.5	10400.7	3768.2
~~1321.0~~	~~725.[illegible]~~	~~305.2~~	~~239.4~~	~~170.0~~	~~158.9~~	~~508.4~~	~~5861.7~~	~~10753.0~~	~~11772.8~~	~~8915.4~~	~~3063.4~~
1391.3	377.3	278.1	377.6	251.3	227.1	225.9	2648.5	7545.4	11144.0	10113.8	2860.3
1023.1	606.5	285.8	283.3	182.8	224.9	242.7	2452.8	10757.0	11368.3	15618.3	6596.3
~~1365.8~~	~~395.4~~	~~296.2~~	~~325.2~~	~~138.1~~	~~179.5~~	~~200.9~~	~~6872.6~~	~~21992.8~~	~~18728.5~~	~~18061.6~~	~~7521.9~~
1984.4	966.1	578.4	317.7	269.6	183.4	342.6	4575.8	16194.3	14814.9	12956.8	5327.8
1693.7	809.1	382.0	290.5	198.9	159.2	278.5	1542.5	11097.3	12135.8	8668.8	2492.1
~~1245.4~~	~~517.3~~	~~225.5~~	~~157.8~~	~~107.4~~	~~55.3~~	~~57.0~~	~~2363.5~~	~~11792.3~~	~~11052.2~~	~~10454.0~~	~~3313.1~~
2091.6	1008.0	762.6	588.9	425.7	364.7	351.5	4441.8	6945.9	11988.6	10491.2	6388.9
2362.2	875.4	640.6	439.0	359.4	372.7	550.4	3924.6	8504.3	10714.0	9619.8	3574.4
~~1710.9~~	~~901.9~~	~~583.6~~	~~371.4~~	~~318.3~~	~~291.8~~	~~371.4~~	~~2913.9~~	~~12052.2~~	~~13554.9~~	~~12539.0~~	~~4839.7~~
1431.1	676.4	411.2	331.6	305.1	265.3	278.5	4314.5	8969.9	13926.3	13541.7	5237.6
1226.8	384.6	245.4	185.7	185.7	145.9	172.4	1206.9	15425.1	10049.5	8690.0	3492.2
~~1947.0~~	~~931.1~~	~~370.9~~	~~291.8~~	~~265.3~~	~~275.9~~	~~424.4~~	~~3268.0~~	~~6163.4~~	~~8960.6~~	~~7644.9~~	~~9224.5~~
1220.2	397.9	318.3	278.5	265.3	265.3	371.4	2160.6	9085.3	10991.2	8530.9	4244.2
2080.5	703.5	453.7	450.4	318.1	440.7	329.6	5435.6	12148.3	14794.5	12896.2	3896.3
~~2167.6~~	~~666.9~~	~~464.5~~	~~340.1~~	~~417.8~~	~~450.0~~	~~288.6~~	~~1051.4~~	~~[illegible]~~	~~15703.6~~	~~13031.1~~	~~2907.3~~
928.4	403.2	228.1	192.3	185.7	192.3	303.7	2344.9	[illegible]	12527.1	5197.8	2935.1
1329.0	664.5	449.6	351.5	293.1	256.0	423.1	2931.2	6648.8	11212.7	8244.4	2581.0
~~700.3~~	~~523.9~~	~~366.1~~	~~225.5~~	~~165.8~~	~~159.2~~	~~179.1~~	~~834.3~~	~~10741.8~~	~~13806.9~~	~~13793.7~~	~~4360.9~~
1378.0	634.0	504.0	449.6	407.2	379.3	358.1	4599.7	8703.3	13860.0	11491.2	3684.5
884.7	428.4	279.9	236.1	217.5	202.9	202.9	1382.0	7614.4	11069.4	9639.7	3242.8
~~1161.9~~	~~612.8~~	~~485.4~~	~~411.2~~	~~[illegible]~~	~~311.7~~	~~347.5~~	~~3370.2~~	~~7483.1~~	~~12662.3~~	~~12324.1~~	~~7231.1~~
2831.7	892.6	505.3	397.9	265.3	265.3	265.3	2175.2	9337.3	16061.7	9675.5	4736.3
2041.2	497.4	224.1	148.5	128.7	119.4	163.1	2394.0	7877.0	11350.6	13369.3	2416.5
~~1185.7~~	~~619.4~~	~~439.0~~	~~352.8~~	~~318.3~~	~~306.4~~	~~326.3~~	~~1986.8~~	~~10946.1~~	~~13276.4~~	~~13501.9~~	~~4916.7~~
1522.6	864.8	582.3	461.6	397.9	326.3	348.8	2693.7	6963.2	11927.6	11464.7	4803.9
1147.3	614.1	413.8	348.8	303.7	269.2	331.6	3701.7	10146.3	12605.3	12172.9	5984.3

TABLE E.29 Homogeneity Test
Annual Instantaneous Peaks

Station	$Q_{20}/Q_2 = Y_{20}$
Susitna River at Gold Creek	1.83
Caribou Creek near Sutton	1.82
Matanuska River at Palmer	1.49
Susitna River near Denali	1.81
Maclaren River near Paxson	2.02
Susitna River near Cantwell	1.68
Chulitna River near Talkeetna	1.47
Talkeetna River near Talkeetna	2.33
Montana Creek near Montana	1.96
Skwentna River near Skwentna	1.49
Tonsina River at Tonsina	1.72
Copper River near Chitina	1.35

$\bar{Y}_{20} = 1.748$ SD = 0.2776

Limits of 95% Confidence Interval (1.11 - 2.39)

TABLE E.30 Homogeneity Test
October - May Instantaneous Peaks

Station	$Q_{20}/Q_2 = Y_{20}$
Susitna River at Gold Creek	1.57
Caribou Creek near Sutton	2.63
Matanuska River at Pamer	2.24
Susitna River near Denali	2.35
Maclaren River near Paxson	3.32
Susitna River near Cantwell	2.33
Chulitna River near Talkeetna	1.98
Talkeetna River near Talkeetna	2.12
Skwentna River near Skwenta	1.76
Tonsina River at Tonsina	2.45
Copper River near Chitina	1.50

$\bar{Y}_{20} = 2.205$ SD = 0.5175

Limits of 95% Confidence Travel (0.99 - 3.41)

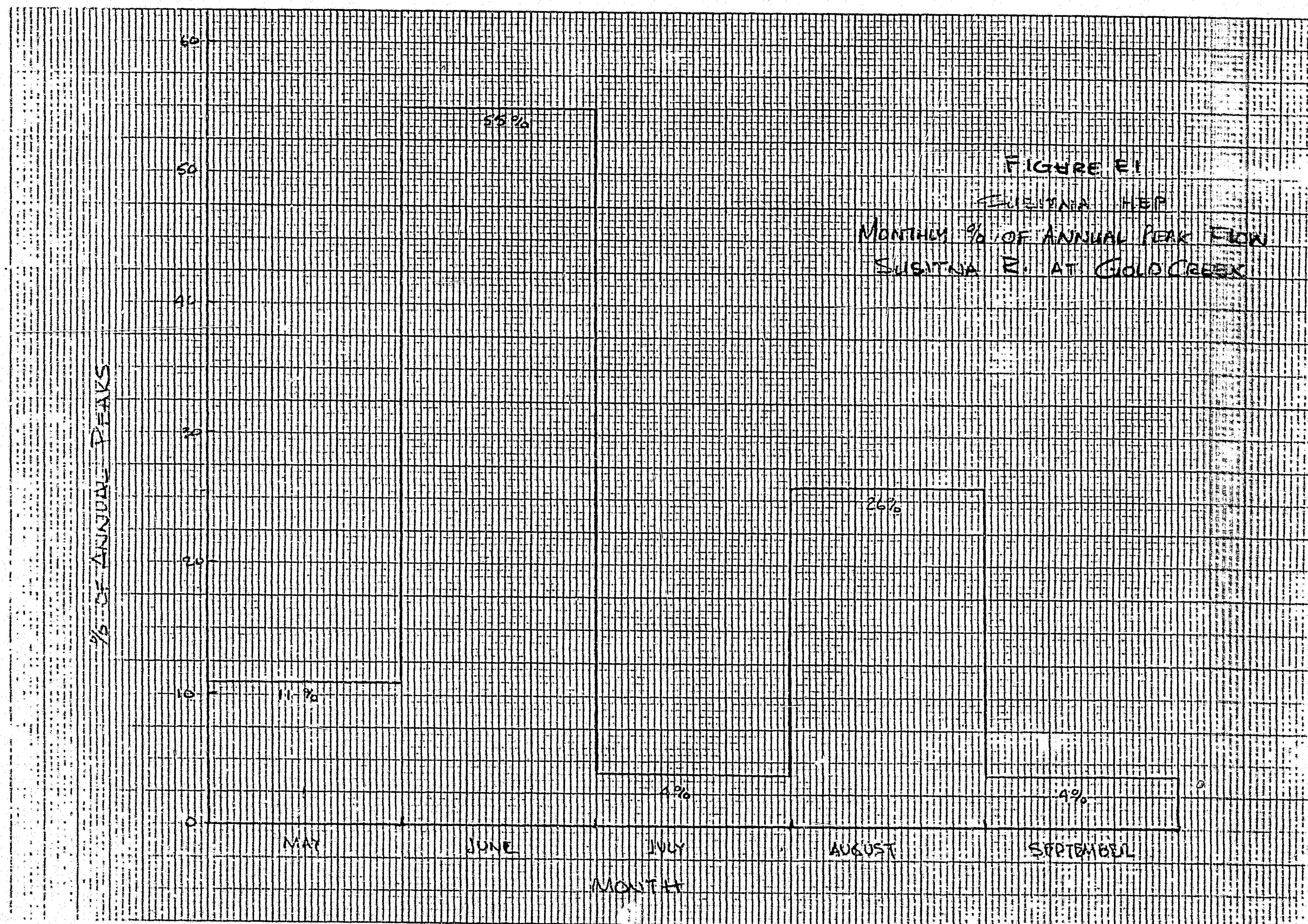
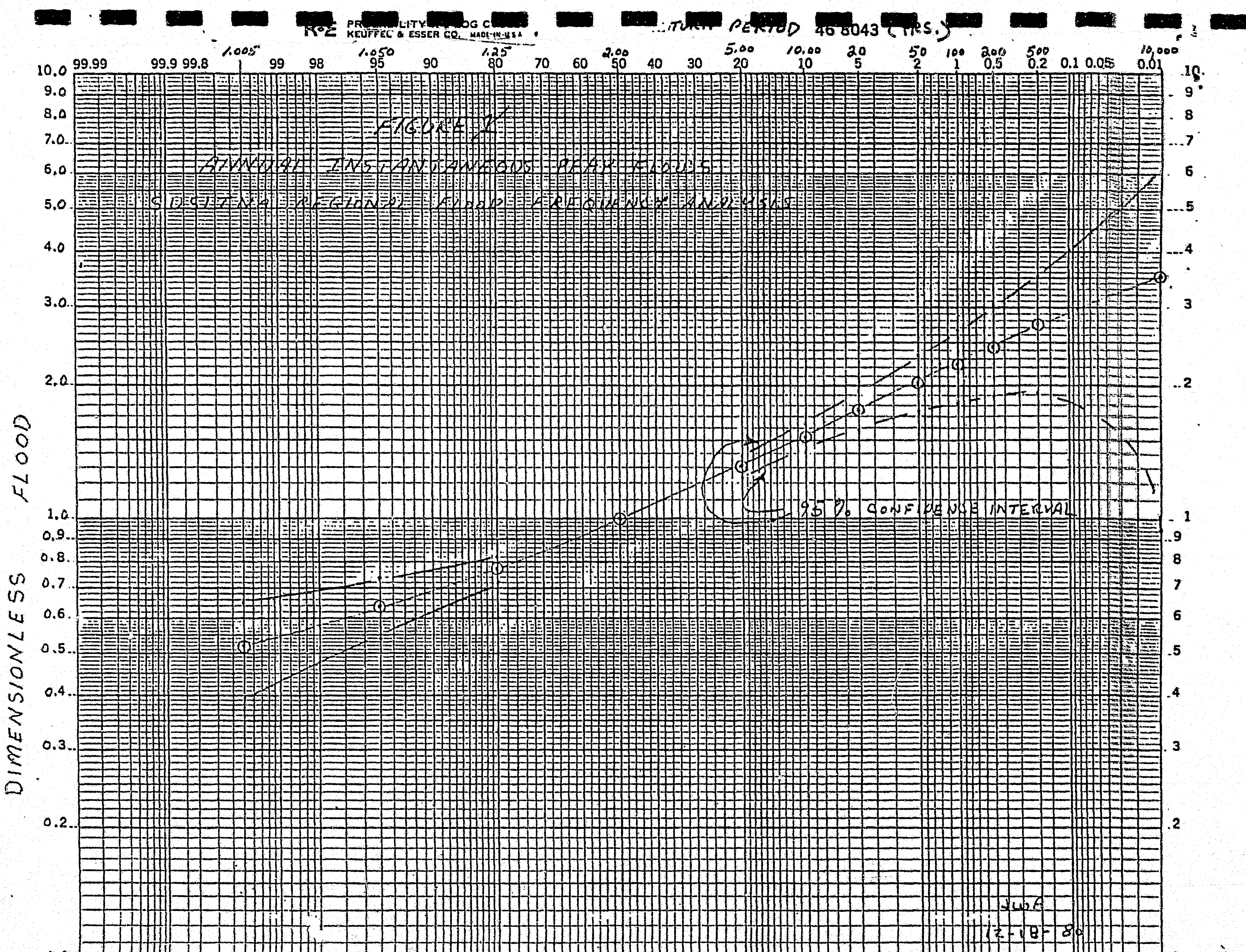


FIGURE E1
SUSITNA HEP
MONTHLY % OF ANNUAL PEAK FLOW
SUSITNA R. AT GOLD CREEK
% OF ANNUAL PEAKS
60
50
40
30
20
10
0
55%
11%
4%
26%
4%
MAY
JUNE
JULY
AUGUST
SEPTEMBER
MONTH



K+E PROBABILITY LOG C
KEUFFEL & ESSER CO. MADE IN USA
TURN PERIOD 46 8043 (YRS.)
1.005 1.050 1.25 2.00 5.00 10.00 20 50 100 200 500 10,000
99.99 99.9 99.8 99 98 95 90 80 70 60 50 40 30 20 10 5 2 1 0.5 0.2 0.1 0.05 0.01
FIGURE 1
ANNUAL INSTANTANEOUS PEAK FLOWS
SUSITNA REGIONAL FLOOD FREQUENCY ANALYSIS
95% CONFIDENCE INTERVAL
DIMENSIONLESS FLOOD
10.0 9.0 8.0 7.0 6.0 5.0 4.0 3.0 2.0 1.0 0.9 0.8 0.7 0.6 0.5 0.4 0.3 0.2
JWB
12-18-80

