SB

103

COMMITTEE REPORT

1/28/77

SENATE

**Finance

4/18/77 Date

Mr. President:

The Committee on RESOURCES has had SB 103
oil and gas properties production tax
under consideration. A majority of the members of the Committee

/_7 recommends it do pass

/_7 recommends it do not pass

/_7 recommends it do pass with attached amendment(s)

/X7 recommends it be replaced with CS for SB 103 and that CS for SB 103 do pass

/_7 (and) recommends it be referred to the ______ committee

/_7 reports it back without recommendation

/_7 AND attaches a report of its intent

/_7 (other) ______

MEMBERS SIGNING THE MAJORITY REPORT:

Tillion	Do Pass	[illegible] Do Pass
[illegible]	No Rec	John Huber Do Pass if Amended
[illegible]	Do Pass	
[illegible]	No Rec	

MEMBERS NOT CONCURRING IN THE MAJORITY REPORT:

______ recommends: ______

______ recommends: ______

______ recommends: ______

AGU 546603

[illegible]
Chairman

MEMORANDUM State of Alaska

TO: R. D. Stevenson
Special Assistant
Department of Revenue

DATE: February 18, 1977

FILE NO:

TELEPHONE NO:

FROM: Thomas K. Williams
Director
Petroleum Revenue Division
Department of Revenue

SUBJECT: SB 103 and HB 144
(identical Bills)

At the outset I would note that the Department of Revenue has recently released its review of Alaska's present taxation methods as they apply to the oil and gas industry. Within that review is the production tax, and recommendations regarding this tax have been made by the Department. This will shortly be followed up with specific bills.

SB 103 and HB 144 are identical. They incorporate a number of suggestions made last Session by the Administration to improve the production tax; however, these Bills do not reflect the latest recommendations in the Department's tax study. The most notable difference is that these Bills retain the basic "stair step" approach based on productivity, while the Department proposes a "curve" (instead of "steps") based on the actual economic condition of a property. The Department's recommendation recognizes and adapts itself to the fact that different areas of the State have different scales of economic production (i.e., in some places a far greater amount of production is needed to break even than is needed in others).

No simple set of "steps" can be structured for statewide application that will reduce the economic effect of the tax as the production of a property declines toward the minimum needed to break even. Either the tax will accommodate Cook Inlet operations and be too insensitive for non-coastal Native lands (whose break-even rates of production will more closely resemble the break-even rates for Prudhoe Bay than those for the Inlet), or else they will reflect the economic scale of operations for Native lands and Prudhoe Bay and give too much away to the Inlet operations.

If the "stair step" approach is to be retained despite its defects, the change to average well productivity as the basis for the "steps" is an improvement over the present tax. Both Bills make this change. However, they seem to give a bit too much away in their present definition of average daily per well production." A well operated only one day in the month would count the same as one operated every day of the month. To prevent the "one-day well" tax dodge, it is suggested that something along the lines of the following be used:

(15) "average daily per well production" means the amount calculated by dividing the total number of barrels of oil produced from a lease or property during the calendar month by the well-days for that lease or property for the calendar month.

(16) "well-days" means the total obtained by determining the number of days each well of a lease or property was operated during the calendar month and then adding those numbers together for all the wells of that lease or property.

Again, this suggestion is made only if "stair steps" are to be retained: it would be unnecessary if the Department's proposed Economic Limit Factor (ELF) is adopted instead.

Despite the difference between "stair steps" and the ELF, these Bills do contain a number of the Administration's recommendations last Session that would still be beneficial.

Most important of these is the specification of the point at which the production is to be valued. There was litigation over this question for Cook Inlet production, and only the fact that the tax is being paid on the cents-per-barrel basis keeps the controversy from boiling up anew. A similar situation could develop at Prudhoe Bay. Specifying the valuation point corrects this and prevents a problem from arising.

Another good feature of the Bills is their proposal to extend the tax to flared gas and to tax that gas at a higher rate. Without a cents-per-Mcf tax, however, the percent-of-value tax could have little if any effect. A producer presumably would argue (before the courts?) that its flared gas has zero value or else why would it be flared.

Neither Bill would change the ordinary gas production tax rate to achieve rate parity with oil. This flaw in the existing tax structure was pointed out in the Department's tax study.

