Appendix F

Statistical Considerations

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Survey Methodology

The Form EIA-23 survey is designed to provide reliable estimates for reserves and production of crude oil, natural gas, and lease condensate for the United States. Operators of crude oil and natural gas wells were selected as the appropriate respondent population because they have access to the most current and detailed information, and therefore, presumably have better reserve estimates than do other possible classes of respondents, such as working interest or royalty owners.

While large operators are quite well known, they comprise only a small portion of all operators. The small operators are not well known and are difficult to identify because they go into and out of business, alter their corporate identities, and change addresses frequently. As a result, EIA conducts extensive frame maintenance activities each year to identify all current operators of crude oil and natural gas wells in the country.

Sampling Strategy

EIA publishes data on reserves and production for crude oil, natural gas, and lease condensate by State for most States, and by State subdivision for the States of California, Louisiana, New Mexico, and Texas. To meet the survey objectives, while minimizing respondent burden, a random sampling strategy has been used since 1977. Each operator reporting on the survey is asked to report production for crude oil, natural gas, and lease condensate for each State/subdivision in which he operates. The term **State/subdivision** refers to an individual subdivision within a State or an individual State that is not subdivided.

The total volume of production varies among the State/subdivisions. To meet the survey objectives while controlling total respondent burden, EIA selected the following target sampling error for the 2001 survey for each product class.

- 1.0 percent for National estimates.
- 1.0 percent for each of the 5 States having subdivisions: Alaska, California, Louisiana, New Mexico, and Texas. For selected subdivisions within these States, targets of 1.0 percent or 1.5 percent as required to meet the State target.
- 2.5 percent for each State/subdivision having 1 percent or more of estimated U.S. reserves or production in 2000 (lower 48 States) for any product class.
- 4 percent for each State/subdivision having less than 1 percent of estimated U.S. reserves or production in 2000 (lower 48 States) for all 3 product classes.
- 8 percent for States not published separately. The combined production from these States was less than 0.2 percent of the U.S. total in 2000 for crude oil and for natural gas.

The volume of production defining the Certainty stratum, referred to as the **cutoff**, varies by product or State/subdivision. The cutoff criteria and sampling rates are shown in **Table F1**. The Certainty stratum, therefore, has three components.

- **Category I** - *Large Operators:* Operators who produced a total of 1.5 million barrels or more of crude, or 15 billion cubic feet or more of natural gas, or both in 2000.
- **Category II** - *Intermediate Operators:* Operators who produced a total of at least 400,000 barrels of crude oil or 2 billion cubic feet of natural gas, or both, but less than Category I operators in 2000.
- **Category III** - *Small Operators:* Operators who produced less than the Category II operators in 2000, but which were selected with certainty. Category III operators were subdivided into operators sampled with certainty (**Certainty**) and operators that were randomly sampled (**Noncertainty**).
  - **Certainty** - A small operators who satisfied any of the following criteria based upon their production shown in the operator frame:
    - Operators with annual crude oil production of 200 thousand barrels or more, or reserves of 4 million barrels or more; or annual natural gas production of 1 billion cubic feet or more, or reserves of 20 billion cubic feet or more.

Table F1. 2001 EIA–23 Survey Initial Sample Criteria

State and Subdivision	Production Cutoffs		Number of	Noncertainty Sample	
	Crude Oil (mbbls)	Gas (mmcf)	Certainty Operators	Single State Operators	Multi–State Operators
Alabama Onshore	107	1,000	46	1	3
Alaska	-	-	5	-	-
Arkansas	21	1,000	93	13	8
California Unspecified	17	88	-	-	-
California Coastal Region Onshore	200	1,000	16	-	-
California Los Angeles Basin Onshore	200	25	17	-	-
California San Joaquin Basin Onshore	200	1,000	43	-	-
Colorado	200	1,000	128	1	16
Florida Onshore	200	1,000	2	-	-
Illinois	200	27	29	12	30
Indiana	12	1	14	2	21
Kansas	85	1,000	168	50	48
Kentucky	37	1,000	22	11	16
Louisiana Unspecified	73	183	-	-	-
Louisiana North	13	633	138	-	7
Louisiana South Onshore	70	1,000	190	-	4
Michigan	200	1,000	39	5	3
Mississippi Onshore	200	1,000	89	3	5
Montana	200	1,000	69	1	12
Nebraska	13	2	24	-	19
New Mexico Unspecified	10	13	-	-	-
New Mexico East	200	1,000	178	-	1
New Mexico West	21	1,000	64	-	-
New York	3	1,000	15	12	3
North Dakota	200	1,000	72	1	8
Ohio	92	1,000	25	46	5
Oklahoma	143	1,000	306	101	54
Pennsylvania	4	1,000	32	-	3
Texas Unspecified	7	118	-	-	-
Texas-RRC District 1	23	800	142	-	-
Texas-RRC District 2 Onshore	200	1,000	166	-	1
Texas-RRC District 3 Onshore	200	1,000	247	-	3
Texas-RRC District 4 Onshore	91	1,000	182	-	1
Texas-RRC District 5	38	630	96	-	3
Texas-RRC District 6	200	1,000	176	-	4
Texas-RRC District 7B	34	82	136	-	7
Texas-RRC District 7C	200	1,000	178	-	4
Texas-RRC District 8	200	1,000	233	-	5
Texas-RRC District 8A	200	1,000	206	-	6
Texas-RRC District 9	52	1,000	139	-	4
Texas-RRC District 10	200	1,000	161	-	12
Utah	200	1,000	48	3	2
Virginia	200	1,000	12	-	-
West Virginia	5	1,000	30	12	6
Wyoming	200	1,000	140	3	12
Offshore Areas	-	-	273	-	
Other States[a]	125	49	24	2	3
Total	**-**	**-**	**[b]899**	**277**	**[b]137**

[a]Includes Arizona, Connecticut, Delaware, Georgia, Idaho, Iowa, Massachusetts, Maryland, Minnesota, Missouri, North Carolina, New Hampshire, Nevada, New Jersey, Oregon, Rhode Island, South Carolina, South Dakota, Tennessee, Washington, and Wisconsin.
[b]Nonduplicative count of operators by States.
Note: Sampling rate was 8 percent except in Alaska, Florida Onshore, Virginia, and Offshore areas where sampling rate was 100 percent.
— = Not applicable.
Source: Energy Information Administration, Office of Oil and Gas.