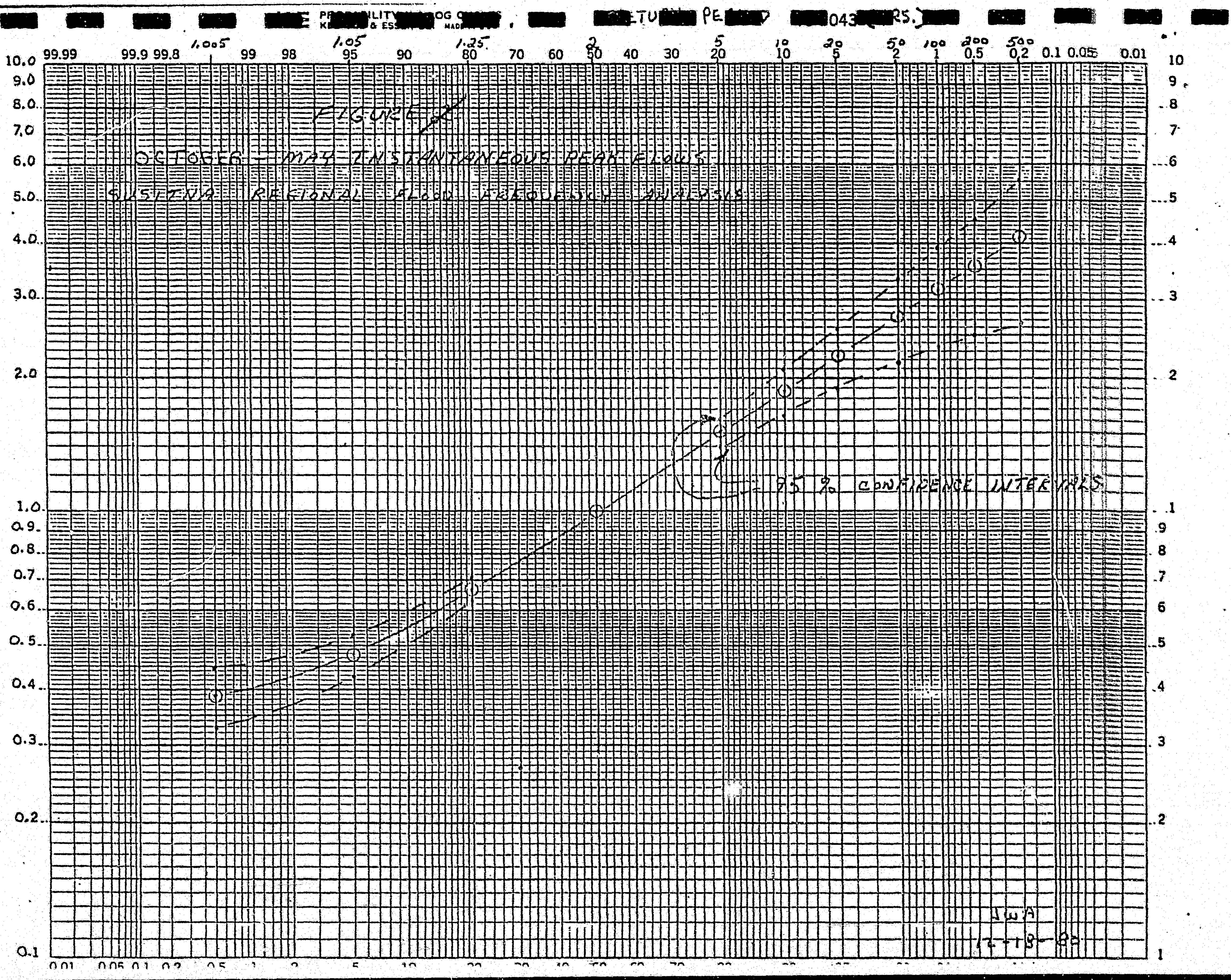
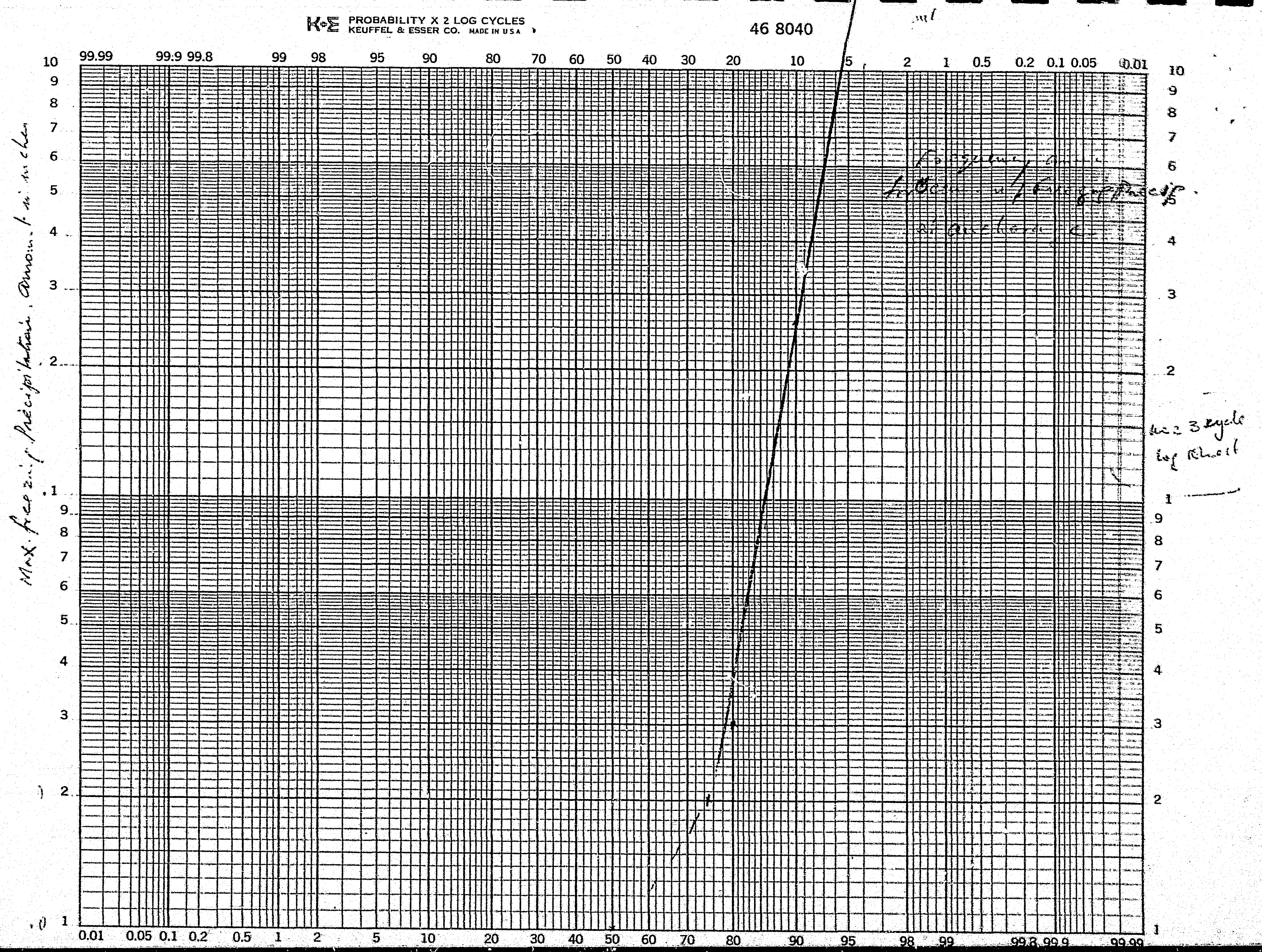


FIGURE
OCTOBER - MAY INSTANTANEOUS PEAK FLOWS
SUSITNA REGIONAL FLOOD FREQUENCY ANALYSIS
95 % CONFIDENCE INTERVALS
JWA


K+E PROBABILITY X 2 LOG CYCLES
KEUFFEL & ESSER CO. MADE IN U.S.A.
46 8040

F - TASK 4 - STATUS REPORT

APPENDIX F

TASK 4 - SEISMIC STUDIES

The studies conducted by Woodward-Clyde Consultants in 1980 are summarized in the following Conclusions section from the Interim Report on Seismic Studies for the Susitna Hydroelectric Project. The summary plates and tables showing the relationships and data upon which these conclusions are based have been referenced and are included at the end of the Appendix.

CONCLUSIONS

Two sets of conclusions have been drawn from the results of the investigation conducted to date. One set, designated technical conclusions, are those conclusions related to scientific data collected. The second set, designated feasibility conclusions, are those conclusions considered important to evaluate the preliminary feasibility of the Project. Both sets of conclusions are discussed below and form the basis for the proposed 1981 study plan.

F.1 Feasibility Conclusions

(a) No faults with known recent displacement (displacement in the last 100,000 years) pass through or adjacent to the Project sites.

(b) The faults with known recent displacement closest to the Project sites are the Denali and Castle Mountain Faults. These faults and the Benioff Zone associated with the subducting Pacific Plate (at depth below the Project site) are considered to be accepted seismic sources.

(c) Preliminary maximum credible earthquakes for the Denali and Castle Mountain Faults and the Benioff Zone have been estimated as: magnitude (M_s) 8.5 earthquake on the Denali Fault occurring 40 miles from the Devil Canyon site and 43 miles from the Watana site; magnitude (M_s) 7.4 earthquake on the Castle Mountain Fault occurring 65 miles from the Devil Canyon site and 71 miles from the Watana site; and magnitude (M_s) 8.5 earthquake on the Benioff Zone occurring 37 miles from the Devil Canyon site and 31 miles from the Watana site.

(d) Within the site region, 13 faults and lineaments have been judged to need additional investigation to better define their potential affect on dam design considerations. These 13 faults and lineaments (designated as significant features) were selected on the basis of their seismic source potential and potential for surface rupture through either site. Four of these features are in the vicinity of the Watana site and nine are in the vicinity of the Devil Canyon site.

(e) At the present time, the 13 significant features are not known to be faults with recent displacement. If additional seismic geology studies show that any of these features is a fault with recent displacement, then the potential for surface rupture through either site, and the ground motions associated with earthquakes on such a fault, will need to be evaluated.

(f) Preliminary estimates of ground motions at the sites were made for the Denali and Castle Mountain Faults and the Benioff Zone (Table F-1). Of these sources, the Benioff Zone is expected to govern the levels of peak horizontal ground acceleration, response spectra, and duration of strong shaking. The ground motion estimates are preliminary in nature and do not constitute criteria for design of project facilities. Finalization of site ground motion estimates and development of design criteria are a part of the next phase of study.

F.2 Technical Conclusions

(a) The site is located within the Talkeetna Terrain. This tectonic unit has the following boundaries: the Denali Fault to the north and northeast; the Totschunda Fault to the east; the Castle Mountain Fault to the south; a broad zone of deformation and volcanoes to the west; and the Benioff Zone at depth (Figure 6.8).

(b) The northern, eastern, and southern boundaries of the Talkeetna Terrain are major fault systems along which displacement occurred during Quaternary time. The Benioff Zone beneath the Talkeetna Terrain represents the upper margin of the Pacific Plate which is being subducted beneath the North American Plate. The western boundary, a broad zone of deformation and volcanoes, does not appear to have brittle deformation along a major fault.

(c) The Talkeetna Terrain appears to be acting as a coherent tectonic unit with the present stress regime. Major strain release occurs along the fault systems bounding the Terrain. Within the Terrain, strain release appears to be randomly occurring at depth within the crust. This strain release is possibly the result of crustal adjustments resulting from perturbation imposed by the Benioff Zone and by stress (associated with plate motion) imposed along the Terrain margin and transmitted throughout the Terrain.

(d) The only fault system within the site region (60 miles from either dam site) which is known to have had displacement in Quaternary time (the last two million years) is the Denali Fault. This fault is approximately 40 miles north of the sites at its closest approach. The Castle Mountain Fault system is immediately south of the site region. This fault system also has had displacement in Quaternary time.

(e) Within the site region 48 candidate significant features have been identified. These features are faults and lineaments for which no evidence of recent displacement was observed, but for which evidence of no recent displacement has not been demonstrated.

(f) Of the 48 candidate significant features, there are 13 significant features which the results of this study suggest need additional investigation. These 13 features were selected on the basis of their seismic source potential and potential for surface rupture through either dam site. Four of these features are in the vicinity of the Watana site and include the Talkeetna Thrust Fault (KC4-1), the Susitna feature (KD3-3), the Fins feature (KD4-27), and lineament KD3-7. Nine of the features are in the vicinity of the Devil Canyon site and include fault KD5-2 and lineaments KC5-5, KD5-3, KD5-9, KD5-12, KD5-42, KD5-43, KD5-44, and KD5-45 (Figures F-1, F-2).

(g) No evidence to support the existence of the Susitna feature has been developed during this study. Reconnaissance level aerial and ground checking has found no evidence of a fault in bedrock and no evidence of deformation in overlying surficial units.

Review of aerial gravity and magnetics data show no evidence of a major tectonic dislocation. Earthquakes correlated with the southern portion of the feature of Gedney and Shapiro (1) occurred at depths greater than 43 miles. These focal depths suggest that the earthquakes occurred in the Benioff Zone well below the crust and well below the extent of the Susitna feature. The feature may be the result of glaciation of stream drainages whose alignment reflects structural control such as joints or perhaps folding.

(h) The Talkeetna Thrust Fault is a northeast-southwest trending fault which may dip either to the northwest of the southeast. The northeastern continuation of the fault is the Broxson Gulch Thrust Fault resulting in a 167 mile long fault that passes approximately 3.5 miles upstream of the proposed Watana site. No evidence of displacement younger than Tertiary (1.8 to 65 m.y.b.p.) in age has been reported for either the Talkeetna or Broxson Gulch Thrust Faults. However, anomalous relationships in Tertiary deposits on the north side of the Susitna river were observed during this investigation and may be related to faulting.

(i) Seismicity within the Talkeetna Terrain can be clearly delineated as crustal events occurring at depths to approximately 5 to 12 miles and as Benioff Zone events which occur at greater depths. The depth to the Benioff Zone increases from approximately 25 miles in the southeastern part of the site region to more than 50 miles in the northwestern part of the microearthquakes area and more than 62 miles in the northwestern site region (Figure F-3).

(j) The largest reported historical earthquake within the Talkeetna Terrain is the magnitude (M_S) 6.25 event of 1929 which occurred approximately 35 and 45 miles northeast of the Watana and Devil Canyon sites, respectively. Four earthquakes greater than magnitude (M_S) 5 occurred during the period 1904 through August, 1980.

(k) Earthquakes as large as magnitude (M_L) 5 to 5.5 may possibly occur in the site region without direct association with surface fault rupture. Such events would probably be constrained to rupture planes deeper than 6 miles.

(l) The largest crust event recorded within the microearthquake study area during 3 months of monitoring was magnitude (M_L) 2.8. It occurred 6.8 miles northeast of the Watana dam site at a depth of 9.3 miles (Figure F-4).

(m) Two clusters of microearthquake activity were observed within the mircroearthquake network during the three-month monitoring period. These two clusters occurred in the same general vicinity east of the southern portion of the Talkeetna Thrust Fault. These clusters of seismicity occurred at depths of 9 to 12 miles. One of the clusters gives a composite focal plane mechanism of N23°E, dipping 50° W, consistent with local geologic trends. The sense of movement is reverse (toward the southeast) with a dextral component of slip (Figure F-4).

(n) The clusters of microearthquake activity described in (m) appear to be related to a small subsurface rupture plane that does not extend to the surface. These clusters do not appear to be related to the Talkeetna Thrust Fault.

(o) Seismicity in the vicinity of the site, including the clusters described above, appears to reflect relatively small-scale crustal adjustments at depth in the crust. These adjustments may be related to stresses imposed by the Benioff Zone.

(p) No association of microearthquake activity with candidate significant or significant features is apparent based on information obtained to date.

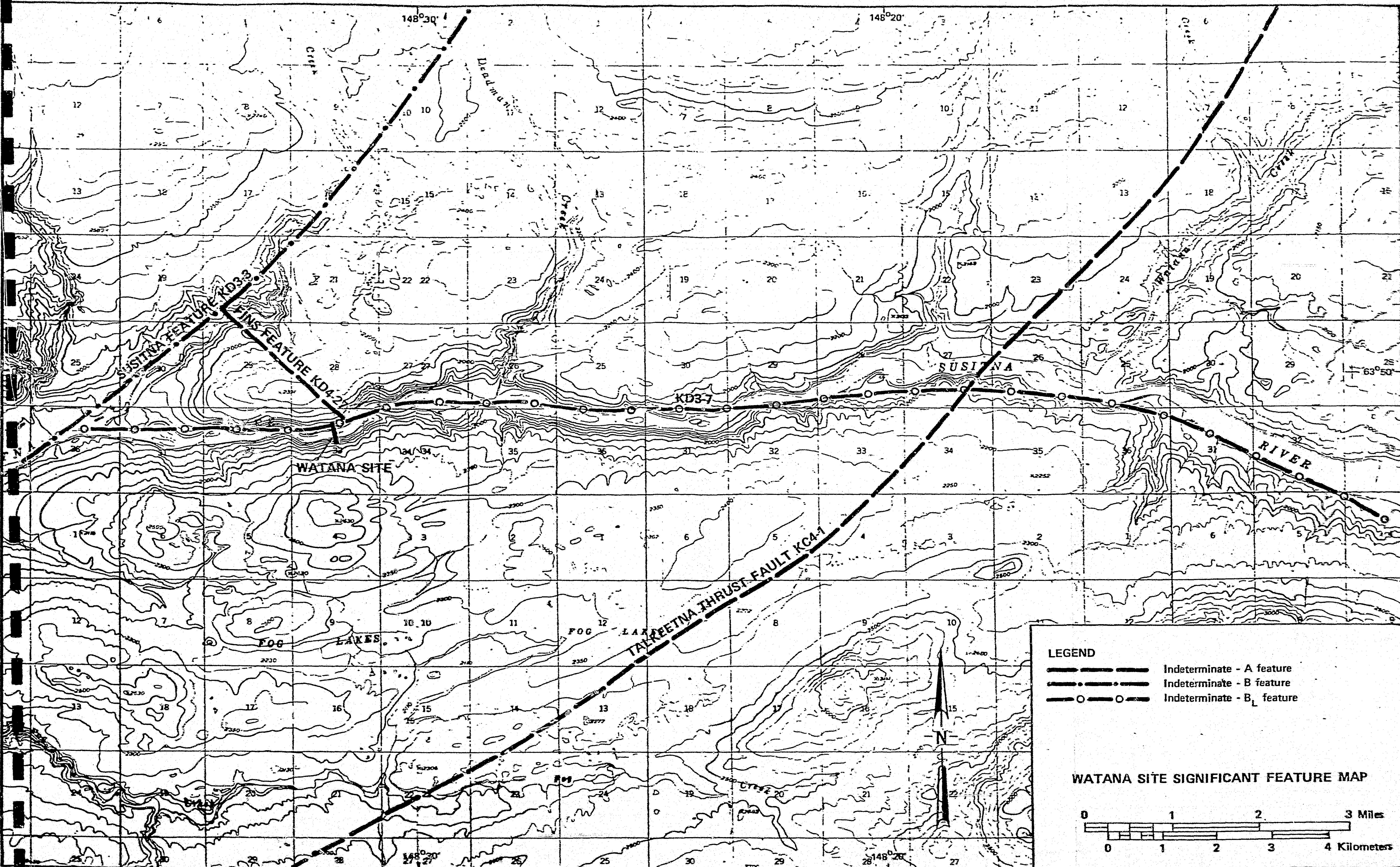
(q) Hydrologically the two reservoirs are considered as one. This combined Watana-Devil Canyon reservoir would be among the deepest and largest in the world. Primarily, because water depth has a major apparent theoretical and empirical correlation with the occurence of reservoir induced seismicity, it is concluded that the likelihood of a reservoir induced earthquake of any size within the hydrologic regime of the proposed reservoir is high (0.9 on a scale of 0 to 1) (Figure F-5).

