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of the system is by fully loading turbines and spreading the frictional loss over the largest amount of kWh.

The assumption that the cost of energy equals the system incremental heat rate is equivalent to assigning *all* the fixed frictional loss in the system to the production of spin, and *none* to the production of energy. It is clear why this formula has problems when attempting to determine the cost of spin for turbines near full load. As a turbine approaches full load, the amount of spin decreases towards zero. DFI's formula still assigns all of the fixed frictional loss of the turbine to the cost of this spin. The cost per unit of spin becomes infinite as the turbine approaches full load because the divisor, the amount of spin, approaches zero.

We now show that DFI's more general expression produces the formula $(A_L - M) \times L/(1-L)$ when applied to a short period of time. We apply the expression to a turbine whose loading characteristics do not change over a one hour time period. Using our previous variables, the amount fuel used over that one hour period is $U \times L \times A_L$. The amount of energy produced is $U \times L$, and the amount of spin produced is $U \times (1 - L)$. Once again, DFI's assumption in the Railbelt analysis is that $\lambda = M$. Making these substitutions gives the equation:

$$U \times L \times A_L = M \times U \times L + \mu \times U \times (1 - L)$$

which simplifies to:

$$\mu = (A_L - M) \times \frac{L}{1 - L} = \textit{Cost of Spin}$$

We have already shown that this formula produces an incorrect answer when applied to a simple numeric example and produces an impossible answer when applied to turbines near full load.

Applying the Correct Formula to the Railbelt Data

We now apply our formula for the cost of spin, $L \times (A_L - M)$, to heat rate data of Anchorage/Kenai thermal units to estimate an average cost of spin. Table 3 summarizes the calculation. The units are arranged in their dispatch order, according to data provided by DFI in Appendix F of the AEA Recon report. We do not analyze units beyond the Beluga CT #1 unit, because the (load + spin) that can be served by the analyzed set of units is approximately 550 MW. This capability combined with the Railbelt Hydro capacity will serve the bulk of the load through the analysis period, if optimal economic dispatch occurs.

When determining the cost of spin for a particular unit, it is necessary to make an assumption about that unit's loading and make an assumption about the incremental heat rate of the rest of the system. We test two different assumptions about the unit loading, 50% and 75% (our heat rate data source did not have heat rates at 25% load). The results are not very sensitive to this assumption. For the system incremental heat rate, we use the 50-75% incremental heat

Table 3 - Cost of Spin for Kenai/Anchorage Thermal Generation Units

Unit	Size MW	50% HR	75% HR	100% HR	Increm HR 50-75%	Spin Cost 50% Ld	Spin Cost 75% Ld
Bel CC #78	101	10,981	9,831	9,391	7,531	Never	Marginal
Bel CC #68	101	10,981	9,831	9,391	7,531	Never	Marginal
AMLP CC #76	109	10,017	9,018	8,628	7,020	1,243	1,115
Bel CT #5	67	15,012	13,448	12,963	10,320	3,996	4,821
Bel CT #3	50	14,822	13,228	12,800	10,039	2,251	2,181
Bern CT #3	27	15,284	14,082	13,700	11,678	2,623	3,032
Bern CT #4	27	15,284	14,082	13,700	11,678	1,803	1,803
AMLP CC #56	48	13,802	11,500	10,365	6,896	1,062	(134)
Bel CT #1	16	17,119	15,602	15,314	12,568	5,112	6,530
						2,584	2,764
						Btu/kWh-spin	

NOTES: Heat rate data from "Railbelt Intertie Proposal Preliminary Economic Assessment", March 1987, Alaska Power Authority, and from "Explanation and Support for Avoided Cost Tariff Proposed by ML&P", MLP, 1989. Data from APA report for Beluga CT #3 was scaled up to match the DFI assumption of a 12,800 Btu/kWh full-load heat rate for the unit. The anomalous results for the Cost of Spin for the AMLP units are due to the fact that they are placed in the dispatch order according to their heat rate times their fuel cost/kWh plus variable O&M. Since AMLP pays a higher price for natural gas, they are placed behind less efficient Chugach units. For this societal resource cost analysis, there is no difference in cost between AMLP and Chugach gas; thus, it is justified to consider the cost of spin in terms of Btus/kWh-spin, without regard to fuel price.

rate of the unit one prior in the dispatch order. In an optimally dispatched system, it is likely that this unit will be the unit that picks up the lost generation caused by shutting off the final unit (units prior to this one are likely to have lower incremental heat rates, and therefore will operating at or near full load).

Adjusting DFI's Result to Arrive at the Correct Operating Reserve Benefit for a New Intertie

The average cost of spin for the units shown is 2,600 Btu/kWh-spin with the 50% loading assumption, and 2,800 Btu/kWh-spin for the 75% loading assumption. For our adjustment of the DFI spinning reserve benefit result, we choose the higher of the two estimates, favoring the new intertie. The average of the Case 1 and Case 2 operating reserve benefit as calculated by DFI is $8.9 million. DFI based this calculation on a cost of operating reserves of 7,000

Btu/kWh-spin (increased from 5.000 Btu/kWh-spin in the AEA Recon report). The following expression adjusts the DFI result to correspond to our estimate of the cost of operating reserves of 2,800 Btu/kWh-spin:

$$\textit{Corrected Operating Reserve Benefit} = \$8.9\ \textit{million} \times \frac{2{,}800\ \textit{Btu/kWh-spin}}{7{,}000\ \textit{Btu/kWh-spin}}$$

$$\textit{Corrected Operating Reserve Benefit} = \$3.6\ \textit{million}$$

This adjustment lowers the present value operating reserve benefits of the new Kenai-Anchorage intertie by $5.3 million.

2.4.2 Unquantified Disputes

Case 1 Results use Too Low of a Transfer Capacity for the Existing Intertie

DFI analyzes two cases when calculating operating reserve benefits. Case 1 assumes that the transfer capacity of the existing intertie for the purposes of operating reserves access is 70 MW input and 61 MW output. Case 2 assumes 90 MW input and 75 MW output. In the Case 1 analysis, the operating reserve benefit of the new intertie is $10.6 million, and the result for Case 2 is $7.1 million.

Sharing operating reserves only involves transferring energy over the intertie during periods of emergencies when the operating reserves are called on. There are no routine transfers of energy associated with sharing operating reserves. Therefore, the most accurate transfer rating of the intertie to use in the calculation is the emergency transfer limit, not the secure transfer limit. The Kenai-Anchorage intertie question is simplified, however, because the Alaska Energy Authority technical consultant states that emergency *and* the secure transfer limit for the existing line will be 90 MW input, 75 MW output after the planned line compensation is installed ["Kenai Export Limits With and Without a New Line, With and Without Additional Compensation", Power Technologies Inc., November 30, 1989, page 5]. We see little justification for incorporating the Case 1 results (70 MW input, 61 MW output) into the expected benefit calculation of the new line.

There has been some dispute concerning PTI's calculation of the *secure* export limit of the existing Kenai-Anchorage line. This calculation is complex because it involves simulating the response of the system to various faults (short-circuits) occurring on the system of transmission lines. A transfer limit is considered secure if the system can "survive" after such faults.

The emergency transfer limit, however, is a much more straight-forward calculation. Simulation of faults is not involved, because the probability of a fault occurring during a period when a transmission line is being relied on for emergency purposes is very low. In the case of sharing operating reserves. the line will only transfer energy for a few dozen hours per year (number of events requiring operating reserves x time required to start a new unit to restore operating reserves). The probability of a line fault occurring during those few hours is exceptionally low.

The emergency transfer limit calculation is a steady-state calculation. The transfer limit of the line is reached when voltages along the line drop too low, or phase relationships become unstable. PTI says that this calculation is quite accurate. They state that the fact that the existing intertie was able to deliver 70 MW to Anchorage before going unstable during the December 11, 1989 outage indicates that the existing intertie should be easily able to deliver 75 MW to Anchorage (Case 2) after the line compensation is added when Bradley Lake is finished.

DFI appears to have recognized and accepted this information before the 138 kV study was performed, as indicated by the following response to a reviewer comment in the AEA Recon Study:

> Although it may be desirable to limit routine transfers over the line to 75 MW (input), there appears to be no reason to forego the additional 15 MW capacity for purposes of spinning reserve. Further, the stability limit does not prevent transfers above 90 MW (input), but suggests that such transfers be of limited duration primarily for emergency purposes. The transfer limit of the existing line for estimating access to Kenai spinning reserve may therefore be substantially higher than 90 MW. [Page J-20 - J-21, AEA Recon Study].

Finally, we find that the transfer limits assumed for the Anchorage-Fairbanks intertie upgrades closely match or even exceed PTI's calculations for the limits of those lines. We disagree with the asymmetrical acceptance of the PTI transfer limit calculations.

Bradley Will Not Have 50 MW of Spin Available at All Times

We also question the assumption that 50 MW of spin will be available from Bradley at all times with the new intertie. With the ability to deliver 110 MW power to Kenai, Bradley must be supplying less than 60 MW load in order for 50 MW of spinning reserve to be available. Bradley averages 42 MW of output, so there will be large amounts of time when it is operating below 60 MW.[9] However, the number of hours where Bradley operates above 60 MW is significant, especially given the use of Bradley for hydro-thermal coordination. During these hours, Anchorage will not be able to rely on Bradley for 50 MW of spinning reserves, with the new intertie. This constraint is less of a problem for the existing intertie, because Bradley is relied on for only 30 MW of spinning reserve. Only operation above 80 MW (delivered to Kenai) will reduce Bradley spin below 30 MW.

[9]However, Bradley needs to be operating in order to provide spin. If Bradley is off-line during some periods of the year, no spin will be provided.

The Assumption Concerning the Unavailability of the Existing Intertie Substantially Increases the Operating Reserve Benefit of the New Intertie

The assumption discussed earlier concerning the assumed unavailability of the existing Kenai-Anchorage line for the 13 year reconstruction period *and* the period thereafter also substantially affects the spinning reserve benefit calculation. If it is believed that the unavailability of the existing Kenai-Anchorage will be less than stated by Chugach, then the spinning reserve benefits of the new intertie will further decline.

"Peak Rating Strategy" Will Increase Probability of Damaging Turbines

We also suspect that the probability for damaging generation units increases when the "peak rating strategy" described on page 7-4 is employed. The expected cost of damage may be significant in the calculation of the benefits of increased reliance on Bradley for spin.

2.5 Capacity Sharing Benefits

The availability of a new Kenai-Anchorage intertie allows Anchorage to utilize additional excess generation capacity present on the Kenai peninsula, and it also allows the long-term reduction of reserve margins (while maintaining equivalent reliability) because of stronger integration of the Kenai and Anchorage areas.

2.5.1 Unquantified Disputes

This calculation involves the estimation of *how much* generation capacity can be avoided by the existence of a new intertie, and the estimation of how much that capacity would have *cost* if the new intertie were not built. We first address the question of how much generation capacity can be avoided by the existence of a new intertie.

Case 2 Transfer Capacity of the Existing Intertie is Overstated, Penalizing Benefits of New Intertie

The reason the new intertie reduces the purchases of generation capacity is because it provides a higher transfer capacity between Anchorage and Kenai. The level of capacity benefits provided is related to the amount that the transfer capacity is increased over and above the existing transfer capacity. Two cases were analyzed. For both cases, the transfer capability of the new intertie was assumed to be 110 MW output. In Case 1, the existing intertie was modeled as being able to transfer 70 MW input and 60 MW output. For Case 2, the intention was to model the existing intertie as being able to transfer 90 MW input and 75 MW output. In actuality, the intertie was erroneously modeled as having an 88 MW output, thus overstating the intended Case 2 transfer capacity.

Case 1 Transfer Capacity is Too Low to Consider in the Capacity Sharing Analysis

The error in the Case 2 transfer capacity of the existing intertie caused the benefits of the new intertie to be *understated*. However, we also reject the Case 1 analysis since it relies upon a transfer capacity estimate that is substantially below the transfer capacity estimated by PTI, the technical consultant for the intertie analysis. See the discussion in section 2.4.2 on page 22. As with the use of the intertie for accessing spinning reserves, using the intertie for capacity benefits involves infrequent transfer of actual energy. Energy is only actually transferred across the intertie when one area has a set of coincident outages of generators that cause the available local capacity to be less than the local load. Such an occurrence does not happen for more than a few hundred hours per year.

We find that the error of overstating the transfer capacity in Case 2 approximately cancels the unjustified use of the low transfer capacity for Case 1. The Case 1 intertie output was modeled at 60 MW and the Case 2 output was modeled at 88 MW. The average is therefore about 75 MW, which is equal to PTI's transfer capacity estimate.

Possibility of Increasing the Transfer Capacity of the Existing Intertie by Adding Compensation is Ignored

Continuing with discussion of the amount of capacity avoided by the new intertie, another very critical issue is degree to which the transfer capacity of the existing intertie can be increased beyond the 90 MW input / 75 MW output level. If cost-effective increases are possible, the capacity benefits of a new intertie will be substantially reduced. Even a modest increase from the 75 MW output level to an 88 MW output level will decrease the benefits of the new intertie by ~$10 million (minus the cost of the transfer capacity upgrade).

PTI states that upgrades of the existing Kenai-Anchorage line are possible, and in fact the line can be upgraded to have a transfer capacity equal to its thermal limit, approximately 145 MW. In PTI's report on the Kenai-Anchorage lines ("Kenai Export Limits With and Without a New Line With and Without Additional Compensation", PTI Report Number R106-89, November 30, 1989, page 5), PTI indicates that the transfer capacity of the existing line can be increased to 122 MW input (by our estimate, approximately 95 MW output) by the addition of series capacitors north of Quartz Creek. This type of upgrade is of the same type being proposed for the northern intertie, the AF100 upgrade. If such upgrades were analyzed for the northern intertie, they should be considered for the Kenai-Anchorage connection also.

The second part of the calculation involves estimation of the cost of capacity that is avoided. The question is: if the new intertie is not built, what will the extra capacity requirements cost? DFI estimates the cost of this capacity at the cost of installing new gas turbines, approximately $51/kW/year. We believe that this assumption, at least for the years prior to 2005, may substantially overstate the actual cost of capacity available to Railbelt utilities. We believe this primarily because the Railbelt utilities have stated that they will acquire substantial capacity through life extension of existing units, and they have also indicated that physically moving capacity from the Kenai Peninsula to Anchorage is an option that may prove cost-effective. These intentions indicate that such capacity acquisitions are less expensive than new capacity.

Cost of Capacity does Not Reflect Railbelt Utilities Intention to Extend Life of Existing Plants

The Railbelt capacity expansion plans given on page F-5 of the AEA Recon study clearly indicate that substantial amounts of capacity will be acquired through life extension of existing units. The critical question is how much less than $51/kW/year will this life extension cost. AML&P states the following in a report concerning avoided cost payments to cogeneration and independent power plants:

> ML&P's other CT's are modern units installed in the 1970's and the 1980's. These units are being well maintained. ML&P's standard operation calls for annual to semiannual inspections and major overhauls approximately every 3 years. At these overhauls ML&P performs both a full inspection and destructive testing on selected (1 blade per row) hot rotating blades. In this way, the CT's are constantly checked and parts are replaced and upgraded. This program on modern CT's should result in an extended life expectancy. Therefore, no other retirements were assumed for the study period. ["Explanation and Support for Avoided Cost Tariff Proposed by ML&P", 1989, page 9].

The study period referred to extends through 2017. Thus, the implication is that an ML&P turbine installed in 1980 will last through 2017, a total of 37 years, with only normal maintenance performed. The DFI analysis assumes existing turbines retire after 20 - 30 years of life. Thus, ML&P's statement indicates that an additional 10-15 years of capacity is available for only the cost of fixed O&M, $13/kW/year, a 74% reduction from the $51/kW/year figure used in the DFI study. The ML&P estimate may be extreme, but it does indicate the possibility of capacity acquisitions at substantially below the $51/kW/year DFI cost.

Potential to Acquire Cheap Capacity by Moving it From Kenai Peninsula is Ignored

Another potential source of capacity that may be cheaper than new capacity is moving capacity from the Kenai Peninsula where there will be substantial capacity excesses for a long period of time. Chugach is already considering moving a 25 MW Bernice unit, as indicated on their data submission to the North American Electric Reliability Council for a reliability study. Movement of the 39 MW Soldotna unit may be even more cost-effective because it is a newer unit, and there may be economies of scale in moving costs. If the Soldotna unit costs $5 million to move and has a 20 year remaining life, the levelized cost, including a $13/kW/year fixed O&M cost would be $23/kW/year, substantially cheaper than $51/kW/year.

ML&P Believes New Capacity will Cost Substantially Less than $51/kW/year in the Future

ML&P's statements in the avoided cost report also call into question the $51/kW/year cost estimate for *new* turbines. This estimate was derived from a $490/kW capital cost of a turbine. a 20 year life. and a $13/kW/year fixed O&M figure. The above quote indicates that turbine lives may be substantially longer than 20 years. Actual data also suggests lives longer than 20 years. as ML&P intends to retire their #1 and #2 units in 1992. after 30 and 28 years of life respectively (page 8. ML&P Avoided Cost Report). They even indicate the ability to repower these units in the future if further capacity is needed.

ML&P's report concludes that future *new* capacity additions (not life extension and repowering options). which they find are not needed until 2017. will cost approximately $177/kW installed. 1988 $ [page 8. ML&P Avoided Cost]. Using this figure. a 30 year life. and a $13/kW/year fixed O&M gives a $25/kW/year capacity cost (1990 $). about half of the DFI $51/kW/year figure. Once again. we do not accept ML&P's very low capacity cost estimates. but they do indicate the need to examine further the high DFI figures.

Considering the "Lumpiness" of Capacity Investments would Increase DFI's Cost of Capacity by about 10%

In the AEA Recon stud[illegible]I identifies a simplification in their capacity analysis that may have caused the capacity be[illegible]its to be understated. Capacity is most cost-effectively added in relatively large "lumps". The DFI analysis does not acknowledge this lumpiness. but instead assumes that exactly the right amount of capacity can be added at any given time. We agree that this assumption understates the cost of capacity. To determine the approximate magnitude of this effect. we built a simplified capacity addition model. If one assumes that load growth is 1.4%/year (Anchorage Mid load growth), 3% of the installed capacity retires every year. and additions of capacity are sized to be 12% of the total installed capacity. the model shows that actual capacity costs are 10% higher than that indicated by assuming perfectly tuned capacity additions. We believe that the previously mentioned concerns about the reduced cost of life extension will more than compensate for this 10% understatement in the capacity benefits.

Analysis Assumes that there is No Opportunity Cost of Using Excess Kenai Capacity

An additional capacity benefit concern is the implicit assumption in the capacity deferral calculation that accessing excess capacity on the Kenai Peninsula is free. There is an opportunity cost associated with using this capacity with an upgraded intertie. If the capacity were left idle because of no new intertie. it could be mothballed (retired early with the potential for future repowering). Doing so would save approximately $13/kW/year of fixed O&M costs. Thus. accessing the Kenai excess capacity may save the $51/kW/year cost of new capacity in Anchorage. but it costs $13/kW/year because of the lost opportunity to mothball the capacity or move and sell it.

No Credit is Given to a New Intertie for Accessing Capacity during Periods when Capacity Reserves are Sufficient

Another potential understatement of capacity benefits in the DFI report follows. No credit is given to the new intertie for increased capacity access during the period prior to additional capacity needs. Although a new intertie will save no money during this period, it will improve reliability because of additional access to capacity under emergency conditions. Even though the 30% reserve margin criteria indicates sufficient capacity for reliability needs, the sharp reserve margin criteria is somewhat arbitrary. Additional capacity beyond 30% reserves does provide some additional reliability benefit.

2.6 Maintenance Cost Savings

The new intertie is credited with the deferral of a number of maintenance activities planned for the existing intertie. When viewed in terms of present value, cost deferral results in a savings. The present value maintenance cost savings that is credited to the new intertie is $5 million. The AEA Recon study attributed no such benefit to the new intertie. This benefit only appears in the 138 kV analysis.

$5 million Maintenance Deferral Benefit does not Account for Increased Failure Repair Costs

We were unable to review this estimate. However, the estimate was supplied by Chugach Electric, an intertie advocate, and therefore deserves careful independent scrutiny. We note that some of the maintenance activities that are intended to be deferred if the new intertie is built are related to lowering the susceptibility of the existing intertie to avalanches. If these activities are deferred, it seems likely that avalanche repair costs will increase. The other deferred maintenance activities will cause similar increase in failure repair costs. It does not appear that these increased failure repair costs were accounted for in the analysis.

2.7 Reliability Benefits

Outages of the existing Kenai-Anchorage intertie sometimes cause utility customers to experience outages. The area importing energy will lose the power supplied by the intertie. If insufficient spinning reserves are present to fill-in for the lost power, some customers will lose power. The area exporting power is less likely to suffer customer outages upon line failure. Most thermal generators can scale back their power production level to maintain proper voltage and frequency conditions. It is more difficult for hydro generation to throttle back power output; however, PTI, the nation's leader in this type of work, is designing a control system for Bradley Lake that will allow a stable reduction in power output in the case of substantial loss-of-load. (The Railbelt utilities express less confidence in the ability of this system to work.)

The existence of a new Kenai-Anchorage intertie will substantially reduce the number of customer outages associated with line failure, since the new Kenai-Anchorage line will avoid much of the tough environment that the existing line traverses. Also the existing intertie will provide a back-up path if the new intertie experiences an outage. Reducing the number of power outages has value to customers. This benefit calculation estimates the amount of power outage reduction and assigns a dollar value to that improved reliability. This benefit is not a reduction in the costs incurred by the Railbelt utilities. It is essentially a measure of how much customers would be willing to pay to avoid the power outages caused by the existing Kenai-Anchorage line.

A new intertie improves reliability also by improving access to generation capacity outside a local area in times of coincident generation outages. This type of intertie benefit was quantified in the "Capacity Sharing Benefit" calculation, not in the calculation in this section.

2.7.1 Quantified Errors

DFI's reliability benefit calculation addresses the customer outages that occur when energy is being transferred over the Kenai-Anchorage line, and a line outage occurs. Loss of this energy flow may cause an outage in the importing area and may also, although much less frequently, cause an outage in the exporting area. The DFI analysis finds that the new Kenai-Anchorage intertie will eliminate all of these outages because of its improved reliability. DFI also concludes that customers would value this reliability improvement at $32 - $50 million, depending on outage assumptions.

Reliability Benefits cannot be Greater than Energy Transfer Benefits of Existing Intertie

The DFI estimate of reliability benefits from the new intertie cannot be greater than the benefits of existing routine energy transfers. The argument is straightforward. The outages which are avoided by the new intertie are an unfortunate side effect of the use of the existing intertie for energy transfer. The outages could also be avoided by stopping existing routine energy transfers. We show in the following paragraphs that the cost of stopping existing routine energy transfers is $17 million present value. Therefore, there are two ways of avoiding the outages caused by existing energy transfer:

- Option 1: stop non-emergency energy transfers and lose $17 million of transfer benefits.
- Option 2: use the new intertie.

The economic benefit of being able to choose option two over option one is $17 million dollars. Both options avoid the outages, but the intertie eliminates the need to stop the existing energy transfers. The intertie saves $17 million.

If the true cost of outages from existing energy transfers is really $32 - $50 million, we should expect to see the Railbelt Utilities stop non-emergency transfers of energy over the existing intertie as a result of the DFI study. In this case the intertie has exactly $17 million of reliability benefits because it avoids the need to stop the transfers. If the true cost of outages is less than $17 million, energy transfers should continue. In this case, the new intertie creates reliability benefits less than $17 million. In either case, the reliability benefits attributable to the intertie cannot exceed $17 million.

DFI acknowledges this type of logical cap on the reliability benefits of the new line. In the AEA Recon study they investigate the potential of using additional spinning reserves to solve the unreliability problems of the existing intertie:

> The value of improved system reliability is the lesser of reduced customer outage costs achieved through the interties and the cost of increased spinning reserves to achieve a similar reduction of customer outage costs. For example, if it is cheaper to attain the same level of reliability through increased spinning reserves, then the costs of increased spinning reserves in the true value of increased system reliability. [AEA Recon, page 4-21].

However, they conclude that using spinning reserves to avoid customer outages caused by failure of the existing KA line is more costly than the costs suffered because of outages.

Existing Routine Energy Transfers are Worth $17 million

We now show how the DFI analysis implies that the energy transfer benefits of the existing intertie amount to approximately $17 million. The energy transfer benefits consist of two components. First, there are the economy energy benefits that DFI's Over-Under model calculated. Second, there are the hydro-thermal coordination energy transfer benefits.

The economy energy benefits calculated by Over-Under are not directly available from the DFI 138 kV report. The report presents the *difference* between the economy energy benefits of the new line and the economy energy benefits of the existing line; i.e. the increase in benefits assignable to the new line. The figure relevant to the reliability cap calculation is the economy energy benefit of the existing line alone. DFI supplied us with the necessary Over-Under runs for the Middle Fuel Price / Middle Load forecast to perform the calculation. One Over-Under model run assumed that the existing intertie was able to transfer energy at its normal level. The other Over-Under allowed no transfers on the existing intertie. The difference between these two runs represents the economy energy value of the existing intertie. This difference, once adjusted for decreased gas royalties to the state, amounts to $9.4 million, present value. The result would be different for different load and fuel price combinations, but we expect that average result would be close to the Mid Fuel / Mid Load result.