- All other operators with production or reserves in a State/subdivision that exceed selected cutoff levels for that State/subdivision.
- The largest operator in each State/subdivision regardless of level of production or reserves.
- Operators with production or reserves of oil or gas for six or more State/subdivisions.

- **Noncertainties** - Small operators not in the certainty stratum were classified in a noncertainty stratum.
  - In most areas, data from the noncertainty operators were sampled at a rate of 3 percent.
  - In these States (Texas, California, Colorado, Louisiana, Montana, New Mexico, South Dakota, Utah, and Wyoming) EIA did not survey the noncertainty operators in 2001. Instead, an imputation function was applied to estimate reserve volumes. The function used EIA historic production and reserves data, State and commercially available production data, and the size classifications of reporting operators.

In each State/subdivision the balance between the number of small certainty operators and the sample size was determined in an iterative procedure designed to minimize the number of total respondents. The iteration for each State/subdivision began with only the Category I and Category II operators in the certainty stratum. The size of the sample of small operators required to meet the target variance was calculated based on the variance of the volumes of those operators. For a number of State/subdivisions with high correlations between frame values across pairs of consecutive years, an adjusted target variance was calculated, that utilized the information about the correlations. This allowed the selection of a smaller sample that still met the target sampling error criteria. At each iteration a small operator, beginning with the largest of the Category III operators, was added to the certainty group and the required sample size was again calculated. The procedure of adding one operator at a time stopped when the proportion of operators to be sampled at random dropped below 3 percent. Independent samples of single location operators (operators who, according to the sampling frame, operate in only one State/subdivision) were selected from each State/subdivision using systematic random sampling.

An additional complexity is introduced because some small operators selected for the sample in another region or regions, sometimes report production volumes in a region in which EIA has no previous record of production.

State/subdivision volume estimates are calculated as the sum of the certainty strata and all of the estimates for the sampling strata in that region. The sampling variance of the estimated total is the sum of the sampling variances for the sampling strata. There is no sampling error associated with the certainty stratum. The square root of the sampling variance is the standard error. It can be used to provide confidence intervals for the State/subdivision totals.

For the States in which subdivision volume estimates are published, the State total is the sum of the individual volume estimates for the subdivisions. The U.S. total is the sum of the State estimates. A sampling variance is calculated for each State subdivision, State, and for the U.S. total.

Total U.S. Reserve Estimates

Conceptually, the estimates of U.S. reserves and production can be thought of as the sum of the estimates for the individual States. Correspondingly, the estimates for the four States for which estimates are published separately by subdivision (California, Louisiana, New Mexico, and Texas) can be thought of as the sum of the estimates by subdivision. The remaining States are not subdivided and may be considered as a single subdivision.

The estimates of year-end proved reserves and annual production for any State/subdivision is the sum of the volumes in the State/subdivision reported by the certainty stratum operators and an estimate of the total volume in the State/subdivision by the noncertainty stratum operators. Mathematically, this may be stated as the following sum:

$$\hat{V}_s = V_{sc} + \hat{V}_{sr}$$

where

$\hat{V}_s$ = estimated total volume in the State/subdivision

V_{sc} = total volume in the State/subdivision reported by Certainty operators

$\hat{V}_{sr}$ = estimated total volume in the State/subdivision of Noncertainty operators.

The total volume of Certainty operators in the State/subdivision is simply the sum of individual operator's volumes:

$$V_{sc} = \sum_{m=1}^{n_{sc}} V_{scm}$$

where

n_{sc} = number of Certainty operators reporting production in the State/subdivision

V_{scm} = volume reported by the *m*-th certainty stratum operator in the State/subdivision.

The estimated total volume of Noncertainty operators in the State/subdivision is the weighted sum of the reports of the noncertainty sample operators:

$$\hat{V}_{sr} = \sum_{m=1}^{n_{sr}} W_{srm} V_{sm}$$

where

n_{sr} = number of Noncertainty operators reporting production in the State/subdivision

V_{srm} = volume reported by the *m*-th Noncertainty sample operator in the State/subdivision

W_{srm} = weight for the report by the *m*-th Noncertainty sample operator reporting production in the State/subdivision.

In many State/ subdivisions, the accuracy of the oil and gas estimates was improved by using the probability proportional to size procedure. This procedure took advantage of the correlation between year-to-year production reports. The weights used for estimating the oil production for a State / subdivision were different from the weights used for estimating the gas production.

The weight used for the estimation is the reciprocal of the probability of selection for the stratum from which the sample operator was selected. In making estimates for a State/ subdivision, separate weights are applied as appropriate for noncertainty operators shown in the frame as having had production in only the State/ subdivision, for those shown as having had production in that State/subdivision and up to four other State/ subdivisions, and for operators with no previous record of production in the State/subdivision. National totals were then obtained by summation of the component totals.

Imputation for Operator Nonresponse

The nonresponse rate for Certainty operators for the 2001 survey was 2 percent and for the Noncertainty operators 5 percent. An imputation was made for the production and reserves for these 42 nonresponding operators.

Imputation and Estimation for Reserves Data

In order to estimate reserve balances for National and State/subdivision levels, a series of imputation and estimation steps at the operator level must be carried out. Year-end reserves for operators who provided production data only were imputed on the basis of their production volumes. Imputation was also applied to the small and intermediate operators as necessary to provide data on each of the reserve balance categories (i.e., revisions, extensions, or new discoveries). Finally, an imputation was required for the natural gas data of the small operators to estimate their volumes of associated-dissolved and nonassociated natural gas. The final manipulation of the data accounts for the differences caused by different sample frames from year to year. Each of these imputations generated only a small percentage of the total estimates. The methods used are discussed in the following sections.

The data reported by operator category by Form EIA-23 respondents for the report year 2001 are summarized in **Tables F2, F3, F4, and F5**. The reported data in **Table F2** shows that those responding operators accounted for 97.5 percent of the published production for wet natural gas and 96.0 percent of the reserves shown in **Table 9**. Data shown in **Table F3** indicate that those responding operators accounted for 97.7 percent of the nonassociated natural gas production and 96.0 percent of the reserves published in **Table 10**. The reported data shown in **Table F4** indicate that those responding operators accounted for 95.4 percent of published crude oil production and 95.8 percent of the reserves shown in **Table 6**. Additionally, **Table F5** indicates that those responding operators accounted for 99.1 percent of the published production and 96.9 percent of the published proved reserves for lease condensate shown in **Table 15**.