(r) Preliminary maximum credible earthquakes (PMCE) have been estimated for crustal faults with recent displacement in and adjacent to the site region and for the Benioff Zone. The PMCE for the Denali Fault is estimated to be a magnitude (M_S) 8.5 event occurring 40 miles from the Watana site. The PMCE for the Castle Mountain Fault is estimated to be a magnitude (M_S) 7.4 event 65 miles from the Watana site. The PMCE for the Benioff Zone is estimated to be a magnitude (M_S) 8.5 event occurring 31 miles beneath the Watana dam site and 37 miles km) beneath the Devil Canyon site (Table F-1).

Table F-1

Preliminary Maximum Credible Earthquake Ground Motions

	Mean Peak Horizontal Ground Acceleration	
Earthquake Source	Watana Site	Devil Canyon Site
Benioff Zone	0.41 g	0.37 g
Castle Mountain Fault	0.06 g	0.05 g
Denali Fault	0.21 g	0.21 g



WOODWARD-CLYDE CONSULTANTS 14658A December 1980

FIGURE F-1

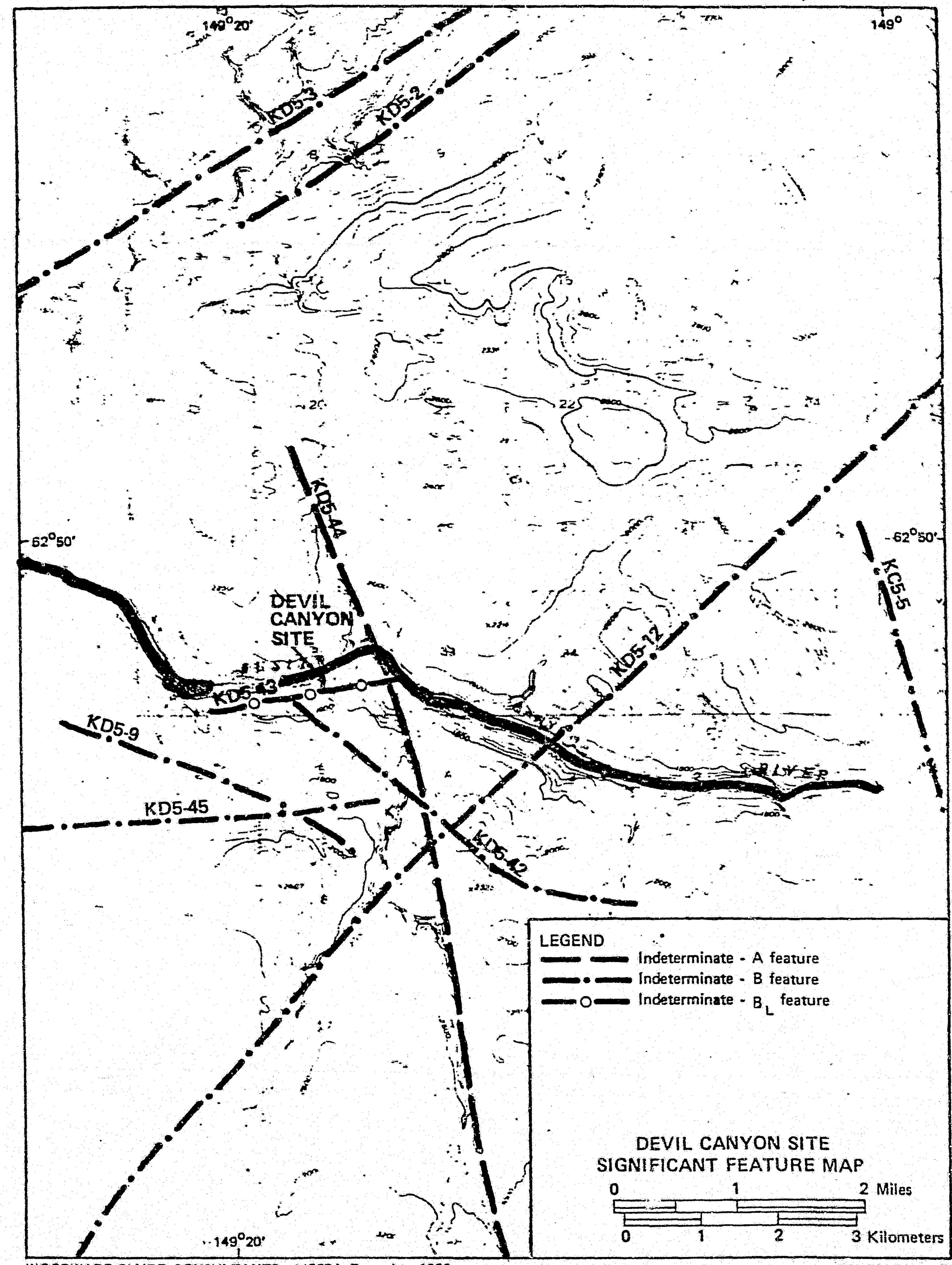
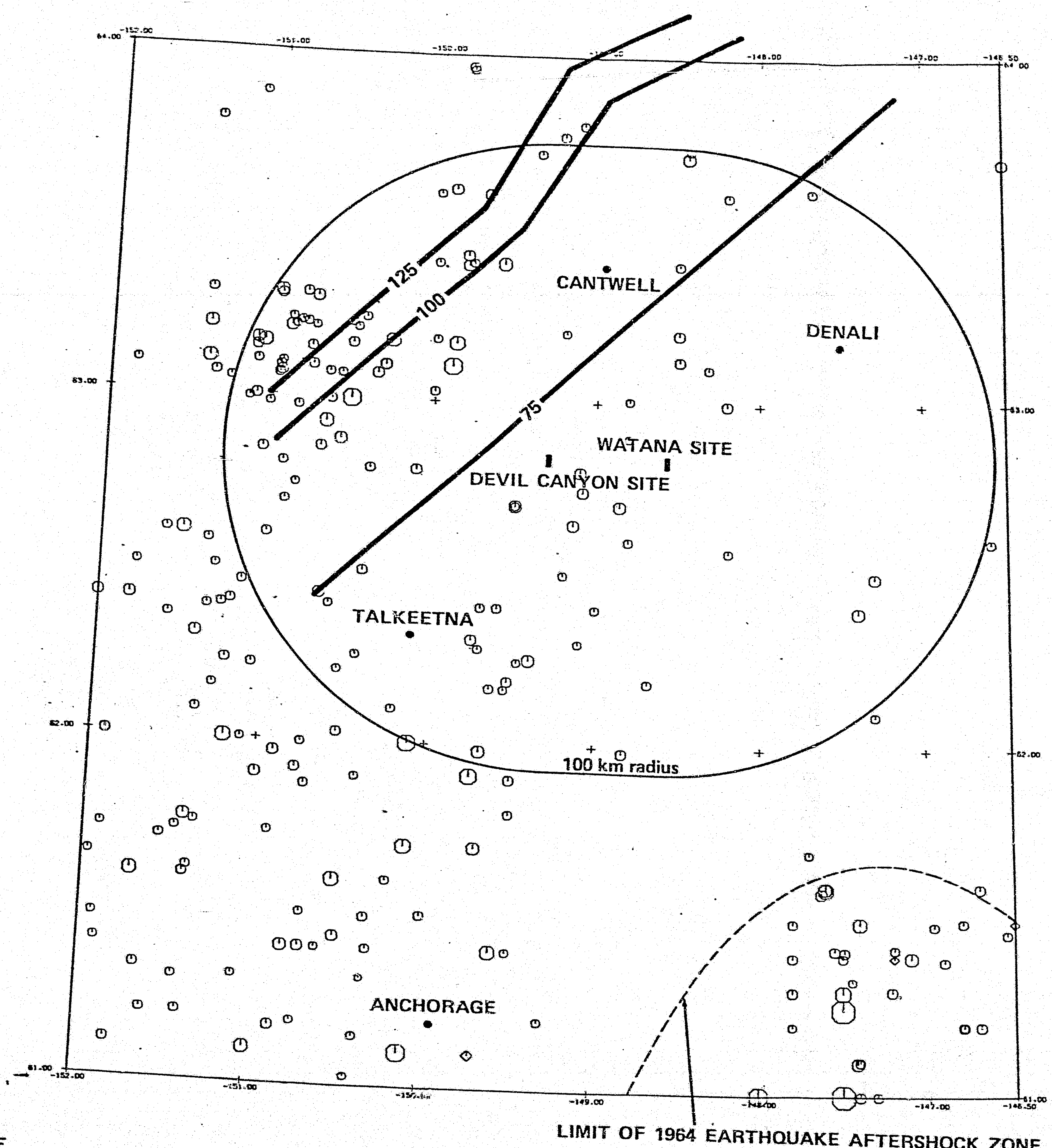
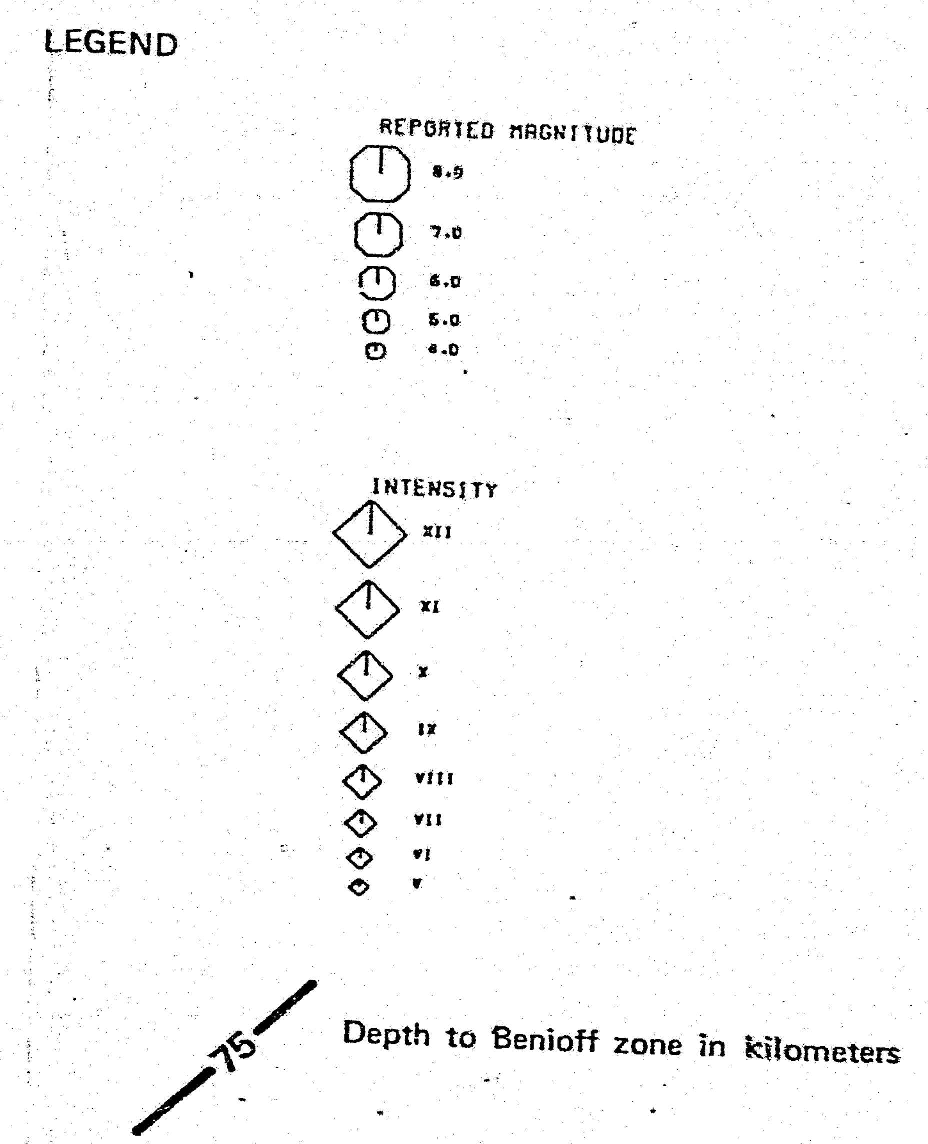

149°20'
149°
KD5-3
KD5-2
62°50'
-62°50'
KD5-44
DEVIL
CANYON
SITE
KD5-12
KC5-5
KD5-43
KD5-9
KD5-45
KD5-42
RIVER
149°20'
LEGEND
Indeterminate - A feature
Indeterminate - B feature
Indeterminate - B_L feature
DEVIL CANYON SITE
SIGNIFICANT FEATURE MAP
0 1 2 Miles
0 1 2 3 Kilometers

FIGURE F-2





NOTES

1. Earthquakes of magnitude greater than 4 or intensity greater than V are shown.
2. Magnitude symbol sizes are shown on a continuous nonlinear scale.
3. Earthquakes are listed in Appendix C.

