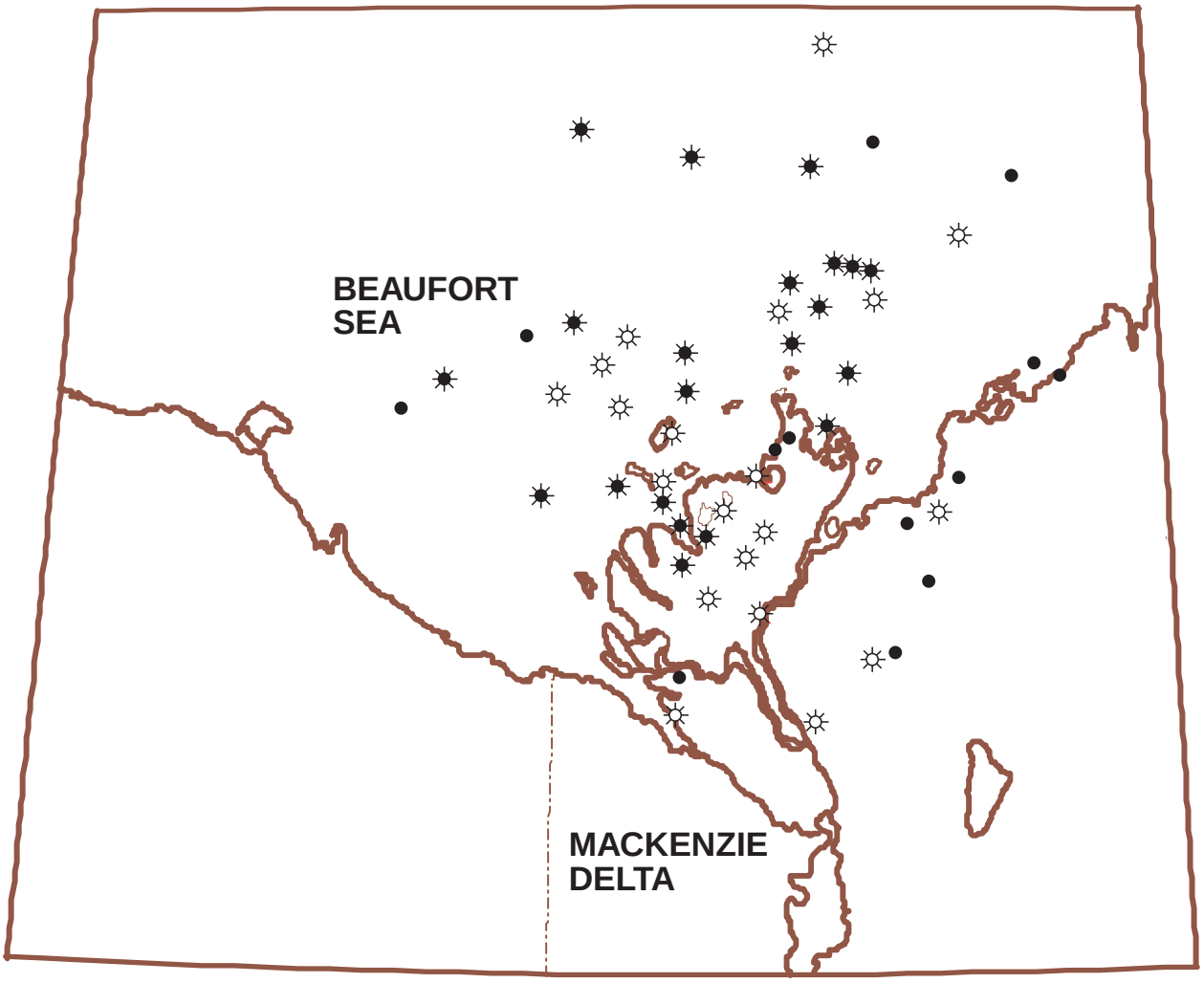
PROBABILISTIC ESTIMATE OF HYDROCARBON VOLUMES IN THE MACKENZIE DELTA AND BEAUFORT SEA DISCOVERIES



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NATIONAL ENERGY BOARD

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Introduction

This study was undertaken by the National Energy Board (Board), for the purpose of providing a comprehensive estimate of the discovered resources in the Mackenzie Delta-Beaufort Sea region from 69° N to 71° N. The 53 discoveries (Figure 1); 20 gas, 13 oil and 20 oil and gas were made between 1970 and 1989 and are divided roughly equally between the Beaufort Sea and the near to onshore Mackenzie Delta. Significant Discovery status, as defined by the Canadian Petroleum Resources Act, was given to the field if at least one zone in the discovery well demonstrated sustainable flow. The largest onshore gas field is Taglu, discovered in 1971, with an estimated marketable gas resource of 58.6 $10^9 m^3$ (2.07 Tcf). The largest offshore field is Amauligak, discovered in 1984, with an estimated recoverable oil resource of 37.3 $10^6 m^3$ (235 million bbl). The best current estimate of the total discovered resource in the basin is; 161 $10^6 m^3$ (1.01 billion bbl) of recoverable oil and 255 $10^9 m^3$ (9.00 Tcf) of marketable gas.

At present, there is no development of the discoveries within the Mackenzie Delta-Beaufort Sea region. However, in 1997, the Board approved a gas development plan for the Ikhil gas field which is estimated by the Board to contain, at best current estimate, 735 $10^6 m^3$ (25.9 Bcf) of marketable gas. The field is currently being evaluated by the operator. In 1989, a gas export application for the export of gas to the United States through the Central Mackenzie Valley, by applicants, Esso Resources Canada Limited, Gulf Canada Resources Limited and Shell Canada Limited was approved by the Board after the Board undertook an estimate of the gas resources within the onshore and offshore discovered gas fields; Taglu, Tuk, Niglintgak, Kumak, Mallik, Parsons, Ya Ya, Amauligak, Hansen, Issungnak, Kadluk, Netserk, Itiyok and Arnak in order to ensure adequate gas supply. In its Reasons for Decision in GH-10-88, the Board generally agreed with the gas export licence applicants' estimates of gas supply, but noted that extensive reliance was placed on the applicants' submitted geophysical data and interpretations. The Board's estimates of gas resources for these fields, in this current study, are lower than those stated in GH-10-88. These differences are due in large part to the recently acquired three dimensional seismic surveys over Taglu, Niglintgak and Kumak

and also to the more conservative estimate of reservoir parameters, by the Board, following an in-depth analysis. At this time none of these fields are considered to contain initial reserves.

This study represents the first, comprehensive, probabilistic resource estimate of the discovered resources for the Beaufort-Mackenzie Basin. An estimate of the total discovered resources, was reported by the Geological Survey of Canada in 1988 following consultations with Canada Oil and Gas Lands Administration. However, since 1988 more seismic data has been acquired and publicly released. These data, along with four new discoveries - Kingark J-54, Nipterk P-32, South Isserk I-15 and Unipkat N-12 have been integrated into the current study. All discovered fields are therefore now included in the overall resource volume.

Terminology

Since the discoveries remain undeveloped, the volumes reported are Currently Uneconomic Volumes, defined as "...those quantities that are currently estimated to be technically recoverable..." (DeSorcy et al 1993), but for which the economic criteria for development have yet to be specified.

The gas resource presented in this study is a sum of the non-associated gas, defined as gas not in contact with crude oil in the reservoir and associated gas, commonly known as gas-cap gas, which overlies and is in contact with the crude oil in the reservoir.

Methodology

The present study calculates the probabilistic resource estimates from stochastic risk analysis using Excel 4.0 templates enhanced by @Risk add-in functions, using in general, the methodology included in the Board's *Natural Gas Assessment, Northeast British Columbia*. The recoverable volumes of oil and the marketable volumes of gas; non-associated and associated, are reported, by field, in the attached table, without consideration to the economic criteria for development. The Amauligak I-65A and O-86 discoveries have been combined into the West Amauligak field for convenience.

As noted, Significant Discovery status was obtained if the well demonstrated sustainable flow from at least one zone. When there was insufficient evidence from the pressure data to determine the hydrocarbon column, the areal extent of the discovery for many of the fields was taken to spillpoint. Since area is the parameter that has the most effect on the volume of the resources, this approach can result in a volume for the resource that is larger than the best current estimate - a point especially important when probabilistic resource estimates are compared to previous deterministic resource estimates.

In support of the methodology for estimating parameter variance for resource calculations, it is interesting to note some general characteristics of the discoveries in the Mackenzie Delta-Beaufort Sea region: the trapping mechanism for the majority of the discoveries is structural closure; only a few of the discoveries, such as those in the deep

water turbidite play, are likely to have a strong stratigraphic component; for 75 percent of the fields, the discovery well is the only well in the field; significant portions of the fields remain undrilled, such as subsidiary fault blocks and the down-dip portions of the reservoir; and not all zones in a pool or pools in a field have been drillstem tested. Therefore a large uncertainty exists in the exact volume that has been discovered and hence the reason for the current probabilistic evaluation of the resources.

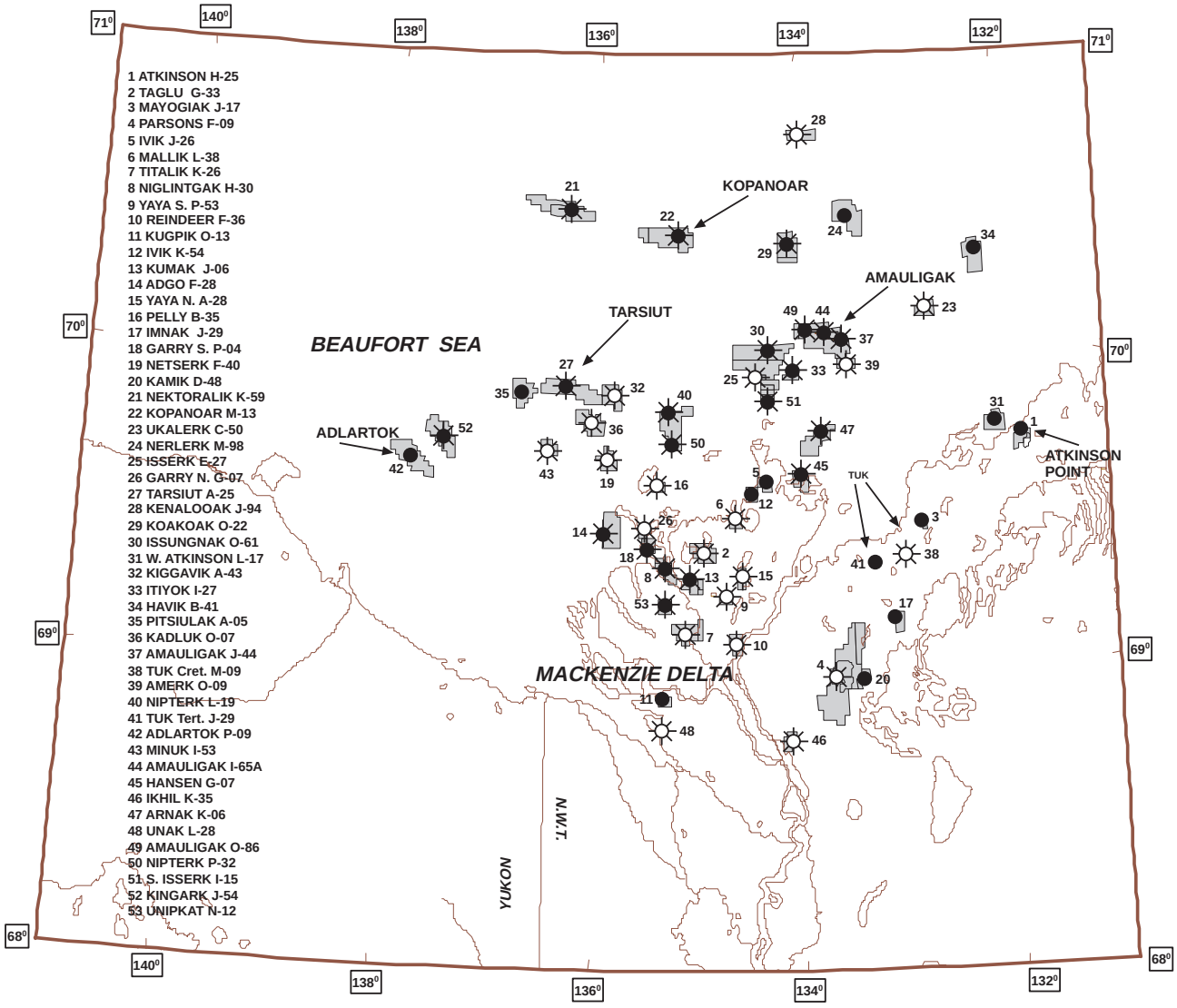
The first step in the assessment process was to establish a range for each parameter in the resource equation - as is generally the case net pay and area were the most significant. A large number of fields required an update to the seismic mapping, depth conversion and pressure-depth evaluations in order to determine the areal extent of the resource. The source for these data was released information files at the Board. For each parameter, a triangular distribution was estimated at the 95%, 50% and 5% levels of confidence. A large variance was used for the triangular distribution if there was considerable uncertainty for the parameter. The triangular distributions for all the resource parameters for an individual pool were run through the risk analysis program @Risk using a Monte Carlo simulation. For pools not flow tested, but where log analysis indicated high probability for hydrocarbons, the pool was conditionally risked at an 80 percent probability of occurrence. Similarly, all pools within a major undrilled fault block were conditionally risked at a 50 percent probability of occurrence. The total volume of the resources for each field was obtained by stochastic summation of the individually defined pools. A similar approach was used to sum the fields, resulting in a probabilistic range for the estimate for total resources. It is noted that with this method only the means of the distributions can be arithmetically summed.

A geological model was used to estimate the depositional trend of the reservoir sands, depending on the nature of the individual play. The extent to which this model was used depended to a large extent on the number of wells throughout the field. Net pay calculations were made in either of two ways: for fields with several wells a weighted average net pay range was calculated; for fields with a single well the average net pay range was estimated from the depositional model. In both cases, the net pay was multiplied by a factor to account for field geometry. Therefore the variance in the net pay was a function of both the number of wells in the pool and the certainty in the depositional model.

Porosity was calculated from the neutron-density wireline log or from core data where available. A porosity cut-off of ten percent for sandstone and three percent for carbonates was used. Unless the geological model indicated otherwise, the mean value for porosity was that determined from the wells in the field. For pools with limited well information, the variance in porosity, was constrained by analogy to similar type pools.

Water saturation was determined from wireline logs or from drillstem test data when available. Determination of water saturations for the Beaufort-Mackenzie Basin is complicated by the thinly laminated sands and shales composing the reservoirs. The older resistivity tools registered a lower apparent resistivity. This lower resistivity calculates very high water saturation for zones that produce clean hydrocarbons on test.

Beaufort Sea - Mackenzie Delta Significant Discoveries



	Gas ☼	Oil ●	Oil and Gas ✹	Total
Oil and Gas Discoveries				
Beaufort Sea	8	4	14	26
Mackenzie Delta	12	9	6	27
Total	20	13	20	53

Figure 1

Especially difficult are the deep water turbidite fields such as Kopanoar and Nektoralik. To account for the uncertainty in the water saturation calculations, a high variance was given, however, no covariance was established with porosity.

Shrinkage was estimated to be between four and six percent based on drillstem test results. However, for wet gas pools, the shrinkage was estimated to be between eight and 11 percent. The drillstem test data for these wet gas pools were used to estimate the recoverable condensate as a fraction of the recoverable gas volume. Condensate volumes are also reported.

Summary

Currently, it is estimated that between 93.0 10^6m^3 (0.585 billion bbl) and 229 10^6m^3 (1.44 billion bbl) of recoverable oil and between 186 10^9m^3 (6.57 Tcf) and 349 10^9m^3 (12.2 Tcf) of marketable gas has been discovered in the Mackenzie Delta-Beaufort Sea region. These estimates are at the 90 percent confidence interval. A brief analysis shows that approximately half of the recoverable oil and just under half of the marketable gas are contained within fields that have just one or two pools. However, future drilling within the fields may reveal additional pools with the potential for increasing the resources.

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Discovered Oil Resources (Currently Uneconomic Volumes)

	Oil Fields in the Mackenzie Delta RECOVERABLE OIL (Thousands of m^3)			
	0.95	median	mean	0.05
GARRY S. P-04	5,605.22	9,157.37	9,085.20	12,106.46
ATKINSON H-25	3,736.35	6,450.39	6,738.43	10,901.08
ADGO F-28	2,672.72	6,195.36	6,183.35	9,723.99
UNIPKAT N-12	3,413.67	5,522.04	5,537.73	7,667.52
NIGLINTGAK H-30	1,780.69	3,395.98	3,392.39	5,014.03
KUMAK J-06	867.20	1,928.86	1,931.47	3,002.43
IMNAK J-29	860.77	1,578.18	1,646.18	2,685.95
W. ATKINSON L-17	337.11	846.23	973.04	2,018.41
IVIK J-26	575.91	940.03	945.10	1,334.00
HANSEN G-07	353.70	623.03	687.49	1,234.71
IVIK K-54	254.94	642.00	675.08	1,213.48
MAYOGIAK J-17	450.22	637.03	652.51	902.86
KUGPIK O-13	372.09	606.13	634.05	990.61
TUK J-29	106.81	181.01	195.88	332.39
KAMIK D-48	96.45	175.38	182.15	289.59
TOTAL	19,517.56	39,422.91	39,460.05	60,064.85

	Oil Fields in the Beaufort Sea RECOVERABLE OIL (Thousands m^3)			
	0.95	median	mean	0.05
AMAULIGAK J-44	28,595.29	36,647.13	37,346.05	48,207.48
ADLARTOK P-09	7,184.00	17,062.85	17,891.47	31,313.72
KOAKOAK O-22	4,203.72	13,022.03	12,946.29	21,433.17
KOPANOAR M-13	5,060.99	9,978.42	10,852.75	19,563.93
TARSIUT A-25	2,381.80	7,426.46	7,398.54	12,175.52
HAVIK B-41	3,162.46	5,779.17	5,913.14	9,113.38
NERLERK M-98	535.62	4,858.15	4,854.99	9,240.33
ISSUNGNAK O-61	3,205.16	4,774.67	4,773.24	6,336.92
PITSIULAK A-05	1,929.68	3,703.24	3,991.75	7,030.77
W. AMAULIGAK I-65A/O-86	1,995.87	3,119.83	3,117.90	4,254.44
NIPTERK L-19	1,840.11	2,631.18	2,674.87	3,631.80
KINGARK J-54, NEKTORALIK K-59	672.79 858.41	2,733.98 2,098.51	2,563.04 2,242.88	4,145.59 4,146.07
S. ISSERK I-15	1,372.40	2,211.21	2,217.16	3,070.67
NIPTERK P-32	1,283.89	1,877.71	1,914.76	2,684.33
ITIYOK I-27	490.21	801.17	803.58	1,125.67
ARNAK K-06	191.47	423.27	427.33	695.19
TOTAL	57,464.72	122,070.60	121,929.74	185,187.40
GRAND TOTAL	92,985.24	161,611.80	161,389.79	228,922.50

Discovered Gas Resources (Currently Uneconomic Volumes)

	Gas Fields in the Mackenzie Delta						
	MARKETABLE GAS Non-associated and Associated (Millions of m^3)				RECOVERABLE CONDENSATE (Thousands of m^3)		
	0.95	median	mean	0.05	0.95	mean	0.05
TAGLU G-33	40,423.68	57,403.70	58,617.26	81,318.27	4,707.51	6,227.32	8,046.00
PARSONS F-09	26,197.76	34,765.49	35,462.47	46,779.79	1,515.83	1,876.12	2,286.80
NIGLINTGAK H-30	8,396.67	12,985.17	13,620.98	20,951.36	16.72	22.51	29.68
GARRY S. P-04	5,170.00	7,174.46	7,291.42	9,738.11	408.68	533.05	670.89
TUK M-09	3,803.71	5,131.65	5,157.81	6,585.25	1,273.03	1,719.39	2,194.01
HANSEN G-07	2,556.23	4,390.91	4,593.91	7,320.07	77.49	183.16	351.05
ADGO F-28	1,808.64	2,986.15	3,205.84	5,277.69			
PELLY B-35	1,043.04	2,640.79	2,948.23	5,750.46			
TITALIK K-26	1,037.95	1,540.49	1,591.69	2,303.69			
YA YA N. A-28	1,031.84	1,496.96	1,498.48	1,958.20			
YA YA S. P-53	576.08	1,365.57	1,357.63	2,136.25	40.77	81.20	120.92
UNAK L-28	742.50	1,024.11	1,041.58	1,406.62	3.15	5.82	9.22
MALLIK L-38	351.62	785.74	754.94	1,056.38			
IKHIL K-35	433.44	700.53	735.37	1,158.65			
KUMAK J-06	308.42	700.55	699.95	1,087.16	19.52	24.24	29.61
REINDEER F-36	211.14	441.06	448.09	700.41			
UNIPKAT N-12	249.29	367.63	381.00	557.01			
GARRY N. G-07	161.90	281.08	291.87	454.33	11.30	16.40	22.05
TOTAL	83,921.94	131,700.60	139,698.52	221,961.50	7,048.60	10,689.22	15,722.90

Discovered Gas Resources (Currently Uneconomic Volumes) con't

	Gas Fields in the Beaufort Sea						
	MARKETABLE GAS Non-associated and Associated (Millions of m^3)				RECOVERABLE CONDENSATE (Thousands of m^3)		
	0.95	median	mean	0.05	0.95	mean	0.05
AMAULIGAK J-44	31,860.28	38,463.46	38,522.66	45,390.39			
ISSUNGNAK O-61	23,288.19	31,232.01	31,956.37	42,968.01	174.90	215.39	260.96
KOAKOAK O-22	564.24	7,545.40	7,507.00	14,454.87			
KENALOOAK J-94	3,450.91	5,050.52	5,216.57	7,580.93			
NIPTERK P-32	2,332.52	3,365.16	3,487.58	5,056.27			
KIGGAVIK A-43	2,144.68	3,293.15	3,404.18	5,021.99			
NETSERK F-40	2,005.73	3,173.17	3,249.29	4,750.57			
S. ISSERK I-15	2,437.12	3,086.17	3,122.81	3,949.44			
UKALERK C-50	2,085.34	2,838.06	2,883.10	3,833.34			
ITIYOK I-27	1,859.33	2,520.40	2,573.36	3,473.48			
MINUK I-53	904.67	2,366.46	2,383.61	4,006.21	7.67	41.86	87.96
KADLUK O-07	1,330.10	1,955.88	2,016.35	2,896.32			
NEKTORALIK K-59	1,062.82	1,781.99	1,879.14	3,029.71	23.98	58.32	111.78
W. AMAULIGAK I-65A/O-86	1,298.99	1,767.10	1,769.40	2,254.61	19.36	25.05	31.65
KINGARK J-54	735.39	1,228.22	1,285.95	2,046.73			
ARNAK K-06	494.86	995.45	1,049.84	1,727.30	120.55	267.37	430.54
TARSIUT A-25	536.43	832.34	834.47	1,130.86			
KOPANOAR M-13/2I-44	536.79	759.57	771.35	1,062.03			
AMERK O-09	349.65	562.07	561.84	768.74	25.96	62.24	111.67
NIPTERK L-19	224.78	398.28	399.31	600.37			
ISSERK E-27	56.64	91.26	95.87	152.25			
TOTAL	80,524.47	110,954.10	114,970.05	162,511.50	359.85	670.22	1,209.03
GRAND TOTAL	186,201.50	247,256.40	254,668.57	349,314.80	7,737.81	11,359.44	16,306.93