The second component of foregone energy transfer benefits is the hydro-thermal coordination benefits. After correcting for the arithmetic error in the DFI calculation (see page 12), the existing intertie provides an average of 55 MBtu/hour of hydro-thermal benefits for an average of 3,500 hours per year. To determine the present value benefit of this gas savings, we ratio off of the original DFI hydro-thermal benefit estimate:

$$\textit{Hydro-Thermal Benefits of Existing Tie} = \$37.5 \times \frac{55\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}{356\ \textit{MBtu/hr} \times 4{,}000\ \textit{hours} - 126\ \textit{MBtu/hr} \times 3{,}500\ \textit{hours}}$$

$$\textit{Hydro-Thermal Benefits of Existing Tie} = \$7.3\ \textit{million}$$

The total of these two components of energy transfer benefit is approximately $17 million.

It is important to note that stopping these routine energy transfers does not require or intend that the existing Kenai-Anchorage line be abandoned. The line would still provide capacity sharing and operating reserve sharing benefits, which only involve small amounts of energy transfer during emergency periods. In fact, the operating reserve sharing benefits of the existing line would increase, since the full line capacity is available for the transfer of spin. The line would still deliver energy to customers along the intertie route. Outages of the line would cause outages for these customers; however, the new KA line was not assumed to improve reliability for these customers either. That which is given up are the economy energy and hydro-thermal coordination transfers between the Kenai and Anchorage load centers. It is these flows of energy that cause the outages addressed by the DFI reliability analysis.

Summary: $17 million is the Upper Bound of Reliability Benefits

To summarize the argument, the reliability benefit of the new intertie is the lesser of two figures: 1) the reduced customer outage costs effected by the new intertie, and 2) the cost of achieving an equivalent reduction in outage cost by some other means. DFI estimates the reduction in outage costs attributable to the new intertie to be $32 - $50 million. However, the same level of outage cost reduction can be achieved by forgoing routine energy transfers across the existing Kenai-Anchorage line. The cost of forgoing these transfers is the amount of lost energy transfer benefits. The DFI analysis implies that these transfer benefits are approximately $17 million. Therefore, $17 million is the correct estimate for the reliability benefit of the new line.

2.7.2 Unquantified Disputes

Ignoring the logical cap on reliability benefits for the moment, we also dispute the estimate of $32 to $50 million of outage cost imposed by the existing intertie due to energy transfers over the line. The estimate involves multiplying the *amount of outages, measured in unserved kilowatt-hours*, by the customer *costs or inconveniences caused by one unserved kWh*. We first discuss the estimate used by DFI for the outage costs associated with one unserved kWh.

A Reliability Survey to Determine Costs per Unserved kWh is Misinterpreted

DFI relied upon the *same* data that was used in the AEA Recon study to determine the costs imposed on commercial customers because of power outages (approximately 90% of the outage costs are suffered by commercial customers, according to DFI). However, the interpretation of that data was changed in a way that caused the estimate of outages costs to more than double.

The survey relied upon was conducted by Ontario Hydro. They asked commercial customers what costs they would suffer as the result of outages of different lengths. The survey respondent was to assume that the outage occurred at *10 am on a Friday in January*, a time when the business was almost certainly open. To convert the respondents dollar answers into a $ per unserved kWh figure, it is necessary to divide by the electrical usage that would have occurred for the duration of the outage. Unfortunately, the survey did not collect this time-of-day load data from the respondents, so the typical usage at 10 am on a Friday in January was not known. What was collected was the *annual average demand* and the annual *peak demand* of the surveyed customers.

For the AEA Recon study, DFI used a $/unserved-kWh figure that was derived from dividing the respondents' outage cost estimates by 75% of annual peak demand. For the Railbelt Utility 138 kV study, DFI used a figure that was based on dividing by annual average demand. In order for this latter interpretation of the data to be correct, the usage during open business hours would need to be equal to the annual average usage. We find this exceptionally unlikely. Only:

1) businesses that are open 24 hours per day, or
2) businesses that use as much electricity when they are closed as when they are open.

would have an open-hour usage similar to their annual average demand. Few businesses participating in the Ontario Hydro survey are likely to fall in that category, as indicated by their load factors. A load factor is the ratio of average annual demand to peak demand. The survey data indicates load factors ranging from 21% for the large industrial customers to 46% for the retail customers. A low load factor usually indicates a usage pattern that has substantial variation over time.

We would estimate open-hour usage as being approximately 1.5 times annual average demand, based on a typical business being open for 3,000 hours per year and having a ratio of open-hour usage to closed-hour usage of 2. Such an estimate implies that DFI's outage cost per unserved kWh is a factor of 1.5 too high.

We note that the EPRI (Electric Power Research Institute) report that provided the outage cost data warns against dividing survey outage costs by annual average demand, as DFI did:

> However, most studies do not have available or do not use estimates of average kWh usage during the interruption period. Instead, outage costs are frequently unitized in terms of $/(maximum kW) or $/(average kWh). Both of these units can be deceiving, depending upon the timing of the

interruptions and the customer's usage pattern. Using maximum demand as the divisor will understate outage costs, since a customer's load during an interruption may not be near its peak level. At the other extreme, average kWh is likely to understate kWh unserved during daytime interruptions and, consequently, overstate outage costs. ["Customer Demand for Service Reliability", Laurits R. Christensen Associates, Inc., EPRI P-6510, September 1989, page 2-14].

A High Outage Cost per Unserved kWh is Applied to Unserved kWh that Occur During Hours When Businesses are Closed

Assume for the moment that the Ontario Hydro survey was interpreted correctly. The $/unserved-kWh figure derived from the survey is reflective of the costs of outages that occur during hours when businesses are open. This is because the survey respondents were asked about the costs of outage occurring at 10 am on a Friday. We find it very unlikely that the outage cost per kWh will be nearly as high for outages occurring during hours when businesses are closed. The electricity usage during closed hours will be lower, say by a factor of 2, but the costs incurred by the outage will be substantially lower, we expect by much more than a factor of 2.

DFI applied an outage cost figure reflective of outage costs during open business hours to *all* the commercial unserved energy caused by the existing Kenai-Anchorage intertie. We expect that a significant fraction of that unserved energy occurs during nights and weekends when businesses are closed. A smaller outage cost per unserved kWh should be applied to this unserved energy occurring during closed hours. DFI's failure to account for this is a further overstatement of the outage costs caused by the existing intertie.

Unserved kWh from AEA Recon Study are Not Reduced to Account for the Unavailability of the Existing Intertie

In the final benefit estimates for the AEA Recon study, the existing intertie was modeled as being available for transfers for all but two weeks of the year. In the 138 kV study, this assumption was changed, and substantial periods of unavailability for the existing intertie were assumed [see page B-2, 138 kV]. This assumption increases the energy transfer benefits and the spinning reserve benefits of the new intertie. However, it decreases the reliability benefits of the new intertie. This adjustment was not made in the 138 kV study.

If the existing intertie is expected to be unavailable for transfers for much of the year, it is also is not causing power outages during those periods. This was directly recognized in the AEA Recon study in a section where DFI briefly discussed the possible effects of an assumption of 2 month per year unavailability of the existing intertie:

> *Outages in Anchorage and Kenai caused by failure of the existing line while transfers are occurring would be avoided for two months per year. Reducing the reliability benefit of the new intertie by one-sixth would mean a reduction of $1 to $2 million in net benefits for the new Kenai-Anchorage line.* [page 13-20, AEA Recon].

This 2 month outage assumption was not included in the final benefit estimates for the AEA

Recon study. However, in the 138 kV study, a *3 month* per year intertie maintenance outage was assumed for years 1994 - 2007, and a 1 month per year maintenance outage was assumed for the years beyond 2007. Thus, the unserved kWh estimates that were taken from the AEA Recon should be adjusted downward by 25% for 1994-2007, and ~[illegible]% for 2008 onward to account for this.

The Unserved kWh in Anchorage Caused by Failures of the Existing Intertie are Substantially Overstated

DFI estimates that 30%-39% of the unserved energy caused by the existing intertie is borne by Anchorage customers. In the calculation of the unserved energy suffered by Anchorage customers, DFI made the assumption that at the times when the existing intertie suffers an outage, there is 60 MW of transfer occurring. They assumed the loss of this transfer would cause a 30 MW outage, because of some spinning reserve protection in Anchorage [see page 4-14, AEA Recon Study. These assumptions were carried forward to the 138 kV study]. These assumptions are extreme and increase the reliability benefits of a new intertie.

If the Railbelt system is optimally dispatched, DFI's analysis shows that the flow of energy northward into Anchorage with the existing intertie will rarely be 60 MW, and will average about 30 MW. (Page 5-8 of the 138 kV study shows a northward flow of energy of about 110 GWh. DFI assumes Anchorage is importing energy for 40% of the time--page 4-13 of AEA Recon. Thus, the average flow is 110,000 MWh/8766 hrs/0.4 = 30 MW.) Anchorage is assumed to have approximately 35 MW of spinning reserve if no new intertie is built (65 MW Total - 30 MW carried by Bradley, see page 7-2 138 kV). Thus, if Anchorage importation of energy occurred at a constant level, 30 MW, there would always be sufficient spinning reserve to cover loss of the line. However, the import varies about the 30 MW average, so there are times when the intertie transfer exceeds the 35 MW of spinning reserve.

To get a sense of how frequently the import exceeds the 35 MW of spinning reserve in Anchorage, we examined the hydro-thermal coordination calculation. Approximately 80% of the total Anchorage imports are due to hydro-thermal coordination. The corrected hydro-thermal calculation presented in Appendix B shows that the average level of *unprotected* transfers into Anchorage is 3 MW.[10] Adding in the additional transfers estimated by the Over-Under model will probably not raise this figure beyond 5 MW. DFI's assumption that failures of the existing intertie cause a 30 MW outage in Anchorage appears to overstate the Anchorage unserved energy by a factor of 6. Correcting this overstatement would lower the *total* reliability benefits of the new line by about 28% (ignoring the logical reliability cap).

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[10]We also note that if the more optimal hydro-thermal coordination regime described on page ? were implemented, the level of unprotected transfers into Anchorage would be substantially less.

The Analysis Implies that if a New Intertie is Built, Kenai Customers will Suffer *No* Outages due to Generation and Transmission Failures

The DFI analysis assumes that Bradley will somewhat reduce the number of outages on the Kenai peninsula due to a reduction in the amount of time Kenai is importing energy and due to the ability of Bradley Lake to restore power to customers more quickly. Beyond this reduction. DFI assumes that a new intertie will eliminate all the remaining unserved kWh on the Kenai peninsula (except unserved kWh for customers along the existing intertie route--e.g. Seward). Thus these Kenai peninsula customers will have the lowest level of G&T unserved kWh in the Railbelt. 0 kWh/customer/year. as compared to 6 kWh/year for Anchorage. 3 kWh/year for Fairbanks. and 2 kWh/year for Copper Valley. This conclusion results from assigning very high reliability benefits to the new intertie. We find the conclusion unlikely.

The Analysis Assumes that Kenai will Suffer Substantial Outages when the Existing Intertie Fails under Kenai Export Conditions, Contrary to Statements by the Technical Consultant, PTI

When the existing intertie fails under Kenai export conditions (Anchorage import), the Bradley Lake hydro project must throttle back its output in a stable manner in response to the loss of load. PTI, Power Technologies Inc., has designed a control system that they claim will perform this task up to export levels of 90 MW (75 MW received in Anchorage). They claim that stable throttling of Bradley will be substantially easier at lower export levels [phone call with Harrison Clark, January 16. 1990]. Given that the average level of export from Kenai is about 35 MW (and substantially lower if the more optimal hydro-thermal regime is implemented), the functionality of PTI's control system is more probable.

DFI assumed that failure of the existing line under conditions of Kenai export would cause Kenai customer outages 40-80% of the time [page 4-12, AEA Recon Study]. This assumption indicates very little faith in PTI's detailed technical design and analysis work.

The Analysis Assumes that Outages cannot be Directed to Those Customers with Lowest Outage Costs

DFI assumes that the unserved kWh fall on customers in proportion to how much energy they consume. For example, if the commercial customers consume 60% of the annual energy in an area, DFI assumed that 60% of the unserved energy was incident on the commercial sector. However, DFI's outage cost figures imply that the outage cost per kWh is 5 times higher for commercial customers than for residential customers ($25/unserved-kWh versus $5/unserved-kWh). If a system manager were to "optimally dispatch outages", as much of the outage burden would be placed on the residential customers. The unfairness of this approach could be mitigated by reducing residential rates relative to commercial rates, to reflect the less reliable power received by the residential customers. Dispatching outages on residential customers is physically accomplished by setting load-shedding relays to first trip distribution feeders that are predominantly residential before tripping feeders that are predominantly commercial.

Appendix A
Hydro-Thermal Computation Error Corrected

Reshaping Savings for New Intertie

101 MW CC, Beluga CC#8

50% Heat Rate = 10,981
Incremental Heat Rate = 7,801

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	0.433	2,481	41	101.7	44.0		
1.14	0.359	2,115	71	150.1	53.9		
1.15	0.116	1,981	89	176.3	20.5		
1.19	0.092	1,704	97	165.3	15.2		
					133.6	37.5%	50.1

47 MW CC, AMLP #56

50% Heat Rate = 13,700
Incremental Heat Rate = 8,718

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	1	4,201	29.4	123.4	123.4		
1.14	0	3,791		0.0	0.0		
1.15	0	3,642		0.0	0.0		
1.19	0	3,332		0.0	0.0		
					123.4	37.5%	46.3

55 MW CT, Beluga #3

50% Heat Rate = 13,136
Incremental Heat Rate = 9,552

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	1	2,728	34.4	93.8	93.8		
1.14	0	2,280		0.0	0.0		
1.15	0	2,116		0.0	0.0		
1.19	0	1,777		0.0	0.0		
					93.8	5.0%	4.7

87 MW CT, AMLP CT#8

50% Heat Rate = 14,029
Incremental Heat Rate = 9,591

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	54.8%	3,579	39.6	141.8	77.6		
1.14	41.3%	3,128	71.0	221.9	91.6		
1.15	4.0%	2,964	85.7	254.0	10.0		
1.19	0.0%	2,623		0.0	0.0		
					179.3	9.0%	16.1

66 MW CT, Beluga CT #5

50% Heat Rate = 15,012
Incremental Heat Rate = 10,914

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.09	82.8%	3,120	37.0	115.4	95.5		
1.14	17.2%	2,608	61.7	161.0	27.7		
1.15	0.0%	2,420		0.0	0.0		
1.19	0.0%	2,033		0.0	0.0		
					123.3	8.0%	9.9

33 MW CT, AMLP CT #4

50% Heat Rate = 18,475
Incremental Heat Rate = 9,372

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings
1.09	1.00	8,263	20.6	170.4	170.4
1.14	0.00	7,823		0.0	0.0
1.15	0.00	7,662		0.0	0.0
1.19	0.00	7,330		0.0	0.0

170.4 3.0% 5.1

100.0% 132.2 MBtu/hr

Reshaping Savings for Existing Intertie

101 MW CC, Beluga CC#8

50% Heat Rate = 10,981
Incremental Heat Rate = 7,801

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings
1.20	15.3%	1,581	30.7	48.6	7.4
1.28	22.2%	1,021	44.8	45.7	10.2
1.31	10.8%	769	57.1	43.9	4.7
1.42	19.0%	0	68.3	0.0	0.0

22.3 37.5% 8.4

47 MW CC, AMLP #56

50% Heat Rate = 13,700
Incremental Heat Rate = 8,718

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings
1.20	70.0%	3,195	24.1	77.0	53.9
1.28	30.0%	2,569	41.7	107.2	32.1
1.31	0	2,287		0.0	0.0
1.42	0	1,286		0.0	0.0

86.0 37.5% 32.3

55 MW CT, Beluga #3

50% Heat Rate = 13,136
Incremental Heat Rate = 9,552

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	55.0%	1,626	25.1	40.8	22.5		
1.28	40.4%	940	44.8	42.1	17.0		
1.31	4.6%	631	54.1	34.1	1.6		
1.42	0	0		0.0	0.0		
					41.0	5.0%	2.1

87 MW CT, AMLP CT#8

50% Heat Rate = 14,029
Incremental Heat Rate = 9,591

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	22.5%	2,472	29.1	71.9	16.2		
1.28	25.5%	1,783	44.8	79.8	20.4		
1.31	12.4%	1,473	57.1	84.2	10.4		
1.42	21.8%	371	68.3	25.4	5.5		
					52.5	9.0%	4.7

66 MW CT, Beluga CT #5

50% Heat Rate = 15,012
Incremental Heat Rate = 10,914

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	40.3%	1,861	26.5	49.3	19.8		
1.28	33.7%	1,077	44.8	48.2	16.2		
1.31	16.3%	724	57.1	41.4	6.8		
1.42	9.7%	0	63.6	0.0	0.0		
					42.8	8.0%	3.4

33 MW CT, AMLP CT #4

50% Heat Rate = 18,475
Incremental Heat Rate = 9,372

Reshaping Energy Req't	Prob	Savings Btu/kWh	Avg MW Load	Unwtd MBtu/hr Savings	Wtd. MBtu/hr Savings		
1.20	100.0%	7,182	20.6	148.1	148.1		
1.28	0.0%	6,509		0.0	0.0		
1.31	0.0%	6,206		0.0	0.0		
1.42	0.0%	5,129		0.0	0.0		
					148.1	3.0%	4.4
						100.0%	55.3 MBtu/hr

Appendix B
Hydro-Thermal Oversimplification Corrected

DFI set up computation bins for particular loading levels of the intertie. With the varying heat rate assumption, we found it computationally easier to set up bins to correspond to different loading levels of each turbine. The reshaping energy requirement for each bin was calculated by interpolating between transmission loss figures given by DFI for the intertie. We used the interpolation method suggested by DFI on page 3-5 of the 138 kV study.

Beluga CC#8

Unit Size = 101 MW
Incremental Heat Rate, 50% - 100% = 7,301 Btu/kWh
Heat Rate at 50% = 10,981 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	2.53	0.00%	71,401	1.01	63,529	160.4	0.00	1.00	63,578	160.5	0.00	0.0	0.00
5.0% - 10.0%	7.58	0.00%	29,001	1.03	20,948	158.7	0.00	1.01	21,124	160.0	0.00	0.0	0.00
10.0% - 15.0%	12.63	0.00%	20,521	1.06	12,243	154.6	0.00	1.02	12,588	158.9	0.00	0.0	0.00
15.0% - 20.0%	17.68	0.00%	16,887	1.09	8,413	148.7	0.00	1.02	8,898	157.3	0.00	0.0	0.00
20.0% - 25.0%	22.73	0.00%	14,868	1.12	6,130	139.3	0.00	1.03	6,811	154.8	0.00	0.0	0.00
25.0% - 30.0%	27.78	6.67%	13,583	1.15	4,612	128.1	3.54	1.04	5,469	151.9	10.13	0.0	0.00
30.0% - 35.0%	32.83	6.67%	12,693	1.19	3,434	112.7	7.51	1.05	4,522	148.4	9.90	0.0	0.00
35.0% - 40.0%	37.88	6.67%	12,041	1.23	2,479	93.9	6.26	1.06	3,806	144.1	9.61	2.9	0.19
40.0% - 45.0%	42.93	6.67%	11,542	1.25	1,808	77.6	5.17	1.06	3,236	138.9	9.26	7.9	0.53
45.0% - 50.0%	47.98	6.67%	11,148	1.25	1,358	65.2	4.34	1.07	2,782	133.5	8.90	13.0	0.87
50.0% - 55.0%	53.03	6.67%	10,830	1.28	831	44.1	2.94	1.08	2,385	126.4	8.43	18.0	1.20
55.0% - 60.0%	58.08	6.67%	10,566	1.31	359	20.9	1.39	1.09	2,060	119.6	7.97	23.1	1.54
60.0% - 65.0%	63.13	6.67%	10,345	1.35	0	0.0	0.00	1.10	1,758	111.0	7.40	0.0	0.00
65.0% - 70.0%	68.18	6.67%	10,157	1.40	0	0.0	0.00	1.11	1,506	102.7	6.85	0.0	0.00
70.0% - 75.0%	73.23	6.67%	9,994	1.46	0	0.0	0.00	1.12	1,266	92.7	6.18	0.0	0.00
75.0% - 80.0%	78.28	6.67%	9,853	1.53	0	0.0	0.00	1.13	1,041	81.5	5.43	0.0	0.00
80.0% - 85.0%	83.33	6.67%	9,728	1.60	0	0.0	0.00	1.14	845	70.4	4.69	0.0	0.00
85.0% - 90.0%	88.38	6.67%	9,618	1.70	0	0.0	0.00	1.15	650	57.4	3.83	0.0	0.00
90.0% - 95.0%	93.43	6.67%	9,520	1.75	0	0.0	0.00	1.16	466	43.5	2.90	0.0	0.00
95.0% - 100.0%	98.48	6.67%	9,432	1.79	0	0.0	0.00	1.17	293	28.8	1.92	0.0	0.00
		100%					36.2				103.4		4.33

AMLP CC#56

Unit Size = 47 MW
Incremental Heat Rate, 50% - 100% = 8,718 Btu/kWh
Heat Rate at 50% = 13,700 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	1.18	0.00%	108,358	1.00	99,601	117.0	0.00	1.00	99,628	117.1	0.00	0.0	0.00
5.0% - 10.0%	3.53	0.00%	41,931	1.01	33,094	116.7	0.00	1.00	33,177	116.9	0.00	0.0	0.00
10.0% - 15.0%	5.88	0.00%	28,646	1.02	19,728	115.9	0.00	1.01	19,867	116.7	0.00	0.0	0.00
15.0% - 20.0%	8.23	0.00%	22,952	1.04	13,912	114.4	0.00	1.01	14,137	116.3	0.00	0.0	0.00
20.0% - 25.0%	10.58	0.00%	19,789	1.05	10,665	112.8	0.00	1.01	10,949	115.8	0.00	0.0	0.00
25.0% - 30.0%	12.93	6.67%	17,776	1.06	8,525	110.2	7.35	1.02	8,899	115.0	7.67	0.0	0.00
30.0% - 35.0%	15.28	6.67%	16,383	1.07	7,045	107.6	7.17	1.02	7,480	114.3	7.62	0.0	0.00
35.0% - 40.0%	17.63	6.67%	15,361	1.09	5,891	103.8	6.92	1.02	6,433	113.4	7.56	0.0	0.00
40.0% - 45.0%	19.98	6.67%	14,579	1.10	5,020	100.3	6.69	1.03	5,614	112.1	7.48	0.0	0.00
45.0% - 50.0%	22.33	6.67%	13,962	1.11	4,244	94.7	6.32	1.03	4,972	111.0	7.40	0.0	0.00
50.0% - 55.0%	24.68	6.67%	13,463	1.13	3,604	88.9	5.93	1.04	4,434	109.4	7.29	0.0	0.00
55.0% - 60.0%	27.03	6.67%	13,050	1.14	3,073	83.0	5.54	1.04	3,996	108.0	7.20	0.0	0.00
60.0% - 65.0%	29.38	6.67%	12,704	1.16	2,590	75.8	5.05	1.04	3,611	106.1	7.07	0.0	0.00
65.0% - 70.0%	31.73	6.67%	12,408	1.18	2,111	67.0	4.46	1.05	3,290	104.4	6.96	0.0	0.00
70.0% - 75.0%	34.08	6.67%	12,154	1.20	1,704	58.1	3.87	1.05	3,009	102.5	6.84	0.0	0.00
75.0% - 80.0%	36.43	6.67%	11,932	1.22	1,299	47.3	3.16	1.05	2,742	99.9	6.66	1.4	0.10
80.0% - 85.0%	38.78	6.67%	11,737	1.23	998	38.7	2.58	1.06	2,521	97.7	6.52	3.8	0.25
85.0% - 90.0%	41.13	6.67%	11,565	1.25	663	27.3	1.82	1.06	2,309	94.9	6.33	6.1	0.41
90.0% - 95.0%	43.48	6.67%	11,411	1.25	532	23.1	1.54	1.06	2,128	92.5	6.17	8.5	0.57
95.0% - 100.0%	45.83	6.67%	11,273	1.24	471	21.6	1.44	1.07	1,950	89.4	5.96	10.8	0.72
		100%					69.8				104.7		2.04

