STATE OF NEW YORK

DIVISION OF TAX APPEALS

In the Matter of the Petitions of **RICHARD SIEGAL (ESTATE OF), GAIL SIEGAL, ADMINISTRATOR** for Redetermination of Deficiencies or for Refund of Personal Income Tax under Article 22 of the Tax Law for the Years 2001 and 2002.	:	DETERMINATION DTA NOS. 826661 AND 826750

Petitioner, Richard Siegal (Estate of), Gail Siegal, Administrator, filed petitions for redetermination of deficiencies or for refund of personal income tax under article 22 of the Tax Law for the years 2001 and 2002.

A hearing was held before Barbara J. Russo, Administrative Law Judge, in New York, New York, on October 19, 20, and 21, 2016, with all briefs and additional submissions due by December 28, 2017, which date began the period for the issuance of this determination pursuant to Tax Law § 2008 (2). Petitioner appeared by Latham & Watkins LLP (Miriam L. Fisher, Esq., and Brian C. McManus, Esq., of counsel). The Division of Taxation appeared by Amanda Hiller, Esq. (Kathleen D. O'Connell, Esq., of counsel).

ISSUES

I. Whether the issuance of the notice of deficiency for tax year 2002 was barred pursuant to the three-year statute of limitations set forth in Tax Law § 683 (a) or was valid pursuant to the exception thereto set forth in Tax Law § 683 (c) (1) (B), which provides that tax may be assessed at any time if a false or fraudulent return is filed with the intent to evade tax.

II. Whether the notices of deficiency for tax year 2001 were barred pursuant to the three-year statute of limitations set forth in Tax Law § 683 (a) or were valid pursuant to the exception thereto set forth in Tax Law former § 683 (c) (11) (B), which provides that tax may be assessed at any time within six years after the return was filed if the deficiency was attributable to an abusive tax avoidance transaction.

III. Whether the Division of Taxation has met its burden of proving fraud for the assertion of an additional penalty for fraud for tax year 2001.

IV. Whether penalties asserted pursuant to Tax Law § 685 (b) (1), (2), and former (p), and Chapter 61 of the Laws of 2005, Part N, § 11 (l) should be abated.

FINDINGS OF FACT

1. Richard Siegal was a New York resident throughout the 2001 and 2002 tax years.

2. Mr. Siegal timely filed New York State personal income tax returns for the years 2001 and 2002 pursuant to extensions on October 15, 2002 and October 15, 2003, respectively.[1]

3. Mr. Siegal filed form 1040 U.S. Individual Income Tax Returns for the years 2001 and 2002.

4. On August 12, 2003, following an audit of PW&F-W-01 Drilling Company and PW&F-S-01 Drilling Company for tax year 2001, PW&F-W-00 Drilling Company for tax years 2000 and 2001, and PW&F-S-00 Drilling Company for tax year 2000, the Division of Taxation's (Division's) Tax Shelter Unit issued correspondence stating that based on the information provided, the Division had closed its audit and inquiry into the matter, and that no further action

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[1] The Division of Taxation entered unsigned copies of Mr. Siegal's 2001 and 2002 New York State and Federal income tax returns into the record, but was unable to produce signed returns or transcripts of the original filed returns.

was required. PW&F-W-01 Drilling Company and PW&F-S-01 Drilling Company are included in Mr. Siegal's partnerships for which the Division is alleging fraud in this matter for 2001.

5. On November 28, 2003, following a review of Mr. Siegal's personal income tax returns, including his federal Schedule E for the years 1999, 2000, and 2001, the Division's Tax Shelter Unit issued correspondence stating that, based on the information provided, the Division closed its audit and inquiry into the matter and that no further action was required.

6. In September 2005, the Division's Income/Franchise Field Audit Bureau initiated an audit of Mr. Siegal's 2002 through 2004 resident income tax returns. The primary issue identified during the pre-audit stage was verification of losses reported by Mr. Siegal on his Schedule E. The Division requested, and was provided with, some information from Mr. Siegal's then representative and tax preparer, Richard Guralnick. In or about the spring of 2006, the Division's Desk Audit Bureau of the Tax Shelter Unit identified two other New York State audit cases involving intangible drilling costs of other taxpayers invested in Siegal-related partnerships that the Division believed might be questionable. Further investigation by the Division of the tax preparer, Richard Guralnick, led to the discovery of approximately 100 oil and gas partnerships, including Belle Isle Drilling Company, all of which used the same firm to prepare their partnership returns. In August 2006, the Field Audit Bureau was contacted by the Division's Tax Shelter Unit, and was informed that Mr. Siegal had been identified in a tax shelter audit. On May 29, 2007, the Division determined to include tax years 2001, 2005 and 2006 in the audit period, based on a six-year statute of limitations for understatements resulting from purported tax shelter activity. In December 2007, the Division sent an information document request (IDR) to Mr. Siegal for the additional audit years of 2001, 2005 and 2006.

7. In response to the IDR, on or about April 1, 2008, Mr. Siegal's representative provided copies of all K-1s issued to Mr. Siegal for the additional audit years of 2001, 2005 and 2006, copies of partnership agreements with related turnkey drilling contracts and notes, prospect agreements, listing of wells, subscription agreements and notes, assumption agreements and note repayment histories for the various oil and gas entities as to which the Division had inquired, in addition to other information.[2]

8. Between 2007 and 2008, Division field auditors and the Internal Revenue Service (IRS) in Houston, Texas, cooperated on their respective audits of the oil and gas partnerships. The Division was provided with copies of many partnership documents and transcripts of interviews with principals and investors in oil and gas partnerships run by Mr. Siegal.[3]

9. On May 14, 2008, the Division sent waivers to extend the statute of limitations for issuing assessments for the years 2001 through 2004 to Mr. Siegal's representative. On May 28, 2008, Mr. Siegal's representative informed the Division that he would not sign a waiver for 2001, as he disputed any tax shelter activity, but would sign waivers for the years 2002 through

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[2] A statement in the Division's audit report for 2001, which states that "[n]o documentation was submitted by the representative for tax year 2001" is directly contradicted by the Division's Tax Field Audit Record, which states that the above information was provided (***see*** Exhibit U, Tax Field Audit Record entries dated 04/01/08 - 04/04/08, 04/07/08, 04/09/08, 04/10/08, 04/15/08, 04/17/08, 04/22/08 ["continued reviewing the large volume of documents submitted by the representative relating to the tax shelter issues"], 05/19/08 ["There is considerable documentation and the review is still in progress"]). Additionally, testimony of the Division's current auditor, James Fahrenkopf, that the previous auditor did not mention in his field audit report what documents he received from Mr. Siegal for 2001 is directly contradicted by the entries in the tax field audit record dated April 1 and 2, 2008.

[3] The IRS issued a number of no-change letters for various Siegal related partnerships and entities, including a letter dated December 8, 2006 to Bistate Oil Management Corp., stating that the IRS completed the examination of Bistate Oil Management's 2004 return and made no changes to the tax reported, and no adjustment letters dated June 20, 2005 to Jocelyn Drilling Company, PAL/ZAV/Williston Associates, and GHKB&W-S99 Associates for tax year 1999, stating that they completed their review of the partnerships' returns and are not proposing any adjustments.

2004, which were part of the original audit.[4] As the six-year statute of limitations was close to expiring for the year 2001, the Division decided to issue an assessment for that year.

10. Although the Division's Tax Field Audit Record and Report of Audit indicate that the audit period began as 2002 through 2004, and was then expanded to include 2001, 2005 and 2006, the last entry in the Tax Field Audit Report, dated July 17, 2008, references only the issuance of the assessment for tax year 2001. The Tax Field Audit Record and Report of Audit do not discuss the issuance of an assessment for 2002. The Division's auditor at that time, Jacob Schmookler, did not issue an assessment to petitioner for 2002.[5]

Tax Year 2001 Notices

11. On August 25, 2008, the Division issued to Mr. Siegal a notice of deficiency, notice number L-030599015, for the tax year ended December 31, 2001, asserting a deficiency of income tax in the amount of $474,401.00, penalties of $207,447.08, plus interest in the amount of $272,576.17. The deficiency resulted from the Division's disallowance of losses reported on Mr. Siegal's 2001 Schedule E that flowed through to him from oil and gas partnerships.

Attached to the Division's Field Audit Report and Tax Field Audit Record is a detail of adjustments showing total disallowed losses of $7,866,549.00. However, Mr. Siegal's share of intangible drilling costs reported for 2001 totaled $7,168,553.00. Of this, the amount of deductions claimed for the 2001 drilling partnerships at issue in this matter totaled $7,030,941.00 (***see*** Appendix A). There was no explanation for the discrepancy.

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[4] The Division has not submitted any waivers into the record.

[5] The Division's current auditor, James Fahrenkopf, testified that Mr. Schmookler did not issue an assessment for 2002 because, "[h]is audit report indicates that he was under the impression that the 2002 tax year was being covered by an IRS audit." Mr. Fahrenkopf's testimony is directly contradicted by the audit report, which does not contain any indication that Mr. Schmookler contemplated that 2002 would be covered by an IRS audit, and instead specifically states, "The audit will continue for years 2002 through 2006 under a separate case number."

Included in the losses disallowed by the Division in 2001 were intangible drilling costs claimed by Mr. Siegal for his proportionate share in Impact Drilling and Cottonwood Drilling, which were unleveraged, cash only partnerships, with no note component. The Division's current auditor, Mr. Fahrenkopf, testified that he does not know the basis for that disallowance.

12. On September 15, 2008, the Division issued to Mr. Siegal a notice of deficiency, notice number L-030651187, asserting an additional penalty in the amount of $272,576.17 for tax year 2001, based on an alleged failure to participate in a voluntary compliance initiative.[6]

13. On January 15, 2014, petitioner and the Division participated in a Conciliation Conference with the Bureau of Conciliation and Mediation Services (BCMS) in relation to notices of deficiency numbers L-030599015 and L-030651187, for tax year 2001. By conciliation order dated October 31, 2014, the conciliation conferee sustained the statutory notices.

14. At some point prior to the conciliation conference, the Division lost its audit file for Mr. Siegal's 2001 tax year.

[6] The Division initially failed to introduce this jurisdictional document into the record. During the hearing in this matter, the Division had introduced a different notice of deficiency, number L-040978086, dated April 14, 2014, asserting that it was the subject notice of deficiency for the voluntary compliance penalty. A review of notice of deficiency number L-040978086 reveals that, contrary to the Division's assertion, this notice assessed a penalty in the amount of $227,000.00, related to the alleged promotion of tax shelter transactions pursuant to Tax Law § 685 (bb). Notice number L-040978086 was not a subject of the petitions filed herein and was not at issue in this matter. This notice was previously canceled by the Division, as indicated in correspondence dated September 16, 2014 from the Division's auditor, Mr. Fahrenkopf, to Becker Tax Controversy Group, LLC. Subsequent to the closure of the record in this matter and the submission of briefs, upon review of the record and briefs in preparation of the rendering of this determination, the undersigned discovered the absence of the jurisdictional document, notice number L-030651187, notified the parties, and reopened the record for the limited purpose of addressing the issue of the missing jurisdictional document, pursuant to ***New York State Dept. of Taxation & Fin. v Tax Appeals Trib.***, 151 Misc 2d 326 (1991). Upon submission by the Division, the correct notice of deficiency was subsequently accepted into the record.

15. On January 23, 2015, petitioner filed a petition with the Division of Tax Appeals seeking review of notice of deficiency numbers L-030599015 and L-030651187 for tax year 2001.

16. On April 8, 2015, the Division filed its answer to petitioner's petition, related to tax year 2001, affirmatively asserting fraud as a new, alternative ground for the deficiency and asserting additional penalties for fraud. The answer specifically references only notice number L-030599015.

Tax Year 2002 Notice

17. In preparation for the conciliation conference for tax year 2001, the Division's auditor from the Tax Shelter Unit, James Fahrenkopf, discovered that an assessment had not been issued to petitioner for the 2002 tax year. Mr. Fahrenkopf notified the audit division, which did nothing in response at that time.

18. Subsequently, the decision to assert a fraud assessment against Mr. Siegal for 2002 was made by the Division's Office of Counsel. Mr. Fahrenkopf testified that the assessment for 2002 was issued at the directive of the Division's Office of Counsel, that the Division's audit section did not make a determination as to fraud, and that he did not know exactly what Office of Counsel looked at to make the determination as to fraud. Mr. Fahrenkopf further testified that Mr. Siegal's level of control over the partnerships was material to the Division's determination of fraud, but that the Office of Counsel made that determination and he did not know the facts upon which the determination was made.

When questioned regarding the Division's disallowance of intangible drilling cost deductions, Mr. Fahrenkopf testified as follows:

> A: "I did not conduct the 2001 audit at all. That was conducted in the field. The 2002 were taken as Schedule E - - for the petitioner were taken as Schedule E nonpassive losses, to which, when we were instructed by Office of Counsel to issue the bill for fraud, we disallowed."
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> Q: "So what was the basis for the disallowance?"
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> A: "At the direction of Office of Counsel that we were registering a level of fraud."
>
> Q: "And what was the basis for the accusation of fraud?"
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> A: "I don't have the basis for the accusation of fraud."

Mr. Fahrenkopf later testified that the Division's fraud determination related to the intangible drilling costs, which in his opinion were "grossly inflated" and marked up 500% from the actual costs. Mr. Fahrenkopf testified that he computed markup as the markup of the capital available in the partnerships as compared to the actual cost to drill the fractional interests in the oil wells that were in each partnership.

In response to further questioning regarding the Division's fraud determination, Mr. Fahrenkopf testified that:

> "petitioner has been forming and participating in these partnerships since the early 80's. We have solid evidence of that from at least 1992 forward. I have heard continuous testimony about how entrenched and how knowledgeable he was in the oil and gas industry, and to see the petitioner consistently, year after year after year, create these partnerships and mark them up with this - - with the same - - I only have 2001 and 2002. I have no reason to believe that the other years at issue - - they [sic] other years weren't equally marked up, and he continued to do so."
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> Q: "And why was it improper for him to markup the turnkey contracts, assuming he did?"
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> A: "Well, we've heard testimony that the industry standards are 25 to 30%. He was marking it up 500% to take advantage of the intangible drilling cost rules."

Q: "So it's the testimony of the markup that's influencing the determination of the fraud allegation?"

A: "That's my opinion on it."

19. Mr. Fahrenkopf calculated purported markup percentages of Palace Exploration Company's (Palace) turnkey drilling contract prices. Mr. Fahrenkopf initially testified that his markup calculations were based on a ratio of the costs assigned to the partners in the Drilling Partnerships through the turnkey drilling contracts to the actual costs of drilling the partnerships' Portfolio Wells. However, Mr. Fahrenkopf later testified that his calculations were based on a ratio of the value of the partners' cash and subscription note contributions to the limited payments that Palace made to third-party drilling vendors.[7] Neither Mr. Fahrenkopf nor his audit team conducted any specific research regarding the pricing and profit margins of turnkey drilling companies in 2002. Mr. Fahrenkopf was unaware if anyone from the Division's audit division performed such research for 2001.

20. Mr. Fahrenkopf did not know if anyone from the Division reviewed or determined Palace's overhead costs for drilling the wells, how much Palace paid for geological analysis of prospect wells, how much Palace spent obtaining and analyzing seismic data, how much Palace paid in salaries, or whether any of those amounts were included in the data that the Division used to determine Palace's purported profit or "markup."

21. The Division did not compare the authorizations for expenditures to the drilling costs expended by Palace as reported in the Bistate System.

[7] Mr. Fahrenkopf testified the he used data from the report of petitioner's expert, Mr. Plastino, for his calculations. The data that Mr. Fahrenkop used includes only payments made to third-party vendors and does not include a large array of costs, including those associated with evaluating well prospects and forming, capitalizing, and administering the oil and gas exploration ventures.

22. Mr. Fahrenkopf conceded that he did not have any reason to doubt or question the accuracy of the reports produced in the Bistate System.

23. Mr. Fahrenkopf testified that, "I don't know that I ever decided that the [turnkey drilling] contract price was too high."

24. During 2013, Mr. Fahrenkopf sent over 100 information document requests (IDRs) to the various partnerships at issue inquiring about the status of the turnkey notes. Based on the responses, Mr. Fahrenkopf concluded that the principal amount on the notes remained outstanding. However, he did not compare the original principal amounts to all the responses he received in order to determine whether any principal had been paid, because "I got three boxes, full boxes of responses. I did not review every single response that was given to me."

25. On December 18, 2013, the Division issued to petitioner a notice of deficiency, notice number L-040539321, for tax year 2002, asserting personal income tax due in the amount of $1,094,491.36, plus penalties in the amount of $2,760,311.69, based on fraud (Tax Law § 685 [e]), substantial understatement (Tax Law § 685 [p]), and failure to participate in the voluntary compliance initiative (Chapter 61 of the Laws of 2005, Part N, section 11 [l]), and interest in the amount of $1,307,680.73.

The 2002 notice of deficiency states that, "We have disallowed $15,748,500 of Schedule E deductions related to the following entities as reported on your return: Bateman Lake Drilling Co., Black Creek Drilling Co., Centrahoma Drilling Co., PWF-W02 Drilling Co., Mayfield Drilling Co., RCCP-02 Associates; Red River Drilling Co.; Silver Spike Co" (the 2002 partnerships).[8]

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[8] The amount of deductions disallowed by the Division for the listed 2002 partnerships exceeds the actual amount of deductions reported for those partnerships on the copy of Mr. Siegal's return that the Division submitted into the record ***(see*** Appendix B). The amount of intangible drilling costs reported on the copy of Mr. Siegal's K-1

26. On or about January 21, 2014, petitioner timely protested the notice of deficiency for tax year 2002 by filing a request for a conference with BCMS.[9] By conciliation order dated November 14, 2014, the conferee sustained the statutory notice for tax year 2002.[10]

27. On December 15, 2014, petitioner filed a petition with the Division of Tax Appeals seeking review of the notice of deficiency for tax year 2002.

28. On February 25, 2015, the Division filed its answer to the petition for tax year 2002.[11] This answer contained general denials and did not contain an assertion of tax fraud.

29. The Division filed an amended answer with respect to the petition for tax year 2002. The amended answer contained more detailed allegations regarding the basis for the Division's assertion of tax fraud than contained in the original answer.[12]

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reconciliation worksheets for the listed 2002 partnerships totals $14,423,816.00 and the total amount of losses reported on the copy of Mr. Siegal's Schedule E for those partnerships totals $12,682,099.00 (passive and nonpassive). There was no explanation in the record as to why the amount of deductions disallowed by the Division for the listed 2002 partnerships exceeds the amount of deductions actually claimed for those partnerships.

[9] During the hearing, the Division introduced the request for conference as Exhibit G, and described it as a request for the 2001 tax year. A review of the document reveals that the request pertains to tax year 2002, not 2001 as stated by the Division at the hearing.

[10] The conciliation order, dated November 14, 2014, was not submitted into the record by either party. Although the copy of the petition for tax year 2002 presented by the Division as Exhibit D does not contain a copy of the conciliation order, the original petition for 2002 filed with the Division of Tax Appeals contains the conciliation order. Since there is no dispute as to the content or issuance of the conciliation order, I take official notice of the order, as maintained in the files of the Division of Tax Appeals (***see*** State Administrative Procedure Act § 306 [4], which provides that "[o]fficial notice may be taken of all facts of which judicial notice could be taken and of other facts within the specialized knowledge of the agency." ***See also Berger v Dynamic Imports, Inc.***, 51 Misc 2d 988, 989, 274 NYS2d 537, 540 [1966]; ***Matter of Kolovinas,*** Tax Appeals Tribunal, December 28, 1990, holding that courts of the State of New York may take judicial notice of their own record of the proceeding of the case before them, their own records of cases involving one or more of the same parties or their own records of cases involving different parties).

[11] The caption of the Division's answer, presented into the record by the Division as Exhibit D-2, references tax year 2001 rather than 2002. Based on the evidence in the record, it is determined that this was a typographical error, and the answer dated February 25, 2015 pertains to tax year 2002.

[12] The amended answer is dated February 24, 2015, a date which precedes the date of the original answers for both 2001 and 2002 (***see*** Findings of Fact 16 and 28). The caption of the amended answer states "for the Year(s)/Period(s) Ending 2001," but the amended answer references DTA #826661, which is the Division of Tax Appeals case number assigned to the petition for tax year 2002. The Division introduced the amended answer into

Industry Background

30. