Economic Analysis of the Potential Sale of the Thorne Bay Electric Utility

Note: This report was prepared as an attorney work product. It has since been approved for release to the public.

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by

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Key Questions Addressed by This Analysis

To perform this analysis of the proposed sale of the Thorne Bay Electric Utility I conducted several quantitative exercises, each designed to shed light on a specific question or issue which I feel is important. I organize the results of these exercises to address the following questions:

1. What is the current cost of electric service in Thorne Bay?
2. How would things change under interim rates or Island-wide rates proposed by AP&T?
3. How are citizens affected in their dual roles as ratepayers (buyers of electricity) and owners (sellers of electricity)?
4. How does the PCE program affect these impacts?
5. Repeat questions 2 through 4 for THREA ownership.
6. How does the Black Bear Lake project affect these outcomes?
7. How would the loss of PCE affect these outcomes?
8. How do declining State of Alaska revenues affect these outcomes?
10. How would Thorne Bay's grant-funded assets be treated for PCE determination?
11. What sale price should the City seek if it decides to sell?

Summary of Findings

1. **Cost of Service.** THREA currently has a substantially higher cost of service than both AP&T and Thorne Bay. While generation efficiencies are approximately equal, THREA has slightly higher fuel and purchased power costs and significantly higher nonfuel operating costs than either AP&T or Thorne Bay. THREA has very high general and administrative costs (G&A) which amount to 7.5 cents/kWh, compared to AP&T's average of about 2.4 cents/kWh in the Craig area. THREA's lower cost of capital gives it a 1.3 cent/kWh advantage, which is not enough to overcome operating cost differences. THREA's total cost of service is about 29 cents/kWh, while AP&T's total cost for an Island-wide system would be only about 18 cents/kWh. If Thorne Bay joins THREA, it will be joining a group of utility service territories that has higher costs. If the City joins AP&T, it will join a group with lower costs. (See Table S1 and Figure 1).

2. **Rates.** A PCE-eligible kWh currently costs the Thorne Bay ratepayer about 19 cents while PCE pays 6 cents. Under AP&T island-wide rates, a PCE-eligible kWh would cost the ratepayer about 12 cents while PCE paid 6 cents. Under THREA's current rates, a PCE-eligible kWH would cost the ratepayer about 13 cents while PCE paid 16 cents. PCE pays for about 86% of the difference between prospective APT&T rates and prospective THREA rates. Both AP&T and THREA have a higher proportion of costs covered by PCE than Thorne Bay, but this situation would change if Thorne Bay began paying for new utility plant.

   Full rates for those not receiving PCE would fall from 25 cents/kWh to about 18 cents/kWh under an AP&T Island-wide rate. Under THREA, however, full rates would rise from 25 cents/kWh to between 26 and 30 cents/kWh. (Table S2 and Figure 2).

Summary of Current and Prospective Costs, Rates, and Impacts

Table S1: Summary of Utility Costs of Service in $/kWh
(Fuel Price Normalized to $.83/gallon)

Line		Thorne Bay FY92	AP&T Proposed	THREA CY91	AP&T Proposed all-Island
1	**Fuel and Purchased Power**	0.0786	0.0702	0.0801	no direct comparison currently available
2	Nonfuel O&M	0.0649	0.0446	0.0580	
3	General, Admin & Customer	0.0102	0.0215	0.0845	
4	**Total Nonfuel Operating**	0.0751	0.0661	0.1426	
5	Depreciation	0.0236	0.0176	0.0339	
6	Interest	0.0000	0.0175	0.0121	
7	Return on Equity/ Margins	0.0000	0.0254	0.0186	
8	Income Taxes & Other	0.0000	0.0171	0.0006	
9	**Total Cost of Capital**	0.0236	0.0777	0.0652	
10	**Total Cost of Service**	0.1773	0.2140	0.2878	0.1773
11	Average Revenue Collected	0.2500	0.2140	0.2878	0.1773

Note: It is a coincidence that current Thorne Bay cost of service and AP&T Island-wide cost are equal.

Table S2: Summary of Rate Impacts (Avg Revenue $/kWh)
(Fuel Price Normalized to $.83/gallon)

Line		Thorne Bay FY92	AP&T Proposed	THREA CY91 Costs	AP&T Island-Wide
1	Average Revenue $/kWh	0.2500	0.2140	0.2878	0.1773
2	PCE-Eligible Cost	0.1579	0.1885	0.2692	0.1571
3	PCE-Eligible kWh:				
4	Consumer Pays	0.1877	0.1255	0.1303	0.1157
5	PCE pays	0.0623	0.0885	0.1575	0.0616
6	kWh Not Eligible for PCE:				
7	Consumer Pays on average	0.2500	0.2140	0.2878	0.1773

Table S3: Summary of Financial Impacts on Residents
(assumes all resident kWh are PCE-eligible)

Line			AP&T Proposed	THREA CY91 Costs	AP&T Island-Wide
1	Decreased Electric Bills	[benefit]	76,785	70,802	88,854
2	Decreased City Revenues				
3	from Residents	[cost]	(89,741)	(89,741)	(89,741)
4	from Nonresidents	[cost]	(55,151)	(55,151)	(55,151)
5	Increased City Revenues from				
6	Invested Sale Proceeds	[benefit]	47,051	50,412	47,051
7	**Net Financial Effect on Residents**		(21,056)	(23,679)	(8,987)

Figure 1:

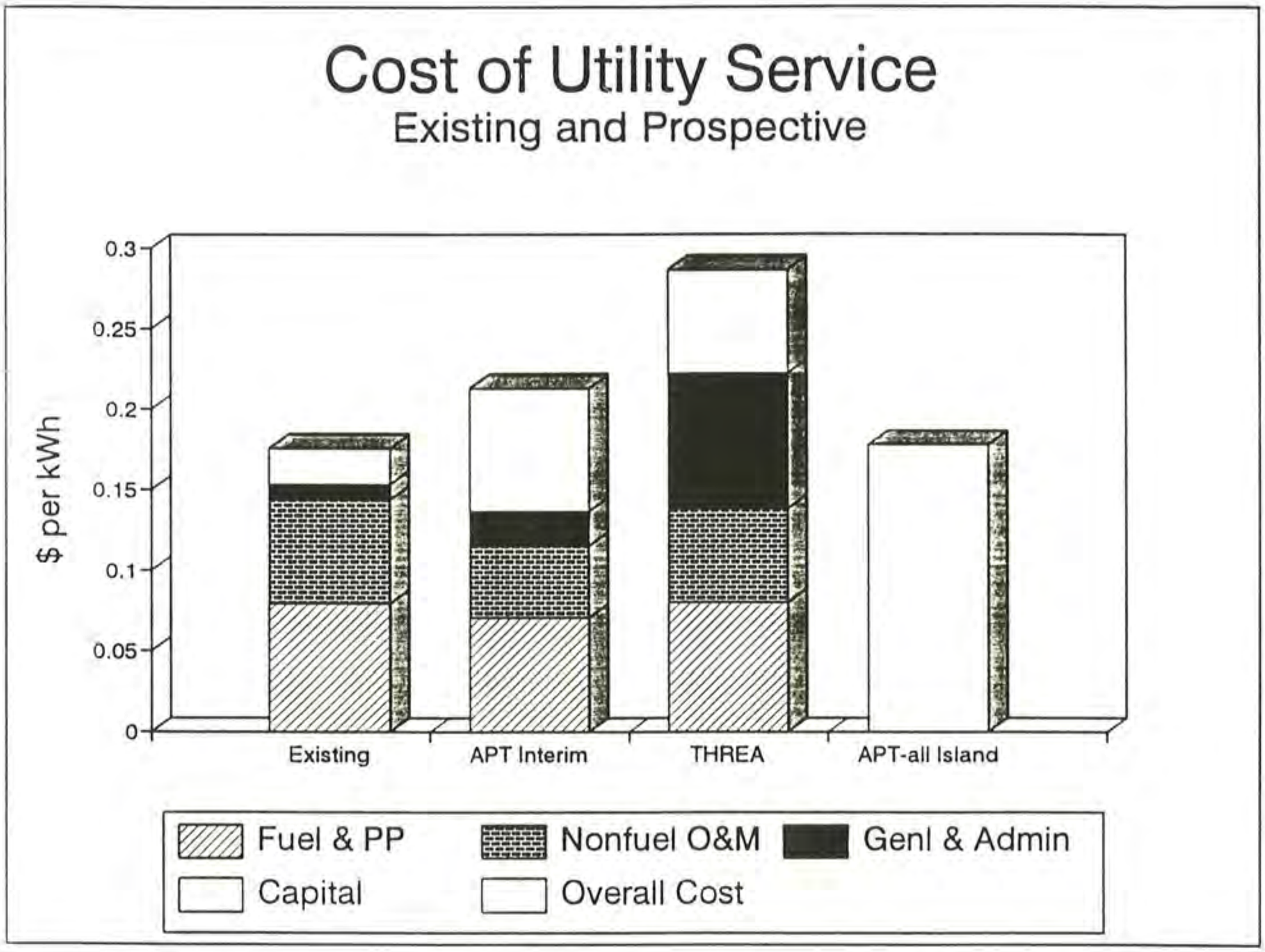
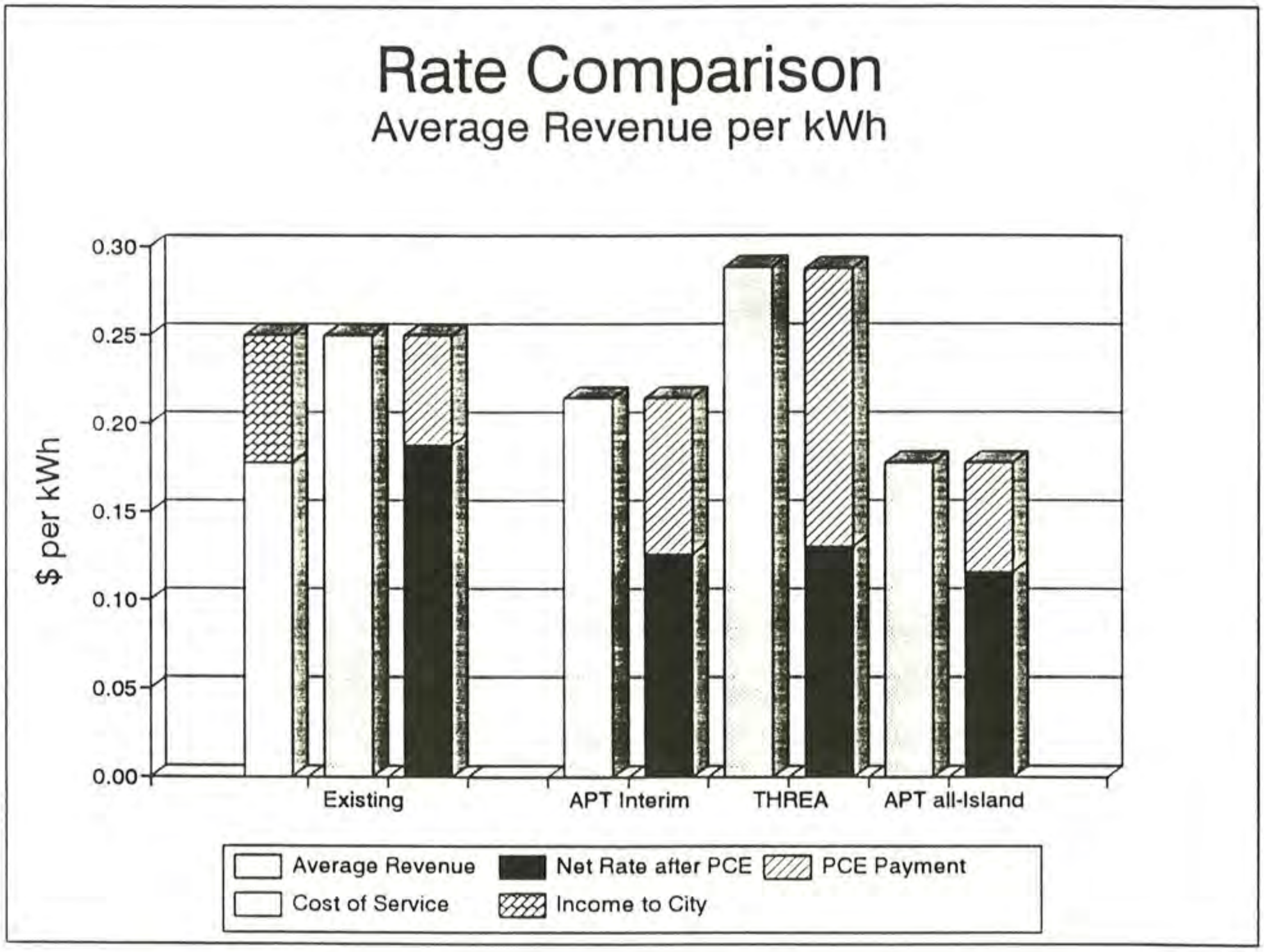

Cost of Utility Service
Existing and Prospective
0.3
0.25
0.2
0.15
0.1
0.05
0
$ per kWh
Existing
APT Interim
THREA
APT-all Island
Fuel & PP
Nonfuel O&M
Genl & Admin
Capital
Overall Cost

Figure 2:



Rate Comparison
Average Revenue per kWh
$ per kWh
0.30
0.25
0.20
0.15
0.10
0.05
0.00
Existing
APT Interim
THREA
APT all-Island
Average Revenue
Net Rate after PCE
PCE Payment
Cost of Service
Income to City

3. **Fiscal Impact on City.** The City of Thorne Bay sells about 38% of all power it generates to the three largest nonresident users: The SE Island School District, the Forest Service, and KPC. The City earned about $55,000 in operating income (after allowance for depreciation) from these three users, plus $90,000 from residents and local small business. This entire $145,000 of utility income would be lost if the utility is sold. If the utility is sold for $700,000 and the proceeds can be invested at 3% above the rate of inflation, the investment could provide $47,000 per year in inflation-adjusted revenues for twenty years. Thus the net fiscal impact of a sale would be a loss of City revenues of about $98,000 per year. (Table S3 and Figure 3).

4. **Overall Financial Effect on Residents.** By "residents" I mean citizens, both residential electric users and local small businesses. As long as PCE remains in effect at roughly current funding levels, residents' electric bills would drop by between $71,000 (THREA) and $89,000 (AP&T Island-wide rates). But residents would also feel the net loss of $95,000 in City revenues, in the form of either reduced services or increased taxes. The net financial impact on residents is a loss of wealth ranging from $9,000 (AP&T Island-wide) to $24,000 (THREA) per year. (Table S3 and Figure 3).