Table F2. Summary of Total Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23 (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

	Operator Category				
Level of Reporting	**I**	**II**	**Non-certainty III**	**Certainty III**	**Total**
Field Level Reported and Imputed Data					
Proved Reserves as of 12/31/00	163,533,701	14,123,379	-	55,553	177,712,633
(+) Revision Increases	17,087,596	1,369,692	-	-	18,457,288
(–) Revision Decreases	18,559,737	1,935,360	-	-	20,495,097
(–) Sales	9,436,158	1,321,055	-	-	10,757,213
(+) Acquisitions	13,240,881	819,413	-	30,615	14,090,909
(+) Extensions	14,456,240	2,577,036	-	-	17,033,276
(+) New Field Discoveries	3,437,563	239,626	-	-	3,677,189
(+) New Reservoirs in Old Fields	2,162,227	631,797	-	-	2,794,024
(–) Production with Reserves in 2001	17,546,614	1,674,533	-	13,554	19,234,701
Proved Reserves Reported as of 12/31/01	168,386,067	14,123,379	-	164,833	182,674,279
Production Without Proved Reserves	20,192	543,159	-	-	563,351
Reserves Imputed for Production Without Proved Reserves	141,691	3,430,877	-	-	3,572,568
Subtotal Production	**17,566,806**	**2,217,692**	**-**	**13,554**	**19,798,052**
Subtotal Proved Reserves 2001	**168,527,758**	**17,554,256**	**-**	**164,833**	**186,246,847**
State Level Reported and Imputed Data					
Production with Reported Proved Reserves	-	6,093	74,952	74,881	155,926
Production without Reported Proved Reserves	41	9,311	92,938	59,637	161,927
Production Estimated from Auxillary data	-	-	4,728	-	4,728
Subtotal Production	41	15,404	172,618	134,518	322,581
Weighted Subtotal Production	**41**	**15,404**	**177,346**	**134,518**	**327,309**
Proved Reserves Reported	-	27,806	763,682	632,394	1,423,882
Reserves Imputed for Reported Production Without Proved Reserves	231	40,768	618,141	318,543	977,683
Reserves Estimated from Auxillary data	-	-	-	71,617	71,617
Subtotal Proved Reserves	231	68,574	1,381,823	1,022,554	2,473,182
Weighted Subtotal Proved Reserves	**231**	**68,574**	**1,453,440**	**950,937**	**2,473,182**
Total Production in 2001	**17,566,847**	**2,233,096**	**177,346**	**148,072**	**20,642,000**
Total Proved Reserves as of 12/31/01	**168,527,989**	**17,622,830**	**1,453,440**	**1,115,770**	**191,743,000**

– = Not applicable.

Notes: Table 9 totals include imputed and estimated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 2001.

Table F3. Summary of Nonassociated Natural Gas, Wet After Lease Separation, Used in Estimation Process, Form EIA-23 (Million Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

Level of Reporting	Operator Category				
	I	II	Non-certainty III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/00	136,979,364	12,405,232	-	53,492	149,438,088
(+) Revision Increases	14,154,267	1,171,328	-	-	15,325,595
(–) Revision Decreases	15,844,085	1,636,258	-	-	17,480,343
(–) Sales	8,841,726	1,084,332	-	-	9,926,058
(+) Acquisitions	12,564,006	715,503	-	30,615	13,310,124
(+) Extensions	13,458,797	2,406,818	-	-	15,865,615
(+) New Field Discoveries	2,161,311	228,662	-	-	2,389,973
(+) New Reservoirs in Old Fields	1,735,830	593,702	-	-	2,329,532
(–) Production with Reserves in 2001	14,803,691	1,483,558	-	13,368	16,300,617
Proved Reserves Reported as of 12/31/01	141,574,359	12,405,232	-	162,958	154,142,549
Production Without Proved Reserves	1,339	472,313	-	-	473,652
Reserves Imputed for Production Without Proved Reserves	9,674	2,998,338	-	-	3,008,012
Subtotal Production	**14,805,030**	**1,955,871**	**-**	**13,368**	**16,774,269**
Subtotal Proved Reserves 2001	**141,584,033**	**15,403,570**	**-**	**162,958**	**157,150,561**
State Level Reported and Imputed Data					
Production with Reported Proved Reserves	-	5,161	64,280	65,054	134,495
Production without Reported Proved Reserves	40	8,118	77,157	52,184	137,499
Production Estimated from Auxillary data	-	-	3,791	-	3,791
Subtotal Production	40	13,279	145,228	117,238	275,785
Weighted Subtotal Production	**40**	**13,279**	**149,019**	**117,238**	**279,576**
Proved Reserves Reported	-	22,775	672,559	556,775	1,252,109
Reserves Imputed for Reported Production Without Proved Reserves	225	35,167	496,371	274,462	806,225
Reserves Estimated from Auxillary data	-	-	-	70,761	70,761
Subtotal Proved Reserves	225	57,942	1,168,930	901,998	2,129,095
Weighted Subtotal Proved Reserves	**225**	**57,942**	**1,239,691**	**831,237**	**2,129,095**
Total Production in 2001	**14,805,070**	**1,969,150**	**546,174**	**130,606**	**17,451,000**
Total Proved Reserves as of 12/31/01	**141,584,258**	**15,461,512**	**1,239,691**	**994,195**	**161,921,000**

– = Not applicable.

Notes: Table 10 totals include imputed and estimated nonassociated wet natural gas proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 2001.