Beluga CT#3

Unit Size = 55 MW
Incremental Heat Rate, 50% - 100% = 9,552 Btu/kWh
Heat Rate at 50% = 13,136 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					Wtd.
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Unprotected S -> N Transfer MW
0.0% - 5.0%	1.38	0.00%	81,232	1.00	71,637	98.5	0.00	1.00	71,667	98.5	0.00	0.0	0.00
5.0% - 10.0%	4.13	0.00%	33,445	1.02	23,719	97.8	0.00	1.01	23,840	98.3	0.00	0.0	0.00
10.0% - 15.0%	6.88	0.00%	23,888	1.03	14,073	96.8	0.00	1.01	14,256	98.0	0.00	0.0	0.00
15.0% - 20.0%	9.63	0.00%	19,792	1.04	9,841	94.7	0.00	1.01	10,119	97.4	0.00	0.0	0.00
20.0% - 25.0%	12.38	0.00%	17,516	1.06	7,427	91.9	0.00	1.02	7,803	96.6	0.00	0.0	0.00
25.0% - 30.0%	15.13	6.67%	16,068	1.07	5,837	88.3	5.89	1.02	6,314	95.5	6.37	0.0	0.00
30.0% - 35.0%	17.88	6.67%	15,066	1.09	4,690	83.8	5.59	1.03	5,270	94.2	6.28	0.0	0.00
35.0% - 40.0%	20.63	6.67%	14,331	1.10	3,783	78.0	5.20	1.03	4,508	93.0	6.20	0.0	0.00
40.0% - 45.0%	23.38	6.67%	13,768	1.12	3,069	71.7	4.78	1.03	3,904	91.3	6.08	0.0	0.00
45.0% - 50.0%	26.13	6.67%	13,325	1.14	2,471	64.6	4.30	1.04	3,418	89.3	5.95	0.0	0.00
50.0% - 55.0%	28.88	6.67%	12,965	1.16	1,874	54.1	3.61	1.04	3,017	87.1	5.81	0.0	0.00
55.0% - 60.0%	31.63	6.67%	12,669	1.18	1,386	43.8	2.92	1.05	2,677	84.7	5.64	0.0	0.00
60.0% - 65.0%	34.38	6.67%	12,419	1.20	969	33.3	2.22	1.05	2,385	82.0	5.47	0.0	0.00
65.0% - 70.0%	37.13	6.67%	12,207	1.22	557	20.7	1.38	1.06	2,123	78.8	5.25	2.1	0.14
70.0% - 75.0%	39.88	6.67%	12,024	1.25	109	4.3	0.29	1.06	1,896	75.6	5.04	4.9	0.33
75.0% - 80.0%	42.63	6.67%	11,864	1.24	0	0.0	0.00	1.06	1,708	72.8	4.85	7.6	0.51
80.0% - 85.0%	45.38	6.67%	11,724	1.24	0	0.0	0.00	1.07	1,524	69.2	4.61	0.0	0.00
85.0% - 90.0%	48.13	6.67%	11,600	1.25	0	0.0	0.00	1.07	1,356	65.2	4.35	0.0	0.00
90.0% - 95.0%	50.88	6.67%	11,489	1.28	0	0.0	0.00	1.08	1,193	60.7	4.05	0.0	0.00
95.0% - 100.0%	53.63	6.67%	11,390	1.29	0	0.0	0.00	1.08	1,049	56.3	3.75	0.0	0.00
		100%					36.2				79.7		0.98

AMLP CT#8

Unit Size = 57 MW
Incremental Heat Rate, 50% - 100% = 9,591 Btu/kWh
Heat Rate at 50% = 14,029 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	EXISTING Reshape Req't MWh/MWh	EXISTING Reshape Savings Btu/kWh	EXISTING Gas Savings MBtu/hr	EXISTING Weighted Gas Savings MBtu/hr	NEW Reshape Req't MWh/MWh	NEW Reshape Savings Btu/kWh	NEW Gas Savings MBtu/hr	NEW Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	2.18	0.00%	98,351	1.01	88,673	192.9	0.00	1.00	89,733	193.0	0.00	0.0	0.00
5.0% - 10.0%	6.53	0.00%	39,178	1.03	29,322	191.3	0.00	1.01	29,506	192.5	0.00	0.0	0.00
10.0% - 15.0%	10.88	0.00%	27,343	1.05	17,259	187.7	0.00	1.01	17,617	191.6	0.00	0.0	0.00
15.0% - 20.0%	15.23	0.00%	22,271	1.07	11,998	182.7	0.00	1.02	12,477	190.0	0.00	0.0	0.00
20.0% - 25.0%	19.58	0.00%	19,453	1.10	8,937	174.9	0.00	1.03	9,604	188.0	0.00	0.0	0.00
25.0% - 30.0%	23.93	6.67%	17,660	1.13	6,866	164.3	10.95	1.03	7,741	185.2	12.35	0.0	0.00
30.0% - 35.0%	28.28	6.67%	16,419	1.16	5,335	150.9	10.06	1.04	6,444	182.2	12.15	0.0	0.00
35.0% - 40.0%	32.63	6.67%	15,508	1.19	4,124	134.5	8.97	1.05	5,462	178.2	11.88	0.0	0.00
40.0% - 45.0%	36.98	6.67%	14,812	1.22	3,115	115.2	7.68	1.05	4,701	173.8	11.59	2.0	0.13
45.0% - 50.0%	41.33	6.67%	14,263	1.23	2,430	100.4	6.70	1.06	4,079	168.6	11.24	6.3	0.42
50.0% - 55.0%	45.68	6.67%	13,818	1.24	1,935	88.4	5.89	1.07	3,561	162.7	10.84	10.7	0.71
55.0% - 60.0%	50.03	6.67%	13,450	1.27	1,230	61.5	4.10	1.08	3,134	156.8	10.45	15.0	1.00
60.0% - 65.0%	54.38	6.67%	13,141	1.29	744	40.5	2.70	1.08	2,744	149.2	9.95	19.4	1.29
65.0% - 70.0%	58.73	6.67%	12,878	1.31	278	16.3	1.09	1.09	2,405	141.2	9.42	23.7	1.58
70.0% - 75.0%	63.08	6.67%	12,652	1.35	0	0.0	0.00	1.10	2,094	132.1	8.81	0.0	0.00
75.0% - 80.0%	67.43	6.67%	12,454	1.40	0	0.0	0.00	1.11	1,835	123.7	8.25	0.0	0.00
80.0% - 85.0%	71.78	6.67%	12,281	1.44	0	0.0	0.00	1.12	1,581	113.5	7.56	0.0	0.00
85.0% - 90.0%	76.13	6.67%	12,127	1.49	0	0.0	0.00	1.12	1,349	102.7	6.84	0.0	0.00
90.0% - 95.0%	80.48	6.67%	11,990	1.56	0	0.0	0.00	1.13	1,124	90.5	6.03	0.0	0.00
95.0% - 100.0%	84.83	6.67%	11,867	1.63	0	0.0	0.00	1.14	914	77.5	5.17	0.0	0.00
		100%					58.1				142.5		5.14

Beluga CT#5

Unit Size = 66 MW
Incremental Heat Rate, 50% - 100% = 10,914 Btu/kWh
Heat Rate at 50% = 15,212 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 109 MW

Available Anchorage Spin = 25 MW

				EXISTING				NEW					
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Wtd. Unprotected S -> N Transfer MW
0.0% - 5.0%	1.65	0.00%	92,374	1.00	81,911	135.2	0.00	1.00	81,945	135.2	0.00	0.0	0.00
5.0% - 10.0%	4.95	0.00%	38,234	1.02	27,070	134.0	0.00	1.01	27,259	134.9	0.00	0.0	0.00
10.0% - 15.0%	8.25	0.00%	27,306	1.04	15,988	131.9	0.00	1.01	16,270	134.2	0.00	0.0	0.00
15.0% - 20.0%	11.55	0.00%	22,623	1.05	11,148	128.8	0.00	1.02	11,540	133.3	0.00	0.0	0.00
20.0% - 25.0%	14.85	0.00%	20,021	1.07	8,331	123.7	0.00	1.02	8,876	131.8	0.00	0.0	0.00
25.0% - 30.0%	18.15	6.67%	18,365	1.09	6,510	118.2	7.88	1.03	7,173	130.2	8.68	0.0	0.00
30.0% - 35.0%	21.45	6.67%	17,219	1.11	5,110	109.6	7.31	1.03	5,979	128.3	8.55	0.0	0.00
35.0% - 40.0%	24.75	6.67%	16,378	1.13	4,036	99.9	6.66	1.04	5,075	125.6	8.37	0.0	0.00
40.0% - 45.0%	28.05	6.67%	15,735	1.16	3,123	87.6	5.84	1.04	4,384	123.0	8.20	0.0	0.00
45.0% - 50.0%	31.35	6.67%	15,228	1.17	2,431	76.2	5.08	1.05	3,812	119.5	7.97	0.0	0.00
50.0% - 55.0%	34.65	6.67%	14,817	1.20	1,734	60.1	4.01	1.05	3,352	116.2	7.74	0.0	0.00
55.0% - 60.0%	37.95	6.67%	14,477	1.23	1,100	41.7	2.78	1.06	2,939	111.5	7.44	3.0	0.20
60.0% - 65.0%	41.25	6.67%	14,192	1.23	728	30.0	2.00	1.06	2,604	107.4	7.16	6.3	0.42
65.0% - 70.0%	44.55	6.67%	13,950	1.25	267	11.9	0.79	1.07	2,295	102.2	6.82	9.6	0.64
70.0% - 75.0%	47.85	6.67%	13,740	1.25	43	2.1	0.14	1.07	2,035	97.4	6.49	12.9	0.86
75.0% - 80.0%	51.15	6.67%	13,558	1.28	0	0.0	0.00	1.08	1,777	90.9	6.06	0.0	0.00
80.0% - 85.0%	54.45	6.67%	13,398	1.29	0	0.0	0.00	1.08	1,565	85.2	5.68	0.0	0.00
85.0% - 90.0%	57.75	6.67%	13,256	1.31	[illegible]	0.0	0.00	1.09	1,355	78.2	5.22	0.0	0.00
90.0% - 95.0%	61.05	6.67%	13,129	1.33	0	0.0	0.00	1.10	1,168	71.3	4.75	0.0	0.00
95.0% - 100.0%	64.35	6.67%	13,016	1.37	0	0.0	0.00	1.10	984	63.3	4.22	0.0	0.00
		100%					42.5				103.4		2.11

AMLP CT#4

Unit Size = 33 MW
Incremental Heat Rate, 50% - 100% = 9,372 Btu/kWh
Heat Rate at 50% = 18,475 Btu/kWh

Existing Transfer Limit, Output = 61 MW
New Transfer Limit, Output = 139 MW

Available Anchorage Spin = 35 MW

				EXISTING				NEW					Wtd.
Unit Loading	Average Range Load MW	Loading Prob.	Range Heat Rate Btu/kWh	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Reshape Req't MWh/MWh	Reshape Savings Btu/kWh	Gas Savings MBtu/hr	Weighted Gas Savings MBtu/hr	Unprotected S -> N Transfer MW	Unprotected S -> N Transfer MW
0.0% - 5.0%	0.83	0.00%	191,432	1.00	182,060	150.2	0.00	1.00	182,060	150.2	0.00	0.0	0.00
5.0% - 10.0%	2.48	0.00%	70,059	1.01	60,602	150.0	0.00	1.00	60,661	150.1	0.00	0.0	0.00
10.0% - 15.0%	4.13	0.00%	45,784	1.02	36,241	149.5	0.00	1.01	36,360	150.0	0.00	0.0	0.00
15.0% - 20.0%	5.78	0.00%	35.381	1.02	25,794	149.0	0.00	1.01	25,943	149.8	0.00	0.0	0.00
20.0% - 25.0%	7.43	0.00%	[illegible]	1.03	19,927	148.0	0.00	1.01	20,137	149.5	0.00	0.0	0.00
25.0% - 30.0%	9.08	6.67%	25,923	1.04	16,159	146.6	9.78	1.01	16,433	149.1	9.94	0.0	0.00
30.0% - 35.0%	10.73	6.67%	23,377	1.05	13,568	145.5	9.70	1.01	13,873	148.8	9.92	0.0	0.00
35.0% - 40.0%	12.38	6.67%	21,509	1.06	11,610	143.7	9.58	1.02	11,979	148.2	9.88	0.0	0.00
40.0% - 45.0%	14.03	6.67%	20,081	1.07	10,090	141.5	9.43	1.02	10,524	147.6	9.84	0.0	0.00
45.0% - 50.0%	15.68	6.67%	18,954	1.08	8,869	139.0	9.27	1.02	9,384	147.1	9.81	0.0	0.00
50.0% - 55.0%	17.33	6.67%	18,042	1.09	7,862	136.2	9.08	1.02	8,444	146.3	9.75	0.0	0.00
55.0% - 60.0%	18.98	6.67%	17,288	1.09	7,060	134.0	8.93	1.03	7,663	145.4	9.69	0.0	0.00
60.0% - 65.0%	20.63	6.67%	16,654	1.10	6,305	130.0	8.67	1.03	7,017	144.7	9.65	0.0	0.00
65.0% - 70.0%	22.28	6.67%	16,115	1.11	5,667	126.2	8.42	1.03	6,450	143.7	9.58	0.0	0.00
70.0% - 75.0%	23.93	6.67%	15,650	1.13	5,102	122.1	8.14	1.03	5,958	142.5	9.50	0.0	0.00
75.0% - 80.0%	25.58	6.67%	15,245	1.14	4,596	117.5	7.84	1.04	5,525	141.3	9.42	0.0	0.00
80.0% - 85.0%	27.23	6.67%	14,889	1.15	4,111	111.9	7.46	1.04	5,155	140.4	9.36	0.0	0.00
85.0% - 90.0%	28.88	6.67%	14,574	1.16	3,691	106.6	7.11	1.04	4,813	139.0	9.26	0.0	0.00
90.0% - 95.0%	30.53	6.67%	14,293	1.17	3,357	102.5	6.83	1.04	4,504	137.5	9.16	0.0	0.00
95.0% - 100.0%	32.18	6.67%	14,040	1.18	2,970	95.6	6.37	1.05	4,237	136.3	9.09	0.0	0.00
		100%					126.6				143.9		0.00

Summary for All Units

Unit Name	Prob. Marginal	- - Existing - - Reshape Savings MBtu/hr	Weighted Reshape Savings MBtu/hr	- - - New - - - Reshape Savings MBtu/hr	Weighted Reshape Savings MBtu/hr	- - Existing - - Unprot. Transfer MW	Weighted Unprot. Transfer MW
Beluga CC#8	37.5%	36.2	13.6	103.4	38.8	4.33	1.62
AMLP CC#56	37.5%	69.8	26.2	104.7	39.3	2.04	0.77
Beluga CT#3	5.0%	36.2	1.8	79.7	4.0	0.98	0.05
AMLP CT#8	9.0%	58.1	5.2	142.5	12.8	5.14	0.46
Beluga CT#5	8.0%	42.5	3.4	103.4	8.3	2.11	0.17
AMLP CT #4	3.0%	126.6	3.8	143.9	4.3	0.00	0.00
			54.0		107.4		3.07

OVERVIEW - BITTER CRAB DISEASE

Alaska State Legislature

House of Representatives

Representative Fran Ulmer

MEMORANDUM

TO: Rep. Lyman Hoffman, Chair
House Finance Subcommittee on AFG&G Budget

FROM: Rep. Fran Ulmer

DATE: January 29, 1990

RE: Funding for monitoring program for bitter crab disease in Tanner crab

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I am requesting an addition of $78.1 to the Commercial Fisheries component in the ADF&G budget for two programs dealing with the bitter crab disease.

Hematodinium_, or bitter crab, as it is more commonly known, is a disease which makes tanner crab very bitter in taste and unable to eat. It is estimated that 90% of all tanner crab in the Northern Southeast area including Lynn Canal is infected with this disease at this time. The mortality rate is 100% and the disease is very infectious, so many of our most productive crab fishing areas in Southeast are becoming barren wastelands. For many years, crab fishermen who discovered the disease in their catch, simply threw the bad crab overboard, many times in an area different from where the crab were caught. We now know that the disease can spread through these dead, raw carcasses to otherwise good crab stocks. An increment of $51.1 is needed to determine acceptable means of disposing of infected crab, and to address the issue of the seasonality of the disease to determine if a change in the harvesting season could significantly reduce the incidence of unmarketable crab.

District 4B — Juneau
P.O. Box V • Juneau, Alaska 99811-3100 • (907) 465-4947

Alaska State Legislature

REPRESENTATIVE BILL HUDSON

P.O. BOX V
Juneau, Alaska
99811
(907)465-3744 or 4991

COMMITTEES:
Transportation
Resources
Foreign Trade

FINANCE SUBCOMMITTEES
DOT/PF
C & RA

May 23, 1989

The Honorable Steve Cowper
Governor of Alaska
P.O. Box A
Juneau, AK 99811-0101

Dear Governor Cowper:

I am asking for your help in identifying the extent of a significant disease now affecting the northern Southeast Alaska tanner crab populations.

Mr. Joseph Donohue of Sitka Sound Seafoods and the M/V STORM FRONT identifies the observed problem of the "bitter crab" disease quite well in the attached paper dated March 23, 1989.

I would appreciate the Department of Fish and Game making some effort to analyze this apparent growing infestation and seeking some solution.

I realize the legislature didn't adequately fund the department for this research Governor, but the spread of this disease may jeopardize this entire crab fishery unless we move now.

Any help you can give will be appreciated.

Respectfully,

Bill

Bill Hudson

cc: Senator Duncan
Senator Eliason
Representative Goll
Representative Grussendorf
Representative Ulmer
Commissioner Collinsworth
Mr. Joe Donohue

BH/klc

January 23, 1990

Representative Bill Hudson
Alaska State Legislature
P.O. Box V
Juneau, AK 99811

Dear Representative Hudson:

Joe Donohue, Chairman of ASMI's Quality sub-committee on Bitter Crab Disease contacted me about a meeting on Monday, January 29th at 8:30 a.m. with you to discuss the status on the problem of bitter crab. I hope that the attached material is helpful in providing you with some background on the subject.

I look forward to meeting you.

Respectfully,

Kevin O'Sullivan
Quality Program Coordinator

Alaska Seafood Marketing Institute
P.O. Box DX
Juneau, Alaska 99811-0800
(907) 586-2902

PROJECT DESCRIPTION:

a) IDENTIFICATION OF THE PROBLEM

The Tanner crab (Chionoecetes bairdi and C. opilio) fishery in Alaska is a multi-million dollar industry which, as a result of the decline of king crab populations, represents the primary crab fishery remaining in Alaska. In Southeast Alaska this industry nets an annual worth of about $4 million dollars per year. The Bering Sea component of this fishery is vastly larger.

Since 1985, an increasing number of Tanner crabs from S.E. Alaska have been found to be infected with a parasitic dinoflagellate similar to Hematodinium sp. (known to infect blue crab on the east coast of the U.S.). In 1988 and 1989 an increasing number of crabs from the Bering Sea have also been found to harbor the parasite. This dinoflagellate causes a syndrome known as Bitter Crab Disease. Crabs affected with the syndrome have a pink carapace, milky hemolymph, and chalky-textured meat which has a distinctly bitter aspirin-like flavor. Such animals are non-marketable.

Unfortunately, fishermen discovered early on that they could identify infected crabs by the pink carapace and such crabs were then thrown overboard. This practice has resulted in the spread of the disease throughout S.E. Alaska and the Bering Sea. Some areas in the S.E. have an incidence of this disease as high as 100%. In 1985 Bitter Crab Disease was only found in the upper Lynn Canal. In 1986 it had spread to some locations in the S.E.. In 1987 it had spread to numerous additional locations in the S.E. and those regions previously identified as positive had a much higher incidence. In 1988, the disease was found in the Bering Sea and still more new locations in the S.E. previously thought to be negative have been found to be positive for the disease. Several areas in the S.E. are already closed to commercial Tanner crab fishing due to heavy infection rates of the parasite. At the rate the disease is spreading, more areas could be closed down in the near future due to the disease. This is a significant problem as many fisherman have permits to fish for both king and Tanner crab and they already have lost the ability to fish for king crab in many areas.

Processors have suffered significant economic losses in the past few years as a result of purchasing tainted crabs and then not being able to sell them. Now the fishermen are suffering as the processors will not buy crabs with visible signs of the disease. The Alaska Department of Fish and Game Commercial Fisheries Division has found that as much as 40-80% of the Tanner crab brought to the processors this season by S.E. fishermen is unmarketable due to this disease. This has resulted in a significant loss of revenue for the fishermen and a decrease in the effective catch per unit effort. The ADF&G Commercial Fisheries Division has estimated a loss of over 80,000 lbs of crab worth over $220,000 this season due to Bitter Crab Disease. These values do not include the number of diseased crabs sorted out by the fishermen prior to going to the processors. Some fishermen were throwing away over 50% of their catches. Consequently this

$220,000 value could increase substantially if the amount of crab sorted out by the fishermen was included. The economic impact this disease has had on the industry in recent years appears to be increasing along with the increased incidence of infected crabs.

Some preliminary work on the pathogenesis of Bitter Crab Disease has been conducted within the last year. However, for a management plan to be made by ADF&G, much more information is needed. Just a few of the questions which need addressing include: is there a seasonality associated with the disease; what is the geographic distribution of the parasite and is the parasite in S.E. the same as that in the Bering Sea; what is the life cycle of the parasite; are other species of crabs susceptible to the infection. Processors need to know if they can market low level infected crabs. Consequently, the compound causing the bitter flavor and meat deterioration has to be identified and a correlation made between the level of infection, concentration of the compound and the quality of the meat.

The purpose of this project is to conduct a study of the parasitic dinoflagellate which causes Bitter Crab Disease in Tanner crabs. The study will involve determination of: the mortality rates and seasonality of the disease in wild populations of crabs in S.E. Alaska; seasonal incidence and intensity of the disease in Bering Sea Tanner crabs; the oxygen carrying capacity, glycogen levels and osmoregulatory capability of infected hemolymph; the effect of stressors on exacerbating the disease; what compound causes the bitter flavor and what concentrations are necessary to do so; how do these concentrations correlate with the arbitrary 1+, 2+, 3+, 4+, 5+ designations for degree of infection in crabs; and is the parasite in the Tanner crab in the Bering Sea the same as that in S.E. Alaska.

This project should be considered in the Alaska Region priority section (E.1.e.) as it involves disease control of a commercially important species. If the concerns mentioned above are not addressed and nothing done to manage the disease then the Alaska Tanner crab fishery will soon go the way of the Alaska king crab fishery. Nothing can be done to protect this fishery until we understand more about the parasite and the pathogenesis of the disease.

B) PROJECT GOALS AND OBJECTIVES

The study will provide basic knowledge concerning the biology and pathogenicity of the dinoflagellate causing Bitter Crab Disease. This information will be used by ADF&G to make management decisions concerning ways to reduce the spread and the incidence of the disease without hurting the industry. The project will also provide the industry with a "yardstick" so that they will know what degree of an infection in a crab will result in an unmarketable product and how to test for it. Thus, trained individuals could monitor suspected crabs for the processors much in the way that fruit and vegetable canneries have people on line who monitor the quality of the products being canned or frozen.

This information will be provided by addressing the following objectives:

1. Determine the mortality rate due to Bitter Crab Disease in wild crab populations from two regions most similar to the S.E. Tanner crab fishing grounds, such as Auke Bay, and Eagle River, AK.

2. Determine the seasonal incidence and intensity of Bitter Crab Disease from the Bering Sea and from Auke Bay, and Eagle River, AK. and the geographic distribution of the agent.

3. Determine the oxygen carrying capacity, blood glycogen levels and osmoregulatory capabilities of infected vs non-infected crabs.

4. Determine the effects that stressors such as overcrowding, handling and increases in freshwater or saltwater have on exacerbating the disease.

5. Determine what the compound is that causes the bitter flavor.

6. Determine what concentrations of this compound are necessary to cause the off-flavors and how these concentrations correlate with the existing 1+ to 5+ designations used to describe the severity of infection.

7. Conduct quantitative tasting panels using meat from crabs variously infected with the parasite to determine the marketability of low level to moderately infected crabs.

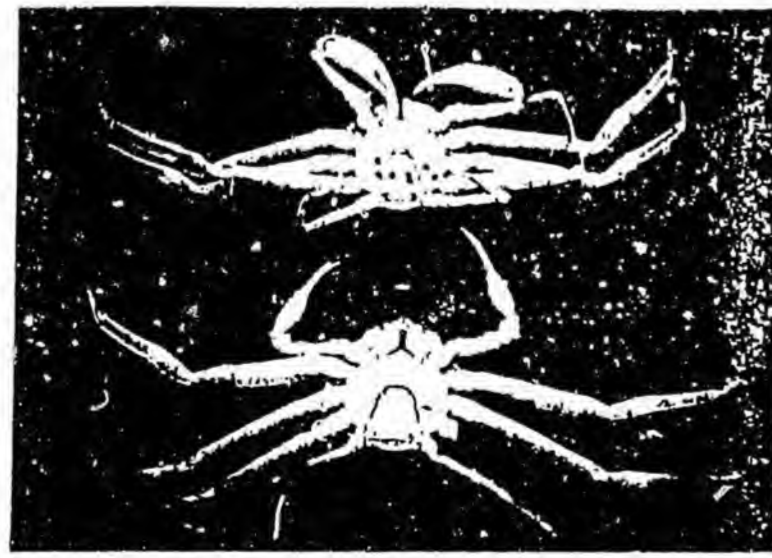
8. Determine if the parasite in the Bering Sea is the same as the parasite in the S.E.. This can be accomplished by simple DNA hybridization techniques.

It is difficult, if not impossible to assign any exact dates of results when experimenting with wild animals in a laboratory and when sampling animals in their natural habitat. Additionally, Bitter Crab Disease is a slow, chronically developing disease, not an acute one, consequently any work on such agents takes longer than with microbes causing acute diseases. Be that as it may, the dates listed should provide an approximate timeline to be used to evaluate the progress of the study.

The project should be completed 24 months after the start of the mark/recapture work in Auke Bay. The final report will be submitted within 2 months of completion of the project. The list below represents the work being conducted within that time:

Bitter Sweet Surprise

by Theodore R. Meyers



Ken Imamura

To some folks this title may suggest a recipe for a gourmet confection gone awry or perhaps an emotional tale of pleasure and woe. It is neither of the above but instead refers to a taste problem found in Tanner crab meats from certain harvest areas in Alaska's panhandle.

Some Southeast Tanner crab sport fishermen have had an unpleasant surprise when it came time to cook and eat their catch. At times the usual firm flesh with its sweet flavor has been replaced by a chalky meat having a bitter asprin-like aftertaste. Such crabs can be recognized beforehand by an exaggerated pink shell and milky appearing tissues and blood observed by cracking a walking leg.