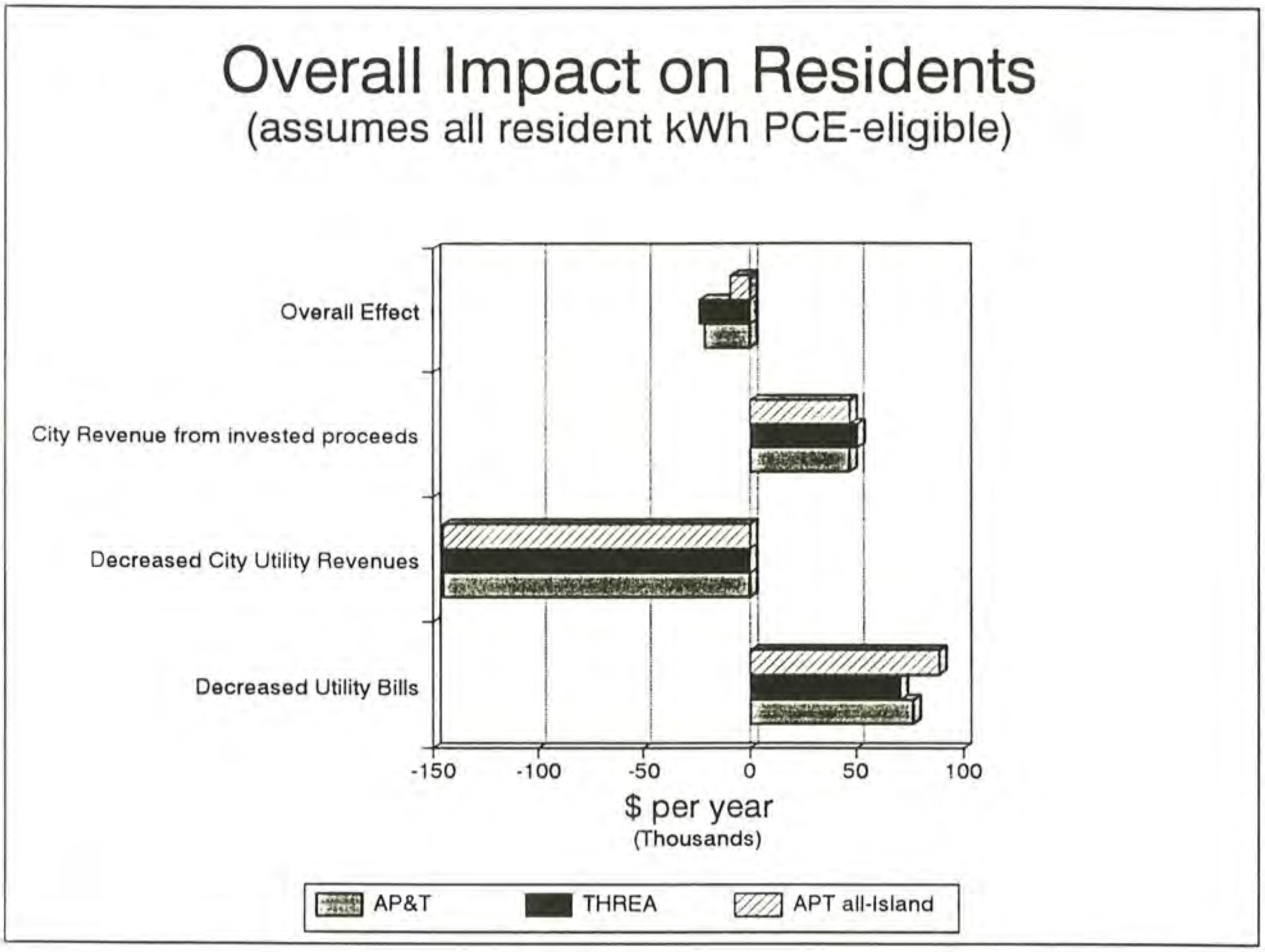
5. **Black Bear Lake.** It is very likely that AP&T will construct the Black Bear Lake hydro project (BBL) within the next 4 years. If Thorne Bay continues to operate its own utility or joins THREA, it would have to rely on grant funding to interconnect with BBL, because it would be uneconomical to build a transmission line based solely on the benefits to Thorne Bay. However, if Thorne Bay joins AP&T's Island-wide service territory, AP&T might be happy to build the transmission line from BBL to Thorne Bay and share the cost of the line with all of its Island customers. This is because customers in Craig would benefit from lower average costs of BBL power if BBL's fixed costs can be spread over the increased sales to Thorne Bay. Under current ratemaking practices, AP&T would *not* be able to share the cost of the transmission line with its Craig ratepayers if it was merely wholesaling power to Thorne Bay.

   In a worst case scenario, Thorne Bay could join AP&T and share in cost increases if Craig loads stagnate and no transmission is built to carry the benefits of Black Bear power to Thorne Bay. These cost increases could amount to 2 or 3 cents/kWh for a few years, then they would rapidly disappear as BBL was depreciated.

6. **Future Costs of Service.** Thorne Bay needs to replace and upgrade its powerhouse and generators at a cost of about $1 million. Under City ownership, these capital replacements would drive up the cost of electric service in Thorne Bay by about 2 cents/kWh, but 86% percent of this increase would be covered by PCE for eligible kWhs. This means the City could raise rates to maintain utility net revenues without affecting PCE-eligible electric bills. Under THREA, or under AP&T Island-wide rates, the cost increases would be shared and diluted among other customers, in addition to being covered by PCE. The need for these replacements does not fundamentally change the rate and cost impacts discussed above.

   During the next 5 years, THREA will probably add Chilkat Valley and other customers, which may drive down its average cost of service. Even with steady declines, however, It is unlikely to reach AP&T's lower cost levels for many years, however, unless AP&T stumbles by building Black Bear Lake while Craig loads stagnate.

Figure 3:



Overall Impact on Residents
(assumes all resident kWh PCE-eligible)
Overall Effect
City Revenue from invested proceeds
Decreased City Utility Revenues
Decreased Utility Bills
-150
-100
-50
0
50
100
$ per year
(Thousands)
AP&T
THREA
APT all-Island

7. **Declining State Revenues.** If PCE funding is eliminated, Thorne Bay residents will be significantly better off under AP&T than they would be under THREA, and somewhat better off with AP&T than with City ownership. The City would feel no direct fiscal impact from the loss of PCE no matter who owned the utility, because PCE pays no part of the net revenues to the City. However, the loss of PCE would eliminate the City's ability to raise rates to cover increasing costs and maintain profits without affecting residents' electric bills.

As state municipal assistance declines, the City may attach greater value to the ability to collect revenues from both nonresidents and residents through the vehicle of net utility income.

8. **Optimal Sale Price.** AP&T is currently offering to pay the entire retained earnings of the Utility because that is likely to be the maximum amount that could be added to its rate base. THREA is simply being competitive with AP&T. Under AP&T, a higher sales price, if allowed as rate base, would lead to higher rates. But because much of that rate increase is paid for by PCE and nonresidents (and, under Island-wide rates, shared with other AP&T service territories), the net benefits to Thorne Bay residents of a higher sale price are positive. AP&T would probably be happy to pay more if it could be recovered in rates. By waiting, the City builds up retained earnings in the Utility enterprise fund even though the cash flow is used for other activities. The maximum allowable price for ratemaking goes up, and AP&T will probably be happy to pay it.

THREA is free to pay essentially whatever it wishes and can afford for the Thorne Bay assets, subject to its own ability to finance the purchase. As with AP&T, a higher purchase price paid by THREA yields net benefits to Thorne Bay because any offsetting rate increases are shared with other communities and PCE. Because Thorne Bay appears to be a relatively low-cost service territory with a significant load, other THREA customers benefit from bringing Thorne Bay into their system. For these reasons, the City way wish to hold out for a significantly higher price if it decides to negotiate with THREA.

10. **Grant-Funded Plant.** THREA is certainly correct that if it took over Thorne Bay's grant-funded assets the City would be in no danger of having to repay them. As an unregulated entity, THREA does not face the question of whether grant-funded assets can be included in the rate base. AP&T is aware of the issue raised by grant-funded plant, and has apparently considered this in limiting its offer to the amount of the City's retained earnings. In any event, the ability to put plant in rate base is not the City's problem. If the rate base is reduced by the APUC it only helps the consumer.

The above considerations do not apply, however, to the determination of *allowable PCE costs*. It is possible that the APUC would continue to disallow the depreciation of grant-funded Thorne Bay Utility assets no matter who owned them. This is a legal, not economic question. It is very important to remember that disallowance of capital costs for *PCE purposes* has no direct effect on the health of the *utility*. Only the ratepayers are affected. Both AP&T and THREA have assumed favorable PCE treatment of the purchased Thorne Bay assets, but they have not provided any promises or explicit statements on this issue in connection with their proposals.