Table F4. Summary of Crude Oil Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Non-certainty III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/00	19,475,088	955,696	-	316	20,431,100
(+) Revision Increases	1,409,850	96,954	-	-	1,506,804
(–) Revision Decreases	1,488,743	104,203	-	-	1,592,946
(–) Sales	293,309	70,370	-	318	363,997
(+) Acquisitions	330,065	56,993	-	327	387,385
(+) Extensions	742,781	61,854	-	-	804,635
(+) New Field Discoveries	1,403,732	4,317	-	-	1,408,049
(+) New Reservoirs in Old Fields	268,259	16,106	-	-	284,365
(–) Production with Reserves in 2001	1,606,681	99,160	-	35	1,705,876
Proved Reserves Reported as of 12/31/01	20,241,101	955,696	-	290	21,197,087
Production Without Proved Reserves	2,010	31,511	-	-	33,521
Reserves Imputed for Production Without Proved Reserves	15,610	203,086	-	-	218,696
Subtotal Production	**1,608,691**	**130,671**	**-**	**35**	**1,739,397**
Subtotal Proved Reserves 2001	**20,256,711**	**1,158,782**	**-**	**290**	**21,415,783**
State Level Reported and Imputed Data					
Production with Reported Proved Reserves	-	1,188	15,268	15,485	31,941
Production without Reported Proved Reserves	-	1,144	35,897	17,584	54,625
Production Estimated from Auxillary data	-	-	1,105	-	1,105
Subtotal Production	0	2,332	52,270	33,069	87,671
Weighted Subtotal Production	**0**	**2,332**	**53,375**	**33,069**	**88,776**
Proved Reserves Reported	-	7,540	171,370	129,198	308,108
Reserves Imputed for Reported Production Without Proved Reserves	-	6,267	173,740	98,575	278,582
Reserves Estimated from Auxillary data	-	-	-	60,695	60,695
Subtotal Proved Reserves	-	13,807	345,110	288,468	647,385
Weighted Subtotal Proved Reserves	**0**	**13,807**	**405,805**	**227,773**	**647,385**
Total Production in 2001	**1,608,691**	**133,003**	**140,202**	**33,104**	**1,915,000**
Total Proved Reserves as of 12/31/01	**20,256,711**	**1,172,589**	**405,805**	**228,063**	**22,446,000**

– = Not applicable.
Notes: Table 6 totals include imputed and estimated crude oil proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.
Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 2001.

Table F5. Summary of Lease Condensate Used in Estimation Process, Form EIA-23
(Thousand Barrels of 42 U.S. Gallons)

Level of Reporting	Operator Category I	II	Non-certainty III	Certainty III	Total
Field Level Detail Report					
Proved Reserves as of 12/31/00	1,308,649	119,271	-	99	1,428,019
(+) Revision Increases	169,732	16,747	-	-	186,479
(–) Revision Decreases	334,968	42,243	-	-	377,211
(–) Sales	65,180	9,914	-	-	75,094
(+) Acquisitions	104,744	8,738	-	874	114,356
(+) Extensions	110,739	24,658	-	-	135,397
(+) New Field Discoveries	68,495	4,782	-	-	73,277
(+) New Reservoirs in Old Fields	55,798	9,296	-	-	65,094
(–) Production with Reserves in 2001	190,036	16,695	-	76	206,807
Proved Reserves Reported as of 12/31/01	1,227,998	119,271	-	897	1,348,166
Production Without Proved Reserves	99	3,911	-	-	4,010
Reserves Imputed for Production Without Proved Reserves	771	19,289	-	-	20,060
Subtotal Production	**190,135**	**20,606**	**-**	**76**	**210,817**
Subtotal Proved Reserves 2001	**1,228,769**	**138,560**	**-**	**897**	**1,368,226**
State Level Reported and Imputed Data					
Production with Reported Proved Reserves	-	29	448	700	1,177
Production without Reported Proved Reserves	1	40	523	327	891
Production Estimated from Auxillary data	-	-	121	-	121
Subtotal Production	1	69	1,092	1,027	2,189
Weighted Subtotal Production	**1**	**69**	**1,213**	**1,027**	**2,310**
Proved Reserves Reported	-	104	2,795	4,564	7,463
Reserves Imputed for Reported Production Without Proved Reserves	4	136	3,363	1,468	4,971
Reserves Estimated from Auxillary data	-	-	-	174	174
Subtotal Proved Reserves	4	240	6,158	6,206	12,608
Weighted Subtotal Proved Reserves	**4**	**240**	**6,332**	**6,032**	**12,608**
Total Production in 2001	**190,136**	**20,675**	**3,086**	**1,103**	**215,000**
Total Proved Reserves as of 12/31/01	**1,228,773**	**138,800**	**6,332**	**6,929**	**1,398,000**

– = Not applicable.

Notes: Table 15 totals include imputed and estimated lease condensate proved reserves rounded at the State/subdivision level. Field level data are reported volumes and may not balance due to submission of incomplete reserve component records.

Source: Form EIA-23, “Annual Survey of Domestic Oil and Gas Reserves,” 2001.

Imputation of Year-End Proved Reserves

Category I operators were required to submit year-end estimates of proved reserves. Category II and Category III operators were required to provide year-end estimates of proved reserves only if such estimates existed in their records. Some of these respondents provided estimates for all of their operated properties, others provided estimates for only a portion of their properties, and still others provided no estimates for any of their properties. All respondents did, however, provide annual production data. The production reported by Noncertainty sample operators and the corresponding imputed reserves were weighted to estimate the full noncertainty stratum when calculating reserves and production as previously described in the section “Total U.S. Reserves Estimates” in this appendix.

R/P Function

A year-end proved reserves estimate was imputed from reported production data in each case where an estimate was not provided by the respondent. A R/P function was derived and used to calculate a reserves-to-production (R/P) ratio, based on operator size and the geographic region where the operator’s properties were located. The R/P function has the following functional form for each geographic region:

*Calculated P/[P+R] = Beta * EXP(Alpha * ln (1 + MOS))*

- *Alpha, Beta* = Regional Coefficients (calculated).
- *MOS = Measure of size* for a respondent, which is equal to the barrel oil equivalent volume of a respondent’s 2001 oil, gas, and condensate production (in units of thousand barrels per year).

Table F6 lists the coefficients used for each region and the number of observations on which it was based. The regional areas used are similar to the National Petroleum Council Regions (**Figure F1**). These regions generally follow the boundaries of geologic provinces wherein the stage of resource development tends to be somewhat similar.

Once the R/P ratio was obtained for an operator, it could be multiplied by the reported or estimated production to give a proved reserves estimate. Operators that had production plus end of year reserves equal to zero were excluded from the respondents selected to calculate the R/P coefficients.

In 2001, the R/P function was used to estimate the proved reserves of all noncertainty operators in these States -- Texas, California, Colorado, Louisiana, Montana, New Mexico, South Dakota, Utah, and Wyoming, rather than rely on a weighted sample. These States were chosen for this new procedure because of the many years of historical production and reserves data within EIA and availability of reliable State government and commercial production data for these States. This technique improved the correlation of EIA data with State and commercial production data, and reduced the burden of reporting and analysis on both EIA and the noncertainty operators in these States.