TKW/fm

cc: Sterling Gallagher
Commissioner of Revenue

John R. Messenger
Deputy Commission er of Revenue

CSSB 103 (FINANCE)

OIL AND GAS PROPERTIES PRODUCTION TAX

A. Difference between CS (Resources) and CS (Finance)

All of the changes occur on page 3. Three words were deleted from the Resources version (See attached page 3, CSSB 103). Language was added to 43.55.012 (c) stipulating a date certain for the rebuttal hearing relative to setting the economic limit of production, and the use of the results of that hearing (See attached page 3. CSSB 103 Finance).

The two added words to sub-paragraph (d) decrease the latitude of the supplies allowed for deduction, and limit fuel deductions to only those actually purchased rather than any used from production.

B. Difference between the CS and the original Bill(s)

1. In general, the CS is a combination of SB 103 and SB 238, with a greater similarity to the latter. Whereas SB 103 was based on a stair-step approach of specific percentages, from zero to 14 percent for specific ranges of production, the CS provides for a smooth curve from zero to 12.5 percent of taxation versus the rate of production, through the entire spectrum of production.

2. The cents per barrel floor provision is maintained somewhere between SB 103 and SB 238, but closer to the existing ceiling than not.

3. Both SB 103 and SB 238 contained price indexing mechanisms though of different natures. The CS has eliminated both the Wholesale Price Index of SB 103 and the Gross National Product Deflator of SB 238.

4. The point of production in both SB 103 and 238 was the point of metering. The CS moves the point of production back to the wellhead, as is presently being done.

5. The gross value of production in both SB 103 and 238 was determined at the point of metering. In addition, SB 238 used the price of delivered imported oil im computing gross value. The CS determines gross value at the wellhead based on delivered price of Prudhoe oil or gas, as is presently being done.

6. Both SB 103 and 238 tax gas flared under permit from DNR. The CS removes the tax from such flared gas.

C. Analysis, CSSB 103

1. CSSB 103 imposes a tax on the gross value of oil or gas, at the wellhead, produced from any lease or property in Alaska.

2. The tax is computed through a formula which has an upper marginal limit expressed as a percent, a cents per barrel floor, an exponential factor, and an economic limit factor.

3. The upper limit, the cents per barrel floor, and the exponential factor are the constants which will be fixed upon passage of this Bill. The economic limit factor is a variable whose size is to be henceforth computed in the manner described in the Bill.

4. The upper marginal limit is set at 12.5%. When mitigated by an economic limit factor of 100 barrels, it becomes an effective 12%. The floor is set at 65 cents, which when mitigated by an economic limit factor of 100 barrels becomes an effective 52 cents (approximate). The higher the economic limit factor, the lower the effective rate of taxation. The exponential factor is designed to give relief to Cook Inlet. If it is lowered or removed, Cook Inlet will pay a much higher effective rate than it presently pays.

5. The use of an economic limit factor recognizes that the cost of production varies from field to field. Thus, two properties producing identical quantities of oil may pay a different tax, depending on the circumstances and location of production.

6. As a point of beginning the State assumes an economic limit of 100 barrels (no tax paid on the first 100 barrels). The taxpayer will get as many barrels free from taxation, over 100, as he can conclusively prove he needs to continue operating.

7. The Bill specifically recites the expense items that can and cannot be deducted from operational costs in computing the economic limit factor.

8. Due date for the tax is moved from the last day of the month to the 20th day.

9. Taxable amount is the oil or gas produced rather than that removed and sold.

10. Under CSSB 103, the effective rate of taxation on the Cook Inlet field has been reduced from 8.9% to 7.9%, with several marginal leases being reduced to zero.

11. Under CSSB 103, the effective rate of taxation on the Prudhoe Bay field has been increased from 7.7% to 12.0%. This is approximately a 50% tax increase on oil production, and an approximately 62% tax increase on total field production when the increase on gas is counted in.

or property is presumed to be 100 barrels times the number of well days for the lease or property during the month for which the tax is to be paid, unless the taxpayer at a formal hearing under AS 43.05.240 provides clear and convincing evidence of a different monthly production rate at the economic limit for the lease or property. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (e) of this section into the average monthly direct operating cost determined under (d) of this section.