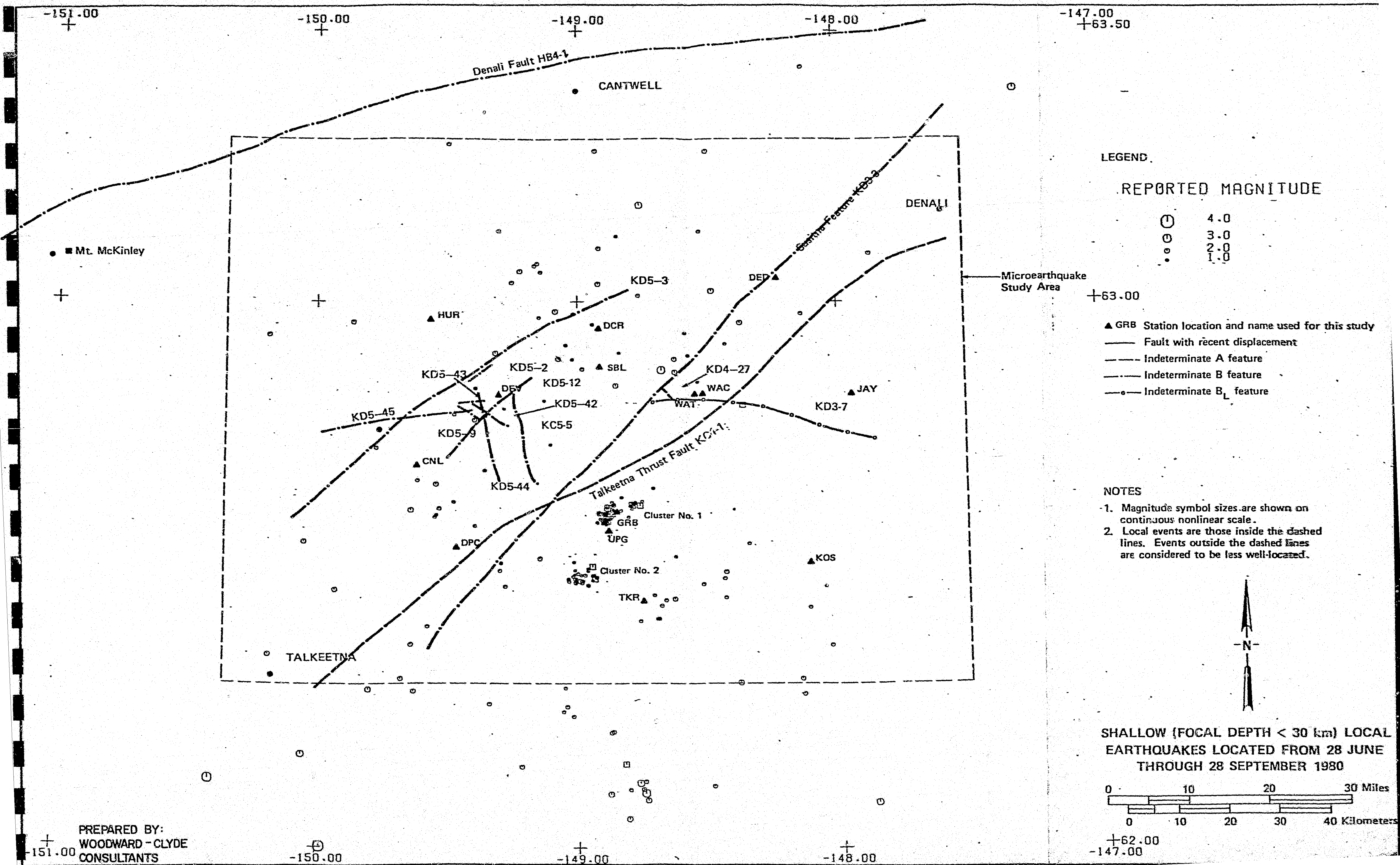
-N-

HISTORICAL EARTHQUAKES OF FOCAL DEPTH GREATER THAN 35 km IN THE SITE REGION FROM 1904 THROUGH 1978

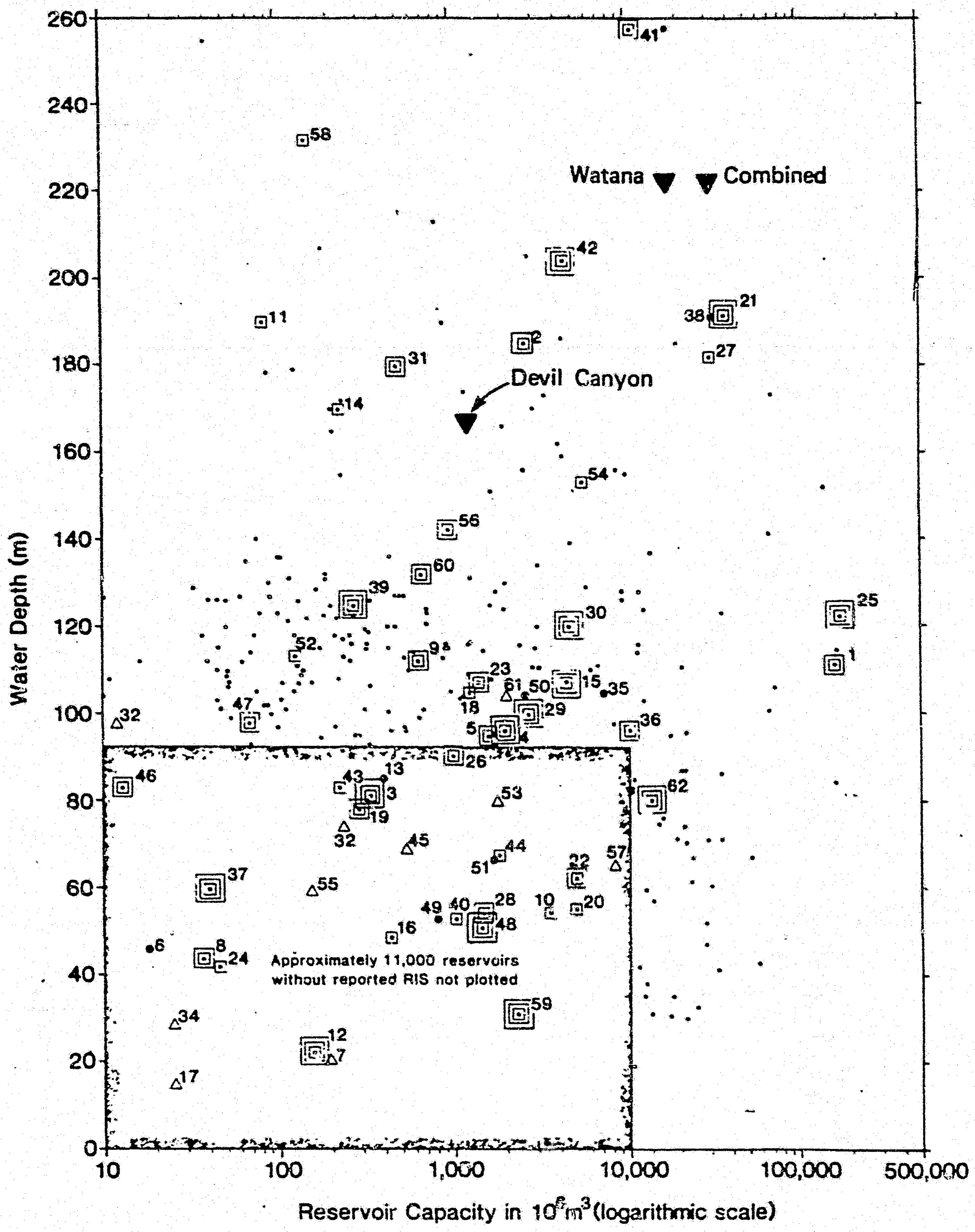
0 10 20 30 40 50 Miles

0 10 20 30 40 50 Kilometers

PREPARED BY:
WOODWARD-CLYDE CONSULTANTS



SHALLOW (FOCAL DEPTH < 30 km) LOCAL EARTHQUAKES LOCATED FROM 28 JUNE THROUGH 28 SEPTEMBER 1980



Note: The following reservoirs were not plotted because of insufficient data: Kinarsani, Sharavathi.

*41 - Nurek (USSR) depth is in excess of 285 m.

LEGEND

- Deep and/or very large reservoir
- Accepted case of RIS, maximum magnitude ≥ 5
- Accepted case of RIS, maximum magnitude 3-5
- Accepted case of RIS, maximum magnitude ≤ 3
- Questionable case of RIS
- Not RIS

PLOT OF WATER DEPTH AND VOLUME FOR WORLDWIDE RESERVOIRS AND REPORTED CASES OF RIS

G - TASK 5 - STATUS REPORT

APPENDIX G

TASK 5 - GEOTECHNICAL EXPLORATION

G.1 Field Program

(a) Introduction

In developing the 1980 exploration program, a review of the available information on the Watana and Devil Canyon sites was conducted. Meetings were held with the Corps of Engineers to discuss those areas their investigations had identified as requiring additonal studies. These areas of particular concern then were considered in formulating the 1980 program. However, the main theme of this program was to allow for flexibility in the collection of as detailed information as possible on the general conditions present, and any as yet undetected problem areas.

This program was inteded to define the feasibility of the dam sites and the quality and availability of construction materials. The investigation included geologic mapping, diamond core and auger drilling, and geophysical surveys to augment the existing knowledge on the characteristics of the dam site areas. The studies covered the depth, distribution and nature of the of the overburden materials; the type and quality of the bedrock geology including discontinuties and their significance to the foundation competency; and the evaluation of the groundwater regime, the permafrost conditions, and potential sources of construction materials. Site gelogic mapping was conducted by Acres with the assistance of R&M Consultants and involved measurement and description of the outcrops, aerial and traverse reconnaissance, and air photo interpretation.

(b) Devil Canyon Site

The previous work at the Devil Canyon dam site had identified several features that require clarification for an informed evaluation. These include the stress relief joints and shear zones in the left (south) abutment area, a suspected fault under the proposed saddle dam and a possible fault zone through the Cheechako Creek borrow area (upstream of the dam site) that showed on previous seismic refraction surveys.

The diamond core holes were drilled in the 1980 season to define the geologic structure and rock quality. Two holes (BH-1 and BH-2) in the right abutment and one hole (BH-4) in the left abutment, were drilled for correlation of the geologic structure encountered in previous drilling and in seismic work in a left abutment shear zone and buried channel area. Two thousand feet of seismic refraction survey were aslo run in the buried channel area near BH-4 to assist in the definition of this shear zone. The holes on the right abutment were drilled to obtain information in the general location of proposed underground structures. The data collected on the left abutment is inconclusive and requires additional work to delineate any left abutment shear zone.

Geophysical logging and permeability determination by water pressure testing were performed in all three holes. The rock core was logged as the drilling proceeded, noting the rock type and quality. Correlations were made with the testing results and the results of other drilling and mapping. Two auger holes were drilled in the large gravel bar just upstream of the dam to explore the extent of available construction materials. These holes confirmed that extensive gravel and sand deposits are available. Reconnaissance mapping north of the river also tended to confirm that sufficient glacial till is easily obtainable for use as impervious material in the proposed left abutment saddle dam.

Because the program was limited by land access restictions near Cheechako Creek, the objective was modified in order to gather as much information as possible within the restrictions (Figure G-1).

In general, the argillite and graywacke at the Devil Canyon dam site is of good quality. Zones of fracturing or shearing were encountered in all of the exploration work, and in most cases correlate with the zones of high water take. However, correlation between the holes themselves is difficult at this time. Weathering generally is moderate, affecting the top 40 feet or so of rock. Below this depth rock quality steadily improves with increased distance from weathering surfaces. It should be noted that the observations are based on a limited number of borings, and will be revised and updated with subsequent drilling.

An instrumentation program was set up to collect static groundwater level and ground temperature data in BH-1 and BH-4. When groundwater and ground temperature return to ambient levels, data will be collected at monthly intervals. This will provide information on permafrost and the groundwater regime at the site.

(c) Watana Site

The 1980 program at Watana involved geologic mapping, diamond core and auger drilling, and seismic refraction surveys. Several areas previously outlined as potential problems were investigated. These include the shear zones called "The Fins", a possible right abutment slide block outlined as a low seismic velocity zone in the 1978 investigations and, "Fingerbuster", a potential fault zone in the river channel (Figure G-2).

Three diamond core boreholes were drilled in the dam area to augment the previous data and were orientated to investigate the geologic structures through the proposed powerhouse on the left abutment (BH-8), the possiblity of a fault in the river channel (BH-6) and the andesite-diorite contact and the possible slide and "Fingerbuster" shear (BH-2) on the right abutment. Permeability testing and geophysical logging was done in these holes for correlation with the rock core.

Approximately 15,000 feet of seismic refraction lines were run through the proposed dam site and the relict channel to delineate the overburden thickness and rock quality of the abutments.

The foundation conditions within the Watana area are generally sound. Weathering is predominantly mechanical in nature and has resulted in the accumulation of talus piles along the canyon. The only intense weathering effects are found in the shear zones. Very little penetrative weathering was observed in the rock except at the joints. The rock appears to have a random effect with zones of competent rock separated by poorer quality sheared or fractured zones recurring 15 to 150 feet apart. The permeability values seem to correspond roughly with the rock quality but overall permeability appears very low. These conditions are normal for diorite masses and are readily treated in construction.

A piezometer and thermistor system similar to those at Devil Canyon was installed in BH-6 and the data collected along with that from the Corps of Engineers' 1978 system, will help define the groundwater and permafrost conditions of the area.

G.2 Laboratory Testing

Representative soil samples obtained by split-spoon and hand sampling from the potential borrow sites of the Watana area were tested to determine their engineering properties and to verify the field classification. The testing program included determination of moisture contents, Atterberg limits, grain size distribution and Modified Proctor density. The summary of the testing program is given in Tables G-1 and G-2.

The Laboratory testing program results substantiated the previous knowledge of the borrow areas. Borrow Area E appears to be the most liklely source of clean sands and gravels for filters and concrete aggregate (Figure G-2). This alluvial deposit located downstream of the dam is composed of six to ten feet of relatively clean, well graded sandy gravel with cobbles up to four inches in diameter, increasing in size with depth. Total depth is estimated at over 50 feet. The material has an average moisture content of 12 percent, ranging from 22 percent in the silty organic material at the top to 1 percent in the gravels at a depth of eight feet.

Borrow Area D is a likely source of impervious and semi-pervious materials and is bounded by Deadman Creek and the right bank relict channel. This area appears to be composed of silty sands, probably of glacial origin, interbedded with gravels and till. The fines in this material are non-plastic in the top 10 feet, however, below 10 feet plasticity increases with depth. The economic recoverable depth will depend on permafrost and natural water content conditions.

Two other source areas of impervious materials were investigated under this program. Borrow Area H, located some seven miles downstream of the dam at a bend of the Susitna River is composed of sediments of glacial origin. The grab samples collected here show this is a possible source of well graded sand to poorly graded, clayey sands with 40 percent fines. The samples have a maximum dry density of 139 pcf. Another potential borrow area, upstream on Deadman Creek about three and a half miles from the dam site, was also identified. The material is composed of clayey sands with a much higher percentage of fines than Borrow Area H. These fines have medium to high plasticity. Only cursory examination was given to these two areas in this program; however, the laboratory results indicate a more in depth investigation is warranted.

G.3 Preliminary Geotechnical Design Parameters

(a) Devil Canayon Site

The proposed dam axis at this site is located several hundred feet downstream of the mouth of Devil Canyon Gorge. The valley is generally asymmetrical in shape with rugged outcrops and cliffs forming the abutments. The valley is about 1,000 feet wide at crest elevation. The river through this part of the gorge is very fast and turbulent.

The area under consideration for the Devil Canyon site is underlain by a complex series of weathered and altered argillite and graywacke. This rock has been folded and fractured during its tectonic history which has resulted in zones of increased weathering and alteration in the foundation area. Excavation to sound rock will require the removal of up to 40 feet, of weathered rock. Permafrost has not been detected at the site, but if it does exist, it is not expected to be substantial or widespread. A thawing program can be incorporated with the grout hole installation.

Overburden within the V-shaped valley at the dam site is estimated to be 35 feet of river alluvium and boulders, which will be removed during construction. On the left abutment, however, a buried channel paralleling the river has been detected crossing the location of the saddle dam. The overburden in this area exceeds 90 feet in depth and will require construction of a cutoff system. Seepage control will be effected throughout the dam site by a grout curtain. A corresponding drain hole curtain, and drainage adits or galleries excavated into the foundation will be constructed to relieve excess pore pressure and to monitor the effectiveness of the grout curtain.

(b) Watana Site

The principal structures at the Watana site will be founded predominatly on a dioritic pluton of good engineering quality. Required foundation excavation will include the removal of approximatley 40 feet under the shells. Within the river channel, up to 80 feet of alluvium will be removed under the dam, due to its potential instability during seismic events. On the abutments, there is an average of 15 feet of overburden that will be removed.

A 400-foot deep relict channel has been delineated on the right abutment. This area will still require further investigation to ascertain its impact on potential reservoir leakage. The overall condition of this site is good, and the amount of preparation and remedial work will be comparable to similar large projects.

The presence of deep permafrost primarily in the south abutment, may require special construction consideration, and so further investigation is underway to define the nature and extent of the permafrost data. The permafrost is "warm" being within approximately one degree (Celsius) of thawing.

(c) General

The information obtained on the dam sites to date indicates that the construction of the large dams and underground facilities is feasible. The rock type and characteristics at both sites are suitable for large fill or concrete dams. While permafrost is prevalent at Watana and may exist sporadically at Devil Canyon, the temperature of the frozen ground is conducive to thawing by convential, proven methods and is not considered likely to be a major problem. Likewise, indications are that conventional rock support systems around underground openings, in conjunction with installation of grout and drainage systems, will be adequate to ensure stability and safety.

From the information obtained to date, it is concluded that adequate amounts of construction materials are available at Devil Canyon for a concrete dam. Adequate sources of material are available at the Watana site for a fill dam with a rock shell. However, further field investigation and laboratory testing are required to located the most economical sources, and to evaluate whether adequate qauantities of rounded boulders and cobbles are avaialbe for a proposed alternative gravel shell dam.

The plan for the 1981 field program is currently being finalized. It will take into account all available data from previous investigations, on-going geologic studies by Government agencies in the area, and the 1980 program results. The scope of the 1981 field program is aimed at providing sufficient data to firm up the feasibility of constructing the dams and power facilities at the two sites from a geotechnical point of view. The program will incorporate the following specific aspects:

(1) Watana Dam Site

- Determination of the location of the most economic construction material sources and the engineering properties of these materials;

- Improved definition of possible shear zones within the dam site so that all project components such as spillways, diversion tunnels, powerhouses and penstocks can be located and appropriate foundation treatment and rock support systems designed;

- More detailed evaluation of the two major shear zones: "The Fins", upstream from the dam and "Fingerbuster" located downstream from the dam;

- Delineation of the geologic contact between the diorite and the andesites adjacent to the dam so that the potential impact of this contact is dealt with in the design of the project, particularly the underground support systems.

(2) Devil Canyon Dam Site

- Determination of the engineering properties of the construction materials for both concrete and earth structures which will include testing for freeze-thaw and saturation durability.

- Additional core drilling in the abutments at lower elevations to determine typical rock conditions, permeabilities and rock strengths;

- Additonal drilling across the river to determine if a fault exists down the length of Devil Canyon under the river;

- A second angle hole on the left abutment to intersect the suspected fault on the left abutment;

- Exploration for impervious core and rock fill sources for use in the saddle dam;

- Additional field mapping to determine more accurately the bedding and joint orientations in order to produce a structural geologic model of the site.