The undesirable flavor and meat quality actually are clinical signs of "bitter crab disease" caused by a tiny single celled blood parasite belonging to the taxonomic group of microorganisms known as *dinoflagellates*. In general, dinoflagellates are a curious collage of organisms, most of which are photosynthetic and classified as algae. A few of these plant forms are also able to produce potent toxins responsible for "red tides" and paralytic shellfish poisoning. The Tanner crab dinoflagellate, however, is a rare parasitic type which is more like a protozoan than algae. Although distasteful, it is harmless if accidentally consumed by humans. Personnel from both the Fisheries Rehabilitation, Enhancement and Development (FRED) and Commercial Fisheries Divisions of ADF&G have been studying the bitter crab parasite for over a year to determine information about its life history and potential effect on Tanner crab populations.

The organism, although simple in appearance, has a complex life cycle involving three distinct forms: a vegetative stage and two different dinospore (or moving morphological) stages. The vegetative stage functions as a replicative form of the organism in the host and is a round nonmoving cell approximately two to three times the size of a crab blood cell. These vegetative stages cannot naturally infect other Tanner crabs but multiply to tremendous numbers within the blood of previously infected crab hosts. They eventually replace most of the blood cells and much of the normal crab tissues since crab blood normally travels some distance in open channels within all parts of the crab's body. Most Tanner crabs infected with the vegetative stages of the parasite die before the stages can develop into dinospores, a process called sporulation. When a crab host survives long enough to allow sporulation, all vegetative stages become transformed within a few days.

Two types of dinospores can occur but not both within the same crab host. One spore type is large and slow moving, while the other is a much smaller rapidly swimming spore. Both are propelled by two flagella (organ of movement). Dinospores are the end stages of the parasite and function to perpetuate its life cycle by escaping the old host and penetrating a new one. Once inside the new host, the spore(s) would conceivably germinate into a vegetative stage, thus completing the circle of life. A mystery yet remaining is whether both dinospore types are infectious. They may instead represent male and female cells which must first unite with each other outside the crab host to form the infectious stage of the parasite. In either case, sporulation kills the surviving crab host within one to two days, allowing escapement of dinospores into seawater when crab tissues decay.

Laboratory experiments have shown that all parasitized Tanner crabs die. However, the progression of the disease and host death may take from 6 to 10 months, a process which may be prolonged further by colder seawater temperatures. Consequently, some crabs may survive for more than one season in colder waters; and distribution of the parasite might be limited to the warmer latitudes in southeast Alaska.

The seasonality of bitter crab disease is still being investigated and it is not yet certain whether the life cycle of the parasite is completed within one year. As suggested by laboratory experiments, sporulation of vegetative stages and infection of other crabs by dinospores may occur in August and September when seawater temperatures average above 7 °C. Vegetative stages developing from dinospores multiply within crab tissues producing the chalky meat and bitter flavor. By the following February or March commercial crab fishermen are able to detect visually those crabs affected by the disease. Some parasitized

All photos by Al Sce[illegible]

crabs would have to survive until August and September to allow sporulation to renew the cycle.

The parasite, while in the process of reproducing and feeding on crab host tissues and fluids, causes muscle fibers to break down, producing poor meat quality. Flavor becomes bland as a result of tissue degradation. The bitter aftertaste is most likely a result of extracellular substances produced by the vegetative parasite or organic materials within the actual parasite cell. The severity of both poor meat quality and off flavor is directly proportional to the progression of the disease and the numbers of the parasite within the crab host.

Commercial fishermen and seafood processors in southeast Alaska have been aware of chalkiness anu bitter flavor in Tanner crabs for at least the past several years. In most instances affected meat lots are considered losses. Such losses are minimized by sorting the pink and milky crabs from the catch on the fishing grounds and at the processor boats or facilities.

The bitter crab dinoflagellate probably evolved within southeast Tanner crab populations long before man began exploiting the resource. However, it may have gone unnoticed when seasons for harvest occurred earlier in the life cycle of the parasite during late fall or early winter and when the market product in demand was meat rather than sections. Low meat yield and off-flavor are more noticeable in the latter market form. If the dinoflagellate parasite has an annual life cycle, meat deterioration and off-flavor would become more noticeable as the disease progresses into February and March. Changing to a commercial season during the earlier stages of the disease might allow all crabs to be marketable and make sorting of affected crabs unnecessary. This alternative is speculative and needs further investigation. Sorting can be an additional hazard in spreading this disease to healthy Tanner crab populations when infected crabs are transported then culled and released into distant waters near the seafood plants or from processor boats. An important realization is that any naturally occurring disease has the potential to negatively impact wild animal populations when human intervention proceeds without necessary precautions. These are common sense approaches which include maintaining the status quo by not overharvesting and not disseminating the disease, either of which or both would tip the balance in favor of the disease agent.

Facing page: Tanner crabs infected with the bitter crab dinoflagellate exhibit an exaggerated pink shell color (bottom) when compared to healthy crabs (top).

A photomicrograph taken by a scanning electron microscope at high magnification shows droplets of an extracellular substance exuding from nonmoving vegetative stages of the parasite (left). These vegetative stages later sporulate into either the large (right) or small type (bottom) of biflagellated dinospore.

Many questions remain concerning bitter crab disease and include the distribution of infected Tanner stocks and whether other Alaskan crab species can become infected. Recent laboratory studies have shown that red king crabs are immune to infection by the parasite. Continued investigation and prudent managment of Tanner crab populations should allow this disease and resultant problems in meat quality to be controlled.

Theodore R. Meyers is Principal Fish Pathologist, FRED Division, Juneau. He holds a Ph.D. in veterinary medicine from Cornell University and a Master's degree in fish pathology from Oregon State University.

The author and three co-authors, Tim Keoneman and Cathy Botelho of the Commercial Fisheries Division, and Sally Short of FRED Division, have treated this subject more thoroughly in an extensive paper to be published in late 1987. Ken Imamura, also with the Commercial Fisheries Division, has participated in this study.

BITTER CRAB DISEASE
Hematodinium sp.

Steps that management has taken:

JANUARY 1987 During the February 15 to March 25, 1986 Tanner fishery, the fleet found a significant percentage of unmarketable crab in waters adjacent to Sullivan Island. In order to protect the remaining stock in that area and to reduce the potential for transportation of infected crab to other locations, an EO was written to close all waters of Lynn Canal north of the lattitude of Point Sherman Light and south of the lattitude of the southermost tip of Point Seduction, and all waters of Chilkat Inlet north of the lattitude of the southern tip of Point Seduction for the January 15, 1987 Tanner fishery.

JANUARY 1988 Areas closed during the January 1987 fishery were reopened for the January 1988 fishery because samples collected between seasons suggested a lessening of the severity of the incidence of the disease. However, populations were found to be at low levels, possibly as a result of the infection.

FEBRUARY 1989 A news release issued in response to public inquiries regarding disposal of bitter crab. In some areas the organism was detectable in more than 80 percent of all sizes and both sexes of Tanner crab. When crab such as these are retained and transported from areas with high rates of infection to areas of low infection there is risk to healthy stocks.

1. Most effective disposal: sanitary landfill
2. Less effective, in order of probable effectiveness:
   a: cooking followed by approved grinding and marine discharge
   b: killing the crab and retaining in leakproof containers
   c: least desirable AND MOST FREQUENTLY EMPLOYED METHOD: over board dumping of newly dead or live infected crab. THe potential exists for healthy crab either consuming or contacting infected crab and becoming infected themselves.

JANUARY 1990 A staff proposal to allow flexible season openings in areas with known high incidence of the disease to possibly maximize utilization of infected crab is presented for consideration by the Board of Fisheries. The progression of the severity of infection in individual crabs seems to be from a low level in late summer or early autumn to a higher level in winter and early spring. Earlier openings in areas of known high incidence could allow harvest of infected crab before the full development of bitter taste associated with the later stages of infection.

When did the disease first appear?

"What we now recognize as signs and symptoms of infected crab has been prevalent in various geographic locations since 1974. At that time the season extended from September through April, progressed at a slow rate with fewer vessels."

In March 1985, a southeastern processor purchased and packed crab which proved to be bitter. They suffered both significant money and market losses.

In February 1986, this same processor discontinued buying Tanners from upper Lynn Canal because of quality control problems...a bitter taste evident in crab from a "pre-molt stage". They took a [illegible] of $40,000 to $50,000 from crab purchased the prior year and feared a me[illegible]al claim against them. Vessels normally delivering from Lynn Canal to them, took their catch elsewhere. Port samplers in Juneau brought some of the "molting" crab to Dr. Ted Meyers to validate the suspicion that the bitter taste was associated with more than a biochemical change prior to molting. The body of knowledge on Hematodinium has slowly grown since.

What have the fishermen lost?

Not all fishermen are sorting their catches on the grounds, either because they are unable to identify the diseased crab visually or they are keeping their entire legal catch for the processor to sort. On one delivery last year, a fishermen was quoted as saying "didn't seem to notice it (bitter crab)". From his catch during rough weather in the canal, 1,346 pounds were accepted; and 1,243 pounds of his delivery rejected. Until this past season, not all processors provided deadloss information as required.

Those that are sorting on the grounds are most often having to return their catch to the sea. Others have kept the diseased crab on deck to freeze and then dumped them overboard; others have actually disposed of their bad crab on land. Most of these figures, of course, have not been reported as deadloss to the department.

Deadloss estimates are very conservative. As the industry has learned to visually sort for this disease and generally become more informed about this disease, the accuracy of reporting has also improved. There is some debate whether the noted increase in reported pounds of rejected crab is due to better reporting or a spread and intensification of the disease. Historical fish ticket information on Tanner deadloss delivered to the dock follows:

	Unmarketable Lbs.	% of Total Catch	$ Value
1985/86	454	0.05	568.00
1986/87	4,416	0.40	7,286.00
1987/88	25,625	2.00	57,656.00
1988/89	80,188	5.20	220,517.00

What research/sampling is being done?

Surveys:

- a: Samples have been collected from various bays in SE during the past four years while conducting the red king crab research cruises.
- b: A limited amount of mark/recapture data is available from a naturally diseased population in the Sullivan Island area.
- c: Some directed test fishing monies have allowed us to take samples in the Sullivan Island area.

Dockside:

- a: Samples (100 per delivery) have been taken from catches delivered from a specific fishing location.
- b: Since the 1985/86 season limited information has been collected from dockisde interviews at the processing facilities in SE.

How has the research/sampling been "funded" to date?

Dr. Ted Meyers has read all slides on a "time available" basis, as an additional task to his regular duties.

Sample collections and slide preparation has been accomplished during red king crab cruises and utilized time, slides, syringes, stain kits and other supplies purchased with population estimate and test fishing funds.

What work needs to be done?

1. Dissemination of information to the fleet and processors. Document and emphasize the severity of the disease to the health of the resource, suggest means of minimizing spread of disease from areas of high incidence to areas with little or no reported incidences of the disease.
2. Implement reasonable and appropriate measures for disposal of diseased crab. Implement measures to minimize transport of diseased crab by fishermen and tendering vessels.
3. Research to understand the impacts of the disease on Tanner crab stocks and on their management.
   a. Determination of life history, infectivity, seasonality, and other biological and physiological parameters associated with Hematodinium.
   b. Analysis of the relationship between the progressive stages of infection and catchability and marketability of the diseased crab. That is, determine the relative seasonal availability of the crab (changes in CPUE) and relative seasonal meat recovery and marketability (fullness, organoleptic and asthetic testing). Standardize criteria for testing acceptability of crab.
4. Continue collection of crabs for Hematodinium sampling during shellfish cruises. Provide for periodic sampling from Sullivan Island or alternate area for seasonality studies. As available, provide crab to industry for quality testing.
5. Support, to the extend possible, on-going and new programs studying various aspects of the organism.

COMMERCIAL FISHERIES

NEWS RELEASE

ALASKA DEPARTMENT OF FISH & GAME

STATE OF ALASKA
Department of Fish and Game
Don W. Collinsworth, Commissioner

Ken Parker
Director

Southeast Regional Office
P.O. Box 20
Douglas, Alaska 99824

Contact: Ken Imamura
Tim Koeneman
(907) 465-4250

FOR IMMEDIATE RELEASE

February 5, 1990

RECOMMENDED DISPOSAL METHODS FOR UNMARKETABLE TANNER CRAB

Juneau . . . . In response to public inquiries, the Alaska Department of Fish and Game is providing, as it did last season, the following information regarding the recommended disposal methods for unmarketable Tanner crab.

A significant number of Tanner crabs in some areas are infected with the bitter crab organism. In some areas, the organism is detectable in more than 80 percent of all sizes and both sexes of Tanner crab. When infected crab such as these are retained and transported from area with high rates of infection to areas with no detectable rates or low rates of infection, there is a risk to currently healthy stocks of crabs.

The safest method of disposal of infected crabs is assumed to be an approved method of land disposal such as in a sanitary landfill. This measure will totally isolate the infected crab and the causative organism from healthy populations of crabs.

Another disposal method that is probably as effective as isolation in landfills involves cooking the infected crab to industry sanitation standards prior to disposal by approved grinding methods and marine discharge.

Killing infected crab and retaining them in leak-proof containers for prolonged periods to kill the infective organism before marine disposal is less desirable from sanitation and aesthetic considerations. The infective organism is known to be extremely hardy and can remain active for days, long after the death of its host crab.

Simple grinding and marine disposal is even less desirable because of the potential for healthy crabs ingesting or contacting fragments of infected crabs and contracting the infection. The least effective means of disposal is probably overboard dumping of freshly killed or living infected crab from tenders or fishing vessels. The risk of spreading or intensifying the infection is greatest with this last method of disposal.

Unfortunately, although disposal methods are improving, much crab disposal in the past has employed the last and least desirable method. More effective methods require considerably more handling, staff involvement, and costs than simple dumping. However, the long-term consequences of unsafe dumping of infected crab could very easily mean spreading or intensifying the infection to such an extent that a commercial fishery will become much less tenable. The industry is asked to do what it can to prevent the spread of bitter crab infection.

Any questions can be directed to Timothy Koeneman, Cathy Botelho, or Ken Imamura at the address or phone number on the letterhead. In addition, Ted Meyers, the staff pathologist for the department, may be contacted at 465-3577 for technical or detailed information regarding this disease.

Phone numbers for the area offices are Juneau 465-4250, Sitka 747-6688, Ketchikan 225-5195, Petersburg 772-3801, and Wrangell 874-3822.

OVERVIEW - DIVISION OF AGRICULTURE

ALASKA AGRICULTURE FACTS

The enclosed information gives a brief overview of Alaska's agriculture. This report was compiled by staff of the Department of Natural Resources, Division of Agriculture.

It is clear from the information provided in this report that agriculture is growing in Alaska. This growth has continued, even with the downturn in Alaska's economy.

Most of the statistics are from Alaska Agricultural Statistics, published annually by the Alaska Crop and Livestock Reporting Service. The agricultural multiplier is from a 1986 master's thesis by John Weddeton and entitled The 1982 Alaska Input-Output Model. The thesis was completed at the University of Alaska.

Alaska GROWN

State of Alaska
Department of Natural Resources
Division of Agriculture
PO Box 949
Palmer, Alaska 99645
Frank G. Mielke, Director

January 1989

ALASKA AGRICULTURE FACTS

General Information

- Currently, sales of farm commodities generate annual cash receipts of $30 million. In 1975, cash receipts totaled only $7 million.
- Based on an average agricultural multiplier of 2, annual farm sales lead to $60 million of revenue activity for the Alaska economy.
- Horticultural and Greenhouse receipts are approximately $13 million annually.
- Alaska agriculture employs 2,000 workers.

Commodity Value Growth

	1975	1987
Milk	$2,817,000	$7,034,000
Hay and Silage	2,271,000	4,508,000
Potatoes	1,463,000	2,250,000
Beef	1,463,000	1,687,000
Barley	287,000	616,000
Lettuce	252,000	350,000
Other Vegetables	138,000	456,000
Pork	76,000	230,000

Improving Production

- In 1988, per acre yield for Delta barley was 48 bushels. The 1975 yield was only 21 bushels per acre.
- Annual milk production per cow was 15,000 pounds in 1987. In 1975, production per cow was 10,500 pounds.

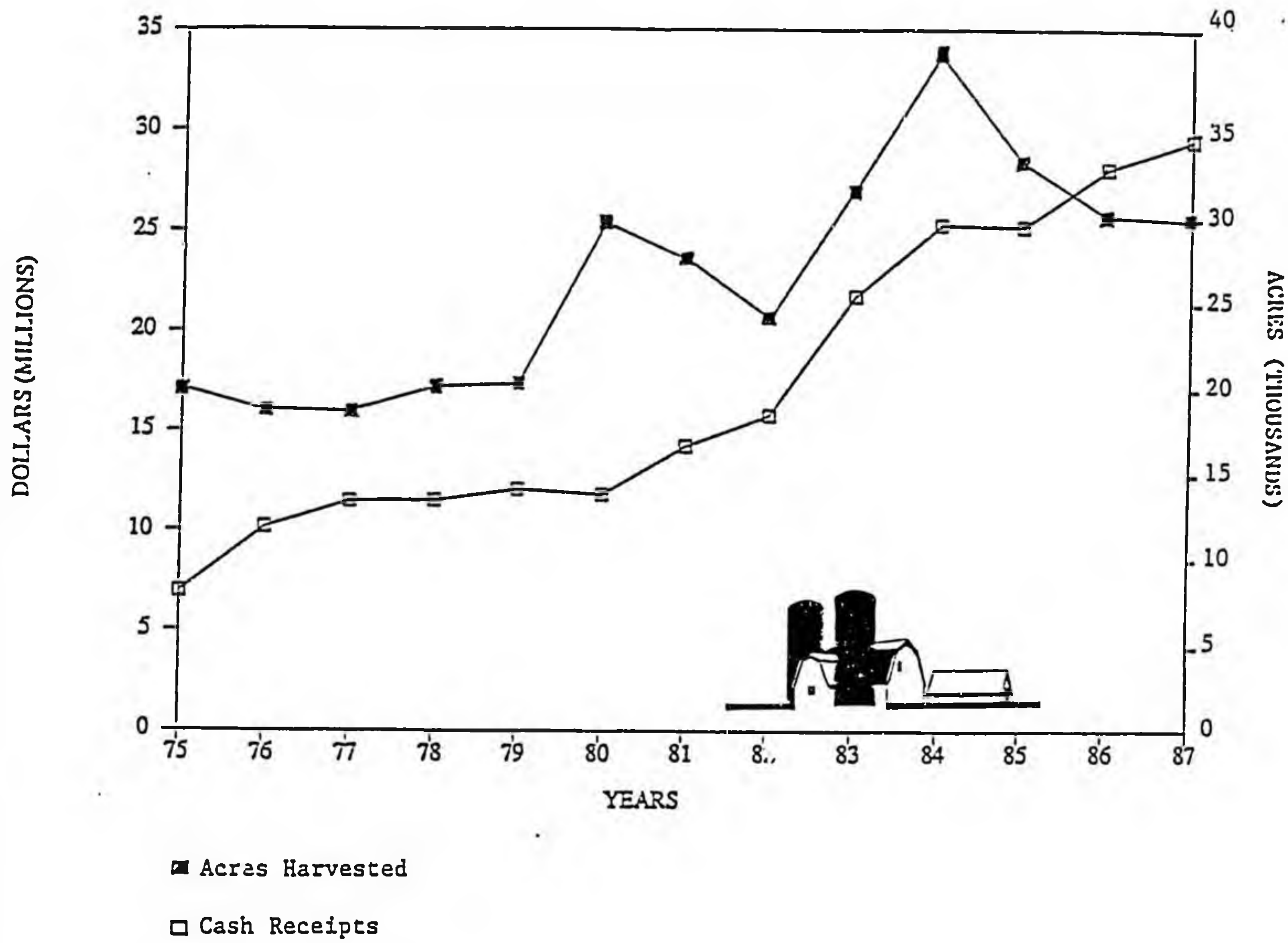
Farm Numbers

- There are currently 660 farms in Alaska. This compares to 300 farms in 1975.

Improving Delinquency Rate - ARLF

- On loans issued in 1987, the delinquency rate is 10%.
- On loans issued in 1988, the delinquency rate has improved to 2.7%.

CASH RECEIPTS & ACRES HARVESTED

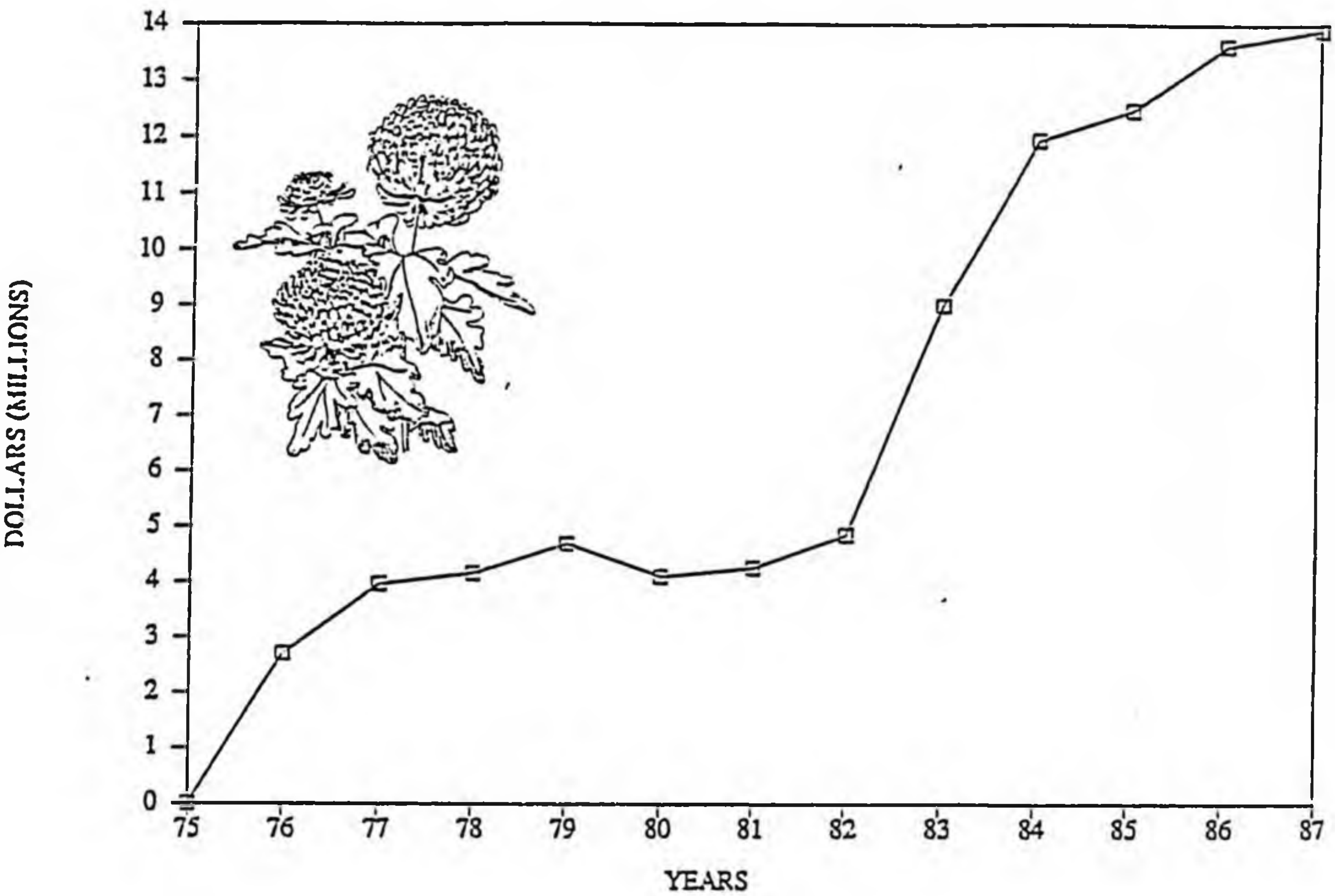


* Cash receipts for Alaska farmers in 1987(latest available figures) totaled $29,473,000.

* Alaska farmers harvested crops from 29,447 acres in 1987.

* While acreage has fallen somewhat in recent years, receipts have grown as Alaska farmers concentrate on higher value commodities.