Current Thorne Bay Cost of Service

The Thorne Bay Electric Utility has a very low cost of service for a utility of its size, even after allowance for its grant-funded plant. Table 1 shows actual FY91 and FY92 costs of service from the City's annual PCE filing with the APUC and its financial statements. Average total cost, after normalizing depreciation at FY92 levels, dropped from 21 cents/kWh in FY91 to 18 cents/kWh in FY92, largely because of a drop in average fuel prices. With current rates set at 25 cents/kWh, the City earned $145,000 in net revenues *after* depreciation from the Utility.

The Utility's high generation efficiency of 13 kWh generated per gallon of fuel is offset by line loss problems which the City is currently investigating. If these losses were stopped, overall cost of service could be reduced by another .7 cents/kWh.

The numbers shown in Table 1 do not include allocated City Manager's time, and hence slightly understate the true cost of service. The City also enjoys grant-funded plant which eliminates interest as a cost item, but this situation may not continue if debt financing is used to fund capital replacements.

I assume the following, based on a very limited review of grant applications, line loss studies, and discussions with utility and AEA personnel:

- The Thorne Bay distribution plant is in fairly good shape.
- The Thorne Bay power plant will have to be replaced or rebuilt soon at a cost of about $1 million.
- No funds from the AEA line extension fund will be available for the power plant rebuild project.
- The Black Bear Lake Hydro project will be built by AP&T and incorporated into their rate base, which is now integrated for all of Prince of Wales Island.

Table 1: Current Thorne Bay Utility Cost Data

	APUC filing FY91 total	FY91 $/kWh	APUC filing FY92 total	FY92 $/kWh
Total kWh generated	2370259		2447808	
Total kWh sold	1832626		1993286	
gallons fuel consumed	178372		188877	
fuel base price $/gal	1.06		0.83	
Total Fuel Cost	189,074	0.1032	156,768	0.0786
labor	83,282	0.0454	80,552	0.0404
parts and supplies	6,422	0.0035	15,244	0.0076
repairs and maint	29,928	0.0163	33,629	0.0169
G&A	26,378	0.0144	20,266	0.0102
Total nonfuel Operating Costs	146,010	0.0797	149,691	0.0751
PCE–eligible depreciation	5,880	0.0032	8,327	0.0042
Book Depreciation (FY91)	46,970	0.0256	46,970	0.0236
Interest	0	0.0000	0	0.0000
Return on Equity	0	0.0000	0	0.0000
Taxes	0	0.0000	0	0.0000
Total Cost of Service	382,054	0.2085	353,429	0.1773
PCE–Eligible Costs	340,964	0.1861	314,786	0.1579
Total Revenue at $.25/kWh	458,157		498,322	0.2500
Estimated Operating Income	76,103		144,893	

Measures of Efficiency	FY91	FY92
kWh sold per gallon fuel	10.27	10.55
kWh generated per gallon fuel	13.29	12.96
Line loss (% of kWh sold)	29.3%	22.8%
Line Loss (% of kWh generated)	22.7%	18.6%
Absolute line loss	537,633	454,522

Source: City of Thorne Bay Annual PCE filings with APUC and FY91 Financial Statements

Note: Expense and revenue figures are based on PCE filings and show slight differences from Financial Statements

Short Run Effects of A Sale to AP&T

Table 2 summarizes my analysis of the short-run effects of a sale to AP&T. The rates and costs derived, while important, should be regarded as interim. After a short period of time (perhaps as short as 1 year), AP&T would seek to integrate Thorne Bay into its Prince of Wales Island service territory. I discuss these effects below. The first three columns of the Table compare actual Thorne Bay FY92 dollar costs to prospective rates proposed by AP&T. The next three columns express these figures as $/kWh. To make the comparison more accurate, I have normalized certain items.

Immediate Changes in the Cost of Service

Based on the assumptions discussed below, the overall cost of service under AP&T would initially rise by about 3.7 cents/kWh, from 17.7 cents/kWh to an average of 21.4 cents/kWh. Because AP&T would implement a customer charge of about $5/month, the actual rate for energy would be about 20.4 cents/kWh, and lower if fuel costs stayed below 83 cents per gallon. The AP&T prospective cost of service numbers were provided to me by the company as a set of confidential "Rate Calculation Schedules" in response to my request for support of AP&T's proposed 20 cents/kWh rate.

kWh Sold. I set the level of kWh sold equal to actual FY92 sales (Table 2, line 2).

Efficiency and Line Losses. AP&T assumes 13 kWh/gallon generation efficiency. This is already occurring (Line 48). They further assume that they will be able to reduce line losses as a percentage of sales from the FY92 level of 22.8% to 10.0% (line 49). The July 1992 line loss study done by Busbe for the AEA and city concludes that line losses are probably due to unmetered loads which will require further research to discover. Attempts to solve the problem are probably underway. For this comparison I adopt AP&T's efficiency assumption. This results in fewer kWh generated by AP&T for the same amount of sales (line 1), and hence fewer gallons of fuel consumed (line 3) and lower fuel costs (line 5). If they are unable to reduce line losses, or if the City solves the problem on its own, the difference between AP&T's cost of service and the City's decreases by about 8/10 of a cent/kWh.

Fuel Price. The largest component of the cost of service is diesel fuel. AP&T suggests that it could procure fuel at a lower price than the City currently does. I have assumed that without their own storage tanks, however, AP&T would have no more leverage over Petro-Alaska than the City currently does. Therefore, I assume that in the short run the price of fuel would be the same. For comparison purposes I use 83 cents/gallon, the August '92 price filed with the APUC to determine the FY93 PCE base rate. Current fuel prices are about 86 cents/gallon, according to January 1993 PCE filings. Note that for PCE-eligible kWh, 86% of any change in fuel price is borne by PCE. (.86 = .9 (budget shortfall) * .95 (statutory coverage. There is no connection between 86 cents/gallon and the PCE coverage ratio of 86%. It is a coincidence.)

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Table 2: Short–Run Comparison With Prospective AP&T Rates

Line	Cost of Service	Actual FY92	AP&T Proposed	Difference	Average $/kWh Actual FY92	Average $/kWh AP&T Proposed	Average $/kWh Difference
1	Total kWh generated	2,447,808	2,192,615	(255,193)			
2	Total kWh sold	1,993,286	1,993,286	0			
3	gallons fuel consumed	188,877	168,663	(20,214)			
4	fuel base price $/gal	0.83	0.83	0			
5	**Total Fuel Cost**	156,768	139,990	(16,778)	0.0786	0.0702	(0.0084)
6	labor	80,552	no		0.0404		
7	parts and supplies	15,244	direct		0.0076		
8	repairs and maint	33,629	comparison		0.0169		
9	G&A	20,266	possible		0.0102		
10	**Total nonfuel Operating Costs**	149,691	131,741	(17,950)	0.0751	0.0661	(0.0090)
11	PCE–eligible depreciation	8,327	35,000	26,673	0.0042	0.0176	
12	Book Depreciation (FY91)	46,970	35,000	(11,970)	0.0236	0.0176	
13	Interest	0	34,975	34,975	0.0000	0.0175	
14	Return on Equity	0	50,714	50,714	0.0000	0.0254	
15	Taxes	0	34,098	34,098	0.0000	0.0171	
16	**Total Cost of Capital**	46,970	154,787	107,817	0.0236	0.0777	0.0541
17	**Total Cost of Service**	353,429	426,517	73,089	0.1773	0.2140	0.0367
18	PCE–Eligible Costs	314,786	392,097	77,311	0.1579	0.1885	0.0306
19	**Total Utility Revenue**	498,322	426,517	(71,804)	0.2500	0.2140	(0.0360)