TABLE G-1

MODIFIED PROCTOR DENSITY RESULTS

SAMPLE	UNIFIED CLASS.	MAX. DRY DENSITY,pcf	OPTIMUM WATER CONTENT
Borrow Area H W-80-256	GC-SC	139.0	6.2%
Deadman Creek W-80-282	CL-CH	102.5	22.0%
Deadman Creek W-80-300	SM	135.0	6.0%

TABLE G-2

SUMMARY OF LABORATORY TEST DATA

PROJECT NO. 052504 CLIENT Acres PROJECT NAME Susitna (Watana Dam Site)	R & M CONSULTANTS, INC. SUMMARY OF LABORATORY TEST DATA	DATE 10-17-80 PARTY NO. ______ PAGE NO C-01

LAB NO.	BORING NO.	SAMPLE NO.	DEPTH	4"	3"	2"	1½"	1"	3/4"	1/2"	3/8"	#4	#10	#40	#200	.02	.005	.002	% Moist.	LL	PI	Unified Class.
BORROW		H	W-80-256			100	95	88	84	81	78	71	64	53	38.2	24.3	13.6	8.6	10.9	21.7	9.2	GC-SC
			(Grab sample)																			
BORROW		H	W-80-257			100	97	92	89	84	81	73	66	54	36.0	19.6	8.9	5.2	12.3	17.1	2.5	GM-SM
			(Grab sample)																			
DEADMAN			W-80-282											100	99.5	81.3	69.6	60.8	42.1	55.9	33.2	CL-CH
			(Grab sample)																			
DEADMAN			W-80-300			100	95	93	89	87	86	80	76	58	26.9	9.2	3.0	1.3	6.6	NV **	NP **	SM
			(Grab sample)																			
STREAM ALLUVIUM			W-80-302	100	92	90	82	69	58	45	38	27	23	14	2.6							GP
			(Grab sample)																			
BORROW		D	AH-D1 #5					100	99	95	94	90	84	69	42.3	19.0	6.1	2.6	11.1	NV	NP	SM
			(6.0 - 7.5')																			
BORROW		D	AH-D1 #6				100	87	87	83	80	75	69	54	28.3	14.4	6.1	3.3	6.7			SM*
			(8.0 - 8.5')																			
BORROW		D	AH-D1 #7						100	91	91	87	76	62	35.7	18.2	8.2	4.9	6.6			SM*
			(10.0 - 10.3')																			
BORROW		D	AH-D2 #3		100	80	80	80	77	73	72	67	61	47	28.5	12.0	3.2	2.9	25.7	NV	NP	SM
			(1.5 - 3.0')																			
BORROW		D	AH-D2 #4				100	94	92	90	89	86	79	62	35.0	21.2	4.1	2.4	11.4	13.9	NP	SM
			(3.0 - 4.5')																			

REMARKS: * Estimated Value

** NV = Non Viscous NP = Non Plastic

NOTE: SIEVE ANALYSIS = PERCENT PASSING

Janice Cecere

APPROVED

LAB NO.	BORING NO.	SAMPLE NO.	DEPTH	4"	3"	2"	1½"	1"	3/4"	1/2"	3/8"	#4	#10	#40	#200	.02	.005	.002	% Moist.	LL	PI	Unified Class.
BORROW		D	AH-D2 #5					100	98	96	92	87	80	59	30.7	13.8	3.9	1.6	11.2	NV	NP	SM
			(4.5 - 6.0')																			
BORROW		D	AH-D2 #8						100	99	97	93	87	70	44.0	22.5	8.9	4.0	11.3	15.5	2.2	SM
			(15.0 - 16.5')																			
BORROW		D	AH-D2 #9				100	96	94	93	91	85	78	61	38.6	21.3	10.3	4.2	9.4	17.5	4.2	SM
			(20.0 - 21.5')																			
BARROW		E	AH-E1 #3										100	99	48.0				19.6			SM
			(1.0 - 1.5')																			
BORROW		E	AH-E1 #4										100	98	59.5				27.3			ML*
			(2.0 - 3.5')																			
BORROW		E	AH-E3 #6		100	89	89	83	80	76	72	62	52	28	6.2				4.4			SP/SM
			(4.5 - 6.0')																			
BORROW		E	AH-E3 #7			**	100	90	76	62	57	40	31	16	3.7				0.7			GW
			(6.5 - 8.0')																			
BORROW		E	AH-E4 #6							100	99	98	92	66	22.2				17.6			SM
			(5.0 - 6.5')																			
BORROW		E	AH-E7 #3				100	85	73	56	49	39	31	12	2.1				2.3			GP
			(2.0 - 3.0')																			
BORROW		E	AH-E9 #2 (1.5 - 3.0')										100	99	28.6				15.7			SM
BORROW		E	AH-E9 #6 (6.5 - 8.0')					100	95	87	79	57	44	33	17.0				4.4			GM

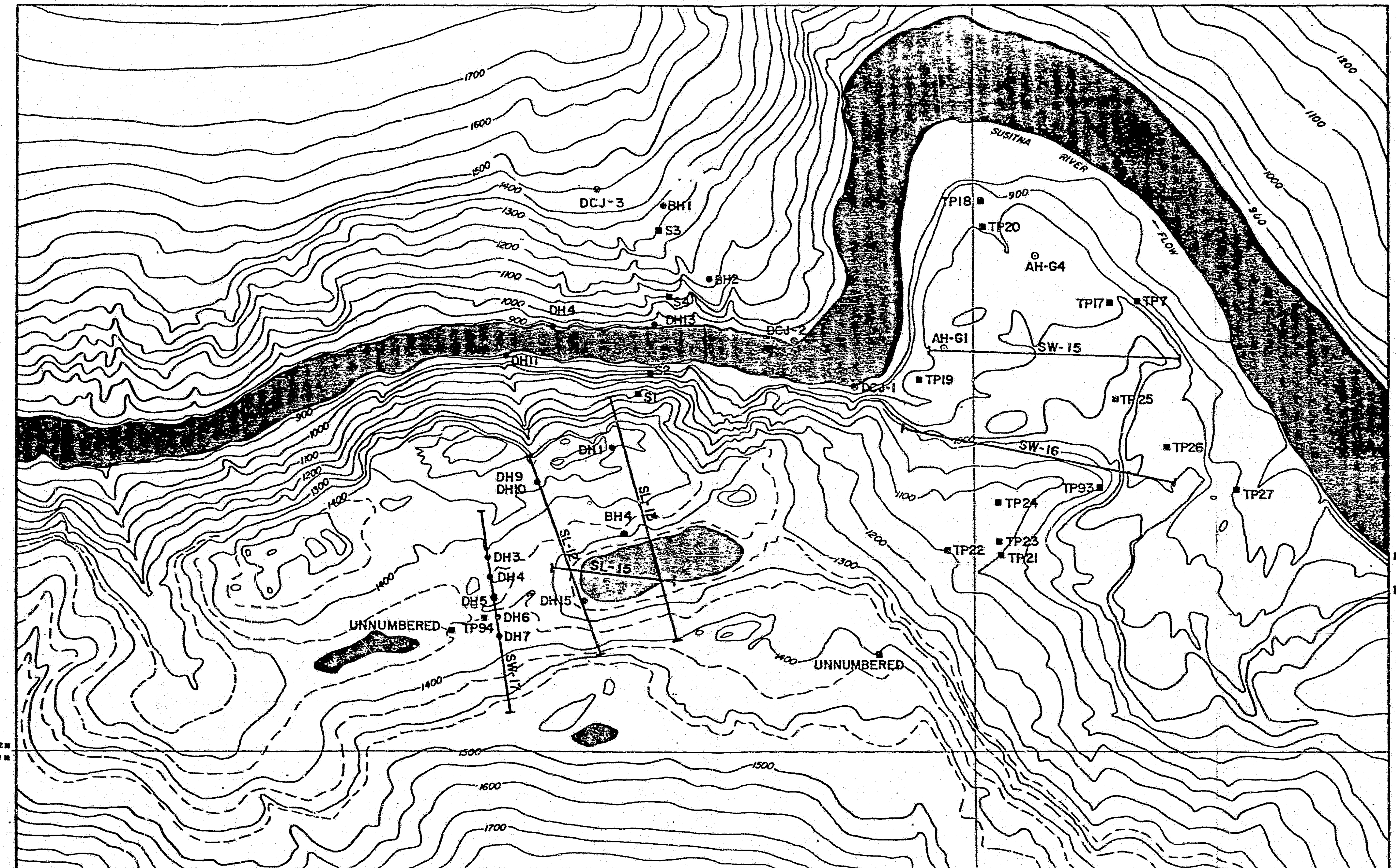
REMARKS: ** 1-2" Rock Present in Sample

* Estimated Value

NOTE: SIEVE ANALYSIS = PERCENT PASSING

Janice Cecere

APPROVED



REFERENCE: USGS, TALKEETNA MOUNTAINS (D-5), ALASKA QUADRANGLE, SEWARD MERIDIAN: T32N, R1E, S32 AND 33.

LEGEND

- DH — BOREHOLES-BUREAU OF RECLAMATION, 1960
- BH — BOREHOLES-SUMMER 1980 PROGRAM
- TP, S, — TEST PITS AND TRENCHES BUREAU OF RECLAMATION, 1960
- AUGER HOLES-SUMMER 1980 PROGRAM
- SW — SEISMIC LINES-CORP OF ENGINEERS, 1978
- SL — SEISMIC LINES-SUMMER 1980 PROGRAM
- DCJ — LOCATION OF JOINT MEASUREMENT

NOTE: TOPOGRAPHIC CONTOURS ARE APPROXIMATE

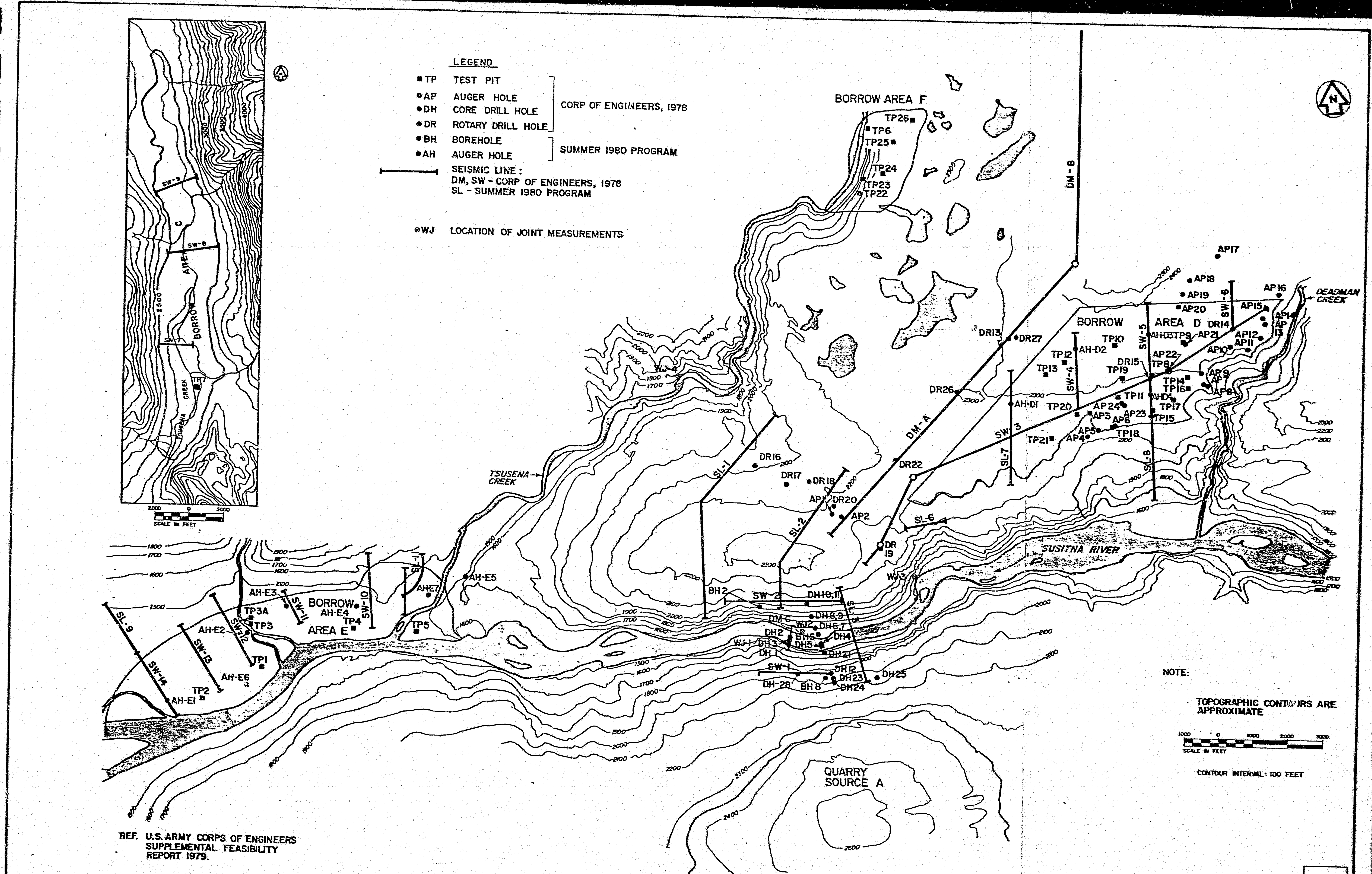
200 0 200 400 600
SCALE IN FEET

CONTOUR INTERVAL 50 FEET
DASHED CONTOUR 25 FEET

DEVIL CANYON LOCATION EXPLORATION MAP

FIGURE G-1

ACRES



WATANA LOCATION EXPLORATION MAP

FIGURE G-2

I - TES REPORTS ON ENVIRONMENTAL IMPACTS

Associated with the Tunnel, Watana/Devil Canyon and High Devil Canyon/Vee Redevelopment Plans.

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

PRELIMINARY ENVIRONMENTAL ASSESSMENT OF TUNNEL ALTERNATIVES

by

Terrestrial Environmental Specialists, Inc.
Phoenix, New York

for

Acres American Incorporated
Buffalo, New York

December 15, 1980

TABLE OF CONTENTS

1 - INTRODUCTION

In response to a request by Acres American, Inc. for input into Subtask 6.02 of the Susitna Hydroelectric Project feasibility study, Terrestrial Environmental Specialists, Inc. (TES) did a preliminary assessment of tunnel alternatives. The objectives of this assessment were:

(1) to compare environmental aspects of four alternative tunnel schemes;
(2) to compare the best tunnel scheme, as selected by Acres, with the two-dam scheme (Watana and Devils Canyon) proposed by the U.S. Army Corps of Engineers;
(3) to compare two revised locations for the downstream powerhouse; and
(4) to comment on alternative methods of disposal of tunnel muck, the rock removed to create a tunnel.

The environmental assessment was based on both the project descriptions in a letter dated October 29, 1980, from Acres to TES, as amended by a letter dated December 11, 1980, and on conversations between representatives of these firms. Copies of these letters may be found in the appendices to this report. At the time this assessment was performed complete information was not available on the various tunnel schemes under consideration. Therefore, TES views this assessment as only a preliminary study.

One assumption made by TES, and confirmed by Acres, is that the dam, pool elevation, and pool level fluctuations of Watana are as described by the Corps of Engineers and would not differ among the five schemes. If, on the contrary, any of the tunnel schemes increase the probability that the pool level at Watana may be lower than that proposed by the Corps or if a particular scheme may moderate the pool fluctuations, then the environmental assessment of the tunnel schemes may, in turn, be affected.

It is recognized that an environmental assessment for ranking alternative schemes must include some subjective value judgements. A given scheme may be preferable from the standpoint of one environmental discipline (e.g. fisheries) whereas another scheme may be better from another aspect (e.g. terrestrial ecology or aesthetics). To recommend any one scheme over another involves the difficult task of making trade-offs among the environmental disciplines. Such trade-offs are likely to be controversial.

2 - COMPARISON OF TUNNEL ALTERNATIVES

2.1 Scheme 1

The environmental impacts associated with this tunnel scheme are likely to be greater than those of at least one of the other tunnel schemes evaluated (i.e. Scheme 3). The main criterion for this assessment is the adverse effects, particularly on fisheries and recreation, of the variable downstream flows (4000-14000 cfs daily) created by the Devils Canyon powerhouse peaking operation. Other negative impacts would result from construction of both the re-regulation dam and a relatively long tunnel. Tunnel impacts are similar to those of Schemes 2 and 4 and include disturbance of Susitna tributaries as a result of tunnel access and the potential problems associated with disposal of a relatively large volume of tunnel muck.

2.2 Scheme 2

Like Scheme 1, this scheme involves adverse environmental impacts associated with variable downstream flows caused by peaking operation at the Devils Canyon powerhouse (4000-14000 cfs). Without the re-regulation dam, however, less land would be inundated and the impacts associated with construction of this relatively small dam would be avoided, although flow fluctuations above Devils Canyon would be more severe. Like Scheme 1 too, the long tunnel proposed here will have negative consequences, including disturbance of tributaries for tunnel access and the potential problems connected with tunnel muck disposal.

2.3 Scheme 3

The overall environmental impact of this scheme is considered less than that related to the two previous schemes, and also less than that related to the fourth scheme as amended (Appendix B). The relatively constant discharge (about 8300-8900 cfs) from the Devils Canyon powerhouse is desirable for maintaining downstream fish habitat and recreational potential. Since it may allow anadromous fish access to a previously inaccessible 15-mile stretch of the Susitna River, Scheme 3 could, in fact, offer a rare opportunity for enhancement of the fisheries resource. The newly available section of river could perhaps be actively managed to create or improve spawning habitat for salmon. This mitigation potential is dependent upon the location of the downstream powerhouse (above or below the present rapids) and the determination of whether project flows through Devils Canyon will still constitute a barrier to fish passage. The data needed for this determination are not yet available.