(d) The average monthly direct operating cost for oil production operations of the lease or property shall be determined based on the number of months operated during the preceding 12-month period. The direct operating costs include drilling supplies, fuel, routine maintenance, and wages and benefits of employees working on the production operations. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the oil production operations of the lease or property, or any other cost not directly related to the oil production operations of the lease or property.

(e) For the purposes of this chapter, the gross value of oil shall be calculated as provided in sec. 150 of this chapter, and the gross value of gas shall be calculated as provided in (h) of this section.

(f) Before February 15 of each year or within six months after commencement of production for a lease or property, the department shall notify the producer of gas of the monthly production rate at the economic

limit for each lease or property in the state for that year. The monthly production rate at the economic limit for a lease or property shall be determined at a formal hearing under AS 43.05.240 and must be established by clear and convincing evidence presented by the taxpayer at that hearing. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (h) of this section into the average monthly direct operating cost determined under (g) of this section.

(g) The average monthly direct operating cost for gas production operations of the lease or property shall be determined based on the number of months operated during the preceding 12-month period. The direct operating costs include drilling supplies, fuel, routine maintenance, and wages and benefits of employees working on the production operations. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the gas production operations of the lease or property, or any other cost not directly related to the gas production operations of the lease or property.

(h) The value at the point of production of gas produced from the lease or property shall be determined on the basis of the highest price paid for gas of like quality and pressure in the same field.

(i) The department may aggregate two or more leases or properties (or portions of them), for purposes of determining economic limit factors under this section and applying them to sec. 11 of this chapter, when economically interdependent oil or gas production operations are

or property is presumed to be 100 barrels times the number of well days for the lease or property during the month for which the tax is to be paid. The taxpayer may rebut this presumption at a formal hearing under AS 43.05.420 by providing clear and convincing evidence of a different monthly production rate at the economic limit for the lease or property. The hearing shall be held before February 15 of the year or within six months after commencement of oil production for a lease or property. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (e) of this section into the average monthly direct operating cost determined under (d) of this section and shall be used for purposes of this section for all oil production during that calendar year from the lease or property.

(d) The average monthly direct operating cost for oil production operations of the lease or property shall be determined based on the number of months operated during the preceding 12-month period. The direct operating costs include production supplies, purchased fuel, routine maintenance, and wages and benefits of employees working on the production operations. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the oil production operations of the lease or property, or any other cost not directly related to the oil production operations of the lease or property.

(e) For the purposes of this chapter, the gross value of oil shall be calculated as provided in sec. 150 of this chapter, and the gross

value of gas shall be calculated as provided in (h) of this section.

(f) Before February 15 of each year or within six months after commencement of gas production for a lease or property, the department shall notify the producer of gas of the monthly production rate at the economic limit for each lease or property in the state for that year. The monthly production rate at the economic limit for a lease or property shall be determined at a formal hearing under AS 43.05.240 and must be established by clear and convincing evidence presented by the taxpayer at that hearing. The monthly production rate at the economic limit for the lease or property based upon the clear and convincing evidence of the taxpayer shall be calculated by dividing the value determined under (h) of this section into the average monthly direct operating cost determined under (g) of this section.

(g) The average monthly direct operating cost for gas production operations of the lease or property shall be determined based on the number of months operated during the preceding 12-month period. The direct operating costs include drilling supplies, fuel, routine maintenance, and wages and benefits of employees working on the production operations. The direct operating costs do not include capital expenditures, tangible or intangible drilling expenses, costs of well workovers, costs for replacement or repairs (other than routine maintenance), depreciation or amortization, taxes, insurance, overhead, money paid or set aside (or booked as being paid or set aside) to cover the cost of terminating the gas production operations of the lease or property, or any other cost not directly related to the gas production operations of the lease or property.

(h) The value at the point of production of gas produced from the lease or property shall be determined on the basis of the highest price paid for gas of like quality and pressure in the same field.