Table F6. Statistical Parameters of Reserves Estimation Equation by Region for 2001

Region Number	Region	Number of Nonzero R/P Pairs Oil	Gas	LC	Equation Coefficients Oil Alpha	Oil Beta	Gas Alpha	Gas Beta	LC Alpha	LC Beta
1	Alaska	7	7	0	-0.1331	0.3956	-0.1170	0.3465	-0.0816	0.3921
2	Pacific Coast States	45	58	4	-0.1331	0.3426	-0.1170	0.4123	-0.0816	0.6527
2A	Federal Offshore Pacific	5	5	0	-0.1331	0.2644	-0.1170	0.2979	-0.0816	0.3921
3	Western Rocky Mountains	83	131	53	-0.1331	0.3169	-0.1170	0.2873	-0.0816	0.2201
4	Northern Rocky Mountains	174	150	44	-0.1331	0.3169	-0.1170	0.2873	-0.0816	0.2201
5	West Texas and East New Mexico	529	529	161	-0.1331	0.3127	-0.1170	0.3456	-0.0816	0.3853
6	Western Gulf Basin	542	859	555	-0.1331	0.4273	-0.1170	0.4223	-0.0816	0.3541
6A	Gulf of Mexico	70	137	112	-0.1331	0.6948	-0.1170	0.6550	-0.0816	0.5103
7	Mid-Continent	347	438	173	-0.1331	0.3333	-0.1170	0.3201	-0.0816	0.2234
8 + 9	Michigan Basin and Eastern Interior	83	59	11	-0.1331	0.2933	-0.1170	0.1863	-0.0816	0.2595
10 + 11	Appalachians	28	70	4	-0.1331	0.2933	-0.1170	0.1863	-0.0816	0.2595
	United States	1,913	2,443	1,117	-0.1331	0.4062	-0.1170	0.3944	-0.0816	0.3921

Source: Based on data filed on Form EIA-23,"Annual Survey of Domestic Oil and Gas Reserves, 2001".

Imputation of Annual Changes to Proved Reserves by Component of Change

Category II and Category III operators that do not keep reserves data were not asked to provide estimates of beginning-of-year reserves or annual changes to proved reserves by component of change, i.e., revisions, extensions, and discoveries. When they did not provide estimates, these volumes were estimated by either:

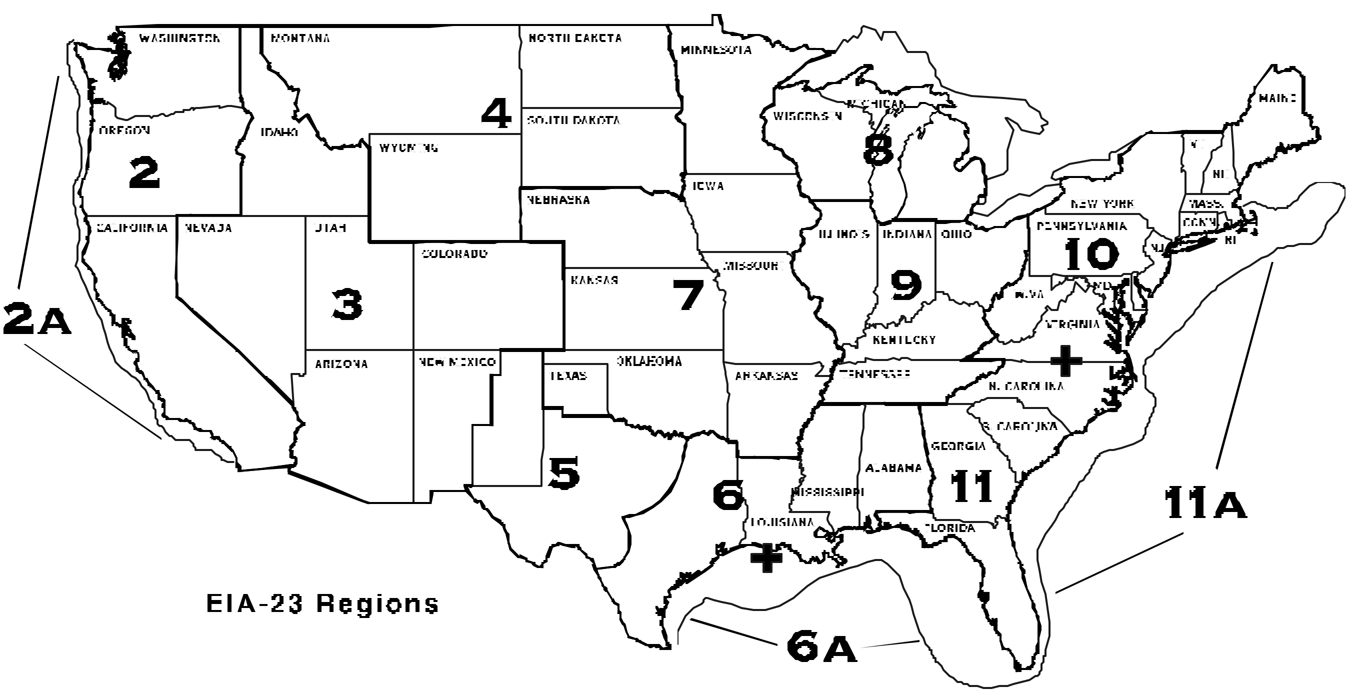
- applying an algebraic allocation scheme which preserved the relative relationships between these items within each State/subdivision, as reported by Category I and Category II operators, or
- applying a modified version of the R/P function to each separate component of change, calculated with its own set of geographically dependent coefficients. This method was used in all four states where the R/P Function was applied to calculate end of year reserves.

Both methods preserved an exact annual reserves balance of the following form:

Published Proved Reserves at End of Previous Report Year
+ Adjustments
+ Revision Increases
– Revision Decreases
– Sales
+ Acquisitions
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Published Proved Reserves at End of Report Year

The algebraic allocation method used for all but nine states in the 2001 survey worked as follows: A ratio was calculated as the sum of the annual production and year-end proved reserves of those respondents who did not provide the reserves balance components, divided by the sum of year-end proved reserves and annual production of those respondents of similar size who did provide these quantities. This ratio was then

Figure F1. Form EIA-23 Regional Boundaries



Source: Energy Information Administration, Office of Oil and Gas.

multiplied by each of the reserves balance components reported by Category I and some Category II operators, to obtain imputed volumes for the reserves balances of the other Category II operators and Certainty and Noncertainty operators. These were then added to the State/subdivision totals.

Imputation of Natural Gas Type Volumes

Operators in the State/subdivision certainty and noncertainty strata were not asked to segregate their natural gas volumes by type of natural gas, i.e., nonassociated natural gas (NA) and associated-dissolved natural gas (AD). The total estimated year-end proved reserves of natural gas and the total annual production of natural gas reported by, or imputed to, operators in the State/subdivision certainty and noncertainty strata were, therefore, subdivided into the NA and AD categories, by State/subdivision, in the same proportion as was reported by Category I and Category II operators in the same area.