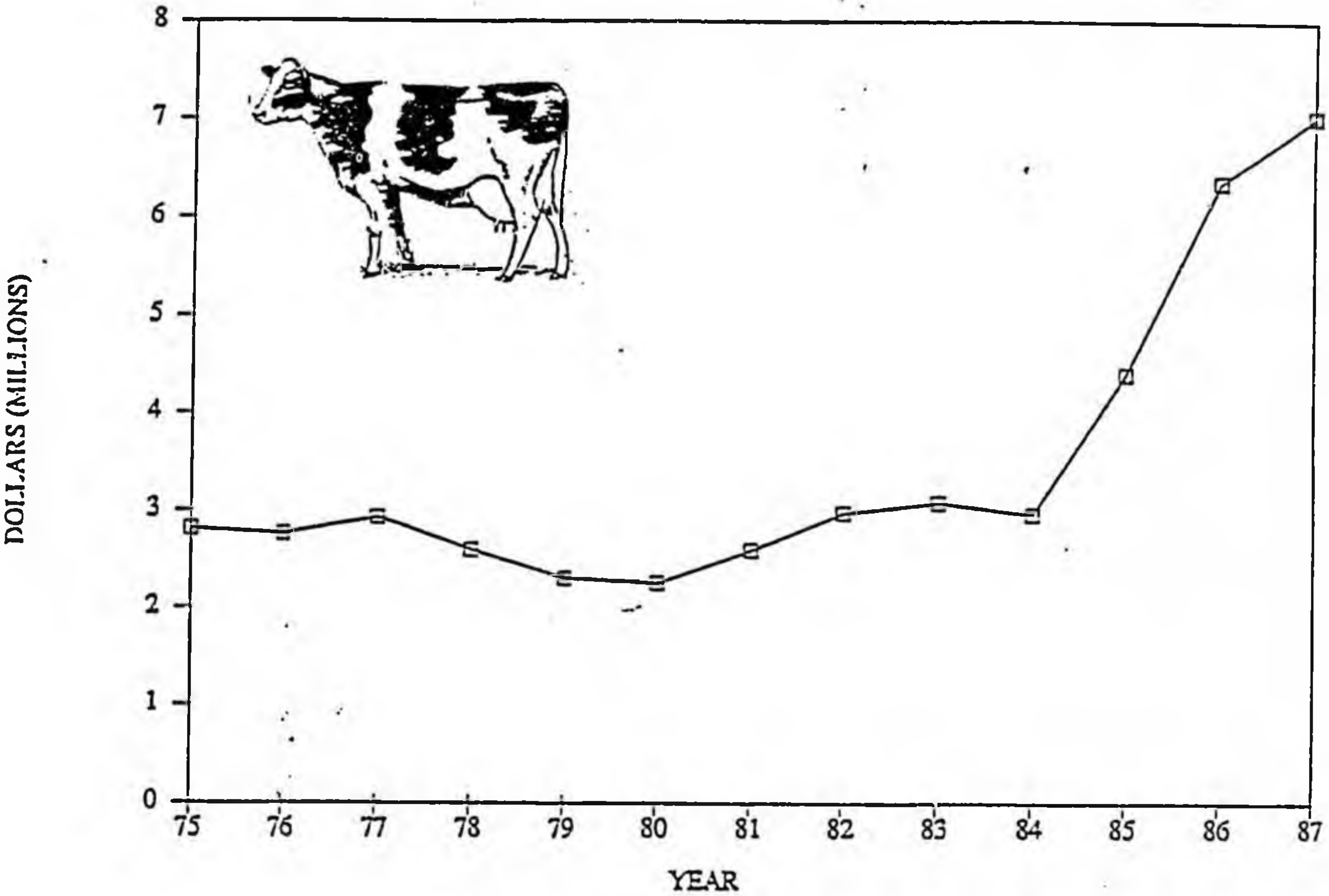
HORTICULTURAL & GREENHOUSE RECEIPTS



* Greenhouse and nursery receipts totaled $13,248,000 in 1987 (latest available figures).

* Dramatic growth has been seen in this segment of Alaska's agricultural industry--major growth began in 1982.

VALUE OF MILK

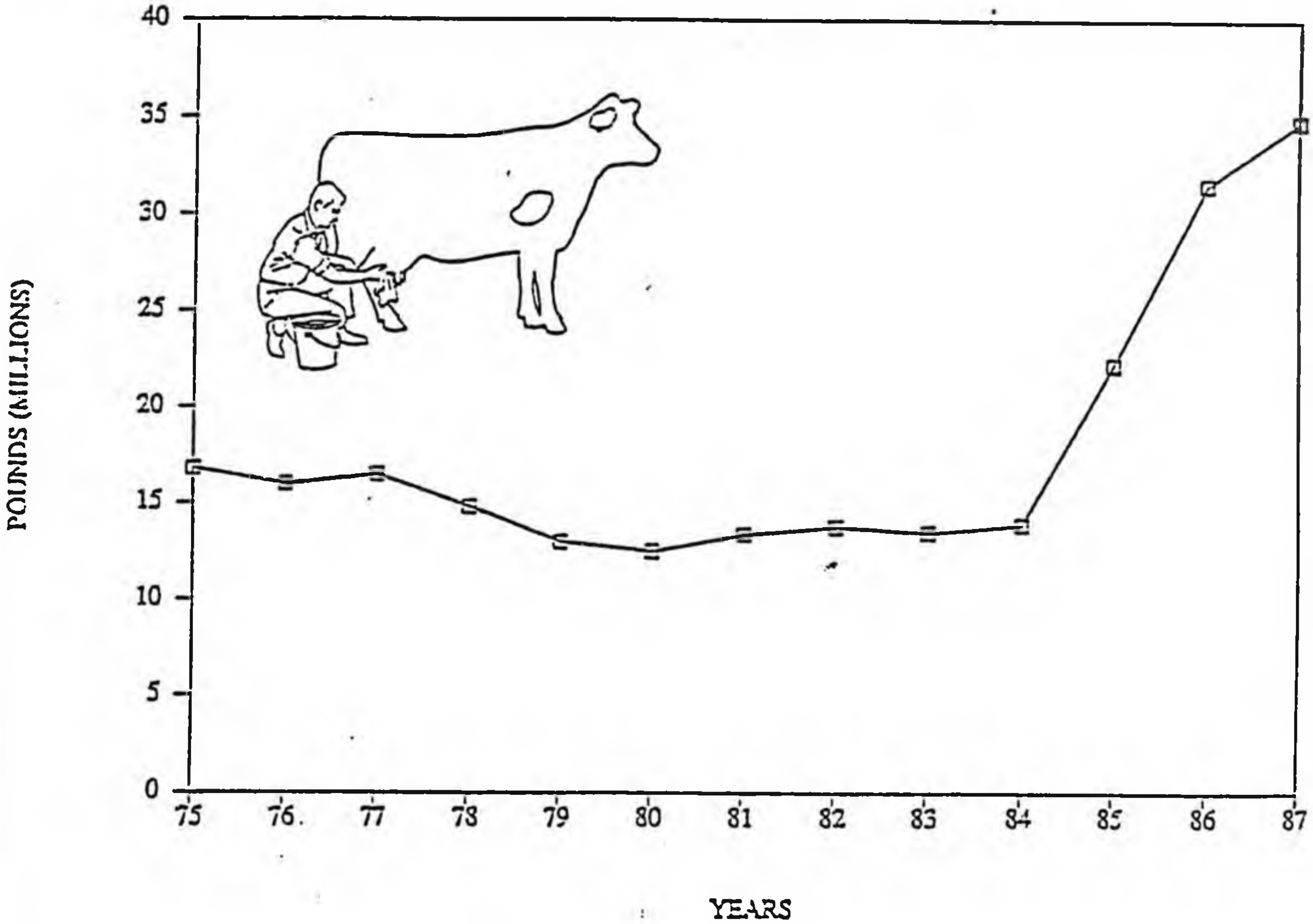


*The value of milk production in Alaska in 1987(latest available figures) totaled $7,034,000.

* Because of the Pt. MacKenzie dairy project, the value of milk production has more than doubled since 1984.

* Some decrease in sales will be seen in 1988 due to financial difficulties of some dairy farmers. However, this should be temporary as restructuring of debt allows the industry to regain its financial footing.

QUANTITY OF MILK IN ALASKA

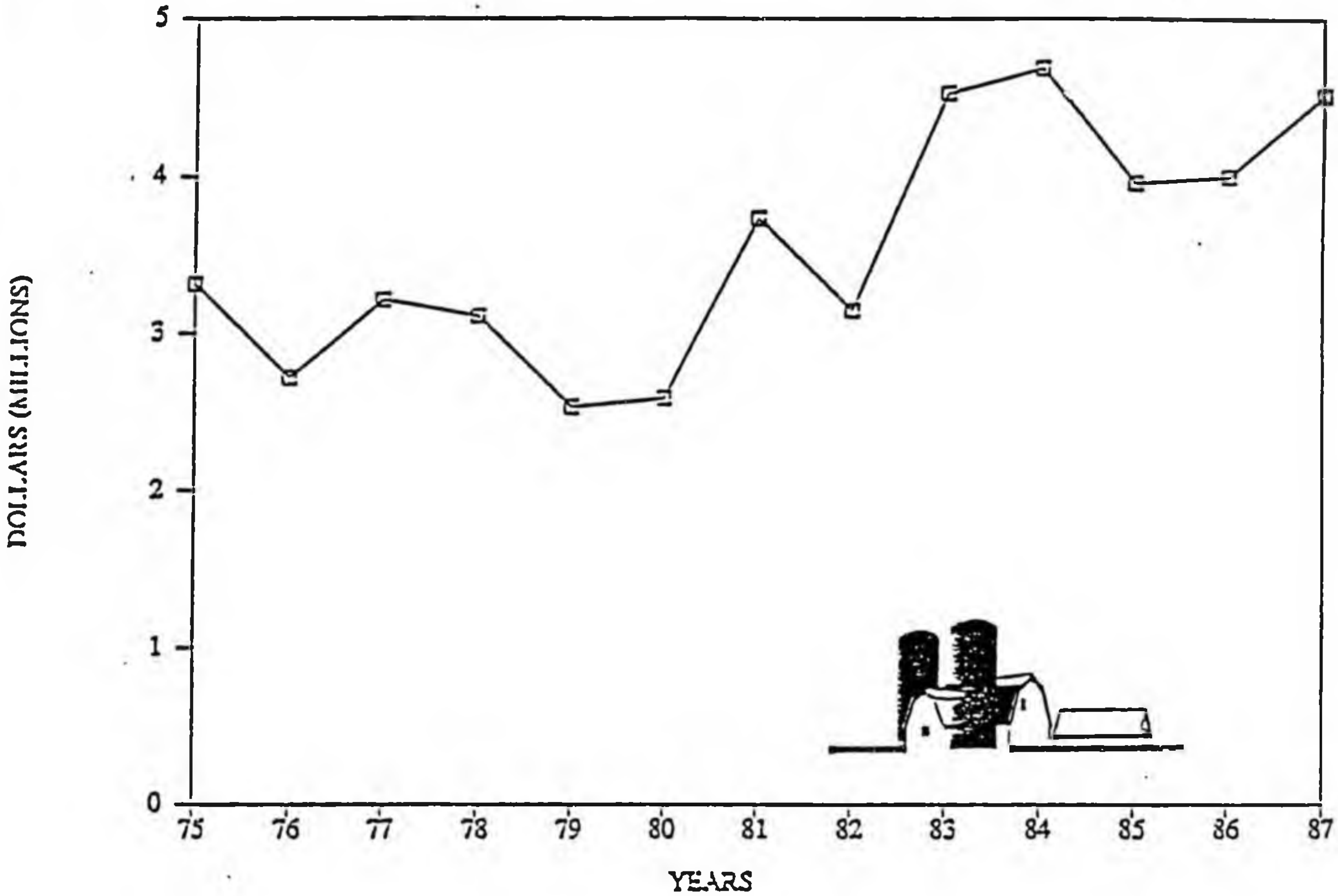


* Alaska milk production totaled 34,800,000 pounds in 1987(latest available figures).

* A decrease in total production will be seen in 1988. Production will still be above 1985 levels.

* Decreases in production will be temporary and will again increase following a short period of industry restructuring.

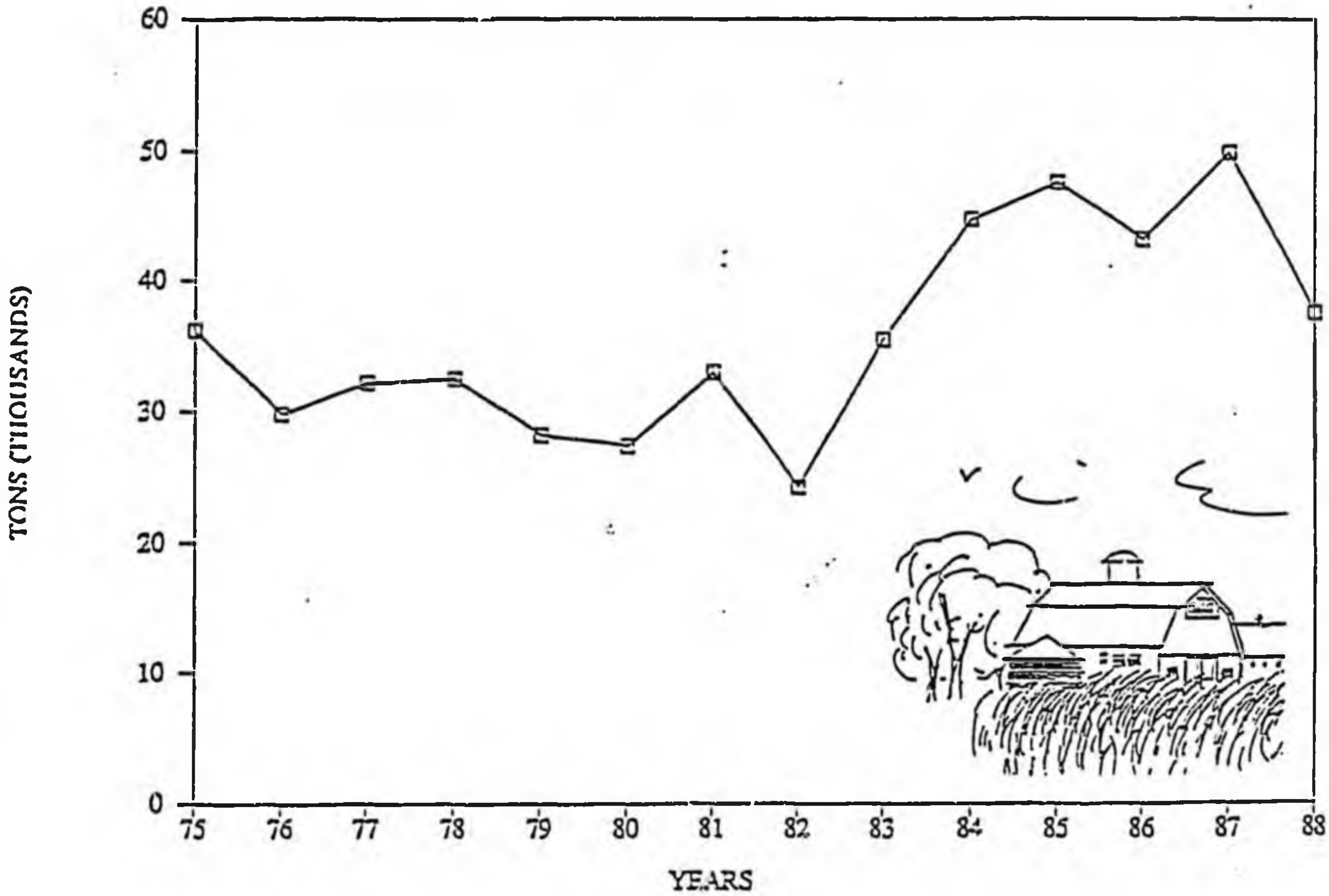
VALUE OF HAY AND SILAGE



* In 1987(latest available figures), the value of hay and silage grown by Alaska farmers totaled $4,508,000.

* Hay and silage production remains a stable segment of Alaska's agricultural industry.

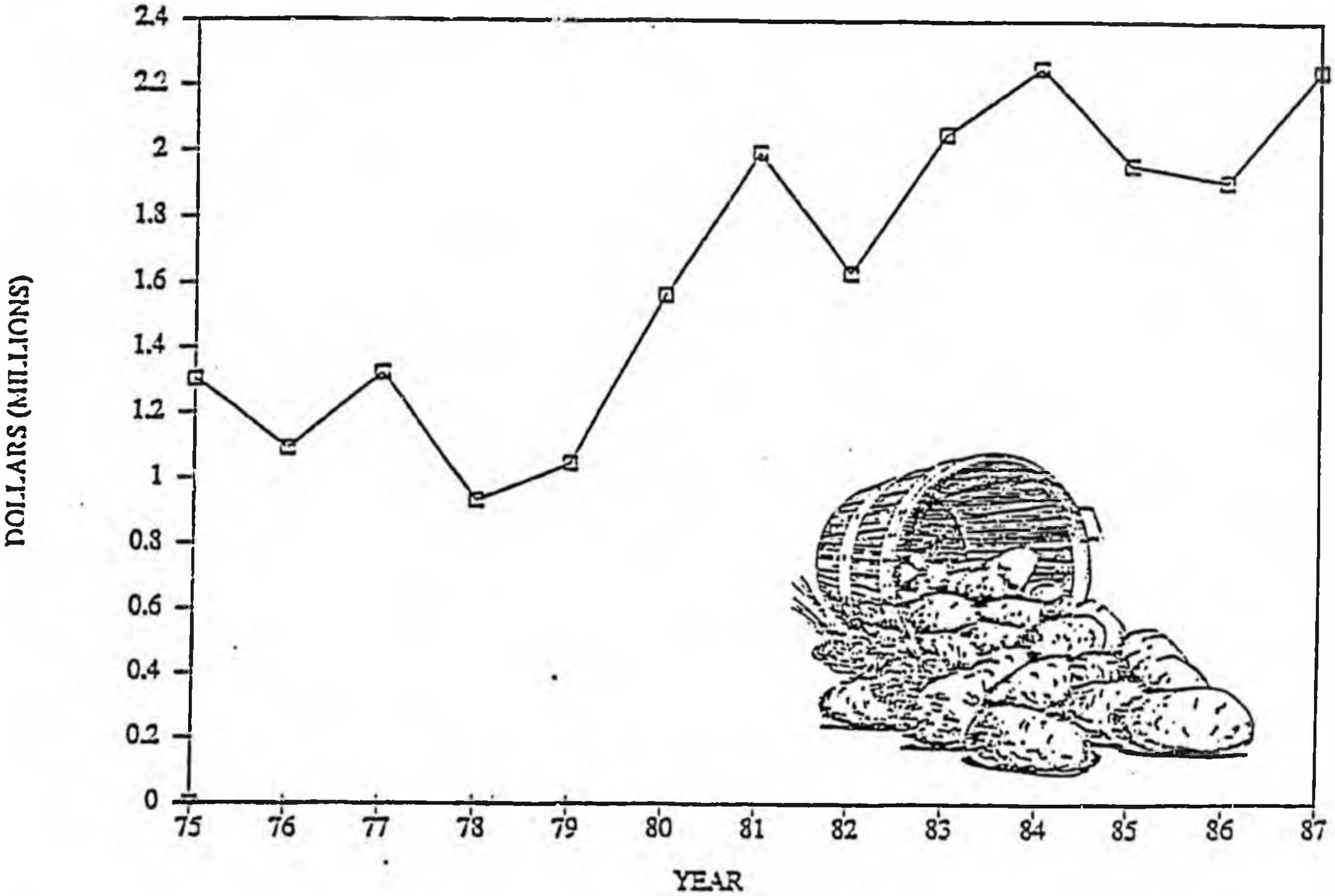
QUANTITY OF HAY AND SILAGE IN ALASKA



* Production of hay and silage in 1988 totaled 37,500 tons.

* Hay and silage are the main feedstuffs for livestock in Alaska. Production has remained relatively stable since 1975.

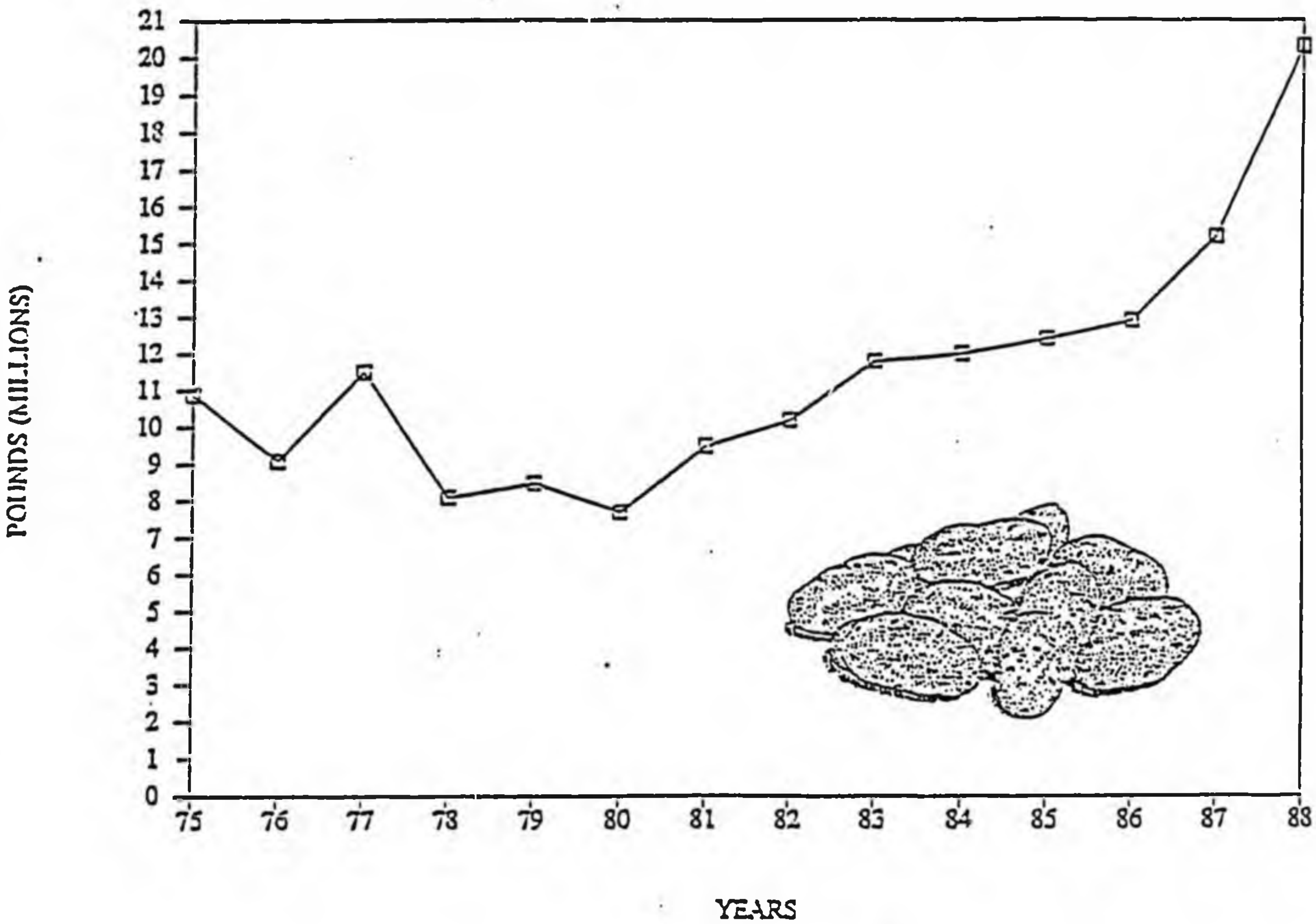
VALUE OF POTATOES



* The value of potatoes grown in Alaska in 1987(latest available figure) amounted to $2,250,000.

* Value figures for 1988 will shown a large increase due to a significant rise in potato production in 1988 over 1987.

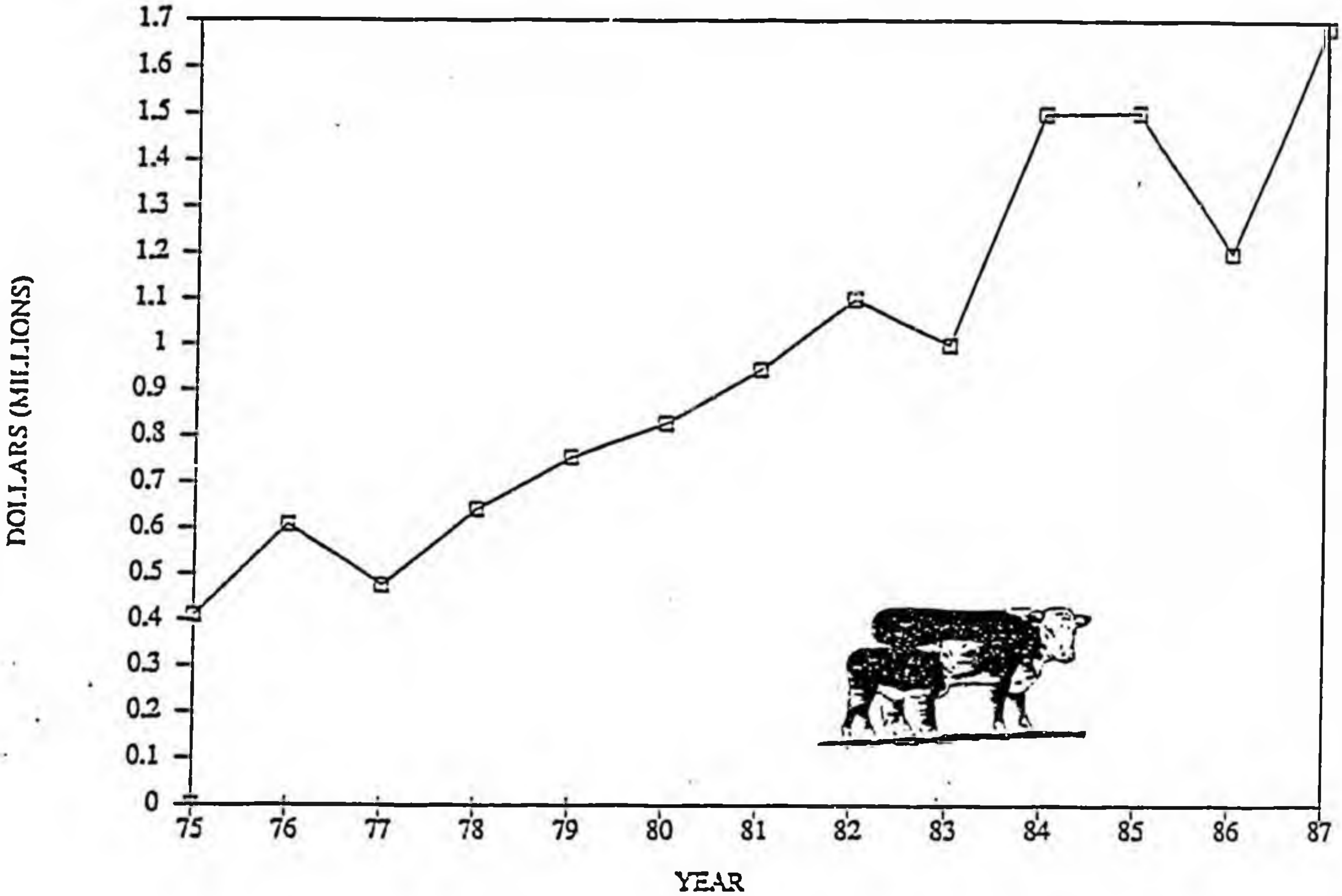
QUANTITY OF POTATOES IN ALASKA



* Alaska farmers produced a total of 20,300,000 pounds of potatoes in 1988. This is the largest production of record since 1960.