Line	**Ratepayer Perspective**	FY92	AP&T	Diff	FY92	AP&T	Diff
22	Sales to Residents (PCE–Eligible)	1,234,570	1,234,570				
23	Sales to Nonresidents (no PCE)	758,716	758,716				
24	Dollars Paid by Residents	231,668	154,883	(76,785)	0.1877	0.1255	(0.0622)
25	Dollars Paid by PCE Program	76,975	109,287	32,312	0.0623	0.0885	0.0262
26	Dollars Paid by Nonresidents	189,679	162,348	(27,331)	0.2500	0.2140	(0.0360)

Line	**City Financial Perspective**	FY92	AP&T	Diff
29	City Operating Income	144,893	0	(144,893)
30	from residents	89,741	0	(89,741)
31	from nonresidents	55,151	0	(55,151)
32	City Endowment Principal		700,000	
33	Endowment Real Rate of Return		3.0%	
34	Potential Annual Income for 20 Yrs	0	47,051	47,051
35	**Overall City Revenue**	144,893	47,051	(97,842)

Line	**Residents' Perspective**				
38	Decreased Utility Bills	[benefit]	76,785	expressed as $ per	0.0622
39	Decreased Revenue for Services			kWh consumed by	
40	from Residents	[cost]	(89,741)	residents:	(0.0727)
41	from Nonresidents	[cost]	(55,151)		(0.0447)
42	Increased Endowment Income	[benefit]	47,051		0.0381
43	**Overall Change in Residents' Wealth**		(21,056)		(0.0171)

Line	**Measures of Efficiency**	Actual FY92	AP&T Proposed	Difference
47	kWh sold per gallon fuel	10.55	11.82	1.26
48	kWh generated per gallon fuel	12.96	13.00	0.04
49	Line loss (% of kWh sold)	22.8%	10.0%	−12.8%
50	Line Loss (% of kWh generated)	18.6%	9.1%	−9.5%
51	Absolute line loss (kWh)	454,522	199,329	(255,193)

Nonfuel Operating Costs. AP&T calculated nonfuel operating costs using average $/kWh sold numbers from other service territories. This method may understate costs if Thorne Bay is significantly smaller than other places but still has the same fixed costs. In any event, I adjusted AP&T's proposed costs by applying their assumptions about $/kWh to FY92 sales. AP&T proposes to save about $18,000 per year (about $.01/kWh) (line 10) by reducing operating and maintenance labor costs below current levels. It is not possible to directly compare line items since AP&Ts line items do not conform to the City's line items.

AP&T includes no explicit costs for lease of City property. Such costs might be reasonably covered out of their their General and Administrative item, however.

Cost of Capital. The City currently charges depreciation of about $47,000/yr. AP&T would charge depreciation estimated at 5 percent of the utility plant gross asset value. The gross asset value is simply the sales price, which I assume to be $700,000. Other components of the cost of capital are determined as a percentage of the rate base, which differs slightly from the gross asset value due to first year depreciation and working capital requirements. The return components are based on AP&T's financing the purchase with a 50/50 debt/equity ratio resulting in an overall after-tax return of 12.25% on rate base (lines 13 and 14). The computed taxes are state and federal income taxes on the pre-tax return to equity.

The need to pay a return on the rate base, including taxes, causes AP&T's cost of capital to be about $108,000 higher than the City's in the first year (line 16). In the long run, the City would have to finance new plant with debt of some kind, increasing its cost of capital. The City would enjoy a tax-free cost of capital, but would likely have higher issuance costs than AP&T for debt financing.

Overall Cost of Service. Based on the assumptions described above, my analysis shows that the overall cost of service would increase by about $73,000 (3.7 cents/kWh) during the first year of AP&T operations.

PCE-Eligible Costs. Currently Thorne Bay has a very low amount of allowable depreciation expense because most of its plant was grant-funded. After buying the assets, AP&T would probably be able to include full depreciation, interest on debt, and income taxes as PCE-eligible costs. Therefore, the level of PCE-eligible costs rises by $77,000 (3 cents/kWh) under AP&T. There is a chance that the APUC might disallow depreciation of AP&T's purchased assets for PCE purposes even while it allowed such depreciation for setting rates, on the grounds that the same grant-funded assets are still being used to provide electricity to Thorne Bay, even if someone else owns them.

Total Revenue Requirement. The City currently collects 25 cents/kWh with no customer charge. Under the assumptions discussed above, the APUC would set the total revenue requirement for AP&T at the cost of service, $426,517 (if FY92 was the test year) (line 17). AP&T would probably propose to recover some of this requirement through a $5/month customer charge. Thus its energy charge per kWh would be 20.2 cents/kWh, but the average revenue collected per kWh would be 21.4 cents (line 19).

Affected Groups

There are four entities or groups that should be kept separate in the analysis:

1. Ratepayers who are residents of Thorne Bay. This group consumes about 62% of the power sold by the Thorne Bay Utility. Most consumption by residents is covered by PCE.
2. Ratepayers who are not residents of Thorne Bay. For this analysis I include in this group only the SE Island School District, the USFS, and KPC. These three users consume about 38% of the power sold by the Utility. None of the nonresident's consumption is covered by PCE.
3. The City of Thorne Bay as a provider of services other than electricity.
4. The State of Alaska as the payer of PCE subsidies.

Obviously the distinction between residents and nonresidents is somewhat arbitrary from both an analytical and philosophical point of view. I have only been able to make a first approximation guess of the sales to the top three nonresident customers for this report, based on 3 months of fall 1992 billing history.

For all my analyses involving PCE, I assume the continuation of the current funding level, which covers 90% of the statutory payment levels.

Immediate Changes from the Ratepayers' Perspective

Sales to nonresidents (line 23) are estimated based on the three months of billing data I was given, covering 10/92 through 12/92. Since these are cold months, my number for nonresident sales may be a bit high. Sales to residents are simply the difference between total FY92 sales and estimated sales to nonresidents. Sales to residents therefore includes, for example, sales to other Municipal departments.

To simplify the analysis, I assume that all sales to residents are PCE-eligible. In reality there are some commercial class resident customers who use more than the PCE maximums, but the total number of ineligible kWh consumed is small.

Using these assumptions, I conclude that residents would see their rates after PCE drop by 6 cents/kWh, from about 19 cents/kWh to 13 cents/kWh (line 24 and Figure 2). This 6 cent decrease is composed of a 3.6 cent decrease in rates (line 19) plus a 2.6 cent increase in PCE payments (line 25). Nonresidents would see their rates drop from 25 cents/kWh to 21 cents/kWh, based on the average calculations shown in the table (line 26). After accounting for the customer charge, the nonresidents would actually pay closer to 20 cents/kWh in energy charges.

Immediate Changes from City's Financial Perspective

The City collected $144,893 in FY92 operating income from the Utility (line 29). Of this, about $90,000 came from residents (line 30) and about $45,000 from nonresidents (line 31). This income would be lost after sale to AP&T.

Partly offsetting this loss of income would be the one-time payment of the purchase price, here assumed to be $700,000 (line 34). It is an important question what the City would do with this money. For this analysis I have assumed that it is invested in a portfolio that earns 3% above the rate of inflation and then drawn down in equal amounts (after adjustment for inflation) over a 20 year period. Under these assumptions the City could expect to collect $47,000 per year in real (inflation-adjusted) dollars for 20 years (line 34). I use a twenty year period to correspond to the approximate life of the utility plant being sold.

The net effect of the lost operating income and the first-year payment from the portfolio is a loss of revenues to the City of about $98,000 in the first year (line 35).

Immediate Changes from Residents' Perspective

This section considers the city residents in their combined roles as ratepayers (buyers of electricity) and owners of the utility (sellers of electricity). As owners of the Utility, the citizens of Thorne Bay can use Utility profits to pay for other city services. The basic premise behind this perspective is that utility profits stemming from residents' purchases of electricity are regarded as money that goes "out one pocket and into the other." In contrast, profits stemming from payments by nonresidents represent net revenues brought in to the City from outside.