Adjustments

The instructions for Schedule A of Form EIA-23 specify that, when reporting reserves balance data, the following arithmetic equation must hold:

Proved Reserves at End of Previous Year
+ Revision Increases
– Revision Decreases
– Sales
+ Acquisitions
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
– Report Year Production
= Proved Reserves at End of Report Year

Any remaining difference in the State/subdivision annual reserves balance between the published previous year-end proved reserves and current year-end proved reserves not accounted for by the imputed reserves changes was included in the adjustments for the area. One of the primary reasons that adjustments are necessary is the instability of the Noncertainty operators sampled each year. There is no guarantee that in the smaller producing States/subdivision the same number of small operators will be selected each year, or that the operators selected will be of comparable sizes when paired with operators selected in a prior year. Thus, some instability of this stratum from year to year is unavoidable, resulting in minor adjustments.

Some of the adjustments are, however, more substantial, and could be required for any one or more of the following reasons:

- The frame coverage may or may not have improved between survey years, such that more or fewer Certainty operators were included in 2001 than in 2000.
- One or more operators may have reported data incorrectly on Schedule A in 2000 or 2001, but not both, and the error was not detected by edit processing.
- Operation of properties was transferred during 2001 from operators not in the frame or Noncertainty operators not selected for the sample to Certainty operators or Noncertainty operators selected for the sample.
- Respondent changed classification of natural gas from NA to AD or vice versa.
- The trend in reserve changes imputed for the small operators, that was based on the trend reported by the large operators, did not reflect the actual trend for the small operators.
- Noncertainty operators, who have grown substantially in size since they were added to the frame, occasionally cause a larger standard error than expected.
- The Noncertainty sample for either year in a state may have been an unusual one.

The causes of adjustments are known for some but not all areas. The only problems whose effects cannot be expected to balance over a period of several years are those associated with an inadequate frame or those associated with any actual trend in reserves changes for small operators not being the same as those for large operators. EIA continues to attempt to improve sources of operator data to resolve problems in frame completeness.

Sampling Reliability of the Estimates

The sample of Noncertainty operators selected is only one of the large number of possible samples that could have been selected and each would have resulted in different estimates. The standard error or sampling error of the estimates provides a measure of this variability. When probability sampling methods are used, as in the EIA-23 survey, the sampling error of estimates can also be estimated from the survey data.

The estimated sampling error can be used to compute a confidence interval around the survey estimate, with a prescribed degree of confidence that the interval covers the value that would have been obtained if all operators in the frame had been surveyed. If the estimated volume is denoted by $\hat{V}_s$ and its sampling error by S.E. ($\hat{V}_s$), the confidence interval can be expressed as:

$$\hat{V}_s \pm k\, S.E.(\hat{V}_s)$$

where k is a multiple selected to provide the desired level of confidence. For this survey, k was taken equal to 2. Then there is approximately 95 percent confidence that the interval:

$$\hat{V}_s \pm 2S.E.(\hat{V}_s)$$

includes the universe value, for both the estimates of reserves and production volumes. Correspondingly, for approximately 95 percent of the estimates in this report, the difference between the published estimate and the value that would be found from a complete survey of all operators is expected to be less than twice the sampling error of the estimate. **Tables F7 and F8** provide estimates for 2S.E. ($\hat{V}_s$) by product. These estimates are directly applicable for constructing approximate 95 percent confidence intervals. For example, the 95 percent confidence interval for dry natural gas proved reserves is 183,460 ± 1,037 billion cubic feet. The sampling error of $\hat{V}_s$ is equal to the sampling error of the noncertainty estimate $\hat{V}_{sr}$, because the certainty total is not subject to sampling error. The estimated sampling error of a noncertainty estimate is the square root of its estimated sampling variance.

The noncertainty estimate for a given State/subdivision had two separately weighted components based on reports of:

- **Type 1 Operators** shown in the frame as having crude oil or natural gas production in the State/subdivision.
- **Type 2 Operators** shown in the frame as having no crude oil or natural gas production in the State/subdivision.

Correspondingly, the sampling variance had two components associated with the estimated production from each component:

$$Var(\hat{V}_{sr}) = Var(\hat{V}_{sr1}) + Var(\hat{V}_{sr2})$$

The *Var(Vsr)* was estimated as the sum of the estimated variances of the two component estimates. The variance for any component, say component *j*, was estimated from the formula:

$$Var(\hat{V}_{srj}) = n_{srj}\left(\frac{W_{srj}-1}{W_{srj}}\right)S^2_{srj}$$

In general, $\hat{V}_{srj}$ denotes the production estimate from component *j* for each of the two types of operator, and $Var\left(\hat{V}_{srj}\right)$ denotes its variance where:

n_{srj} = Number of operators in sample in component *j*

w_{srj} = Weight for operator reports in component *j*

S^2_{srj} = variance between operator reports in component *j*.

If the subscripts *sr* are dropped, S^2_{srj} can be expressed as:

$$S_j^2 = \frac{\sum_i^{n_j} V_{ji}^{'2} - \left(\sum_i^{n_j} V_{ji}^{'}\right)^2 / n_j}{n_j - 1}$$

Where

$V_{ji}^{'}$ = Weighted production or reserves volume for the *i*-th sample operator in the component *j*.

The variance of the estimated total volume for a State having subdivisions is the sum of corresponding Type 1 and Type 2 components where the classification of operators by type is with regard to the State as a whole; e.g. Type 2 operators at the State level are those that were not shown in the sample frame as having production anywhere in the State.

Since there are no operators in the frame who would be classified as Type 2 at the U.S. level, there would be no Type 2 components at the U.S. Level. Therefore, at the U.S. Level, there was only one sample variance component calculated for Type 1 operators.