A compensation flow release of 1000 cfs at the re-regulation dam is not the same as 1000 cfs at the Watana dam. Because fewer tributaries will augment the compensation flow under this re-regulation scheme, the compensation flow will need to be slightly greater than with the other schemes to result in the equivalent flow at Devils Canyon. Compensation flow should be sufficient to maintain a certain degree of riverine character, and thus should be kept to a maximum even in the absence of a salmon fishery. Of course, if the viability of a tunnel scheme is jeopardized, the impacts of the alternative scheme must be compared to the impacts of a lesser compensation flow.

As with any of the tunnel schemes, the wildlife habitat in the stretch of river bypassed by the tunnel might improve temporarily because of an increase in riparian zone vegetation. With Scheme 3, however, this stretch of river is shorter than with the other tunnel schemes; so a smaller area would benefit. The wildlife habitat downstream of Devils Canyon powerhouse may well benefit from the flow from the hydroelectric project, regardless of the tunnel scheme chosen. The improvements to that habitat may be somewhat greater, though, with the constant flows allowed in Scheme 3 than with the variable flows resulting from peaking in the other tunnel schemes.

One environmental disadvantage of this scheme compared to the others is the larger area to be inundated by the re-regulation reservoir. This area includes known archeological sites in addition to wildlife habitat. Nevertheless, it is felt that this disadvantage is offset by the more positive environmental factors associated with constant discharge from the Devils Canyon powerhouse.

2.4 Scheme 4

Scheme 4, as originally described (Appendix A), was determined to be environmentally superior to the other tunnel schemes, because of constant downstream flows combined with the lack of a lower reservoir. However, Acres' analysis determined that this baseload operation is most likely incapable of supplying the peak energy demand. Scheme 4, as amended (Appendix B), is a peaking operation at Watana with baseload operation at the tunnel. Since the net daily fluctuations in flow below Devils Canyon would be considerable (in the order of 4000-13000 cfs), the amended Scheme 4 was judged as less desirable than Scheme 3 from an environmental standpoint. Although Scheme 4 would avoid the impacts associated with the lower dam and its impoundment (as planned under Scheme 3), the adverse impacts that would result from fluctuating downstream flows are considered to be an overriding factor.

Another, less significant disadvantage of Scheme 4 (and shared by Schemes 1 and 2) in contrast to Scheme 3 is the longer tunnel length planned for the former and, perhaps, the proposed location of the tunnel on the north side of the river. The sites chosen for disposal of tunnel muck and for the required access roads in any of these schemes (as yet undetermined) will further influence this comparison.

2.5 Location of Devils Canyon Powerhouse

Alternative locations for the Devils Canyon powerhouse have been proposed. These consist of an upstream location about 5 miles above the proposed Corps of Engineers dam site and a downstream location about 1.5 miles below Portage Creek, as alternatives to the site illustrated in Appendix A. The major environmental consideration is that a powerhouse upstream of Devils Canyon would preserve much of the aesthetic value of the canyon. In addition, the shorter tunnel would confine construction activities to a smaller area and may result in slightly less ground disturbance, particularly if there are fewer access points, as well as a smaller muck disposal problem. A downstream powerhouse location, on the other hand, might create a mitigation opportunity by opening up a longer stretch of river that perhaps could be managed to create salmon spawning habitat. Until large-scale aerial photographs and cross-sectional data on the canyon have been received and analyzed, a determination cannot be made as to whether project flows through the canyon will still constitute a barrier to fish passage.

Our primary responsibility is to avoid, or at least to minimize, adverse impacts to the environment, and it must take precedence over our desire to enhance or expand a resource. It is our opinion that losing a resource (the aesthetic value of the Devils Canyon rapids) is worse than losing a possible mitigation opportunity. It is not yet known if this opportunity even exists. Furthermore, there are always other means by which to enhance the fishery, although not necessarily so conveniently associated with the hydroelectric project. Thus, at this time the upstream powerhouse location is preferred.

2.6 Disposal of Tunnel Muck

There are a number of options to be considered for disposal of the rock removed in creating the tunnel. These include: stockpiling the material for use in access road repair, construction of the re-regulation dam, or stabilization of the reservoir shoreline; disposal in Watana reservoir; dike construction; pile, cover, and seed; and disposal in a ravine or other convenient location. It is unlikely that the most environmentally acceptable option will also be the most economical. Because many unknown factors now exist, a firm recommendation cannot be made without further evaluation. It is quite likely, however, that a combination of disposal methods will be the best solution.

Stockpiling at least some of the material for access road repairs is environmentally acceptable, provided a suitable location is selected for the stockpile. Perhaps the material could be utilized for construction of any of the access road spurs or temporary roads that are not already completed at the time the tunnel is dug.

Another acceptable solution might be to stockpile the material for use in construction of the re-regulation dam. This rock could also be a potential source of material for stabilization of the reservoir shoreline if required. As with the previous option, an environmentally acceptable location of the stockpile would be required. Disposal of the material in Watana Reservoir might also be environmentally acceptable. Consideration should be given to the feasibility of using the material in the construction of any impoundment control structures such as dikes. A small amount of tunnel muck could possibly also be used for stream habitat development. With any of these options, the possible toxicity of minerals exposed to the water should be first determined by assay, if there is any reason to suspect the occurrence of such minerals.

To pile, cover, and seed the material is worthy of further consideration, and would require proper planning. For example, borrow areas used in dam construction could perhaps be restored to original contour by this method.. The source of soil for cover is a major consideration, as earth should only be taken from an area slated for future disturbance or inundation. If trucking soil from the reservoir area is determined to be feasible, it might also be worthwhile to transport a portion of the muck back for disposal in the reservoir area.

The most economical solution might be to fill a ravine with the material or to dispose of it in another convenient location. Unless the chosen disposal site will eventually be inundated, however, such an arrangement is environmentally unacceptable, especially since better options are obviously available.

3 - COMPARISON OF TUNNEL SCHEME 3 WITH CORPS OF ENGINEERS' SCHEME

Scheme 3 emerged as superior in Acres' preliminary economic and technical screening. After amendment of Scheme 4, Scheme 3 was also considered to be the best scheme from an environmental standpoint. Therefore, Scheme 3 is to be compared with the two-dam scheme proposed by the U.S. Army Corps of Engineers.

Further analysis will be in order after complete details are available on Tunnel Scheme 3. At present, many gaps exist in the available data. Additional information on design, operation, and hydrology, combined with environmental field investigations at the locations of project facilities, would permit a much more detailed comparison of these two development alternatives. Nevertheless, from what is presently understood about Scheme 3, there is little doubt that it is, by far, environmentally superior to the Corps of Engineers' proposal. Of course, extensive additional study needs to be performed on whatever scheme is selected to identify its impacts and to develop mitigation plans.

Tunnel Scheme 3 has, by any measure, a less adverse environmental impact than the Corps of Engineers' scheme. By virtue of size alone, construction of the smaller dam (245 ft.) would have less environmental impact than the Devils Canyon dam proposed by the Corps. The river miles flooded and the reservoir area created by the Scheme 3 re-regulation dam would be about half those of the Corps' plan for Devils Canyon, thereby reducing negative consequences, such as loss of wildlife habitat and possible archeological sites. In addition, the adverse effects upon the aesthetic value of Devils Canyon would be substantially lessened with Scheme 3, particularly with the powerhouse location upstream of the proposed Corps dam site. Furthermore, Tunnel Scheme 3 may possibly present a rare mitigation opportunity by creating new salmon spawning habitat that could be actively managed. With the increase in riparian zone vegetation allowed by Scheme 3, the wildlife habitat in the stretch of river bypassed by the tunnel might be temporarily improved. The impacts associated with tunnel access and disposal of tunnel muck necessitated by Scheme 3 are more than offset by the plan's advantages. Thus, Tunnel Scheme 3 far exceeds the U.S. Army Corps of Engineers' proposal in terms of environmental acceptability.

APPENDIX A

DESCRIPTIONS OF TUNNEL SCHEMES

ACRES

RECEIVED 4 Nov '80 C218.578

October 29, 1980
P5700.06
T507

Terrestrial Environmental Specialists, Inc.
R.D. 1
Phoenix, NY 13135

Attention: Vince Lucid

Dear Vince:

Susitna Hydroelectric Project
Subtask 6.02

We would like you to review the environmental aspects of the tunnel alternative (Subtask 6.02), which you were introduced to on October 3, 1980. Your environmental assessment will be included in the Subtask 6.02 close-out report, November 1980. In order to complete this close-out report on schedule the environmental assessment is required by November 13, 1980.

The environmental assessment should include a small section on each of the four tunnel schemes (Schemes 1, 2, 3, & 4). Physical factors of the schemes and the COE selected plan are presented in Table 1. Tunnel scheme plan view and alignments are enclosed.

Scheme 1 is composed of the COE Watana Dam and powerhouse, and a small re-regulation dam with power tunnels leading to a powerhouse at Devil Canyon. Peaking operations will occur at both Watana and the Devil Canyon powerhouses. A constant compensation flow discharge will be provided between Watana and Devil Canyon. Peaking operations will create daily water level fluctuations of unknown magnitude downstream of Devil Canyon.

Scheme 2 is composed of the COE Watana Dam and powerhouse with power tunnels from the Watana Reservoir to a powerhouse at Devil Canyon. Upon completion of the tunnel scheme the Watana powerhouse will be reduced to 35 MW and will supply a constant compensation flow between Watana and Devil Canyon. The Devil Canyon powerhouse will operate as a peaking hydro facility. Water level fluctuations downstream of Devil Canyon are similar to that of Scheme 1.

Scheme 3 is composed of the COE Watana Dam and powerhouse, and a re-regulation dam with power tunnels leading to a powerhouse at Devil Canyon. The Watana powerhouse will operate as a peaking facility which discharges into a re-regulation reservoir. The re-regulation reservoir is capable of storing the daily peak discharges and releasing a constant discharge into the power tunnels. A four foot daily water level fluctuation in the re-regulation reservoir is required. The Devil Canyon powerhouse will operate as a base load facility, thus, no daily water level fluctuations will occur downstream of Devil Canyon.

ACRES AMERICAN INCORPORATED
Consulting Engineers
The Liberty Bank Building, Main at Court
Buffalo, New York 14202
Telephone 716-853-7525 Telex 91-6423 ACRES BUF
Other Offices: Columbia, MD; Pittsburgh, PA; Raleigh, NC; Washington, DC

The general layout of Scheme 4 is similar to Scheme 2. Scheme 4 is a base load scheme and has a very limited potential to produce additional peak energy. Daily water level fluctuations downstream of Devil Canyon are similar to Scheme 3.

Preliminary economic and technical screening showed Scheme 3 as superior. Preliminary environmental assessment ranked Scheme 4 environmentally superior. Scheme 4 is most likely not capable of supply the required peak energy demand. Thus, Scheme 3, ranked second environmentally, was preliminarily chosen as the best tunnel scheme. If you should disagree with the selection of Scheme 3 please contact me as soon as possible.

The objective of Subtask 6.02 is to compare the best tunnel scheme with the COE selected scheme (High Watana and Devil Canyon). The environmental assessment should include a section comparing the impacts of tunnel Scheme 3 with the COE selected scheme. Include conclusions and a description of additional study required..

In regards to disposal of tunnel muck (rock removed to create tunnel) we can assume that additional costs will be incured to dispose of the muck in an environmentally acceptable manner. An environmental assessment of alternative disposal methods would help to define this added cost. The following lists only a few disposal ideas, feel free to consider others.

- Stockpile and use for access road repairs.
- Stockpile and use for dam material (Scheme 3 only).
- Dump in Watana Reservoir.
- Fill the nearest ravine.
- Leave in the most convenient location.
- Pile, cover, and seed.

Please do not hesitate to contact me for any additional information that may be required.

Sincerely,

Kevin Young

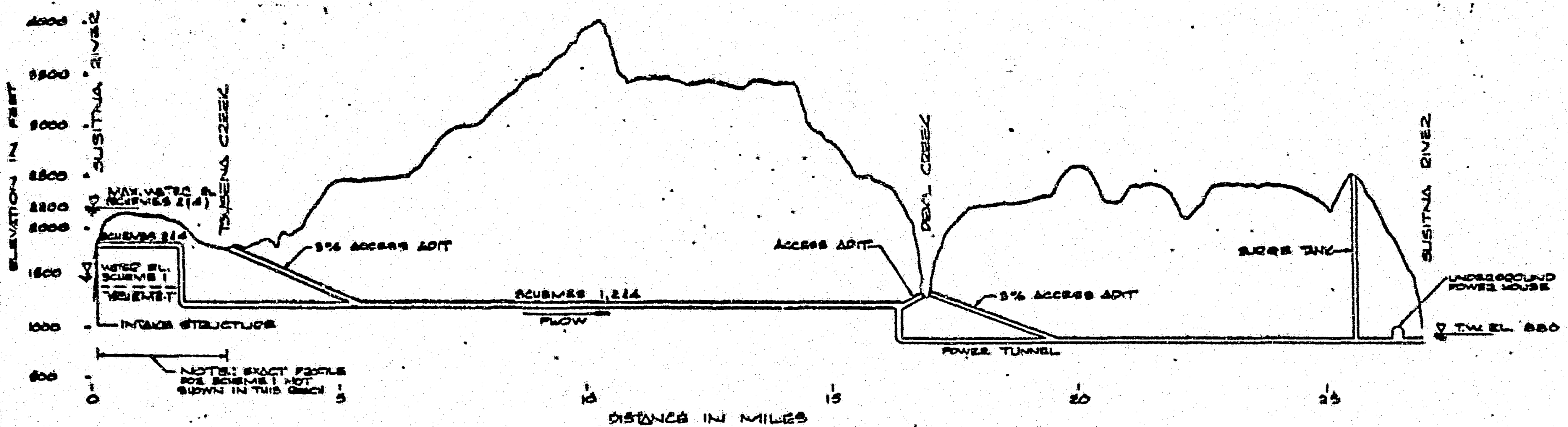
Kevin Young

RJW:ccv

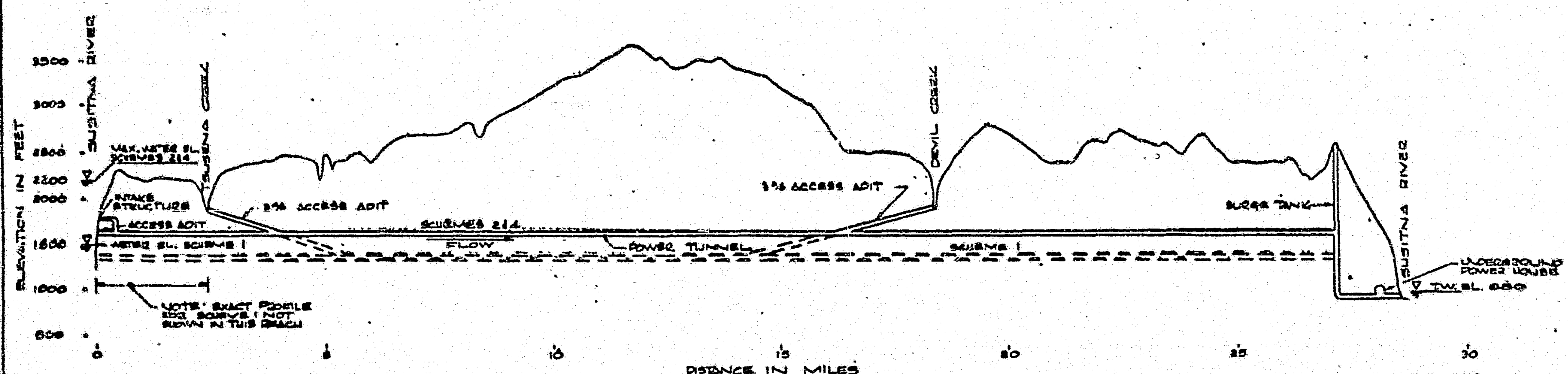
TABLE 1

Susitna Tunnel Schemes
Physical Factors

	COE Devil Canyon	1	2	3	4
Reservoir Area (Acres)	7,500	320	-0-	3,900	-0-
River Miles Flooded	31.6	2.0	-0-	15.8	-0-
Tunnel Length (Miles)	--	27	29	15.8	29
Tunnel Volume (Yd^3)	--	10,749,000	11,545,000	4,285,000	6,494,000
Compensation Flow (cfs)	--	500 to 1000	500 to 1000	500 to 1000	500 to 1000
Downstream Reservoir Volume (Acre-Feet)	1,100,000	9,500	-0-	350,000	-0-
Devil Canyon Powerhouse Discharge	Constant	Peaking	Peaking	Constant	Constant
Dam Height (feet)	520	[illegible]	--	245	--