There are of course problems with this perspective. The major problem is that different people consume different combinations of electricity and city services. If poor people consume little electricity and lots of visits to the health clinic, then they are helped when high electric rates help cover the cost of running the clinic. If rich peole consume lots of electricity and few city services, then they benefit when rates are lowered and do not feel the reduction in services. These are basic tax equity considerations. In fact, electric rates in excess of costs are just like a sales tax on electricity.

Having said this, I still believe it is useful to consider the immediate costs and benefits from the perspective of all residents taken together. As ratepayers, this group would see its utility bills drop by $76,785 (line 38). As citizens, they would see three things. First, a loss of Utility income from sales to nonresidents: this is significant at $55,000 (line 31). Second, a loss of Utility income from sales to residents, which amounts to about $90,000 (line 30). (This income now comes both from residents and from PCE.) Third, the increased City revenues from the invested proceeds of the sale, which amounts to $47,000 (line 34). The overall effect on residents is a loss of about $21,000 in the first year (line 43 and Figure 3).

Impacts of Island-Wide AP&T Rates

AP&T recently proposed and received approval for uniform electric rates in Craig, Hydaburg, and Hollis. The company would probably seek to integrate Thorne Bay into this unified service territory after as little as one year of operation. Table 3 and Figure 2 show the impacts of Island-wide AP&T rates for Thorne Bay. Under these rates, the unified cost of service and hence the full rate, would be 17.7 cents/kWh, a significant drop from the "stand-alone" Thorne Bay cost of service of 21.4 cents derived above. The overall cost drops because of the low costs and large loads in Craig. I estimate that PCE would pay 6 cents towards each eligible kWh, leaving a net average rate for eligible kWh of 11.6 cents. After deducting costs allocable to customer charges, the energy rate would be about 10.9 cents. This is one of the lowest rates available to any community using diesel for generation.

Table 3: Prospective AP&T Island–Wide Rates with Thorne Bay

Existing* AP&T (Without Thorne Bay):

Line		1990 Kwh Sold	Revenue Reqt	Avge $/kWh	Revenue from Cust Chg	Energy Charge $/kWh	Approx. PCE $/kWh	Estimated Net Rate
1	Craig	6,939,098	1,122,837	0.1618	37,560	0.1564	0.0484	0.1080
2	Hydaburg	1,241,070	245,154	0.1975	9,960	0.1895	0.0914	0.0981
3	Hollis	154,746	57,798	0.3735	2,820	0.3553	0.2093	0.1460
4	Allocated to THREA:		(20,956)					
5	**Island–Wide**	8,334,914	1,404,833	0.1685	50,340	0.1625	0.0541	0.1084

* Proposed in 1992 AP&T Cost of Service Study; probably adopted by APUC substantially as proposed

Prospective AP&T (With Thorne Bay):

Line		1990 Kwh Sold	Revenue Reqt	Avge $/kWh	Revenue from Cust Chg	Energy Charge $/kWh	Approx. PCE $/kWh	Estimated Net Rate
10	Other Island	8,334,914	1,404,833	0.1685	50340	0.1625	0.0541	0.1084
11	Thorne Bay (FY92)	1,993,286	426,517	0.2140	17,700	0.2051	0.0885	0.1166
12	**Island–Wide**	10,328,200	1,831,350	0.1773	68,040	0.1707	0.0616	0.1091

Source: AP&T 1992 Cost of Service Study and Table 2

Short Run Effects of a Sale to THREA

THREA Cost of Service

In response to my request for justification of its proposed 15 cents/kWh net rate (after PCE), THREA cited its existing rates and overall cost of service. I summarize this in Table 4. In order to provide the most realistic comparison with current Thorne Bay costs, I normalized the price of diesel fuel at 83 cents per gallon. This results in a calculated revenue requirement about 1 cent/kWh lower than the average actually collected in CY91.

Generation Efficiency and Line Losses. THREA has good generation efficiency of 12.6 kWh generated per gallon, and a superb line loss and station service percentage, at only 10.2% of sales.

Fuel Costs. THREA apparently suffers from slightly higher fuel costs at Hoonah relative to AP&T's at Craig. THREA is forthright in noting that it would have to carefully consider the costs and benefits of building its own fuel tanks in Thorne Bay. I have normalized the fuel price at Thorne Bay's actual August 1992 level of 83 cents per gallon.

Purchased Power. THREA purchases power for Klawock from AP&T's Craig generators. The average cost of this power is 10.5 cents/kWh.

Nonfuel O&M Costs. THREA appears to have slightly higher O&M costs than AP&T, but is is impossible to make precise comparisons without more detailed data.

General and Administrative Costs. THREA's G&A expenses are quite high, at least compared to AP&T's costs. If customer accounts (line 14) and other G&A (line 15) are added together, total G&A comes to almost 8.5 cents/kWh, or $719 per customer per year. It is not at all obvious to me why these costs are so high, but they cause the total nonfuel operating costs of 14.3 cents/kWh, almost twice the current levels in Thorne Bay and more than twice AP&T's prospective 6.6 cents.

THREA believes, with much merit, that it could serve Thorne Bay without adding to its *total* G&A costs. Therefore the average G&A with Thorne Bay would be slightly lower than it currently is. However, simply adding the Thorne Bay load would not bring average G&A costs down by more than about 1.4 cents/kWh, even if there were *zero* increases in THREA's total G&A expense as a result of serving Thorne Bay..

Overall Cost of Service. THREA's overall cost of service (Table 4, line 22) is 28.8 cents/kWh for a fuel price of 83 cents/gallon. Actual revenues collected in CY91 averaged 29/7 cents/kWh.

PCE-Eligible Costs. All of THREA's costs except margins were eligible for PCE reimbursement in 1991. There is a chance that the APUC might disallow depreciation of THREA's purchased assets for PCE purposes even while it allowed such depreciation for setting rates, on the grounds that the same grant-funded assets are still being used to provide electricity to Thorne Bay, even if someone else owns them.

Table 4: Current THREA Cost Data (CY91 with Normalized Fuel Price)

Line		CY91 total	CY91 $/kWh sold	CY91 $/cust	source
1	Number of Customers	1287			REA form 7
2	Total kWh generated	9,219,380			REA form 7
3	Total kWh purchased	2,719,800			APUC/PCE92
4	Total kWh sold or used (note 1)	10,942,661			APUC/PCE92
5	from purchased power	2,573,241			APUC/PCE92
6	from generated power	8,369,420			APUC/PCE92
7	gallons fuel consumed	729,597			APUC/PCE92
8	fuel base price $/gal	0.83			Thorne Bay 7/92 Actual
9	Total Fuel Cost	605,566	0.0724		
10	Total Purchased Power Cost	270,528	0.1051		REA form 7
11	**Total Fuel and Purch Power Cost**	876,094	0.0801		
12	Nonfuel Misc Generation	443,816	0.0406		APUC/PCE92
13	Repairs and Maintenance	191,127	0.0175		APUC/PCE92
14	Customer Accounts & Info	108,317	0.0099	84	APUC/PCE92
15	Other G&A	816,870	0.0747	635	REA form 7
16	**Total nonfuel Operating Costs**	1,560,130	0.1426	1,212	
17	**Total Operating Costs** (note 2)	2,436,223	0.2226		
18	Book Depreciation (Actual CY91)	370,946	0.0339		REA form 7
19	Interest	132,425	0.0121		REA form 7
20	Operating Margins (Actual CY91)	203,394	0.0186		REA form 7
21	Other	6,564	0.0006		REA form 7
22	**Total Revenue Requirement**	3,149,552	0.2878		
24	**Total Revenue Collected CY91**	3,246,191	0.2967		
25	PCE–Eligible Costs	2,946,158	0.2692		line 22 – line 20
26	Residential PCE subsidy (90% of statute)		0.1575		
27	Residential Retail Rate: 1st 300 kWh		0.3165		Tarriff sched R
28	**Residential Net Rate: 1st 300 kWh**		0.1590		

Measures of Efficiency

Line			
29	Line Loss from Purch Power (% of PP)	5.4%	
30	kWh sold per gallon fuel	11.47	
31	Losses and Sta Svc from Gen Power (as % of sales and street lites from gen power)	10.2%	

Note 1: Includes street lights

Note 2: Total operating costs slightly less than total reported production cost on REA form 7. Difference due to cost of fuel.