* Production in 1988 was nearly double the 1975 figure.

VALUE OF BEEF



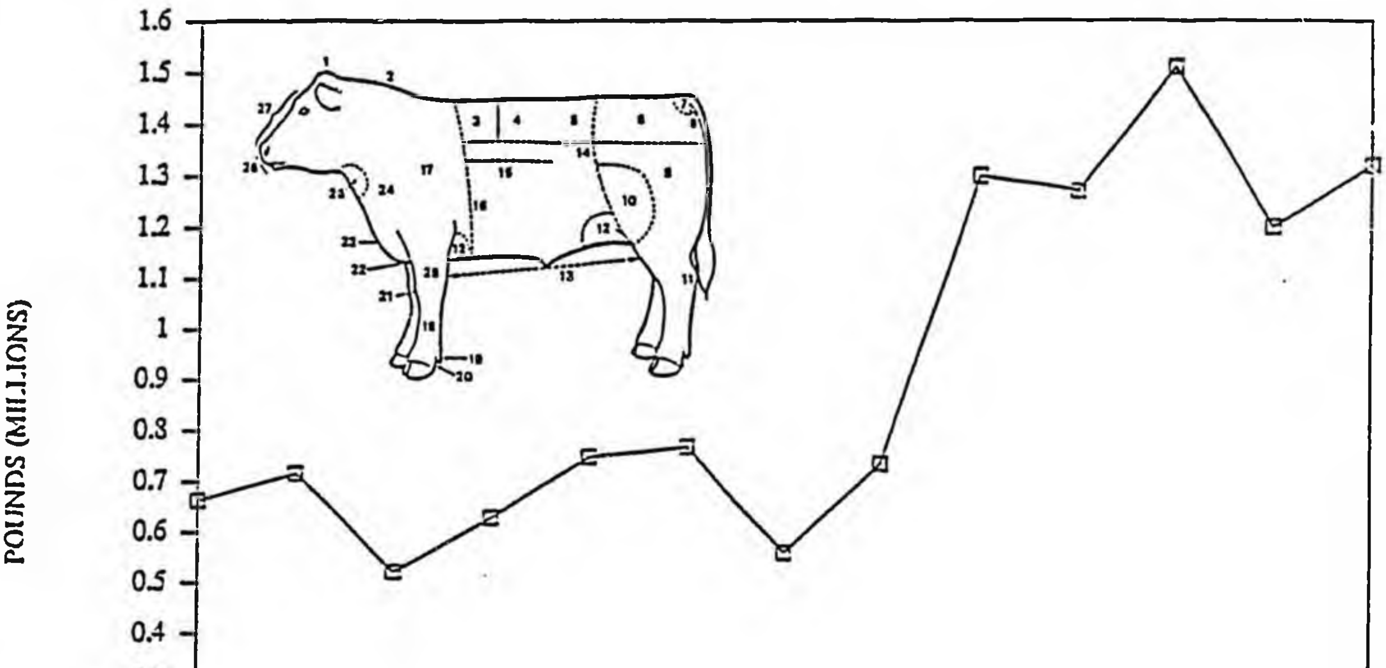
* The value of beef production in Alaska totaled $1,687,000 in 1987 (latest available figure).

* The value of beef production in Alaska has shown continuing growth since 1975.

* Stability and further growth will be enhanced by the continuing operation of the Palmer meat plant.

* The Palmer meat plant is operated by the Department of Corrections under an agreement with the Division of Agriculture as an in-house prison industries facility.

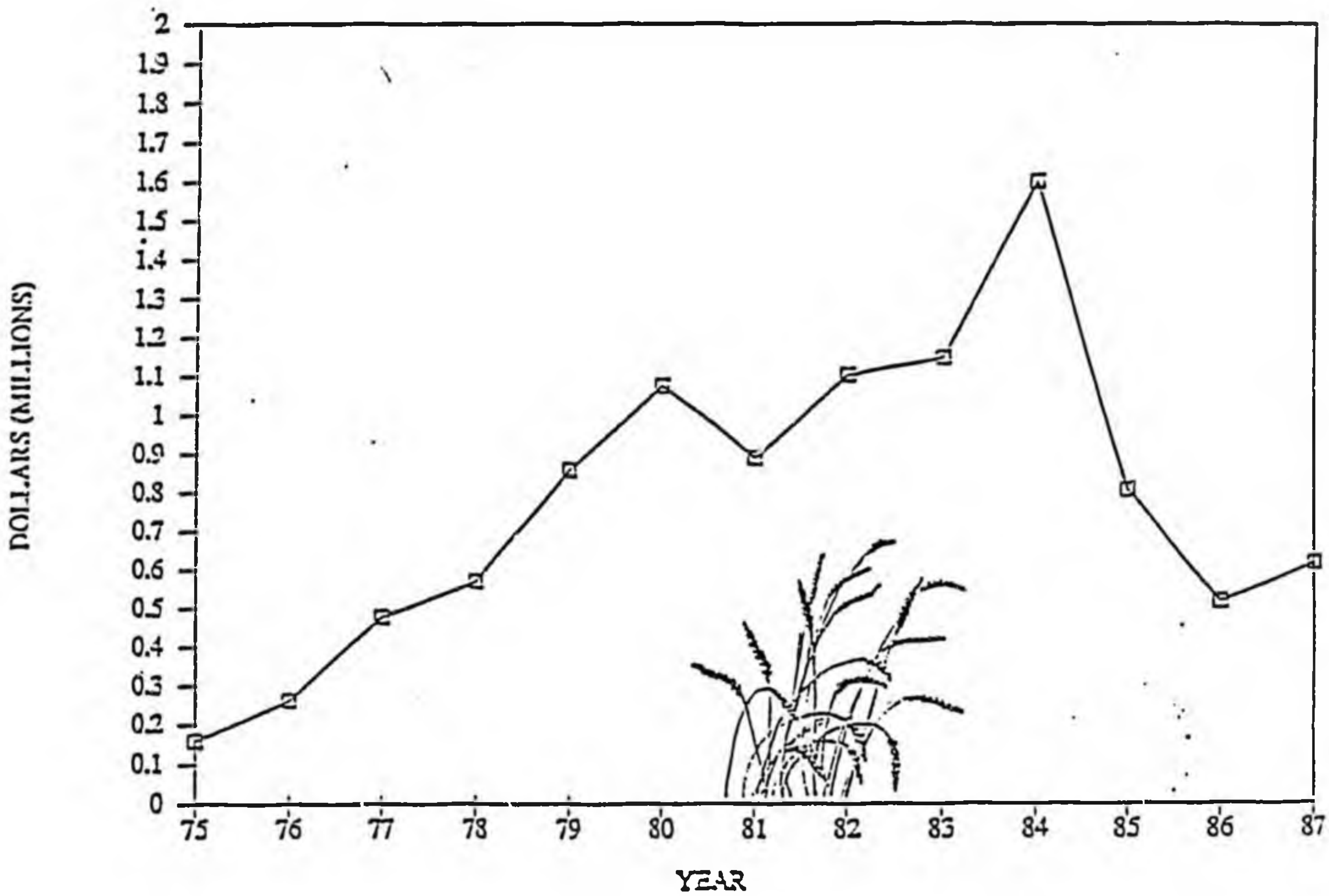
QUANTITY OF BEEF IN ALASKA



* Beef production in Alaska totaled 1,318,000 pounds in 1987 (latest available figure).

* Final figures for 1988 should show an increase over 1987--due in part to the stability provided by the operation of the Palmer meat plant.

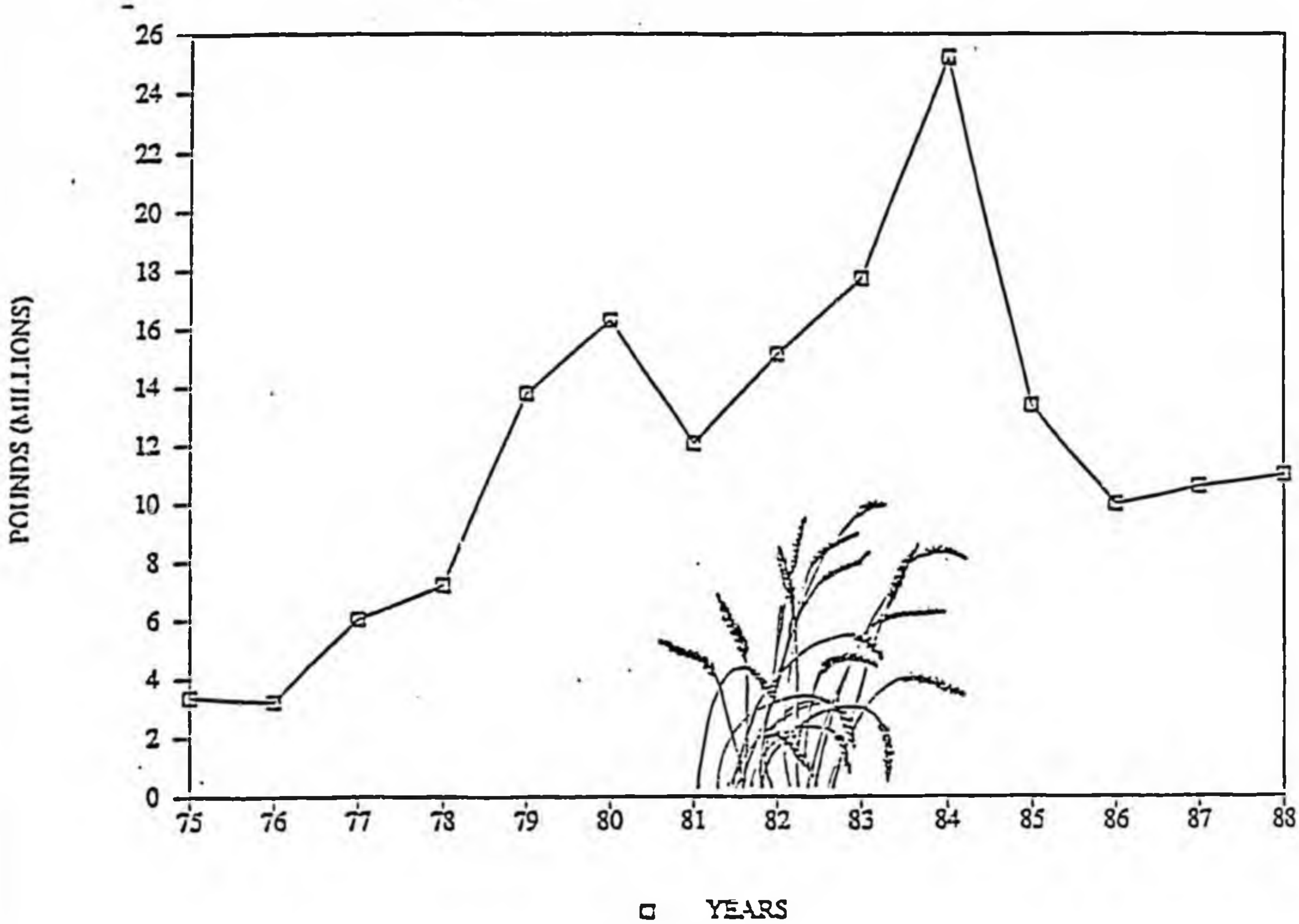
VALUE OF BARLEY



* In 1987(latest available figure), barley production in Alaska had a total value of $616,000.

* Final figures for 1988 will show an increased value for Alaska's barley crop as both production and prices increased over 1987.

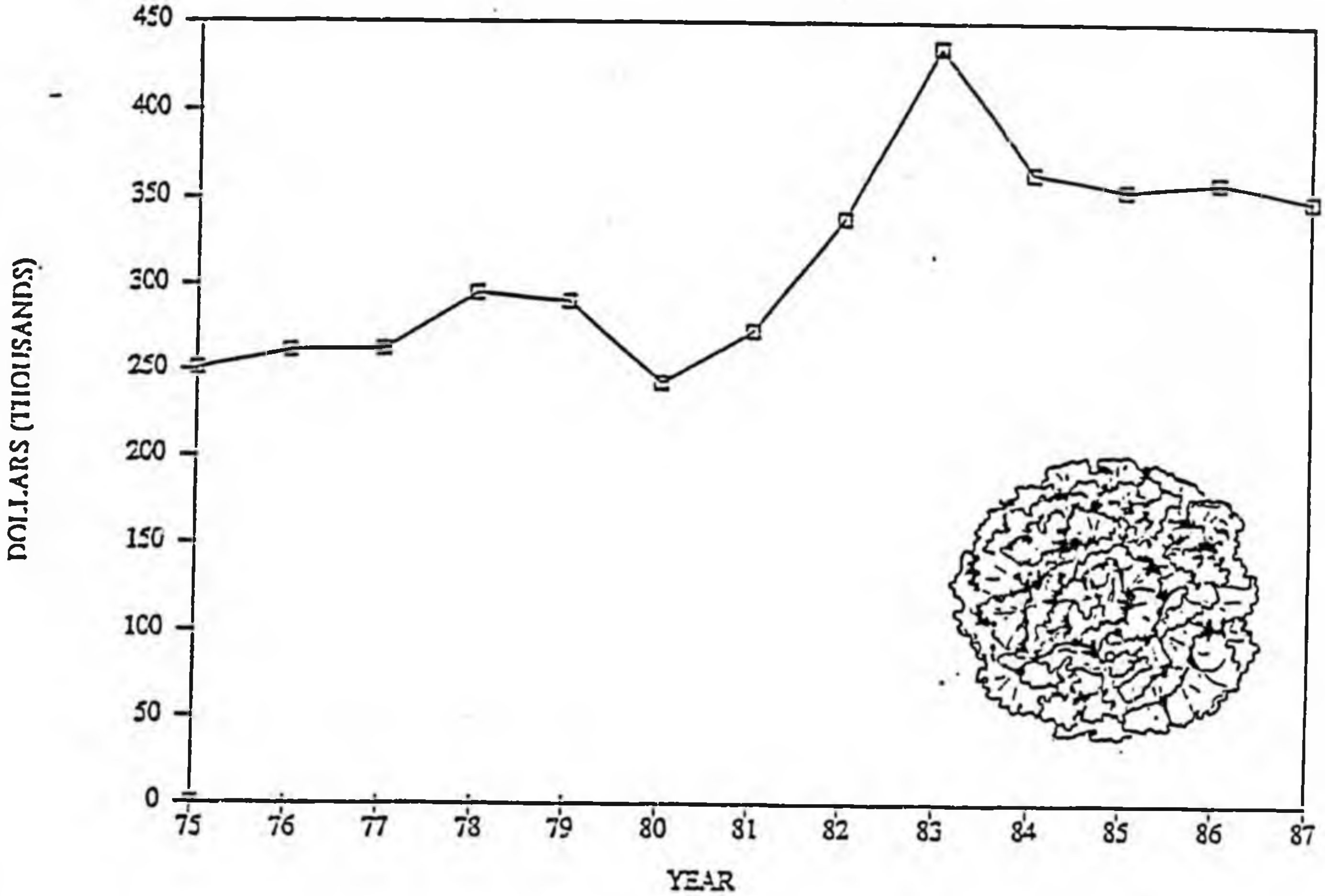
QUANTITY OF BARLEY IN ALASKA



* Alaska farmers produced 11,364,00 pounds of barley in 1988.

* The last two years have seen a reversal in the decline of barley production in Alaska. A gradual upward trend has been initiated.

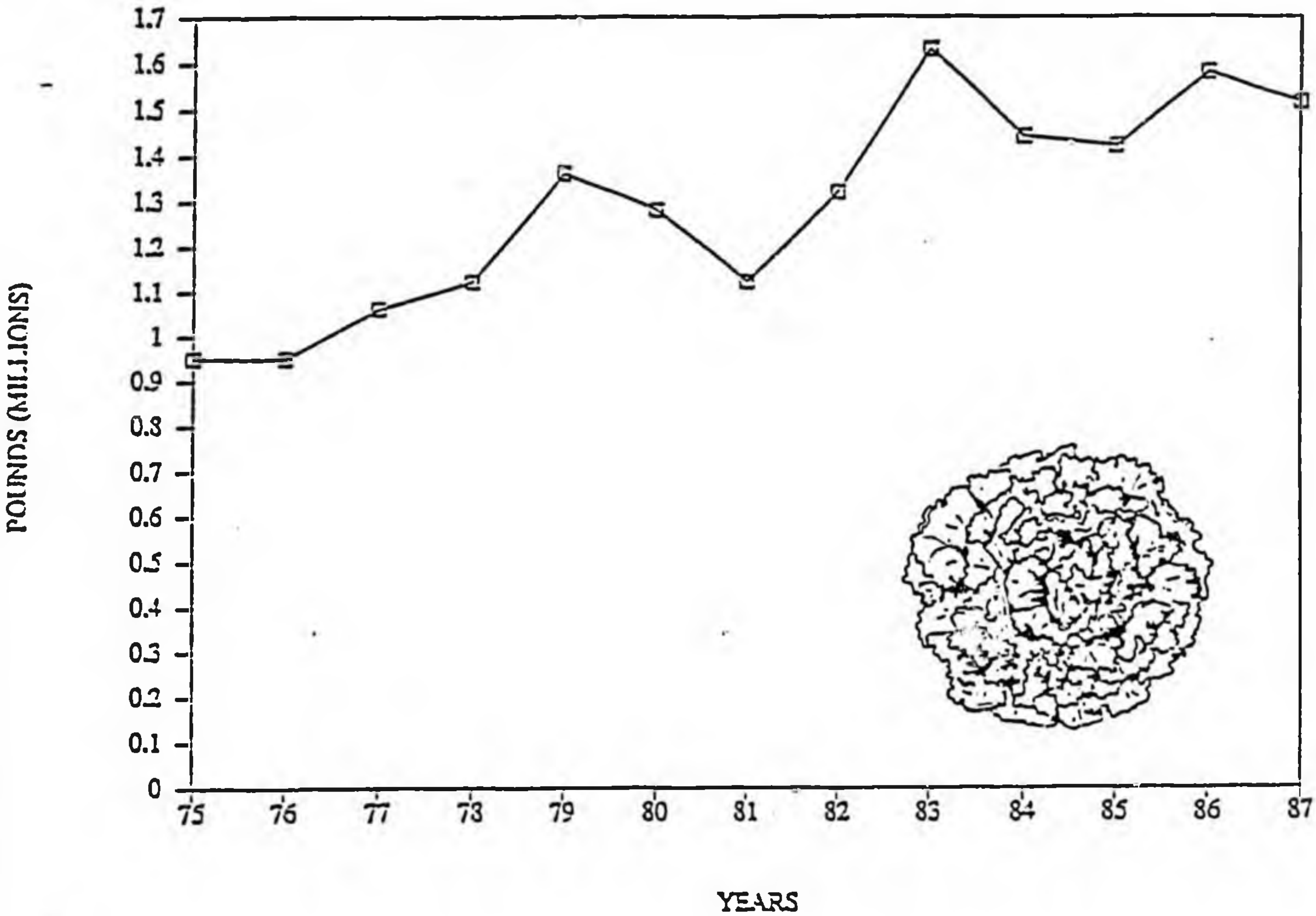
VALUE OF LETTUCE



* The value of lettuce in Alaska grown by Alaska farmers totaled $350,000 in 1987(latest available figura).

* Lettuce production remains a stable and significant part of Alaska's agricultural industry.

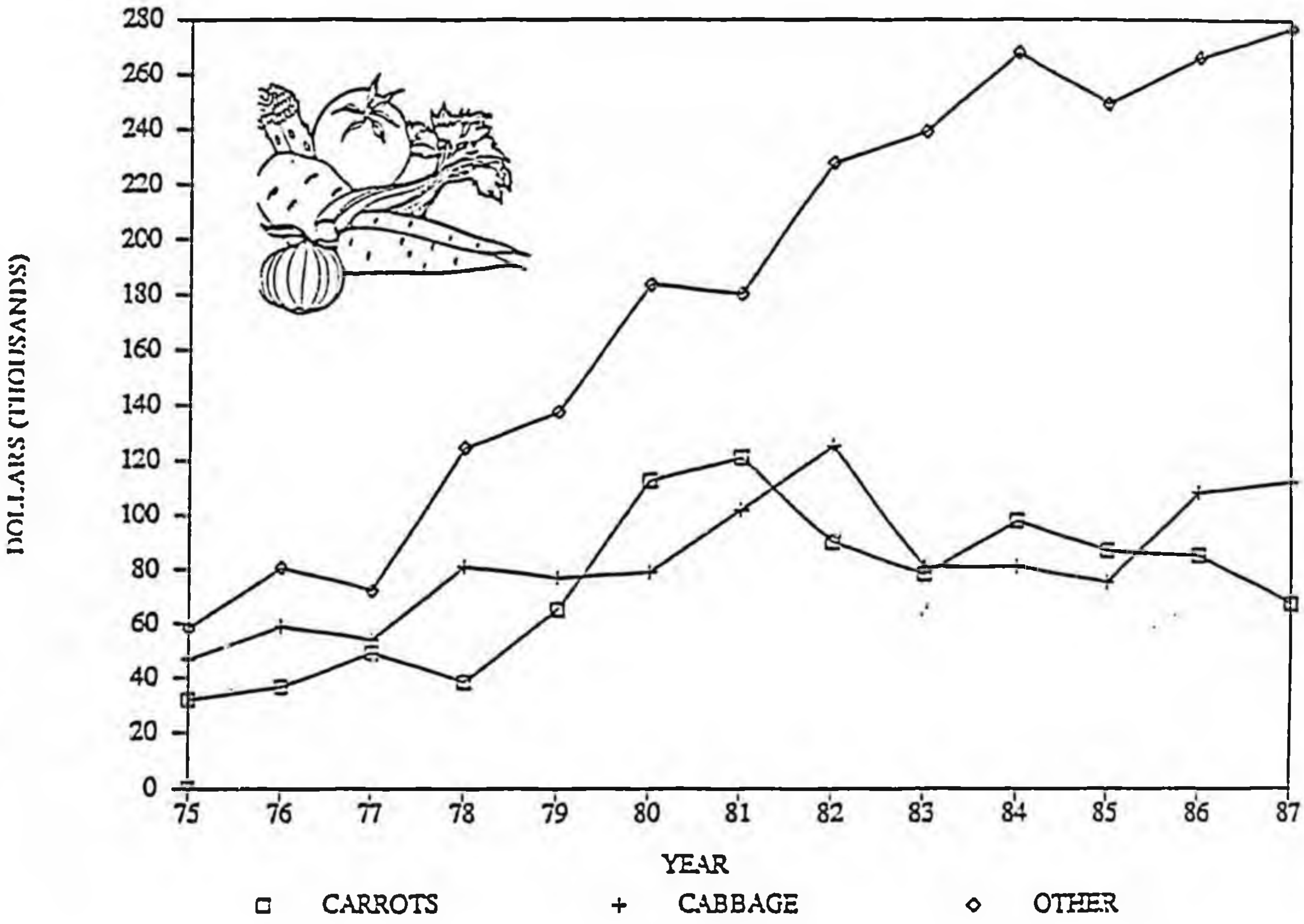
QUANTITY OF LETTUCE IN ALASKA



* Lettuce production totaled 1,516,000 pounds in Alaska in 1987(latest available figure).

* Lettuce production has shown substantial growth during the period 1975-1987.

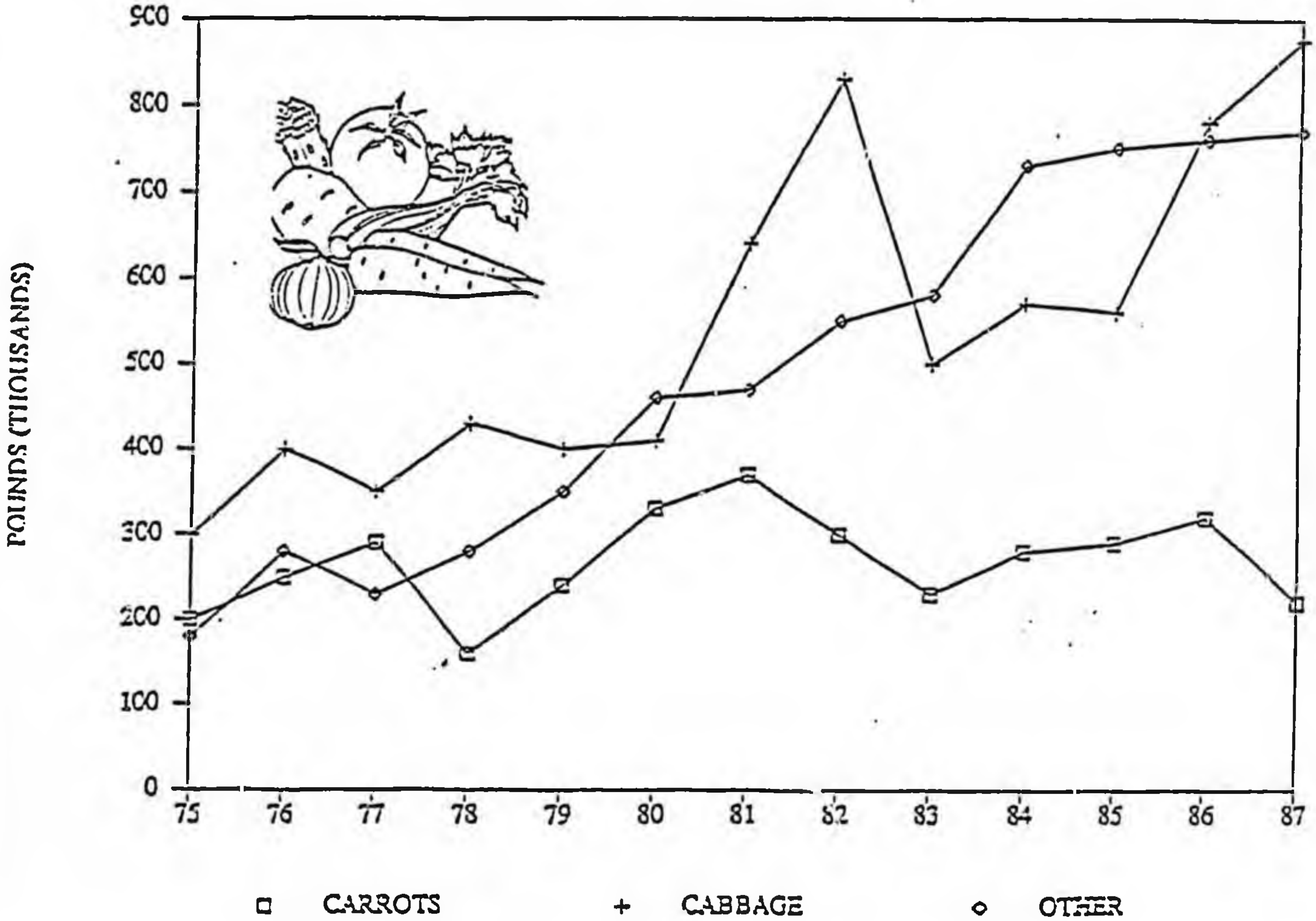
VALUE OF OTHER VEGETABLES



* In 1987 (latest available figures), the production of carrots had a total value of $67,000, cabbage production had a value of $112,000, and the production of other vegetables had a value of $277,000.

* The value of carrot and cabbage production has moved slowly upward since 1975, while the value of other vegetables rose dramatically.

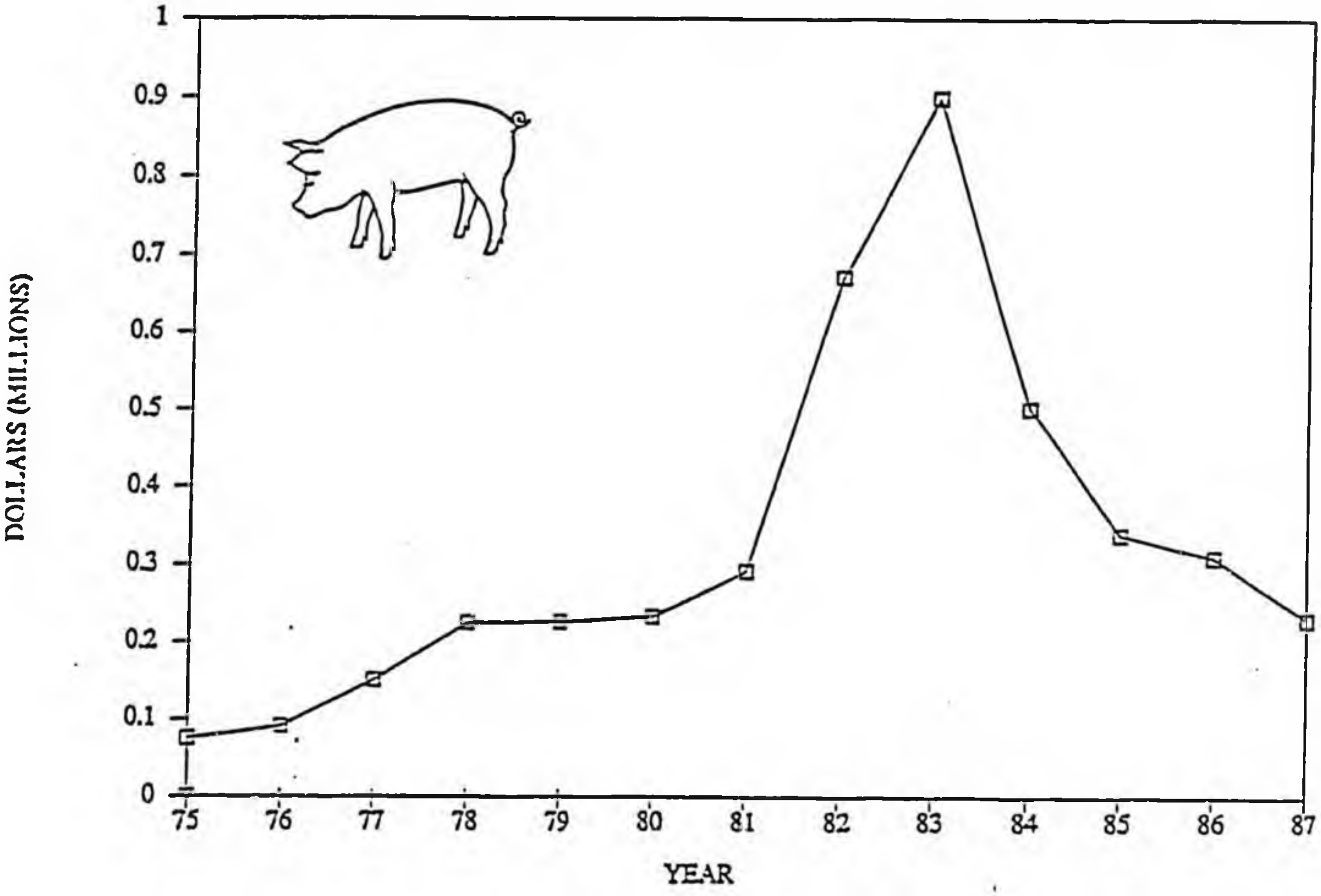
QUANTITY OF OTHER VEGETABLES IN ALASKA



* In 1987(latest available figures), carrot production totaled 220,000 pounds, cabbage production totaled 875,000 pounds, and the production of other vegetables totaled 770,000 pounds.

* During the period 1975-1987, carrot production has remained relatively constant while the production of cabbage and other vegetables has been increasing.

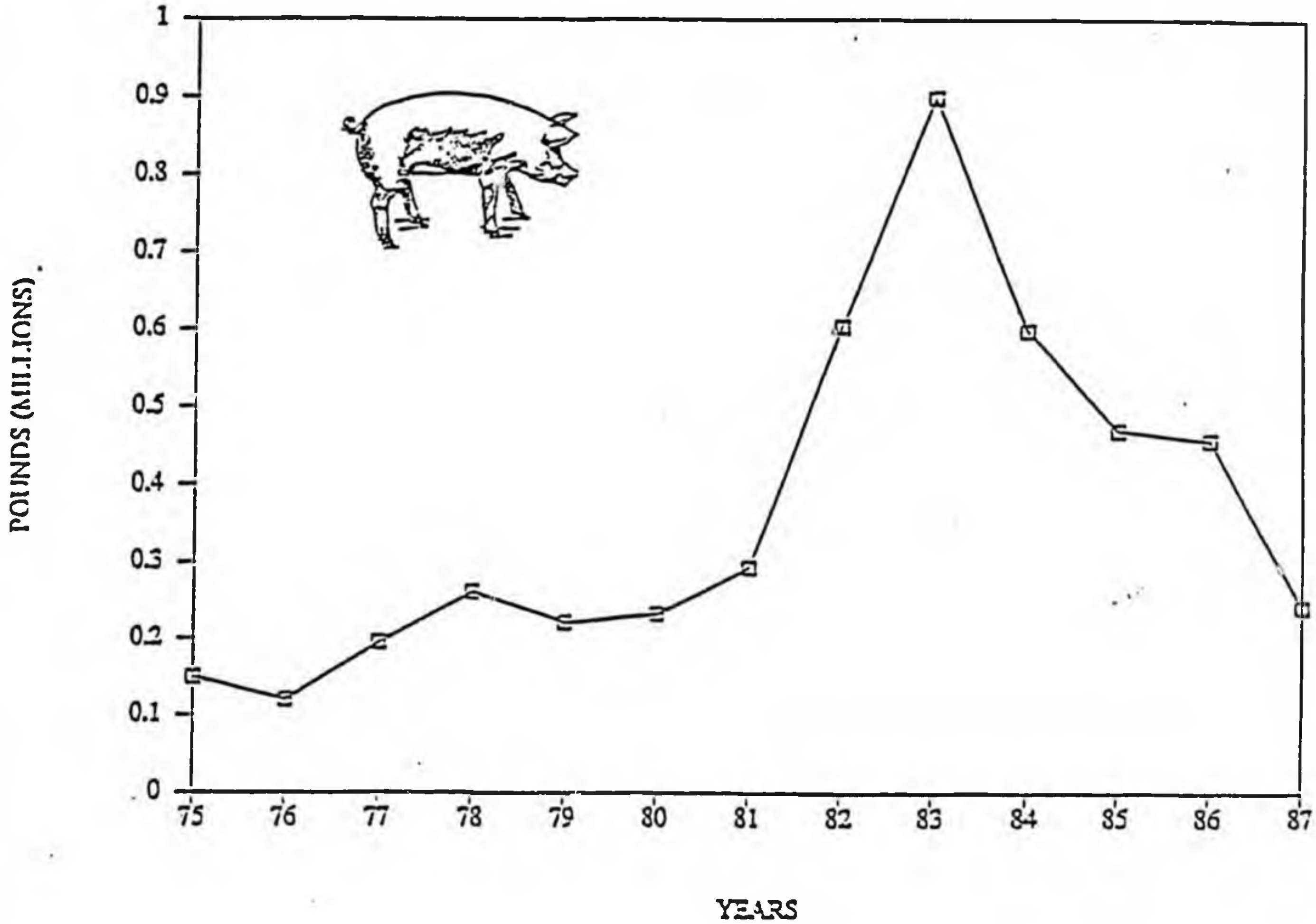
VALUE OF PORK



* The value of pork production totaled $230,000 in 1987(latest available figure).

* While the value of pork production has fallen steadily since 1983, increased future production and value are likely because of an available market at the Palmer meat plant.

QUANTITY OF PORK IN ALASKA



* The production of pork in Alaska in 1987(latest available figure) totaled 240,000 pounds

* The production of pork is feasible in Alaska and a rebound in production is anticipated in coming years.

Working Together:

- Conservation Districts
- The Soil Conservation Service
- State Soil Conservation Agencies
- State Associations of Districts
- National Association of Conservation Districts

The National Association
of Conservation Districts
and
USDA Soil Conservation Service

WORKING TOGETHER

... is the only way conservation and resource development can insure the continued well-being of America's resources and people.

A close partnership between district officials and the Soil Conservation Service staff assigned to the district is vital. Each needs to fully understand the policies, procedures, goals, and priorities of the other.

They need to have common understanding of the role and duties of any district- and SCS-employed staff.

They need to keep each other informed and up-to-date through constant and timely communication
... a two-way flow of ideas and assistance.

On the State level, both State Soil Conservation Agencies and State Associations of Conservation Districts assist conservation districts in achieving their goals. Nationally, the National Association of Conservation Districts represents conservation districts and their state associations.

This booklet describes these members of the conservation team. It discusses their mutual aims and gives some hints for working together smoothly in a way that gets best results.

SHARED OBJECTIVES

Conservation districts and the SCS believe that effective soil and water conservation:

* Is urgent, and will become even more urgent as population pressures on the land increase.

* Should begin with and be led by people in their own communities in cooperation with their neighbors.

* Is defined in state and federal policy to be in the public interest. Districts have a responsibility to implement that policy.

* Combines goals of the land user with scientific use and treatment of land according to its potential and needs.

* Is an important early step in achieving local and national water quality goals.

* Takes into account all renewable natural resources and their multiple use to provide benefits to the environment, economy, and social well-being of people.

* Is a job that neither districts nor SCS can do alone!

CONSERVATION DISTRICTS

Conservation districts are local units of government organized under state law. The arrangement varies among states:

* Most are subdivisions of state government. Some follow county borders, some cover parts of counties or two or more whole counties.

What districts are called varies, as does the title of their elected or appointed officials. Their responsibilities or authorities vary somewhat. Basically, districts provide information to land users and units of government to encourage sound resource management decisions.

In their work, districts call on many other state and federal agencies, organizations, and individuals. Some employ their own staff to supplement assistance provided by SCS and other agencies. They also have organized into associations for action on mutual issues and activities on an area, state, regional, and national basis.

District responsibilities include:

* Furnishing effective local leadership.
* Developing a long-range program that recognizes conservation needs, interests of district citizens and sets conservation work priorities in the district.
* Developing an annual work plan which enlists assistance from other agencies in accomplishing its goals.
* Informing the public of resource conservation needs and achievements.
* Coordinating conservation and resource development programs in the district.
* Cooperating with other districts in comprehensive planning and resource development activities.
* Managing the business affairs of the district.

STATE SOIL CONSERVATION AGENCIES

An important member of the conservation team, state soil conservation agencies are charged by state law to assist conservation districts by:

* Providing funds for district activities and staff.

* Administering state laws, regulations, and procedures and seeing that districts operate in accordance with the law.

* Serving as a central contact for the district with other state agencies.

* Providing direct, specialized technical assistance of various kinds to the district.

* Conducting training programs and providing materials to keep district officials informed.

* Helping the interchange and coordination of program ideas among districts.

* Representing state government in matters affecting soil conservation programs.

Names of the state conservation agencies vary (committee, board, commission, division, or department). Some of their members usually are conservation district officials.

STATE ASSOCIATION OF DISTRICTS

Conservation districts in each state have organized a statewide group primarily to serve as a vehicle for unified action by districts, exchange of information, and discussion of issues. The state association speaks for the districts within the state on legislative and other matters of concern to districts.

The state association usually has active committees or study groups on major conservation issues. It holds a yearly conference, and many states hold area or regional meetings as well. It helps individual districts organize area-wide units where common geographical or social conditions exist.

Many state associations conduct education and information programs to encourage proper land use and conservation of resources. Land judging, essay, and poster contests and publication of newsletters and other materials are examples of such activities.

The state association represents districts in the state through its membership on the Council of the national association.

NATIONAL ASSOCIATION OF CONSERVATION DISTRICTS

The National Association of Conservation Districts (NACD) is a voluntary, non-governmental, nonprofit association controlled by its member districts through their state associations. It is financed mainly by voluntary member contributions on the basis of annual quotas. Business firms and individuals also support NACD as non-voting or associate members.

In addition to servicing districts and representing them before Congress and with federal agencies and national groups, NACD holds national and regional conventions each year to discuss major issues and adopt national policies. Among other programs, NACD leads in organizing the Conservation Tillage Information Center; sponsors Soil Stewardship Week, a national program carried out through the churches for recommitment to the conservation ethic; and publishes a weekly newsletter and a variety of education and information materials.

Officers are a President, Vice President, Secretary-Treasurer, Executive Vice President, and General Counsel. A staff, headed by the Executive Vice President, maintains seven offices throughout the country -- including a major library, and a Service Department, which provides publishing services to the districts and NACD.

The Conservation Districts Foundation, Inc., is the educational arm of NACD. The Foundation operates the Davis Conservation Library and the Environmental Film Service as well as publishing and distributing the annual District Planning Workbook and responding to requests for free material from teachers and students.

SOIL CONSERVATION SERVICE

An agency of the U.S. Department of Agriculture (USDA), the Soil Conservation Service (SCS) is the principal source of federal assistance to districts. It is mainly through conservation districts that SCS aids individuals, groups, and units of government in natural resource conservation.

SCS has leadership within USDA for a number of major national programs to gather resource facts, interpret them, and aid local communities.

The first line of contact between SCS and districts is the district conservationist, an SCS employee assigned to provide technical aid to the district and its cooperating landowners. The district conservationist aids the district in working toward goals outlined in the district's long-range plan. In many states, area conservationists provide technical and administrative support to the district conservationist.

Overall direction to SCS programs in each state is given by the state conservationist and his staff. SCS responsibilities include:

- Furnishing technical assistance to the district.
- Providing basic resource data for district planning.
- Assisting districts in long-range and annual planning.
- Developing an annual plan of operations based on the district annual work plan and other national or state priorities.
- Keeping the district informed about SCS work and developments affecting district programs.
- Cooperating with other resource agencies assisting the district.

WORKING TOGETHER -- THE PARTNERSHIP

A conservation district signs a memorandum of understanding with the U.S. Department of Agriculture. Assistance from SCS is furnished under a supplemental memorandum with the district.

These memoranda of understanding identify areas of responsibility of the district and SCS as well as various federal and state laws, USDA regulations and policies established by the State Conservation Agency.

For a most effective working relationship, the SCS representative and the district governing body should be equally and thoroughly familiar with each other's responsibilities and the applicable agreements, laws and regulations.

WORKING TOGETHER

. . . depends on full agreement among all team members on what they want to achieve and how they should go about it. On an annual basis, district leaders and the SCS district conservationist should:

* Review the basic memorandum of understanding between the district and USDA, the supplemental agreement with SCS and any other agreements the district may have entered.

* Review the long-range plan on which the memoranda are based. Change it as needed to reflect current conservation problems and goals.

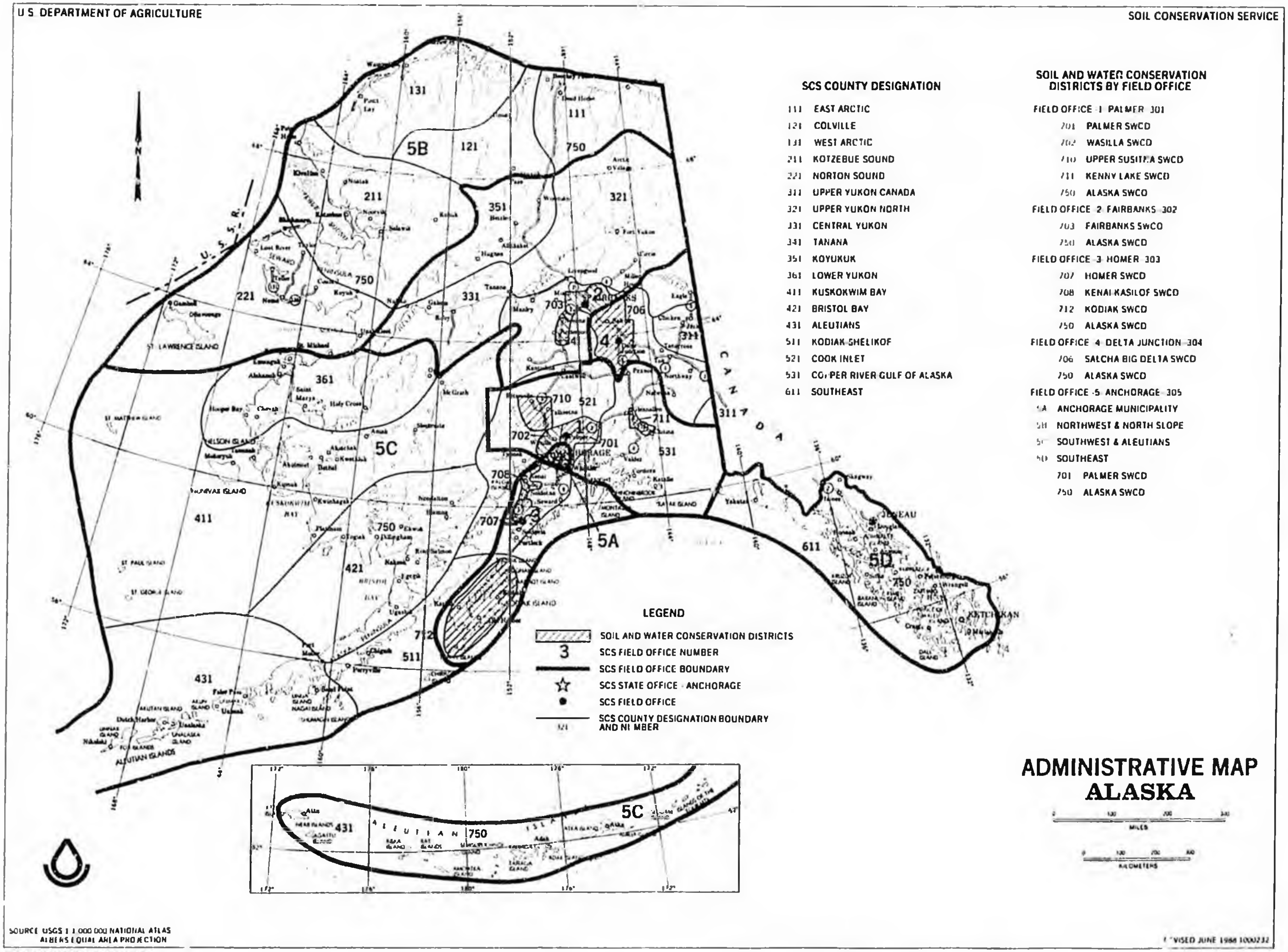
* Cooperate in shaping the district's long-range program and annual work plan so SCS assistance can be allocated.

* Meet together and with other cooperating agencies to review requests for assistance and consider opportunities for starting or expanding programs.

On a more frequent basis, district leaders and the SCS district conservationist should:

* Review current resource problems, set priorities and consider solutions.

* Develop district meeting agenda to focus on immediate conservation needs.



U.S. DEPARTMENT OF AGRICULTURE
SOIL CONSERVATION SERVICE
SCS COUNTY DESIGNATION
111 EAST ARCTIC
121 COLVILLE
131 WEST ARCTIC
211 KOTZEBUE SOUND
221 NORTON SOUND
311 UPPER YUKON CANADA
321 UPPER YUKON NORTH
331 CENTRAL YUKON
341 TANANA
351 KOYUKUK
361 LOWER YUKON
411 KUSKOKWIM BAY
421 BRISTOL BAY
431 ALEUTIANS
511 KODIAK-SHELIKOF
521 COOK INLET
531 COPPER RIVER GULF OF ALASKA
611 SOUTHEAST
SOIL AND WATER CONSERVATION DISTRICTS BY FIELD OFFICE
FIELD OFFICE 1 PALMER 301
701 PALMER SWCD
702 WASILLA SWCD
710 UPPER SUSITNA SWCD
711 KENNY LAKE SWCD
750 ALASKA SWCD
FIELD OFFICE 2 FAIRBANKS 302
703 FAIRBANKS SWCD
750 ALASKA SWCD
FIELD OFFICE 3 HOMER 303
707 HOMER SWCD
708 KENAI-KASILOF SWCD
712 KODIAK SWCD
750 ALASKA SWCD
FIELD OFFICE 4 DELTA JUNCTION 304
706 SALCHA BIG DELTA SWCD
750 ALASKA SWCD
FIELD OFFICE 5 ANCHORAGE 305
5A ANCHORAGE MUNICIPALITY
5B NORTHWEST & NORTH SLOPE
5C SOUTHWEST & ALEUTIANS
5D SOUTHEAST
701 PALMER SWCD
750 ALASKA SWCD
LEGEND
SOIL AND WATER CONSERVATION DISTRICTS
SCS FIELD OFFICE NUMBER
SCS FIELD OFFICE BOUNDARY
SCS STATE OFFICE - ANCHORAGE
SCS FIELD OFFICE
SCS COUNTY DESIGNATION BOUNDARY AND NUMBER
U.S.S.R.
CANADA
ALEUTIAN ISLANDS
ADMINISTRATIVE MAP
ALASKA
MILES
KILOMETERS
SOURCE USGS 1:1,000,000 NATIONAL ATLAS
ALBERS EQUAL AREA PROJECTION
REVISED JUNE 1988 1000232

ALASKA SOIL AND WATER CONSERVATION DISTRICTS

The soil and water conservation districts in Alaska receive funding for conservation projects from a wide variety of state and federal sources. As authorized by state statute, soil and water conservation districts may enter into agreements and accept contributions in money, services, materials, or equipment from federal, state, or any other source. The following is a list of funds used for projects in Alaska which have been made available through the conservation districts.

Source of Funding	District	Purpose	Amount
*US Soil Conservation Service	All	Soil surveys Conservation plans	$1,900,000
*Agricultural Stabilization & Conservation Service	Delta, Wasilla, Palmer, Fairbanks SWCDs	Farmland coservation	644,200
*US Navy	Alaska District	Soils & range survey	75,000
US Fish & Wildlife Service	Alaska District	Soils & range survey	15,000
Bureau of Indian Affairs	Alaska District	Range survey	25,000
*National Park Service	All	Snow surveys	50,000
US Forest Service	Upper Susitna SWCD	Forestry inventory	20,000
*US Army	Palmer SWCD	Erosion control	16,000
Environmental Protection	Salcha/Big Delta SWCD	Hydrologic study/ Agency water erosion	47,000
EPA (These funds are available for 1989).	All	Non-point source water pollution inventory	95,000

*In 1988, the Alaska Soil & Water Conservation District program brought a total of $2,685,200 to the state.