ALTERNATIVE DIRECT ALIGNMENT (SCHEMES 1,2&4)



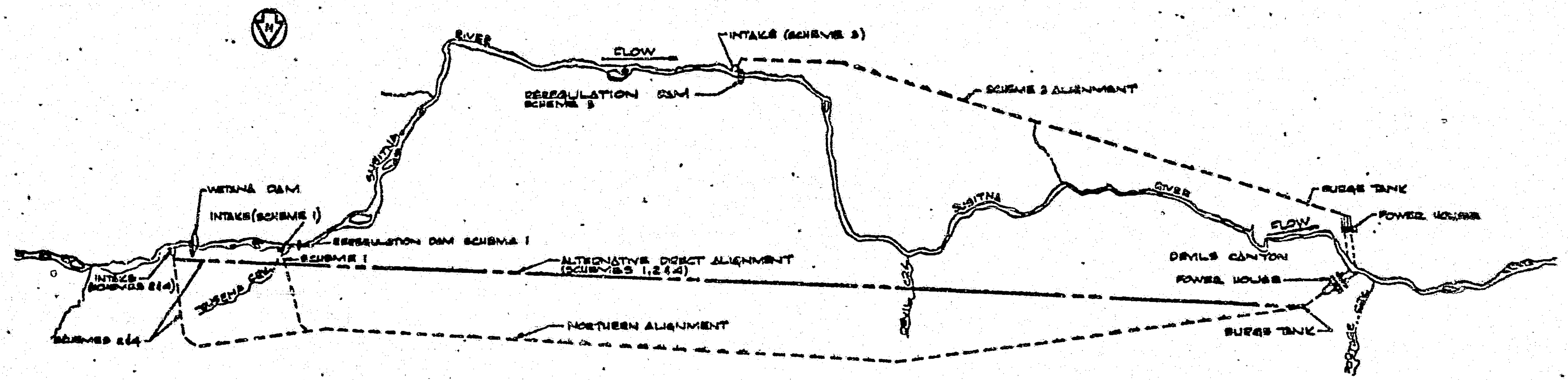
NORTHERN ALIGNMENT (SCHEMES 1,2&4)

ALASKA POWER AUTHORITY

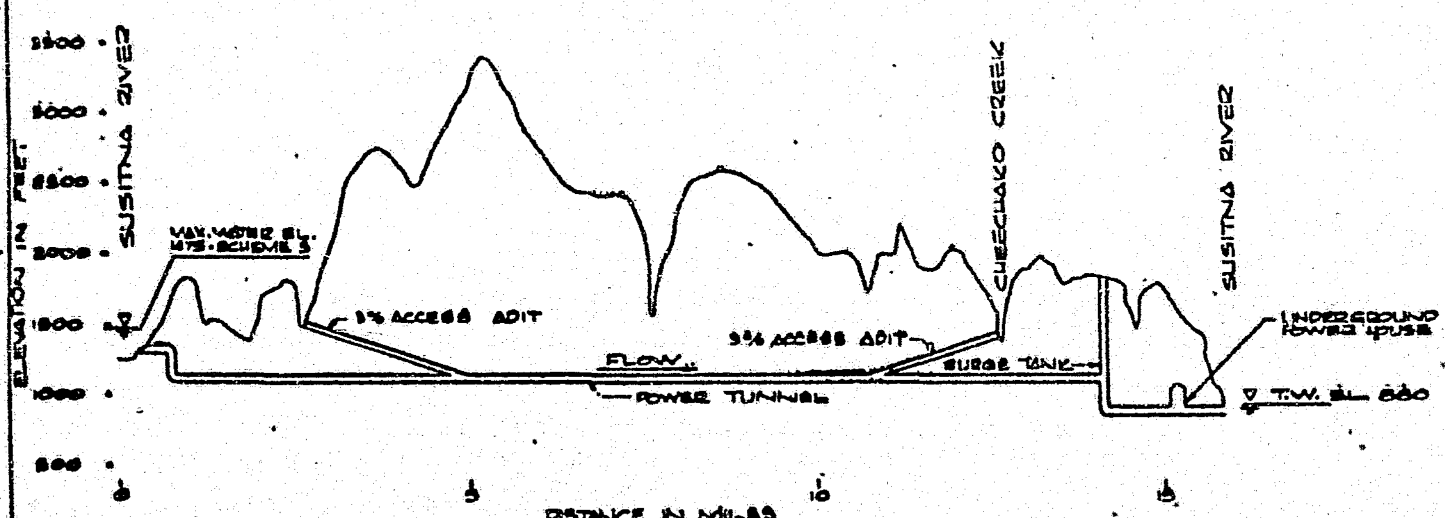
SUSITNA HYDROELECTRIC PROJECT

CONCEPTUAL TUNNEL ALTERNATIVES PROFILES SCHEMES 1,2&4

AS SHOWN



TUNNEL PLAN



SCHEME 3 ALIGNMENT

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

CONCEPTUAL TUNNEL ALTERNATIVES - PLANS & PROFILE OF SCHEME 3

AS SHOWN

APPENDIX B

AMENDED DESCRIPTION OF TUNNEL SCHEME 4

ACRES

RECEIVED
13 Dec '80
R215, 660

December 11, 1980
P5700.11.30
T.606

Mr. Vince Lucid
Terrestrial Environmental Specialists, Inc.
RD 1
Box 388
Phoenix, New York 13135

Dear Vince:

Susitna Hydroelectric Project
Revised Description of Tunnel Alternatives

Enclosed please find a memo from B. Wart outlining our revised description of tunnel alternatives.

Please use this description in your assessment of tunnel alternatives.

In addition, I have completed your table outlining tunnel design information.

Sincerely,

Judy Herbst for
Kevin Young
Environmental Coordinator

KRY/ljr

Enclosure

ACRES AMERICAN INCORPORATED
Consulting Engineers
The Liberty Bank Building, Main at Court
Buffalo, New York 14202

Telephone 716-853-7525 Telex 91-6423 ACRES BUF

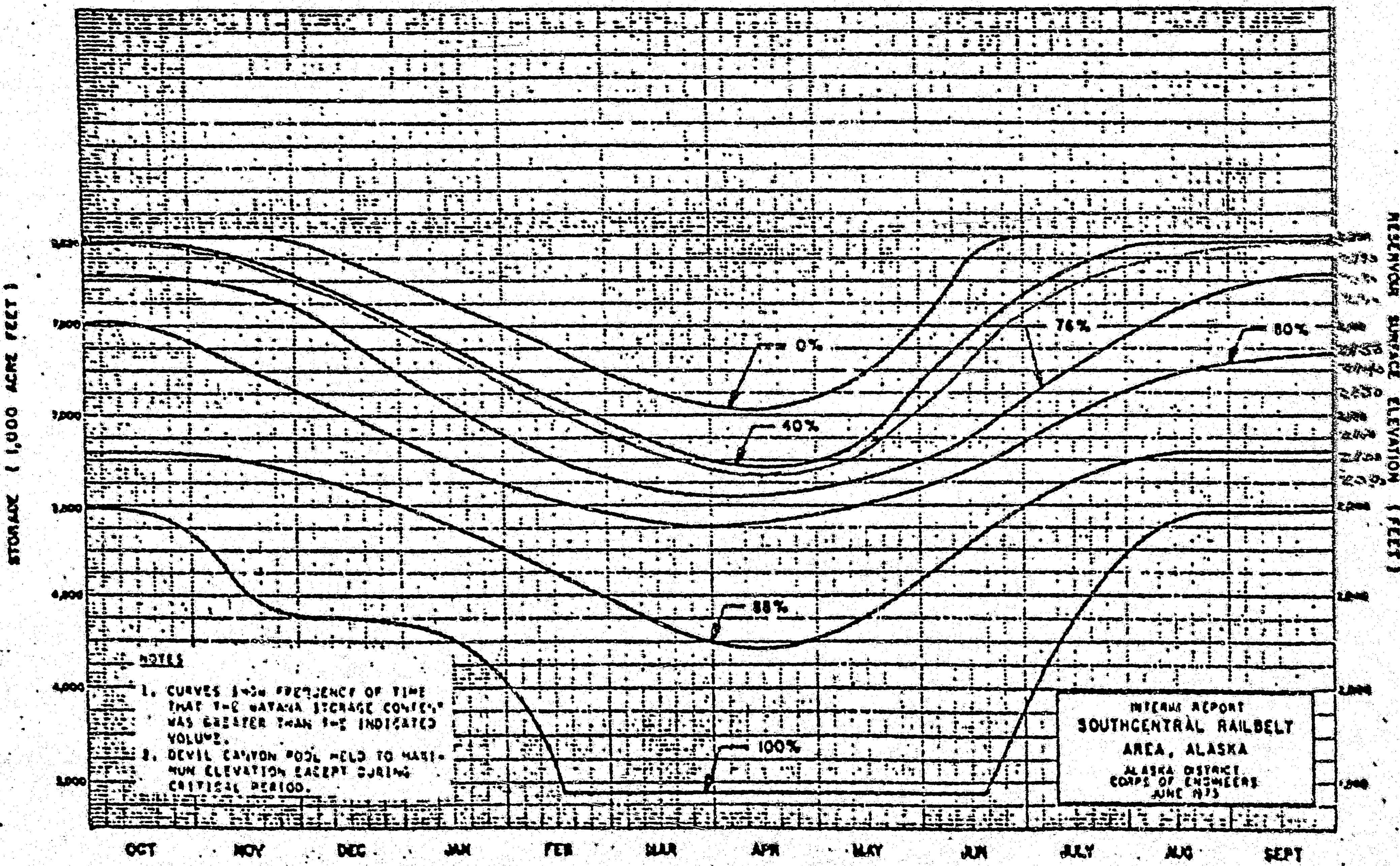
Other Offices: Columbia, MD; Pittsburgh, PA; Raleigh, NC; Washington, DC

SUSITNA TUNNEL SCHEMES - PHYSICAL FACTORS (addendum)

	Typical	COE	1	2	3	4
Range of discharge (cfs) at Devil Canyon Powerhouse	daily	6,000 to 13,000	4,000 to 14,000	4,000 to 14,000	8300 to 8700	4,000 to 13,000
	seasonal	fluctuations are to	less than existing to	natural fluctuations to	and are similar to	for all plans to
Range of river stage below Devil Canyon powerhouse (corresponding to discharges listed above)	daily	Small to To Date	Large to no Detailed	Large to Information is	Small to available.	Large to
	seasonal	to All To Date	plans to have no Information	identical seasonal to -tion is	fluctuations to available.	which are less th[an] to natural fluctuati[ons]
Maximum fluctuations (ft) in Watana Reservoir	daily	< 1	Same as COE	Same as COE	Same as COE	Same as COE
	seasonal	See Graph	~~See Graph~~ Same as COE	~~See Graph~~ Same as COE	~~See Graph~~ Same as COE	~~See Graph~~ Same as COE
Maximum fluctuations (ft) in downstream reservoir	daily	2	Large	NA	4	NA
	seasonal	None	None	NA	None	NA
Generating Capacity (MW)	Watana	792	792	35 (792)*	792	792
	Devils Canyon	776	550	1150	365	365
Total Project Costs ($)		2,150,000,000	2,502,100,000	2,394,600,000	2,144,300,000	2,079,200,000
Total Annual Energy (GWH)		6895	5704	5056	5924	4140

* Watana Capacity is reduced after completion of tunnel project.

WATANA MONTHLY STORAGE FREQUENCY
FOR THE DEVIL CANYON AND WATANA SYSTEM



Terrestrial Environmental Specialists, inc.
R.D. 1 BOX 388 PHOENIX, N.Y. 13135

January 16, 1981
218.443

Project Manager
Susitna Hydroelectric Project
Acres American, Inc.
Liberty Bank Building
Main at Court
Buffalo, New York 14202

Attention: Kevin Young
Re: Alternative Development Schemes

Dear Kevin:

In response to your request of December 10, 1980, and as discussed in my letter to you on January 8, 1981, TES, Inc. has prepared some comments on the Vee/High Devil Canyon/Olson scheme in comparison with the Watana/Devil Canyon scheme. Enclosed for your review and comment is a draft of a brief report entitled "Environmental Considerations of Alternative Hydroelectric Development Schemes for the Upper Susitna Basin".

We will be pleased to discuss the contents of this report with you.

Sincerely,

Vince

Vincent J. Lucid, Ph.D.
Environmental Studies Director

VJL/vl
Enc.
cc: R. Krogseng

DRAFT

ALASKA POWER AUTHORITY
SUSITNA HYDROELECTRIC PROJECT

ENVIRONMENTAL CONSIDERATIONS OF ALTERNATIVE HYDROELECTRIC DEVELOPMENT SCHEMES FOR THE UPPER SUSITNA BASIN

by

Terrestrial Environmental Specialists, Inc.
Phoenix, New York

for

Acres American, Inc.
Buffalo, New York

January 16, 1981

TABLE OF CONTENTS

1 - INTRODUCTION

This report documents preliminary environmental considerations of alternative hydroelectric development schemes for the Upper Susitna Basin. The need for the report stems from discussion at a meeting held in Buffalo on December 2, 1980 between staff of Acres American and TES, Inc. The alternative development schemes are described in a December 4, 1980 memo from I. Hutchison to K. Young for transmittal to TES, Inc. (Appendix A). Additional details were obtained and the approach agreed upon in subsequent conversations and data transmittal between K. Young and V. Lucid concerning these alternative development schemes.

The following assessment is based upon a familiarity with the Watana/ Devil Canyon area obtained during the first year of environmental studies. At this writing, however, we do not have the benefit of information to be contained in the 1980 Annual Reports, which are to be completed by TES subcontractors by March 1981. Because much of the Vee reservoir lies outside of the study area for many disciplines, comments concerning this impoundment rely heavily upon intuitive judgement.

2 - APPROACH

2.1 The Development Schemes

Environmental considerations were preliminarily identified for two different hydroelectric development schemes for the Upper Susitna Basin: Watana/Devil Canyon and Vee/High Devil Canyon/Olson. The three staging variations for each of these schemes (Appendix A) will likely have different short-term impacts, but an attempt to address these possible differences at this time would be too speculative in most disciplines to be meaningful. In disciplines such as socioeconomics and land use, however, the staging of the development will largely determine the magnitude of impacts. Thus, the environmental considerations identified in this report are based in most cases upon the two ultimate schemes with occasional references to the staging options. It was assumed that whatever staging alternative is selected, all stages of development would be completed. The result would be one of the two schemes outlined in Table 1.

2.2 Assumptions of Environmental Constraints

The identification of potential advantages and disadvantages of the two schemes, from an environmental standpoint, requires that certain assumptions be made concerning environmental constraints that will govern the design and operation of the facilities. Among these are:

(a) that constant, or nearly constant, downstream flows be maintained, both during and after development, whether by means of a re-regulation facility or operational constraints;

(b) that drawdown of the reservoirs would be similar in magnitude to corresponding reservoirs in the other scheme (e.g. Watana vs. Vee), and would be within environmental constraints; and

(c) that a minimum release or compensation flow be maintained (of a volume to be determined) to preserve the riverine habitat between the reservoirs.

Table 1
Descriptions of Two Alternative Hydroelectric Development Schemes for the Upper Susitna Basin[a]

	Watana/Devil Canyon	Vee/High Devil Canyon/Olson
Maximum pool elevation (ft)	2200/1450	2300/1750/1020
Dam Height (ft)	750/570	425/725/120
Installed Capacity (MW)	800/600	400/800/100±
Probable On-Line Date of Last Stage	2010 to 2020	2020
Daily Peaking	Yes/No	Yes/Yes/No
Approximate[b] Reservoir Area (acres)	40,000/7,500 (Total = 47,500)	16,000/21,700/900 (Total - 38,600)
Approximate[b] River Miles Flooded[c]	60/30 (Total = 90)	95/58/7 (Total = 160)

[a] Derived from descriptions of three staging alternatives for each scheme, which are presented in Appendix A.

[b] Preliminary values.

[c] Mainstream Susitna only, tributaries not included.

3 - DISCUSSION

Potential advantages and disadvantages of the two development schemes are presented below for each of the major environmental study disciplines.

3.1 Socioeconomics

There could be significant differences in type, degree, and chronology of socioeconomic impacts resulting from the various plans under consideration. An important concern relates to alternative staging plans and associated factors such as: (a) cost of stage, (b) scheduling of various stages (i.e., length of construction period per stage and spacing), (c) construction manpower requirements by time period, (d) access point of origin, and (e) whether or not a construction "community" will be established. Impacts generally will fall into two categories: those associated with project economics and construction, and those associated with power production and sales. Both types of impacts will exhibit a variety of local, Railbelt, and statewide ramifications. In the absence of practically any project economics information, detailed analysis is impossible at this time. In general, however, it can be expected that a scheme involving on-line production capability of 800 MW by the year 2000 will have greater and more significant impacts than a scheme in which that capability is not attained until 2010 (e.g., Plan 1 compared to Plan 2). This difference would occur because, in the latter plan, the demand on resources will be spread out over time. In addition, it is reasonable to expect that the economic base of Mat-Su Borough will be larger in 2010 than in 2000, even without the project. Therefore, there likely would be a greater capacity to deal with project impacts.