PRUDHOE BAY

EFFECT OF PROPOSED SEVERANCE TAX INCREASES
CSSB 103

(In Millions)

Oil Revenues* =	$139,146	
Oil Tax @ 7.7% =	10,714	(Current Rate)
Oil Tax @ 12.0%=	16,697	(Proposed Rate)
Increase on Oil =	$ 5,983	

Gas Revenues** =	$ 20,700
Gas Tax @ 4% =	828
Gas Tax @ 10% =	2,070
Increase on Gas =	$ 1,242

INCREASE ON BOTH OIL AND GAS = $7,225 +62.2%

* 1977-2005, From Wainwright Securities 4/1/77 Report

** Assumes 23 trillion CF Total Production at a constant $1.00 per MCF Wellhead Price.

AGO 546608 +

THE LEGISLATURE OF THE STATE OF ALASKA
TENTH LEGISLATURE

FISCAL NOTE

I. REQUEST
Bill/Resolution No. SB 103
Title Act concerning the oil and gas properties production tax
Requested by _____ Date _____

II. FISCAL DETAIL
Agency Affected Revenue
Program Category Affected General Government - Fiscal Services
Budget Request Unit(s) Affected Petroleum Revenue

EXPENDITURES (Thousands of Dollars)

	FY 77	FY 78	FY 79	FY 80	FY 81	FY 82
100 PERSONAL SERVICES						
200 TRAVEL						
300 CONTRACTUAL						
400 COMMODITIES						
500 EQUIPMENT						
600 LAND & STRUCTURES						
700 GRANTS, CLAIMS, ETC.						
TOTAL	None	None	None	None	None	None

FUNDING (Thousands of Dollars)

GENERAL FUND	-0-	-0-	-0-	-0-	-0-	-0-
FEDERAL FUNDS						
OTHER (Specify)						

POSITIONS

FULL TIME	None	None	None	None	None	None
PART TIME						
TEMPORARY						

III. ANALYSIS (See Fiscal Note Preparation Instructions, Section III)

This Bill would facilitate the administration of the present production tax, making it fully auditable for the first time since "stair steps" were introduced into the statute in 1970. No additional staff or other costs are anticipated to administer this Bill. Assuming a full and fair market price for Prudhoe Bay oil, estimated receipts under the Bill for production from the main reservoir of that field would be $131.3 million in FY 78, $205.6 million in FY 79, $362.4 million in FY 80, $585.9 million in FY 81 and $636.3 million in FY 82. Further comments (which are hereby incorporated into and made part of this Analysis) on the Bill appear in the attached memorandum from Thomas Williams to R. D. Stevenson.

IV. DATE February 18, 1977 PREPARED BY Thomas L. Williams
AGENCY Revenue
PHONE (907) 276-1363

Original: Legislative Finance
cc: Budget and Management
Prime Sponsor (First Legislator Named)

AGO 546623

RICHARD KILGORE Okay, I would then like to turn to the severance tax. ... I said in my general remarks, if you're interested in raising the severance tax, both of these bills that we're going to consider seem to in general follow our guidelines, and has to do with more the specifics of how each one of them works. We'll start with HB 144, SB 103. This bill does several things. One is it moves to lease averaging rather than wells in the calculation, and we think that makes an awful lot of sense from the administrative standpoint, and probably should be done even if you don't raise the severance tax, probably even amending your present severance tax would do that, and would make sense. Page 1, Line 11 of the bill moves the point of tax from the wellhead to a new point of production which is later defined.

SENATOR HUBER - How is this defined?

RICHARD KILGORE - It's defined back on Page 4, line 9, gross value at the point of production means for oil, the value of the oil at the point where it is metered or measured in a condition of pipeline quality on the premises of the lease or property from which it is recovered. So in come cases it would change the point of taxation from the wellhead to somewhere beyond up to a point where it was meter measured and made put in pipeline conditions, so it clearly, and this is pointed out by someone else, moves the point of taxation

and in a sense in certain situations it would tend to tax the transportation and upgrading of the crude oil. That's clearly the case.

SENATOR HUBER - I think it had another reason for being in there. I think it was on account of that Kenai deal to where if they transferred our royalty share portion that went into resale that they were subject to the APUC, and doing it this way, while they pushed their royalty share through our line, they were not subject to our APUC. There was quite a problem on that in Kenai, it happens to be in gas, but we're talking jointly here and I think this was done for the company's benefit.