Nonsampling Errors

Several sources of possible error, apart from sampling error, are associated with the Form EIA-23 survey. These include bias due to nonresponse of operators in the sample, proved reserve estimation errors, and reporting errors on the part of the respondents to the survey. On the part of EIA, possible errors include inadequate frame coverage, data processing error, and errors associated with statistical estimates. Each of these sources is discussed below. An estimate of the

Table F7. Factors for Confidence Intervals (2S.E.) for Crude Oil Proved Reserves and Production, 2001
(Million Barrels of 42 U.S. Gallons)

State and Subdivision	2001 Reserves	2001 Production
United States	33	5
Alabama	2	0
Alaska[a]	0	0
Arkansas	12	2
California[b]	0	0
Coastal Region Onshore[b]	0	0
Los Angeles Basin Onshore[b]	0	0
San Joaquin Basin Onshore[b]	0	0
State Offshore[a]	0	0
Colorado[b]	0	0
Florida[a]	0	0
Kansas	15	1
Kentucky	10	1
Louisiana[b]	0	0
North[b]	0	0
South Onshore[b]	0	0
State Offshore[a]	0	0
Michigan	0	0
Mississippi	4	1
Montana[b]	0	0
New Mexico[b]	0	0
East[b]	0	0
West[b]	0	0
New York	0	0
North Dakota	24	5
Ohio	7	0
Oklahoma	12	1
Pennsylvania	0	0
Texas[b]	0	0
RRC District 1[b]	0	0
RRC District 2 Onshore[b]	0	0
RRC District 3 Onshore[b]	0	0
RRC District 4 Onshore[b]	0	0
RRC District 5[b]	0	0
RRC District 6[b]	0	0
RRC District 7B[b]	0	0
RRC District 7C[b]	0	0
RRC District 8[b]	0	0
RRC District 8A[b]	0	0
RRC District 9[b]	0	0
RRC District 10[b]	0	0
State Offshore[a]	0	0
Utah[b]	7	1
Virginia[a]	0	0
West Virginia	1	0
Wyoming[b]	0	0
Federal Offshore[a]	0	0
Pacific (California)[a]	0	0
Gulf of Mexico (Louisiana)[a]	0	0
Gulf of Mexico (Texas)[a]	0	0
Miscellaneous[d]	11	1

[a]Sampling rate was 100 percent in Alaska, Florida Onshore, Virginia, and Offshore areas.
[b]Sampling was not used. Estimates for each operator were made using an imputation function.
[c]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Notes: Confidence intervals are associated with Table 6 reserves and production data. Factors for confidence intervals for each State and the United States are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 2001.

Table F8. Factors for Confidence Intervals (2S.E.) for Natural Gas Proved Reserves and Production, Wet After Lease Separation, 2001
(Billion Cubic Feet at 14.73 psia and 60 Degrees Fahrenheit)

State and Subdivision	2001 Reserves	2001 Production
United States	213	22
Alabama	0	0
Alaska[a]	0	0
Arkansas	35	6
California[b]	0	0
Coastal Region Onshore[b]	0	0
Los Angeles Basin Onshore[b]	0	0
San Joaquin Basin Onshore[b]	0	0
State Offshore[b]	0	0
Colorado[b]	0	0
Florida[a]	0	0
Kansas	58	7
Kentucky	23	3
Louisiana[b]	0	0
North[b]	0	0
South Onshore[b]	0	0
State Offshore[a]	0	0
Michigan	108	11
Mississippi	52	6
Montana[b]	0	0
New Mexico[b]	0	0
East[b]	0	0
West[b]	0	0
New York	102	4
North Dakota	27	7
Ohio	116	13
Oklahoma	70	9
Pennsylvania	0	0
Texas[b]	0	0
RRC District 1[b]	0	0
RRC District 2 Onshore[b]	0	0
RRC District 3 Onshore[b]	0	0
RRC District 4 Onshore[b]	0	0
RRC District 5[b]	0	0
RRC District 6[b]	0	0
RRC District 7B[b]	0	0
RRC District 7C[b]	0	0
RRC District 8[b]	0	0
RRC District 8A[b]	0	0
RRC District 9[b]	0	0
RRC District 10[b]	0	0
State Offshore[a]	0	0
Utah[b]	0	0
Virginia[a]	0	0
West Virginia	55	3
Wyoming[b]	0	0
Federal Offshore[a c]	0	0
Pacific (California)[a]	0	0
Gulf of Mexico (Louisiana)[a c]	0	0
Gulf of Mexico (Texas)[a]	0	0
Miscellaneous[d]	1	0

[a]Sampling rate was 100 percent in Alaska, Florida Onshore, Virginia, and Offshore areas.
[b]Sampling was not used. Estimates for each operator were made using an imputation function.
[c]Includes Federal offshore Alabama.
[d]Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Nevada, Oregon, South Dakota, and Tennessee.
Notes: Confidence intervals are associated with Table 8 reserves and production data. Factors for confidence intervals for each State and the United States are independently estimated and do not add.
Source: Factor estimates based on data filed on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves," 2001

bias from nonresponse is presented in the section on adjustment for operator nonresponse.

Assessing the Accuracy of the Reserve Data

The EIA maintains an evaluation program to assess the accuracy and quality of proved reserve estimates gathered on Form EIA-23. Field teams consisting of petroleum engineers from EIA's Reserves and Production Division conduct technical reviews of reserve estimates and independently estimate the proved reserves of a statistically selected sample of operator properties. The results of these reviews are used to evaluate the accuracy of reported reserve estimates. Operators are apprized of the team's findings to assist them in completing future filings. The magnitude of errors due to differences between reserve volumes submitted by operators on the Form EIA-23 and those estimated by EIA petroleum engineers on their field trips were generally within accepted professional engineering standards.

Respondent Estimation Errors

The principal data elements of the Form EIA-23 survey consist of respondent estimates of proved reserves of crude oil, natural gas, and lease condensate. Unavoidably, the respondents are bound to make some estimation errors, i.e., until a particular reservoir has been fully produced to its economic limit and abandoned, its reserves are not subject to direct measurement but must be inferred from limited, imperfect, or indirect evidence. A more complete discussion of the several techniques of estimating proved reserves, and the many problems inherent in the task, appears in Appendix G.

Reporting Errors and Data Processing Errors

Reporting errors on the part of respondents are of definite concern in a survey of the magnitude and complexity of the Form EIA-23 program. Several steps were taken by EIA to minimize and detect such problems. The survey instrument itself was carefully developed, and included a detailed set of instructions for filing data, subject to a common set of definitions similar to those already used by the industry. Editing software is continually developed to detect different kinds of probable reporting errors and flag them for resolution by analysts, either through confirmation of the data by the respondent or through submission of amendments to the filed data. Data processing errors, consisting primarily of random keypunch errors, are detected by the same software.