3.2 Cultural Resources

Field surveys in the Watana/Devil Canyon impoundment area during the summer of 1980 have documented 37 archeological sites. A preliminary assessment of the data indicates a greater number of archeological sites towards the east end of the study area. In 1953, a preliminary field survey conducted for the National Park Service near Lakes Louise, Susitna, and Tyone identified approximately six archeological sites. There is a high potential for discovering many more sites along the lakes, streams, and rivers in this easterly region of the Upper Susitna River Basin. Additional sites are expected to be identified near caribou crossings of the Oshetna River. In summary, a preliminary assessment of available information suggests that there perhaps could be a greater number of archeological sites associated with the Vee/High Devil Canyon/Olson scheme than with the Watana/ Devil Canyon scheme.

3.3 Land Use

At present, much of the Upper Susitna Basin is subjected to almost negligible human activity. Either of the development schemes (and any of the staging plans) will cause changes in land use patterns in the Upper Susitna Basin. Regardless of the scheme chosen, impacts on local land usage and human activity in the Upper Basin will be significant in terms of area inundated and land cover changes resulting from project facilities. With either the Watana/Devil Canyon or Vee/High Devil Canyon/Olson scheme, Deadman Falls will be inundated and Devil Canyon will be greatly reduced in scenic value. The Vee/High Devil Canyon/Olson scheme would also eliminate Tsusena Falls and would destroy the existing aesthetics of Vee Canyon by dam construction at this site. Although the Vee/High Devil Canyon/Olson scheme has a smaller reservoir area, it would inundate approximately 70 miles more of the Susitna River than would the Watana/Devil Canyon scheme (Table 1). Development of a recreation plan for the project would vary according to the design scheme and staging plan selected.

Broader concerns associated with land use are related to staging, as discussed in the previous section regarding socioeconomics. The influence of staging on land use impacts applies to land use factors concerned with existing regional transportation systems. The existing transportation systems (and communities and land uses associated with them) which connect to the selected access route will be affected by construction-related activity. In this context, the degree of construction-related activity within a given time frame could be a significant factor. This consideration is similar to the socioeconomic concern identified previously. The proportionately greater degree of construction activity associated with a plan in which 800 MW capability would be achieved by 2000 - as compared with one in which this would not be achieved until 2010 - concentrates impacts on land uses in a shorter time frame.

3.4 Fish Ecology

All development schemes must be examined with the downstream anadromous fishery receiving primary consideration. Any scheme or staging plan that allows for daily peaking without a re-regulation dam downstream could be detrimental to this resource. Therefore, the maintenance of constant, or nearly constant, downstream flows is an environmental constraint that must be met for any development scheme to be acceptable.

The Vee/High Devil Canyon/Olson scheme has at least one major disadvantage, with respect to fish ecology, in comparison to development at Watana/Devil Canyon. It is that the Olson site is downstream of Portage Creek, which is known to be a very important spawning stream for salmon. Dam development at the Olson site would provide an obstruction to anadromous fish passage and two miles of Portage Creek would be inundated. Even with facilities for fish passage, the impacts on this spawning area could be severe.

Because the Vee/High Devil Canyon/Olson scheme would inundate about 70 additional miles of the Susitna River, plus different tributaries, than would the Watana/Devil Canyon scheme, impacts on resident fish can be expected to differ between the two schemes. Data are not presently available to permit an assessment of these impacts.

3.5 Wildlife Ecology

Although the area that would be inundated by the Vee reservoir has not been thoroughly investigated, project personnel have sufficient familiarity with the area to make a fairly strong recommendation at this time. With the exception of impacts on avian species, it is felt that the Watana/Devil Canyon scheme is superior from a wildlife impact standpoint to the Vee/High Devil Canyon/Olson scheme. The basic trade-offs associated with this comparison involve the areas to be flooded by the Vee dam as opposed to the flooding of much of the Watana Creek drainage and the higher portions of the canyon walls along the Susitna. For a variety of reasons the area to be flooded by the Vee dam seems more valuable for wildlife than the areas that would be inundated by the Watana/Devil Canyon dams.

A Vee/High Devil Canyon/Olson scheme would flood more acreage of critical river bottom habitat than would the Watana/Devil Canyon scheme. These areas are important for moose during severe winters and the additional reduction in such habitat could have a major impact on moose populations. In addition, the Vee impoundment would flood key winter habitat for at least three subpopulations of moose that range over large areas east of the Susitna and north of the MaClaren River. The area that would be saved by the Vee dam scheme, the Watana Creek drainage, is inhabitated by a subpopulation of moose that appears to be declining in condition and increasing in age, thus indicating that within 10 to 15 years this subpopulation may be far less important than at present. The habitat quality within the Watana Creek drainage also seems to be decreasing. TES has previously recommended that the pool elevation of Watana be lowered to preserve as much of the Watana Creek drainage as possible. Nevertheless, the trade-off between Watana Creek and the Vee impoundment favors flooding the Watana Creek area.

The area that would be flooded by the Vee dam is historically used by the Nelchina caribou herd, particularly in moving to their calving grounds near Kosina Creek. Although caribou movement patterns are highly variable and appear to change as the size of the herd changes, this area has been frequently traversed by members of this herd. The potential for impacting caribou movement is greater than with the present Watana scheme. Like Watana, the Vee reservoir would be subject to large drawdown and possible ice-shelving. In addition, the three-dam scheme would result in a greater division of the Nelchina herd's range due to the greater length of the impoundments involved and thus increase the likelihood of impacts on this herd.

There is an indication that the area to be flooded by the Vee dam is more important to some key furbearers, the red fox in particular, than areas such as Watana Creek that would be spared by a Vee dam. There is also more trapping conducted by residents in the area upstream from the Vee site than in areas downstream from that area. The Vee dam, especially due to the drawdown schedule that would be operative with this dam, also has the potential of more severely impacting both muskrat and beaver populations.

It appears that only avian species might suffer less adverse impacts from the Vee/High Devil Canyon/Olson scheme than from Watana/Devil Canyon. Although the Vee dam would eliminate more river bottom habitat, it would spare a considerable amount of deciduous forest (birch and aspen) that exists along the south-facing slopes of the Susitna canyon and along some of the tributaries. This is the only area, of any extent, that contains this type of habitat, and its associated avifauna, within the Upper Susitna Basin.

Although a more detailed recommendation could be made if a better data base were available, the reasons given above seem to indicate that the Watana/Devil Canyon scheme is superior to a Vee/High Devil Canyon/Olson scheme. This is especially true if one considers that the greatest potential for more severe impacts concern moose and caribou, which are unquestionably the key big game species in the area.

3.6 Plant Ecology

Both schemes will primarily flood deciduous forests (white birch, balsam poplar, and aspen types), coniferous woodlands and forests (white spruce and black spruce), and shrub communities (alder, birch, and willow types). The relative amounts of habitats flooded will vary with the two schemes. The Vee/High Devil Canyon/Olson combination will probably flood more floodplain habitats such as balsam poplar forests, while the Watana/Devil Canyon scheme will probably flood more birch and aspen forests.

The primary advantage of the Vee/High Devil Canyon/Olson scheme is that approximately 9,000 fewer acres would be flooded (Table 1). The primary disadvantages of this scheme are: more lakes and wetlands flooded, more river floodplains flooded, and a greater amount of associated floodplain habitats, such as balsam poplar, eliminated. The amount of wetland eliminated would be a very small proportion of the total wetland in the region. Nevertheless, the importance of wetlands, floodplains, and associated habitats has been emphasized by Executive Orders and various federal agencies.

3.7 Transmission Line Impacts

Because of the distance traversed, the construction of a transmission line to the intertie from a Vee/High Devil Canyon/Olson project offers several disadvantages when compared to a line constructed from a Watana/Devil Canyon project. A line from the Parks Highway to Watana would be approximately 50 miles in length. Following the same route to Watana and extending the line to the Vee site would add approximately 40 miles to its total length, an increase in mileage of some 80 percent. Generally, the longer the line, the greater the impact. In addition, the added length would cross a presently roadless remote parcel of land, thereby necessitating additional miles of access road construction. Additional vegetation clearing would be required due to the longer route. Assuming a 300 foot wide right-of-way, approximately 1500 additional acres would need to be cleared during construction and maintained during operation of this line, thereby potentially impacting wildlife habitat. To the extent that land use, aesthetic and recreational opportunities are impaired by transmission facilities, a larger impact zone will be created. Similarly, areas of significant cultural resource potential will be impacted to a greater degree than with the shorter line. A greater number of streams tributary to the Susitna River will need to be crossed, posing additional areas of potential impact. In summary, constructing transmission facilities to the Vee site considerably increases the potential impact of project transmission lines.

3.8 Access Road Impacts

At present, an access route for the Watana/Devil Canyon scheme has not been decided upon, and no information at all is available with regard to access for the Vee/High Devil Canyon/Olson scheme. Also, it has not even been determined which of the two schemes would have the shorter access road. By virtue of the relative dispersion of the dam sites, however, the two schemes may differ with respect to the area opened up to access and the resultant dispersion of human disturbance over the Upper Susitna Basin. The Watana/Devil Canyon scheme may confine access to a smaller portion of the basin, especially if access is from the west. The Vee/High Devil Canyon/Olson scheme, especially if it is a staged development, may be more likely to have access from both north (Denali Highway) and west, thereby opening access to a larger area, and from several directions.

3.9 Summary

In each of the environmental study disciplines, differences exist in the potential impacts of the Vee/High Devil Canyon/Olson scheme in comparison to the Watana/Devil Canyon scheme. The Vee/High Devil Canyon/Olson scheme has more apparent disadvantages than advantages; most of these disadvantages are due to the Vee impoundment rather than the High Devil Canyon impoundment. In socioeconomics and in some aspects of land use, the differences due to staging are of more significance than those due to the location of the dams. Nevertheless, it is noteworthy that the Vee/High Devil Canyon/Olson scheme may affect more canyons and waterfalls of outstanding scenic value than would Watana/Devil Canyon. Existing information suggests that there is a high potential for occurrence of cultural resources in the vicinity of the Vee reservoir, perhaps even more than in the vicinity of Devil Canyon and Watana. A major disadvantage of the Vee/High Devil Canyon/Olson scheme is the impact of Olson on anadromous fish spawning in Portage Creek; daily peaking from High Devil Canyon without re-regulation is also environmentally unacceptable. There is evidence that impacts upon big game (particularly moose and caribou) and furbearers would be more severe with the Vee/High Devil Canyon/Olson scheme than with Watana/Devil Canyon, although this is not necessarily the case with birds. Although the Vee/High Devil Canyon/Olson scheme would flood less acreage than Watana/Devil Canyon, a larger amount of floodplain and wetland habitat would be inundated. Because of the longer distance traversed, potential impacts of the transmission line would be proportionately greater with development at the Vee site. The dispersion of the dam sites in the Upper Basin with Vee/High Devil Canyon/Olson would also likely result in a larger impact zone due to increased access.

4 - CONCLUSION

Although some potential advantages and disadvantages have been identified for both the Watana/Devil Canyon scheme and the Vee/High Devil Canyon/Olson scheme, sufficient information is not yet available upon which to base a firm recommendation. The evidence that is available, however, when combined with intuitive judgement, suggests that the Watana/Devil Canyon scheme may be preferable to the Vee/High Devil Canyon/Olson combination. The comments contained in this report will be reviewed and refined after the 1980 Annual Reports are available and when more construction and operational details are known. Comparison of the two schemes will still be hampered by the scarcity of information concerning the Vee impoundment area.

APPENDIX A

DESCRIPTION OF STAGING ALTERNATIVES

RECEIVED
11 Dec 80

K. Young
(for transmittal to TES)
I. Hutchison

December 4, 1980
P5700.14.06

Susitna HEP
Current Susitna Basin Development Schemes

As requested, the schemes currently being investigated are summarized on the attached sheets. Please note that the probable on-line dates are estimates at this stage and will be firmed up over the next two weeks.

I. Hutchison

IH:ccv
Attachments

cc: J.D. Lawrence
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E.N. Shadeed
R. Ibbotson

SCHEME Plan 1 (Total installed capacity = 1400 MW)

Stage I Development

Dam Site Watana (2200)

Height 750 ft.

Installed Capacity 800 MW

Probable on Line Date 1995-2000

Mode of Operation Daily Peaking

Separate Re-regulation Dam Possibly

Stage II Development

Dam Site Devil Canyon (1450)

Height 570 ft.

Installed Capacity 600 MW

Probable on Line Date 2010-20

Mode of Operation No Daily Peaking

Separate Re-regulation Dam No

Stage III Development

Dam Site ________

Height ______ ft.

Installed Capacity ______ MW

Probable on Line Date ______

Mode of Operation ______

Separate Re-regulation Dam ______

Stage IV Development

Dam Site ________

Height ______ ft.

Installed Capacity ______ MW

Probable on Line Date ______

Mode of Operation ______

Separate Re-regulation dam ______

NOTE: Figures in brackers behind dam site name indicate maximum water surface elevation in feet.

SCHEME Plan 2 (Total installed capacity = 1400 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site Watana (2000)	Dam Site Watana (2200)	Dam Site Devil Canyon (14501)	Dam Site ______
Height 550 ft.	Height 750 ft.	Height 570 ft.	Height ______ ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 600 MW	Installed Capacity ______ MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date ______
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation ______
Separate Re-regulation Dam Possibly	Separate Re-regulation Dam Possibly	Separate Re-regulation Dam No	Separate Re-regulation dam ______
	Watana Dam raised 200' Installed Capacity Increased by 400 MW		

SCHEME Plan 3 (Total installed capacity = 1400 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site Watana (2200)	Dam Site Watana (2200)	Dam Site Devil Canyon	Dam Site
Height 750 ft.	Height 750 ft.	Height 570 ft.	Height ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 600 MW	Installed Capacity MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation
Separate Re-regulation Dam Possibly	Separate Re-regulation Dam Possibly	Separate Re-regulation Dam No	Separate Re-regulation dam
	Installed Capacity Increased by 400 MW		

SCHEME Plan 4 (Total installed capacity = 1300 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site High D.C. (1755)	Dam Site Vee (2300)	Dam Site Olson (1010)	Dam Site
Height 725 ft.	Height 425 ft.	Height 120 ft.	Height ft.
Installed Capacity 800 MW	Installed Capacity 400 MW	Installed Capacity ±100 MW	Installed Capacity MW
Probable on Line Date 1995-2000	Probable on Line Date 2010-20	Probable on Line Date 2020 —	Probable on Line Date
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking	Mode of Operation
Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam No	Separate Re-regulation Dam No	Separate Re-regulation dam

* Olson may serve as the re-regulation dam in which case the Olson dam would constitute part of Stage I. The powerhouse at Olson could still be built at a later stage.

SCHEME Plan 5 (Total installed capacity = 1300 MW)

Stage I Development	Stage II Development	Stage III Development	Stage IV Development
Dam Site High Devil Canyon (1610)	Dam Site High Devil Canyon (1750)	Dam Site Vee (2300)	Dam Site Olsom (1020)
Height 570 ft.	Height 725 ft.	Height 425 ft.	Height 120 ft.
Installed Capacity 400 MW	Installed Capacity 800 MW	Installed Capacity 400 MW	Installed Capacity ±100 MW
Probable on Line Date 1995	Probable on Line Date 2000-10	Probable on Line Date 2010-20	Probable on Line Date 2020
Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation Daily Peaking	Mode of Operation No Daily Peaking
Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam Possibly*	Separate Re-regulation Dam No	Separate Re-regulation dam No
	High Devil Canyon Dam Raised 140'		
	Installed capacity Increased by 400 MW		

* Olson may serve as the re-regulation dam in which case the Olson dam would constitute part of Stage I. The powerhouse at Olson could still be built at a later stage.

SCHEME Plan 6 (Total installed capacity = 1300 MW)

Stage I Development

Dam Site High Devil Canyon (1750)

Height 725 ft.

Installed Capacity 400 MW

Probable on Line Date 1995

Mode of Operation Daily Peaking

Separate Re-regulation Dam Possibly*

Stage II Development

Dam Site High Devil Canyon (1750)

Height 725 ft.

Installed Capacity 800 MW

Probable on Line Date 2000-10

Mode of Operation Daily Peaking

Separate Re-regulation Dam Possibly*

Installed Capacity increased by 400 MW

Stage III Development

Dam Site Vee

Height 425 ft.

Installed Capacity 400 MW

Probable on Line Date 2010-20

Mode of Operation Daily Peaking

Separate Re-regulation Dam No

Stage IV Development

Dam Site Olsom (1020)

Height 120 ft.

Installed Capacity ±100 MW

Probable on Line Date 2020

Mode of Operation No Daily Peaking

Separate Re-regulation dam No

* Olson may serve as the re-regulation dam in which case the Olson dam would constitute part of Stage I. The powerhouse at Olson could still be built at a later stage.