RICHARD KILGORE - Well, I think also in Cook Inlet, as I understand it, there have been continuing disputes about questions of wellhead and where one taxes, and I think this is all intended to straighten this matter out by legislation. This is where it is, and we don't have to argue about backing out transportation or whatever, this is what they're talking about. This makes administration of it easier, clearly, I think that some of the testimony yesterday it was complained that there would be a cost to the companies in a sense that they wouldn't be taxed on transporting and upgrading. I think that if it's administratively easier and there is a cost, perhaps what you should do here is get a better idea of what you're really talking about in terms of cost and dollars and

cents. What is really the extra costs that companies would bear by doing this, or some idea. I think that's how you would have to assess that. Now lets look at the tax rates in this bill. I think you are all familiar with the fact that it adds higher well brackets and puts in these higher brackets at higher tax rates than exist in the present legislation, and it also lowers the tax rates, both the cents per barrel tax and the percentage tax for lower productivity wells. Now, just to give you a rough idea of what this does, and I'd like to just give you some numbers on how it would seem to us to effect, say, Prudhoe Bay, and then look at the Cook Inlet situation under this bill. All the numbers I'm going to use are ease of comperability for 27 gravity crude oil. Now, in Prudhoe Bay, and I'm assuming for purposes of this calculation that the wellhead value on Prudhoe Bay is say $7.50 per barrel just as illustriative. Under the present tax for a 5,000 barrel a day well in Prudhoe Bay, and these figures are cents per barrel of gross production not of taxable production, but you still get an idea of the relative increase in the tax. The present tax for 5,000 barrel a day well at $7.50 is 49 and 1/2 cents per barrel of gross production. This tax for the same well, a 5,000 barrel a day well would raise the tax to 68.9 cents. That's about a 37% increase in taxation of a 5,000 barrel a day well in Prudhoe Bay. If you went to a 10,000 barrel a day well, the percentage increase and the tax is greater. As against

about 51 cents at the present time, this tax would raise it to about 80 cents, so on a very productive 10,000 barrel a day well at Prudhoe Bay, the increase there would be about 58%, increased through this tax over what you have today. The effective rate on gross barrels produced would go from about 7.8% on a 10,000 barrel a day well to about 12.2% under the new tax, so this is what it does to Prudhoe Bay, very significant increases. And the percentage as I gave you were really the effective rate on taxable barrels going from 7.8 to 12.2. So you are ending up on the very productive well, you end up with an average effective rate on taxable barrels of just under 12 and 1/2 percent in Louisiana. I think that's what was intended. So that's the impact it has on Cook Inlet, I mean on Prudhoe Bay. Now, lets look at Cook Inlet, and particularly the old oil because we've always been worried about effective taxation of old oil. Now, this bill does retain the cents per barrel feature that exists in the present bill, and it retains the cents per barrel feature with basically the same floor price as you have today. It works out for 27 gravity crude to about $6.10 today. So it retains that, but what it does at the same time is that it does lower the rates of taxation both percentage and the cents per barrel taxes in the lower well brackets, so despite the cents per barrel feature still being in there, it does lower taxes on low productivity wells below what they are today. I'll again give you some examples, and they'll

again be on the same basis as before. 27 gravity crude, and these are figures on a gross barrel basis. At the present time a 100 barrel a day well in Cook Inlet would be on the cents per barrel tax and it would pay 26.6 cents per barrel. This bill on a 100 barrel a day well would eliminate the tax. It would go to zero, and a very substantial gain for a 100 barrel per day well. For a 300 barrel a day well, would also pay under the present tax, 26.6 cents. Under this bill, under our calculations, it would drop that 26.6 to 14.2 cents per barrel. So you have about a 12 and 1/2 cent reduction for a 300 barrel a day well, and if you move up to a 500 barrel a day well, you still get a reduction. Under the present tax it would be 28.7 cents. Under SB 103 it would be 21.2. So even for a 500 barrel per day well, you're going down by about 7 and 1/2 cents per barrel, and in fact this new tax as compared with the present lowers the tax up to somewhere wells in the range of 1,000 to 2,000 barrels a day. Somewhere in that range, the new tax gets higher than the old tax, so it does provide very significant relief for low productivity wells.