Impacts on Affected Groups

Table 5 shows the short run ratepayer and fiscal impacts of a sale to THREA on the same four groups discussed above.

Resident ratepayers would see their net rates for PCE-eligible kWH drop from 19 cents/kWh to 13 cents. This 6 cent decline is composed of an increase in the retail rate from 25 to 29 cents/kWh, offset by a 10 cent/kWh increase in PCE subsidies, from 6 cents to 16 cents (line 24,25).

Nonresident ratepayers would see a rate increase, from 25 cents/kWh to somewhere between 26 and 30 cents, depending on usage and customer class (line 26).

Impacts on City finances are the essentially the same as for a sale to AP&T: A loss of $90,000 in net income from residents and $55,000 in net income from nonresidents (line 30,31) is only partially offset if the sales proceeds are invested at 3% above inflation to yield $50,000 per year for twenty years. The net effect is a loss of City revenue of $95,000 per year (line 35). Using the proposed THREA purchase price of $750,000 gives the City about $3,000 more annual investment revenue than under AP&T.

Overall impacts on residents are essentially the same as under AP&T. Electric bills drop by $71,000 (line 38) while City revenues decline by $95,000. The net effect is a decrease in residents' wealth of $24,000 (line 43, Figure 3).

Table 5: Short–Run Comparison With Prospective THREA Rates

Line	Cost of Service	Actual FY92	THREA CY91	Difference	Average $/kWh Actual FY92	Average $/kWh THREA CY91	Average $/kWh Difference
1	Total kWh generated	2,447,808	no			CY91	
2	Total kWh sold	1,993,286	direct			THREA	
3	gallons fuel consumed	188,877	comparison			averages:	
4	fuel base price $/gal	0.83	possible				
5	**Fuel and Purchased Power Cost**	156,768			0.0786	0.0801	0.0014
6	labor	80,552	no		0.0404	CY91	
7	parts and supplies	15,244	direct		0.0076	THREA	
8	repairs and maint	33,629	comparison		0.0169	averages:	
9	G&A	20,266	possible		0.0102		
10	**Total nonfuel Operating Costs**	149,691			0.0751	0.1426	0.0675
11	PCE–eligible depreciation	8,327	no		0.0042	0.0339	
12	Book Depreciation (FY91)	46,970	direct		0.0236	0.0339	
13	Interest	0	comparison		0.0000	0.0121	
14	Margins	0	possible		0.0000	0.0186	
15	Other	0			0.0000	0.0006	
16	**Total Cost of Capital**	46,970			0.0236	0.0652	0.0416
17	**Total Cost of Service**	353,429			0.1773	0.2878	0.1105
18	PCE–Eligible Costs	314,786			0.1579	0.2692	0.1113
19	**Total Utility Revenue**	498,322	573,714	75,393	0.2500	0.2878	0.0378
	Ratepayer Perspective	FY92	THREA	Diff	FY92	THREA	Diff
22	Sales to Residents (PCE–Eligible)	1,234,570	1,234,570				
23	Sales to Nonresidents (no PCE)	758,716	758,716				
24	Dollars Paid by Residents	231,668	160,866	(70,802)	0.1877	0.1303	(0.0573)
25	Dollars Paid by PCE Program	76,975	194,472	117,497	0.0623	0.1575	0.0952
26	Dollars Paid by Nonresidents	189,679	218,376	28,697	0.2500	0.2878	0.0378
	City Financial Perspective	FY92	THREA	Diff			
29	City Operating Income	144,893	0	(144,893)			
30	from residents	89,741	0	(89,741)			
31	from nonresidents	55,151	0	(55,151)			
32	City Endowment Principal		750,000				
33	Endowment Real Rate of Return		3.0%				
34	Potential Annual Income for 20 Yrs	0	50,412	50,412			
35	**Overall City Revenue**	144,893	50,412	(94,481)			
	Residents' Perspective						
38	Decreased Utility Bills		[benefit]	70,802	expressed as $ per		0.0573
39	Decreased Revenue for City Services				kWh consumed by		
40	from Residents		[cost]	(89,741)	residents:		(0.0727)
41	from Nonresidents		[cost]	(55,151)			(0.0447)
42	Increased Endowment Income		[benefit]	50,412			0.0408
43	**Overall Change in Residents' Wealth**			(23,679)			(0.0192)

Line	**Measures of Efficiency**	Actual FY92	THREA Average	Difference
47	kWh sold per gallon fuel	10.55	11.47	0.92
48	kWh generated per gallon fuel	12.96	12.96	0.00
49	Line loss (% of kWh sold)	18.6%	10.2%	–8.4%

Longer Term Issues

Changes in Cost of Service

Thorne Bay needs to replace and upgrade its powerhouse and generators at a cost of about $1 million. Under City ownership, these capital replacements would drive up the cost of electric service in Thorne Bay by about 2 cents/kWh, but 86% percent of this increase would be covered by PCE for eligible kWhs. This means the City could raise rates to maintain utility net revenues without affecting PCE-eligible electric bills. Under THREA, or under AP&T Island-wide rates, the cost increases would be shared and diluted among other customers, in addition to being covered by PCE. The need for these replacements does not fundamentally change the rate and cost impacts discussed above.

During the next 5 years, THREA will probably add Chilkat Valley and other customers, which may drive down its average cost of service. It is unlikely to reach AP&T's lower cost levels for many years, however, unless AP&T stumbles by building Black Bear Lake while Craig loads stagnate.

Black Bear Lake Hydro Project

AP&T is close to acquiring a FERC license to build and operate a 4.5 Megawatt hydro project at Black Bear Lake (BBL). With the ability to generate 23.1 million kWh/year, the BBL project would initially be oversized for nearby loads in Craig and Klawock. Also, because of the way rates are determined, long-lived projects cost lots more during their first few years of operation than during later years. For both of these reasons, the initial output of BBL is likely to cost about 12 cents/kWh if the project serves only the Craig-Klawock area. This is higher than the production cost of diesel power and will cause electric rates to rise in the Craig area for a few years under most scenarios.

If AP&T could spread the fixed costs of BBL over a larger amount of consumption, the cost in cents/kWh would decline. The Thorne Bay load provides such an opportunity; its load could reduce average BBL costs from 12 cents/kWh down to about 10 cents/kWh. However, to connect this load requires a $3 million transmission line from Big Salt Lake to Thorne Bay.

The Big Salt transmission line cannot be justified on the basis of its benefits to Thorne Bay alone, because the cost of transmission would be about 12 cents per kWh of power *delivered to Thorne Bay*. However, the transmission line would provide benefits to other BBL customers by reducing the average cost of BBL power. My quick analysis suggests that the initial average cost of the "BBL plus transmission" package would be the same as the initial cost of BBL alone. (In fact, the necessary condition for a transmission project to reduce the average cost of delivered hyrdopower is simply that the relative increase in total cost from adding the transmission line must be less than the relative increase in total load served).

If the City continues to run the Thorne Bay Utility or sells to THREA, neither utility has a practical way of sharing the costs of the transmission line with AP&T's Craig ratepayers, even though those Craig ratepayers would share the benefits of reduced average hydro costs. (In theory, AP&T could offer BBL power to Thorne Bay at extremely low "surplus" rates which would make it feasible for Thorne Bay to build transmission, but it is extremely unlikely that such rates would be approved, because the appropriate rate would have to be very close to zero.)

If Thorne Bay joins AP&T's Island-wide service territory, however, AP&T might be happy to build the transmission line from BBL to Thorne Bay and share the costs (and the benefits!) of the line with all of its Island customers.

There is a possible down side to the BBL project. In a worst case scenario, Thorne Bay could join AP&T and share in an increased cost of power (relative to its own diesel system) if Craig loads suddenly stagnate and no transmission is built to connect the Thorne Bay load. These cost increases could amount to 2 or 3 cents/kWh for a few years, then they would rapidly disappear as BBL was depreciated. The potential exposure to a BBL-driven increase in the cost of service is far less than the current difference between AP&T's cost of service and THREA's.

Declining State Revenues

If PCE funding is eliminated or sharply reduced, Thorne Bay residents will be significantly better off under AP&T than they would be under THREA, and somewhat better off with AP&T than with City ownership. The City would feel no direct fiscal impact from the loss of PCE no matter who owned the utility, because PCE pays no part of the net revenues to the City. However, the loss of PCE would eliminate the City's ability to raise rates to cover increasing costs and maintain profits without affecting residents' electric bills.

As state municipal assistance declines, the City may attach greater value to the ability to collect revenues from both nonresidents and residents through the vehicle of net utility income.

Grant-Funded Assets

THREA is certainly correct that if it took over Thorne Bay's grant-funded assets the City would be in no danger of having to repay them. As an unregulated entity, THREA does not face the question of whether grant-funded assets can be included in the rate base. AP&T is aware of the issue raised by grant-funded plant, and has apparently considered this in limiting its offer to the amount of the City's retained earnings. In any event, the ability to put plant in rate base is not the City's problem. If the rate base is reduced by the APUC it only helps the consumer.

The above considerations do not apply, however, to the determination of *allowable PCE costs*. It is possible that the APUC would continue to disallow the depreciation of grant-funded Thorne Bay Utility assets no matter who owned them. This is a legal, not economic question. It is important to remember that disallowance of capital costs for *PCE purposes* has no direct effect on the financial health of the *utility*. Only the ratepayers are affected. Therefore we should not expect the potential buyers to have a passionate interest in exploring this issue. In fact, both AP&T and THREA have simply assumed favorable PCE treatment of the purchased Thorne Bay assets. They have not provided any promises or explicit statements on this issue in connection with their proposals.

If the capital costs of grant-funded plant were disallowed for PCE purposes, it would not matter much to Thorne Bay residents if the disallowance were spread over all THREA or all AP&T customers. To date, the APUC has determined PCE-eligible costs by utility rather than by community.

Should The City Hold Out for a Higher Price?

Incentives Facing the Bidders

THREA's Incentives. As an unregulated entity, THREA can offer whatever purchase price it wishes for the Thorne Bay Utility. If THREA is acting in the best interests of its customers, then it should be seeking the lowest price it can get, but willing to pay any purchase price which yields lower overall rates for its customer base after the transaction. Since Thorne Bay appears to have lower fuel costs and the additional G&A required to serve the City may be quite low, THREA can afford to pay a good deal more than its current offer of $750,000 and still come out ahead by lowering its overall average cost of service. It is possible to calculate this "maximum feasible offering price" as a function of assumptions about load growth and future costs, but I have not attempted to do so for this report.

AP&T's Incentives. In theory, AP&T stockholders should be largely indifferent to the price the company pays for the current assets of the Utility, so long as the price can be recovered in rates. In practice, however, a larger rate base helps a utility that is growing rapidly and for which variable costs are less than approved rates. AP&T satisifies both of these criteria.

The reason a larger rate base helps such a utility is that last year's total allowed costs are generally divided by last year's sales to determine next year's allowable $/kWh. By increasing the total allowed costs, a utility can increase the allowed rate in $/kWh. If next year's kWh sales equalled last year's, the total revenue recovered would be exactly equal to total allowed costs no matter what they were. But if next year's kWh sales exceed this year's, the utility earns a pure profit on every such additional kWh. The pure profit rises directly with the size of the utility's fixed costs, such as return on rate base. Therefore, AP&T has an incentive to seek the highest purchase price which it feels could be recovered in rates.

Effect of Higher Purchase Price on Rates

AP&T Case as Example. For every additional dollar by which the rate base is raised under AP&T, all ratepayers and the State of Alaska PCE program taken together must pay about 21 cents (total, not 21 cents/kWh) in rates during the first year to cover depreciation, return on investment, and taxes. This amount declines rapidly over the assumed 20 year life of the rate base.

If there were no external ratepayers (PCE and nonresidents), and if the City was able to easily raise revenues through taxes, then the following strong case could be made for a *lower* purchase price. Since an additional dollar invested in privately owned utility plant must provide state and federal income taxes and an equity component of return, the increase in rates caused by a higher purchase price is greater than the increase in city income from investing the higher proceeds. Conversely, if the price is reduced by a dollar, the decrease in rates outweighs the loss of income from investing the dollar. This argument could be extended to the logical conclusion that the city should simply give away the assets.

There are three big problems with this argument. First, there are external ratepayers (PCE and nonresidents) who would shoulder much of the cost of a higher purchase price, while the City would get all the benefits. Second, A complete giveaway would benefit people who consume lots of electricity but few city services, and hurt those who consume little electricity and lots of city services. So, for equity reasons alone, it is unlikely the city would see a giveaway as a good idea. Third, the City is constrained in the ways it can raise revenue. With State municipal assistance likely to decline in the future, the ability to raise revenue from whatever source will be increasingly important. Therefore, if the City does sell the utility, it might place a higher value on the income from the invested proceeds than it does on reduced electric rates, because it is hard to turn around and "tax back" some of the value of the reduced rates.

I have made a quantitative comparison of higher vs lower purchase prices with consideration of the effect of external ratepayers. This analysis shows that under reasonable economic assumptions, a higher purchase price from AP&T is beneficial to City residents because most of the resulting rate increase is paid for by PCE and nonresidents (and, under Island-wide rates, shared with other AP&T service territories). The same logic applies to a THREA purchase, where the cost of capital is lower and where additional rate base would be immediately shared with THREA customers in other communities.

Cash vs. Installment Payments

THREA's offer to provide $100,000 cash at closing followed by 9 annual payments of $100,000 is financially equivalent to its offer of $750,000 in cash *if* the City can earn 7.055% on the invested cash. In other words, THREA's proposed installment payments are sufficient to pay off a $750,000 purchase price with $100,000 down and $650,000 repaid over 9 years at 7.055%. If the City can earn more than 7.055%, it should take the $750,000 cash and invest it. If not, the installment payments offer a greater financial return. Obviously the City must also consider its ability to control the use of a cash payment. It may wish to lock itself in to the installment plan to avoid dissipating the lump sum payment.

Commitment to Interconnect as a Substitute for Higher Purchase Price

I have argued above that AP&T would be happy to pay more for utility plant if it thought it could get such plant in the rate base. I have also suggested that the transmission line from Big Salt to Thorne Bay might be a feasible investment if the costs and benefits of the project are shared by all AP&T ratepayers on the island. The best possible outcome from the City's point of view would be for Thorne Bay to have its own low rate (eg, not island-wide) during the first few years of Black Bear Lake operation, followed by the construction of a transmission line when the cost of BBL power drops significantly below diesel.

The City may wish to attempt to negotiate this outcome in the form of enforceable commitments from AP&T to maintain rates at or below the minimum of (1) the cost of service to run Thorne Bay's diesel system by itself and (2) the island-wide cost of service with Black Bear Lake and a tranmission line to get get BBL power to Thorne Bay. Many stipulations are possible toward this end, the most obvious being some form of commitment by AP&T to build transmission when the cost of Black Bear power drops below a certain level relative to Diesel. The main points, however, are (1) that AP&T has its own incentives (an increased rate base) for building the line and (2) that building the line is economically analogous to paying a higher purchase price for the Thorne Bay Utility, but offers additional benefits because it could significantly lower the cost of power.