Imputation Errors

Some error, generally expected to be small, is an inevitable result of the various estimations outlined. These imputation errors have not yet been completely addressed by EIA and it is possible that estimation methods may be altered in future surveys. Nationally, 4 percent of the crude oil proved reserve estimates, 4 percent of the wet natural gas proved reserve estimates, and 3 percent of the lease condensate proved reserve estimates resulted from the imputation and estimation of reserves for those Certainty and Noncertainty operators who did not provide estimates for all of their properties, in combination with the expansion of the sample of Noncertainty operators to the full population. Errors for the latter were quantitatively calculated, as discussed in the previous section. Standard errors, for the former, would tend to cancel each other from operator to operator, and are, therefore, expected to be negligible, especially at the National level of aggregation. In States where a large share of total reserves is accounted for by Category III and smaller Category II operators, the errors are expected to be somewhat larger than in States where a large share of total reserves is accounted for by Category I and larger Category II operators.

Frame Coverage Errors

Of all the sources of controllable error connected with the Form EIA-23 survey, errors in the operator frame were expected to be the most important. If the frame does not list all operators in a given State, the sample selected from the frame for the State will not represent the entire operator population, a condition called under coverage. Under coverage is a problem with certain States, but it does not appear to be a problem with respect to the National proved reserve estimates for either crude oil or natural gas. While it is relatively straightforward to use existing sources to identify large operators and find addresses for them, such is not the case for small operators. A frame such as that used in the 1999 survey is particularly likely to be deficient in States where a large portion of total reserves and production is accounted for by small operators. These States are not likely to allocate sufficient resources to keep track of all operators on a current basis. Some under coverage of this type seems to exist, particularly, with reference to natural gas operators. EIA is continuing to work to remedy the under coverage problem in those States where it occurred.

Calculation of Reserves of Natural Gas Liquids and Dry Natural Gas

Natural Gas Liquids Reserve Balance

The published reserves, production, and reserves change statistics for crude oil, lease condensate, and natural gas, wet after lease separation, were derived from the data reported on Form EIA-23 and the application of the imputation methods discussed previously. The information collected on Form EIA-64A was then utilized in converting the estimates of the wet natural gas reserves into two components: plant liquids reserve data and dry natural gas reserve data. The total natural gas liquids reserve estimates presented in **Table 14** were computed as the sum of plant liquids estimates (**Table 15**) and lease condensate (**Table 16**) estimates.

To generate estimates for each element in the reserves balance for plant liquids in a given producing area, the first step was to group all natural gas processing plants that reported this area as an area-of-origin on their Form EIA-64A, and then sum the liquids production attributed to this area over all respondents. Next, the ratio of the liquids production to the total wet natural gas production for the area was determined. This ratio represented the percentage of the wet natural gas that was recovered as natural gas liquids. Finally, it was assumed that this ratio was applicable to the reserves and each component of reserve changes (except adjustments), as well as production. Therefore, each element in the wet natural gas reserves balance was multiplied by this recovery factor to yield the corresponding estimate for plant liquids. Adjustments of natural gas liquids were set equal to the difference between the end of previous year reserve estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Natural Gas Reserve Balance

This procedure involved downward adjustments of the natural gas data, wet after lease separation, in estimating the volumes of natural gas on a fully dry basis. These reductions were based on estimates of the gaseous equivalents of the liquids removed (in the case of production), or expected to be removed (in the case of reserves), from the natural gas stream at natural gas processing plants. Form EIA-64A collected the volumetric reduction, or **shrinkage**, of the input natural gas stream that resulted from the removal of the NGL at each natural gas processing plant.

The shrinkage volume was then allocated to the plant's reported area or areas of origin. Because shrinkage is, by definition, roughly in proportion to the NGL recovered, i.e. the NGL produced, the allocation was in proportion to the reported NGL volumes for each area of origin. However, these derived shrinkage volumes were rejected if the ratio between the shrinkage and the NGL production (gas equivalents ratio) fell outside certain limits of physical accuracy. The ratio was expected to range between 1,558 cubic feet per barrel (where NGL consists primarily of ethane) and 900 cubic feet per barrel (where NGL consists primarily of natural gasolines). When the computed gas equivalents ratio fell outside these limits, an imputed ratio was utilized to estimate the plant's natural gas shrinkage allocation to each reported area of origin.

This imputed ratio was that calculated for the aggregate of all other plants reporting production and shrinkage, and having a gas equivalent ratio within the aforesaid limits, from the area in question. The imputed area ratio was applied only if there were at least five plants to base its computation on. If there were less than five plants, the imputed ratio was calculated based on all plants in the survey whose individual gas equivalents ratio was within the acceptable limits. Less than one percent of the liquids production was associated with shrinkage volumes imputed in this manner. Based on the 2001 Form EIA-64A survey, the national weighted average gas equivalents ratio was computed to be 1,397 cubic feet of natural gas shrinkage per barrel of NGL recovered. The total shrinkage volume (reported plus imputed) for all plants reporting a given area of origin was then subtracted from the estimated value of natural gas production, wet after lease separation, yielding dry natural gas production for the area. The amount of the reduction in the wet natural gas production was then expressed as a percentage of the wet natural gas production. Dry natural gas reserves and reserve changes were determined by reducing the wet natural gas reserves and reserve changes by the same percentage reduction factor.

A further refinement of the estimation process was used to generate an estimate of the natural gas liquids reserves in those States with coalbed methane fields. The States where this procedure was applied were Alabama, Colorado, Kansas, New Mexico, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming. The first step in the process was to identify all Form EIA-23 reported coalbed methane fields. The assumption was made that coalbed methane fields contained little or no extractable natural gas liquids. Therefore, when the normal shrinkage procedure was applied to the wet gas volume reserve components, the estimate of State coalbed methane volumes were excluded and were not reduced for liquid extraction. Following the computation for shrinkage, each coalbed field gas volume reserve components was added back to each of the dry gas volume reserve components in a State. The effect of this is that the large increases in reserves in some States from coalbed methane fields did not cause corresponding increases in the State natural gas liquids proved reserves.

Adjustments of dry natural gas were set equal to the difference between the end of previous year reserves estimates, based upon the current report year Form EIA-23 and Form EIA-64A surveys, and the end of current year reserve estimates published in the preceding year's annual reserves report.

Each estimate of end of year reserves and report year production has associated with it an estimated sampling error. The standard errors for dry natural gas were computed by multiplying the wet natural gas standard errors by these same percentage reduction factors. **Table F7** provides estimates for 2 times the $S.E.(\hat{V}_s)$ for dry natural gas.