SENATOR HUBER - Madam Chairman - the figures which we have in the committee they are open to him now, I think, I just wonder when he finishes there. If you have any dispute with those, I think that they confirmed his testimony.

RICHARD KILGORE - Yes Senator, we did do our own homework on this obviously, and we have had a chance to look at what legislative affairs has, and they coincide with what I'm testifying here.

SENATOR HUBER - I was wondering. It would help us a lot to know that they do or don't or if there are differences.

RICHARD KILGORE - No they don't they calculate the same way we do.

Now, so this bill does, I think, meet our objections really to the present taxation of old oil at Cook Inlet which has the high effective rates because of the cents per barrel feature. At least its present operatior would reduce the tax substantially for low productivity wells, and we think that's a good feature of this bill. I should point out though, this bill does retain cents per barrel and it does retain escalation of that cents per barrel, so it is possible that under this bill we would again be back in the same problem that we have today. If the escalation manages to raise the cents per barrel tax high enough, we could be back in this problem again of taxing old oil in Cook Inlet at high prices, it's possible. The potential is still in this bill.

SENATOR HUBER - This evades it from present time, and we might have to look at it again in future years if we don't do something with cents per barrel.

RICHARD KILGORE - Yes, it may be back again.

SENATOR HUBER - Well, I'd sure look at it again, Madam Chairman, than I would to have Tom Fink for Governor.

RICHARD KILGORE - I think I was on record the first time I testified as saying that if you do retain a cents per barrel that perhaps what you do is at least consider no further escalation in cents per barrel, and perhaps that could be in this bill too. I don't know. I want to only point out that it could happen again. So that's basically what this tax does. It raises fairly significantly, the tax in Prudhoe Bay, but it does lower the tax considerably on low productivity old oil priced wells in Cook Inlet. It also has a severance tax for gas that is flaired, and a very substantial one, five times the rate. I think before you do this kind of thing and add such a tax, you ought to look very carefully at where gas is being flaired and why. There has been testimony yesterday about safety flairs and so on. I think you ought to look very carefully at what it is that you would be taxing and why the flairing is going on at the present time. Now, if what you're really trying to do is tell companies to find a use for this flaired

gas and find markets for it, I think that at the very least if there is gas being flaired now which you think you could find markets for, therefore you're going to try to compel people through this tax, somebody used the word incentive the other day, but you're compelling them through this tax that at least you ought to provide somebody with a grace period before they would pay this tax. That is, you wouldn't start right away. You would make it clear to them that they had certain time within which to find markets for this. You wouldn't penalize them in the meantime, but if you don't find gas for which it's logical to find markets, that you would say at some point in the future you're going to start paying a tax on this, so you had better get busy and look for markets. I don't think I.....

SENATOR HUBER - I think, Madam Chairman, that we should make sure in there. I think we should find out the required safety flair of no more than a certain amount except during an emergency blowout or something like that. The idea was, as long as it's economically unfeasible to take small amounts of gas and reinject them, the State loses its royalty share on it, and the nation loses the energy strictly because at a given space in time, using if you will excuse me, a cash discounting flow and everything else, that we determine its value and we say it's nothing, and what's nothing is moving down the pike another twenty or thirty years may be all we have, and Prudhoe Bay, in spite of an absolute no

flair restriction has been allowed to flair and everybody knows it. Somehow or other, it does have to be stopped, and if you make it so it isn't economically feasible to flair, then it becomes economically feasible to build a small compressor system for saving.

GEORGE SILIDES - Madam Chairman, I know that the flairing _____ as Huber pointed out, _____ that the flairing of course, and the word allowed is important, they get permission from the State, and we have to do something about the bill, that we don't have competition between the taxing department and the Department of Oil and Gas Conservation. They are the ones that give the permission, and you have to apply and you have to point out that it's being done with safety and so on. I don't think that the bill intended to penalize somebody for entering into a safety feature, and so am I correct Mr. Kilgore?

RICHARD KILGORE - I would assume that that's the intent. You'r not really interested in taxing gas.....

SENATOR HUBER - But that board still has the power and makes the exemptions and has been constantly making the exemptions, and it's a matter of record, both at Prudhoe Bay and elsewhere, they make the exemptions, they're legally made, but the product is gone, the resource is gone, it is flaired, and so at least putting in a fairly stiff recovery there does at

least give us something off of our severance tax that went up in flair too.