HOMER SOIL & WATER CONSERVATION DISTRICT 10/88 page 1

Dennis Abrahamson	SR Box 979	Anchor Point, AK	99556
William Alred	SR A Box 40	Homer, AK	99603
Elton Anderson	Box 441	Homer, AK	99603
Randell Anderson	Box 1222	Soldotna, AK	99669
Don Bailey	Box 79	Anchor Point, AK	99556
Daniel Barber	SR Box 25	Anchor Point, AK	99556
Vasily Basargin	Box 2325	Homer, AK	99603
Joe & Lynn Bennett	Box 911	Homer, AK	99603
John Bittner	Box 730	Homer, AK	99603
Kenton Bloon	Box 1141	Homer, AK	99603
Floyd Blossom	Box 3	Ninilchik, AK	99639
Fred Boden	SR Box 923	Anchor Point, AK	99556
Michael Bostwick	Box 39431	Ninilchik,AK	99639
William Brody	Box 12	Ninilchik, AK	99639
Craig Burns	Box 1187	Homer, AK	99603
James Calkin	Box 1108	Homer, AK	99603
Reuben Call	Box 521	Homer, AK	99603
Michael Campbell	Box 852	Homer, AK	99603
Spike Christopher	SR A Box 58	Homer, AK	99603
John Clabo	Box 12	Anchor Point, AK	99556
Michael Cline	SR A Box 29D	Homer, AK	99603
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Gregg Demers	Box 2612	Homer, AK	99603
Brantly Edens	Box 602	Homer, AK	99603
Dr M H Fritz	Box 158	Anchor Point, AK	99556
David Garcia	Box 1481	Homer, AK	99603
Steve Gibson	SR A Box 50D	Homer, AK	99603
Robert Gillas	SR A Box 44	Homer, AK	99603
M F Harper	3103 Dawson	Anchorage, AK	99501
City of Homer		Homer, AK	99603

Election District 5 A-B

Kenai-Kasilof Soil & Water Cons. District
Homer Soil & Water Cons. District

119 Cooperators

1aHomer High School	11SR A Box 50	12Homer, AK	99603 3
1bRobert James	11SR A	12Homer, AK	99603 3
1cKenny Jandt	11Box 2234	12Homer, AK	99603 3
1dDan Jerrel	11Box 938	12Homer, AK	99603 3
1eM Walter Johnson	11521 G St	12Anchorage, AK	99501 3
1fCecil Jones	11SR A Box 49A	12Homer, AK	99603 3
1gCharles L Jones	11SR Box 980	12Anchor Point, AK	99556 3
1hTroy Jones	11SR A Box 49 AA	12Homer, AK	99603 3
1iW S Jones	11SR A Box 49	12Homer, AK	99603 3
1jSelo Kachemak	11Boc 1618	12Homer, AK	99603 3
1kEdwin Otto Kilcher	11Box 353	12Homer, AK	99603 3
1lYule Kilcher	11Box 353	12Homer, AK	99603 3
1mNeil Kinney	11SR Box 900	12Anchor Point, AK	99556 3
1nRobert Klein	11SR A Box 29 C	12Homer, AK	99603 3
1oSteve Koskella	11SR Box 908	12Anchor Point, AK	99556 3
1pKathryn Leis	11Box 923	12Homer, AK	99603 3
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1rJohn Lindeman	11Box 85	12Ninilchik	99639 3
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1tDarol & Mildred Martin	11Box 2652	12Homer, AK	99603 3
1uFrank Matushev	11Box 1765	12Homer, AK	99603 3
1vArthur Dee Miller	11Box 762	12Homer, AK	99603 3
1 Deborah Noerr	11Box 1871	12Homer, AK	99603 3
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1eChris Rainwater	147010 Kunz Rd	12Homer, AK	99603 3
1fRonald J Records	11Mile 145	12Anchor Point, AK	99556 3
1gLeo & Deborah Renault	11Box 2873	12Kenai, AK	99611 3

Homer 10/88 page 3

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Peter Roberts	Box 1134	Homer, AK	99603
Paul Roderick	Box 836	Homer, AK	99603
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Lloyd Schade	SR A Box 48	Homer, AK	99603
Richard Schollenberg	Box 22	Anchor Point, AK	99556
David Schroer	SR A Box 31 F	Homer, AK	99603
Stephen Shapiro	SR A Box 52 B	Homer, AK	99603
Tom Simmons	Box 61	Anchor Point, AK	99556
Bill & Terry Smith	Box 848	Homer, AK	99603
John A Stefun	Box 399	Homer, AK	99603
Lloyd & Jean Strutz	Box 1143	Homer, AK	99603
Emmitt & Mary Trimble	Box 193	Anchor Point, AK	99556
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Glenn Veater	SR Box 128	Anchor Point, AK	99556
Dennis & Susan Wade	SR A Box 49 H	Homer, AK	99603
Bruce Willard	SR A Box 28	Homer, AK	99603
Virginia Wilson	Box 224	Anchor Point, AK	99556
Pat Yourcowski	Box 2136	Homer, AK	99603

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Charles Carney	HC33 Box 3054	Wasilla, AK 99687
Pat Carney	PO Box 871746	Wasilla, AK 99687
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LeRoi Heaven	HC31 Box 5113	Wasilla, AK 99687

Election District 16 A-B

Palmer Soil and Water Cons. District
Wasilla Soil and Water Cons. District
Upper Susitna Soil & Water Cons. Dist.

284 Cooperators

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U of A Exper. Station	PO Box AE	Palmer, AK 99645
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Ellis J White	HC30 Box 5406	Wasilla, AK 99687
Robert A Williams	HC02 Box 7298	Palmer, AK 99645
Tom Williams	PO Drawer 1145	Eagle River, AK 99577

3 Wasilla SWCD 10/88 page

1aJoe Wilson	11PO Box 875109	12Wasilla, AK 99687 3
1bDianna & Jeff Wiseman	11PO Box 91	12Delta Jct, AK 99737 3
1cDiane Woelfel	11HC07 Box 3455	12Wasilla, AK 99687 3
1dMalcolm Wolf	11PO Box 875652	12Wasilla, AK 99687 3
1eSande Wright	11PO Box 874508	12Wasilla, AK 99687 3
1fTraci Wright	11HC02 7470	12Palmer, AK 99645 3
1gWright, Walsh & Smith	11PO B 874508	12Wasilla, AK 99687 3
1hWm Yaskolski	11PO Box 870322	12Wasilla, AK 99687 3
1iRichard Zobel	11PO Box 872288	12Wasilla AK 99687 3

KENNY LAKE SOIL CONSERVATION SUBDISTRICT 10/88

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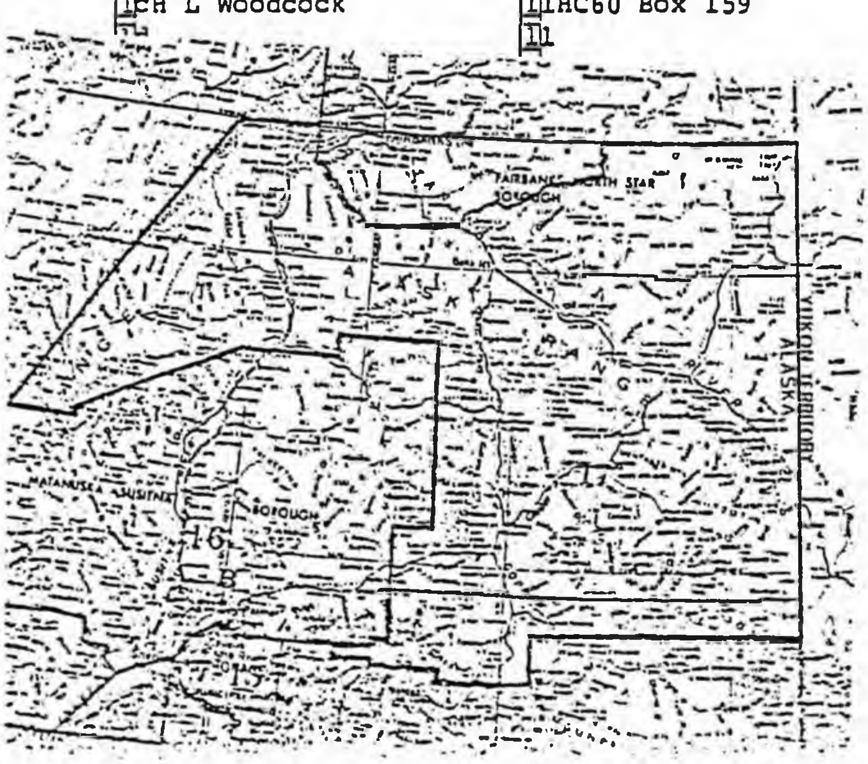
Daniel E Allen	HC60 Box 345	Copper Center, AK 99573
Charles Benjamin	HC60 Box 228	Copper Center, AK 99573
Bruce Cain	1565 Alder Dr	Anchorage, AK 99501
Ed Carns	HC 60 Box 252	Copper Center, AK 99573
Chugach Alaska Corp	3000 A St	Anchorage, AK 99503
Church at SAPA	HC60 Box 289	Copper Center, AK 99573
Calvin Datta	HC60 Box 245	Copper Center, AK 99573
Bill Etchells	HC60 Box 244	Copper Center, AK 99573
Ed Gerrue	HC60 Box 337	Copper Center, AK 99573
Terry Gilmore	HC60 Box 216	Copper Center, AK 99573
Bruce Gordon	HC60 Box 214	Copper Center, AK 99573
Ken Hoisington	HC60 Box 279	Copper Center, AK 99573
Dan Hovermalen	HC60 299C	Copper Center, AK 99573
Victor Kennedy	HC60 Box 308	Copper Center, AK 99573
Kenny Lake School		Copper Center, AK 99573
Frances Kibble	HC60 Box 286	Copper Center, AK 99573
Sam Lightwood	HC60 Box 229	Copper Center, AK 99573
Jerome Luebke	Box 64	Glennallen, AK 99588
Keith Murray	HC60 Box 217	Copper Center, AK 99573
Eric Nashlund	HC60 Box 271	Copper Center, AK 99573
Alfred Roig	HC60 Box 274	Copper Center, AK 99573
Eugene Shorten	HC60 Box 20	Copper Center, AK 99573
Kathy Sloboda	HC60 Box 262	Copper Center, AK 99573
David Stone	PO Box 248	Nenana, Alaksa 99760
Bill Sutton	HC60 Box 298	Copper Center, AK 99573
Keith Swisher	HC60 Box 341	Copper Center, AK 99573
Mike Swisher	HC60 Box 339	Copper Center, AK 99573
Wm H Weaver	HC60 Box 309	Copper Center, AK 99573
Dave Wellman	HC60 Box 227	Copper Center, AK 99573
Billy J Williams	HC60 Box 100	Copper Center, AK 99573
Dean Wilson	HC60 Box 288	Copper Center, AK 99573
H L Woodcock	HC60 Box 159	Copper Center, AK 99573



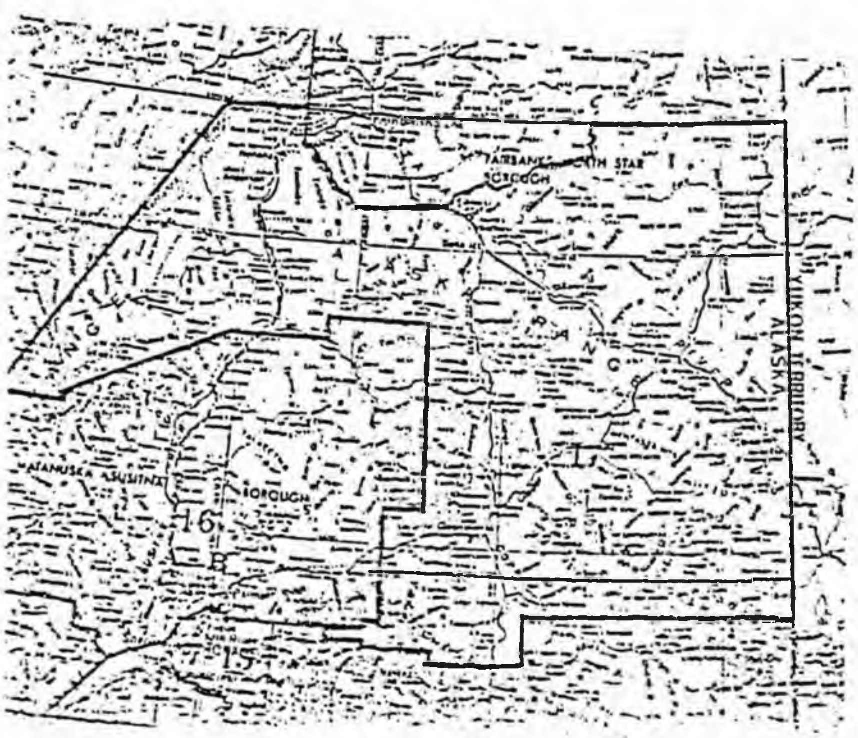
Election District 17

Salcha-Big Delta Soil & Water Conservation District
Kenny Lake Soil & Water Conservation District

298 Cooperators

3 DELTA SOIL & WATER CONSERVATION DISTRICT 10/27

1aDorothy Agen	11PO Box 871370	12Delta Junction, Ak 99737 3
1bRichard Anderson	11PO Box 806	12Delta Junction, Ak 99737 3
1cAgie Arnold	11Mi 237	12Delta Junction, AK 99737 3
1dWilliam Arpino	11PO Box 111	12Tok, AK, 99780 3
1eRobert Atkinson	11SR Box 18	12Seward, AK 99664 3
1fJacob Baart	11Mi 39 Richardson Hwy	12Fairbanks, AK 99701 3
1gJoseph Balch	117665 Salcha Rd	12Salcha, Ak 99714 3
1hRichard Brunk	11SR 90336	12Fairbanks, AK 99701 3
1iAl Bannon	11Box 652	12Delta Junction, Ak 99737 3
1jBruce Barton	11Box 385	12Delta Junction, Ak 99737 3
1kMike Bear	11Box 1226	12Delta Junction, Ak 99737 3
1lLeo Bednarik	11PO Box 1087	12Delta Junction, Ak 99737 3
1mJoe Belegrin	11SR 50717	12Delta Junction, Ak 99737 3
1nJohn Benson	114329 Jack Waren Rd	12Delta Junction, Ak 99737 3
1oJon Bernard	11Box 83446	12Fairbanks, Ak 99737 3
1pCheryl Bobo	11Mi 14.2	12Delta Junction, Ak 99737 3
1qJerry Boehlke	116800 Canady	12North Pole, Ak 99705 3
1rFrank Borman	118502 Peck Ave	12Anchorage, Ak 99504 3
1sChristopher Bran	11Box 298	12Delta Junction, Ak 99737 3
1tLyall Brasier	11Box 483	12Delta Junction, Ak 99737 3
1uGerald Brehmer	11Mi 1403	12Delta Junction, Ak 99737 3
1vJohn Bridgers	11Box 433	12Tok, Ak 99780 3
1wDebra Brown	114154 Lancaster Ave	12Newburghy, NY 12550 3
1xRichard Anderson	11PO Box 806	12Delta Junction, Ak 99737 3
1yRobert Brown	11PO Box 1065	12Delta Junction, Ak 99737 3
1zVictor Brown	11Mi 1403.5 Alaska Hwy	12Delta Junction, Ak 99737 3
1aRichard Brunk	11SR 90336	12Fairbanks, Ak 99701 3
1bFrank Buck	1110419 Crosby Rd NE	12Woodborn, OR 99071 3



Election District 17

Salcha-Big Delta Soil & Water Conservation District
Kenny Lake Soil & Water Conservation District

298 Cooperators

3 Delta 10,'88

1	Don	Bunsellmeir	Box 465	Delta Junction, AK 99737	4
1	David	Burchom	Box 441	Delta Junction, AK 99737	4
1	Robert	Buzby	SR 90678	Fairbanks, AK 99701	4
1	Dennis	Buzby	SR 90678	Fairbanks, AK 99701	4
1	Lyle	Carlson	Box 2741	Fairbanks AK 99707	4
1	Charles	Carlson	Box 953	Delta Junction, AK 99737	4
1	Mark	Carpenter	Box 765	Delta Junction, AK 99737	4
1	Wayne	Carpenter	Box 416	Delta Junction, AK 99737	4
1	Ken	Cassity	4341 MacAlister Dr.	Anchorage, AK 99515	4
1	Lynn	Castle	Box 1616	Fairbanks, AK 99707	4
1	James	Cavanaugh	4823 Daniece St.	North Pole, AK 99705	4
1	Elaine	Cederberg	2730 East 50th Ave	Anchorage AK 99504	4
1	Cathy	Christman	5159 Sundown Trail	Salcha, AK 99714	4
1	Peter	Chytil	Box 208	Delta Junction, AK 99737	4
1	Patrick	Clemans	1243 Crescent Ave	Anchorage, AK 99508	4
1	Nick	Columbo	Box 966	Delta Junction, AK 99737	4
1	Terry	Conkel	Box 1629	Delta Junction, AK 99737	4
1	Norman	Cosgrove	Box 861	Delta Junction, AK 99737	4
1	Randy	Davenport	2074 Davenport Rd, Box 627	Delta Junction, AK 99737	4
1	Claudia	Delaughter	SR 90513	Fairbanks AK 99701	4
1		Delta FFA	Pouch 1	Delta Junction, AK 99737	4
1	Michael	Demarco	SR Box 90508	Fairbanks, AK 99701	4
1	Jack	Detzel	Box 278	Delta Junction, AK 99737	4
1	Tim	Dietzler	Box 1111	Delta Junction, AK 99737	4
1	Sam	Dighton	Box 121	Delta Junction, AK 99737	4
1	Joe	Ditchen	Box 1097	Delta Junction, AK 99737	4
1	Elden	Ditchen	Box 1097	Delta Junction, AK 99737	4
1	Carl	Ditchen	Box 1097	Delta Junction, AK 99737	4
1	Larry	Dorshorst	Box 289	Delta Junction, AK 99737	4
1	Jerry	Dowling	Box 125	Delta Junction, AK 99737	4
1	Mike	Dress	Box 14007	Salcha, AK 99714	4
1	Henry	Dube	Box 109	Delta Junction, AK 99737	4
1	Edwin	Eddy	SR 90679	Fairbanks, AK 99701	4

3 Delta 10/88

1	David	Edwards	Box 5283	North Pole, AK 99705	4
1	Pam	Ellis	Box 1260	Delta Junction, AK 99737	4
1	John	Emery	605 23rd St.	Fairbanks, AK 99701	4
1	Ed	Enderic.	Mi 41 Richardson Hwy	Fairbanks, AK 99701	4
1	Ken	Engellant	Box 314	Geraldine, MT 59446	4
1	Robert	Erickson	Box 1196	Delta Junction, AK 99737	4
1	Stanley	Evans	1168 Hayes	Fairbanks, AK 99701	4
1	Dorothy	Evans	Box 1105	Delta Junction, AK 99737	4
1	Phil	Faulkner	2603 Jefferson	North Pole, AK 99705	4
1	Larry	Fett	Box 881	Delta Junction, AK 99737	4
1	Lee	Fett	Box 881	Delta Junction, AK 99737	4
1	Tom	Fett	Box 881	Delta Junction, AK 99737	4
1	Larry	Field	1607 Kennedy	Fairbanks, AK 99701	4
1	Jerry	Flodin	4000 Marian Luther	Fairbanks, AK 99701	4
1	Charles	Forck	Box 929	Delta Junction, AK 99737	4
1	David	Fortune	Box 1093	Delta Junction AK 99737	4
1	Lee	Foster	Box 671	Delta Junction, AK 99737	4
1	Sheila	Frost	Box 509C, Route 6	Mt. Home, AK 72653	4
1	Doug	Fulton	7409 Spruce Rd, #1	Anchorage, AK 99507	4
1	Wayne	Gentz	3330 Holden Rd	Fairbanks, AK 99709	4
1	Greg	Gerhart	Box 287	Delta Junction, AK 99737	4
1	Robert	Giese	Box 209	Delta Junction, AK 99737	4
1	Ed	Giese	Box 352	Delta Junction, AK 99737	4
1	E L	Gilbert	Box 149	Delta Junction, AK 99737	4
1	Roy	Gilbertson	Box 1069	Delta Junction, AK 99737	4
1	James	Gollogy	411 Fourth Ave	Fairbanks, AK 99701	4
1	Daniel	Grantham	47.5 Richardson Hwy	Fairbanks, AK 99701	4
1	Dan	Green	Box 986	Delta Junction, AK 99737	4
1	Don	Hall		Delta Junction, AK 99737	4
1	Everett	Harris	Box 962	Delta Junction, AK 99737	4
1	Ted	Harris	Box 10	Delta Junction AK 99737	4
1	Dan	Haslett	538 S Klevin	Anchorage AK 99503	4
1	Walter	Hastings	6760 Canady Dr	North Pole, AK 99705	4

3 Delta 10/88

1	Troxell	Hebert	Box 1018	Delta Junction, AK 99737	4
m	Roy	Hefer	Box 60813	Fairbanks, AK 99706	4
1	Glen	Helkenn	1403.5 Alaska Hwy	Delta Junction, AK 99737	4
1	Steve	Holcomb	Mi 1392 Alaska Hwy	Delta Junction, AK 99737	4
1	Byron	Hollembaek	1403.5 Alaska Hwy	Delta Junction, AK 99737	4
1	Walter	Holmes	Mi 35 Richardson Hwy	Fairbanks, AK 99701	4
1	John	Hotchkiss	Box 613	Delta Junction, AK 99737	4
1	B W	Houger	PO Box 56806	North Pole, AK 99705	4
1	Neil	Huckins	SR 90646	Fairbanks, AK 99701	4
1	Dick	Jensen	Box 1201	Delta Junction, AK 99737	4
1	David	Johnson	Box 601	Delta Junction, AK 99737	4
1	William	Johnson	Box 914	Delta Junction, AK 99737	4
1	Tunnie	Johnson	Box 914	Delta Junction, AK 99737	4
1	Gary	Jurgens	Box 184	Delta Junction, AK 99737	4
1	Wes	Keaster	Box 947	Delta Junction, AK 99737	4
1	Richard	Karr	Box 60782	Fairbanks, AK 99706	4
1	Leonard	Kelly	Box 816	Eagle River, AK 99577	4
1	Robert	Kern	Box 10034	Fairbanks, AK 99701	4
1	Robert	Koon	Box 216	Delta Junction, AK 99737	4
1	Walter	Kopp	Box 427	Delta Junction, AK 99737	4
1	Tom	Kraus	1210 Sherman Court	North Platte, NE 69101	4
1	Patricia	Krebs	Box 5065	Delta Junction, AK 99737	4
1	Ron	Krishnek	6609 Johnson Road	Salcha, AK 99714	4
1	Julius	Kusz	Box 984	Delta Junction, AK 99737	4
1	Neal	Kutchins	Box 81	Delta Junction, AK 99737	4
1	Howard	Lanni	Box 665	Delta Junction, AK 99737	4
1	William	Lappart	Box 45	Delta Junction, AK 99737	4
1	Richard	Larimore	811 East Ninth	Wellington, KS	4
1	Charles	Leap	4-E-3 Fairview Manor	Fairbanks, AK 99701	4
1	Ron	Lester	6971 Lester Lane	Delta Junction, AK 99737	4
1	Neda	Lihle	Box 874	Delta Junction, AK 99737	4
1	Ernest	Line	Mi 41 Richardson Hwy	Fairbanks, AK 99701	4
1	Don	Lintelman	5887 Nistler	Delta Junction, AK 99737	4

1	Robert Lizardi	Box 167	Delta Junction, AK 99737	4
1	Robert Loveless	SR 90658	Fairbanks, AK 99701	4
1	Patricia Lunsford	Box 923	Delta Junction, AK 99737	4
1	LLoyd Maggard	Box 1176	Delta Junction, AK 99737	4
1	Jerry Mamo	Box 140031	Salcha, AK 99714	4
1	Michael Mandulak	Box 195	Delta Junction, AK 99737	4
1	Ellen Mannion	Box 128	Delta Junction, AK 99737	4
1	Paul Marchuk	Box 859	Delta Junction, AK 99737	4
1	R G Markgraf	8750 Richardson Hwy	Salcha, AK 99714	4
1	Don Marsh	Sr 1057H	Anchorage AK 99501	4
1	Florence Marshall	1211 Fourth Ave	Fairbanks, AK 99701	4
1	Bruce McClain	Box 71	Delta Junction, AK 99737	4
1	David McCracken	Box 1155	Delta Junction, AK 99737	4
1	Doug McCullum	Box 313	Delta Junction, AK 99737	4
1	Harlan Mead	Mi 77 Richardson Hwy	Delta Junction AK 99737	4
1	Paul Mertz	Box 1267	Delta Junction, AK 99737	4
1	Ed Milam	Mi 1415 Alaska Hwy	Delta Junction, AK 99737	4
1	Elaine Miller	Box 869	Delta Junction, AK 99737	4
1	Scott Miller	Box 1275	Delta Junction, AK 99737	4
1	Joe Miller	PO Box 310	Delta Junction, AK 99737	4
1	Earl Mitchell	1412 Alaska Hwy		4
1	Mr. Mock	box 1241	Delta Junction, AK 99737	4
1	Arthur Moe	3633 W 79th Ave	Anchorage AK 99502	4
1	William Montano	SR Box 10033	Fairbanks, AK 99701	4
1	Ray Morgan		Fairbanks, AK	4
1	Gary Moritz	Mi 254.5 Richardson Hwy	Delta Junction, AK 99737	4
1	Harry Morris	Mi 30 Richardson Hwy	Fairbanks, AK 99701	4
1	Hoyt Moss	Box 182	Delta Junction, AK 99737	4
1	Ron Mull	Box 1074	Delta Junction, AK 99737	4
1	Henry Muth	Box 1004	Delta Junction, AK 99737	4
1	Ron Nelson	Box 888	Fairbanks, AK 99707	4
1	Sid Nelson	Box 553	Delta Junction, AK 99737	4
1	Joseph Nistler	6369 Nistler Rd	Delta Junction, AK 99737	4