GEORGE SILIDES - Madam Chairman, I might make another comment. I think that in view of the comments being made, we're going to have to look into the legality of being able to tax a safety feature.

SENATOR HUBER - No, we don't tax the safety feature. Let's not get crossways on that. We should put an exemption in here for the safety flair only, and somewhere we need to come up with a figure of what is the amount that may be flaired to date per well or per safety flair. We definitely shouldn't tax them on what is a safety requirement. But there isn't a provision. The gas that's being burned in significant, is not being burned in so called legal actual safety flairs. It's being flaired otherwise by legal permits by the board.

CHAIRMAN POLAND - I think we have to check with the Board as to why they are giving the tax.

SENATOR HUBER - That's why the Governor's bills has it in it. That's why committee's bills has had this for two years, and we should certainly, like Dick says, make sure that we don't tax the necessary safety flairs. I asked yesterday what

was, and they said a million cubic feet. That's a thousand MCF's a day. I'm not sure that that isn't considerably over what's needed to burn there in case, I need a good definition of a safety flair.

RICHARD KILGORE - I think also you might consider if you really feel the gas is being flaired that you don't want to be flaired other than as safety purposes or whatever, that's something you might consider as an alternative just tightening up your regulatory bill and your regulations rather than do it through a taxing approach.

SENATOR HUBER - We've done everything but tar and feather the board.

REPRESENTATIVE OSTERBACK - Madam Chairman, could anybody tell us how much gas they will be flairing at Prudhoe Bay? Anything that burns is energy. We're talking about we're running short of energy. Somebody talked about the railroad. If they took it in there, they could take out about a hundred tanks of gas a day, and they didn't think it would be enough to pack that out with flairing, and that would be an awful lot of energy, but most of us don't really know what this gas is with the flairing, but I know anything that burns is energy, and we're talking we're running out of energy. So I think there should be something done about it. Anything

that you can save as energy, you can sell. There's no problem in that.

RICHARD KILGORE - Well, I agree with you, if what we're really talking about is waste, then I think we should eliminate that. It is energy, and you're abs lutely right, and I think you should look very carefully at what's going to happen at Prudhoe Bay, and how your regulatory people will handle it.

SENATOR HUBER - Might we, Madam Chairman, Al brought it up and it's very important. I think that it's understood that they have stopped flairing or are to stop flairing. It was only for that refinery that they flaired at Prudhoe Bay, and they didn't pump it back down the gas well even though they were drawing gas out to run the refinery because it would have cost more money than the gas was worth, so naturally the gas was worth nothing, so it wouldn't cost money to pump it back down into the ground. If it had a value of 20 cents an MCF, it would have been a lot cheaper to pump it back down into the ground, but just so that the record is straight, we aren't really looking for flairing at Prudhoe Bay, but if you will take a look at the Valdez terminal, you will find that we don't flair no more, but we've got three huge oxidizers there, and there's going to be a tremendous amount of energy unless the LPG's that are in that gas and the vapors that are in the gas at Valdez,

unless there's a plant built to recover those and use them which is not in the plan, it is going to effectively flair trillions of BTU's before Valdez is over with. That's because the plant and the tanks will not stand the pressure in the storage.

GEORGE SILIDES - Madam Chairman, I think the point is well made that something's got to be done about defining what is meant by safety gas, what is being wasted, and I think also that the bill had intended to address the bottom of the possible wasting of carbon dioxide. There was a considerable amount in this particular natural gas, and I suppose what we're getting to is that we have to do something about those things, either by definition or by amending the bill. I think this is a point that we're going to have to look into. I don't think we're going to get it solved right here.

SENATOR HUBER - I think they're willing, George, not to flair the carbon dioxide, but I'm not sure if they will get rid of it.

GEORGE SILIDES - It doesn't burn anyway, Senator.

CHAIRMAN POLAND - We'll be checking on this flairing part.

SENATOR HUBER - Well, it's important on both ends. I think that the bill needs to not penalize them, but by all means

should be retained in the bill, and we may of course have to put it in in some other places. I don't think this is going to effect it when it comes to the flairs in Valdez.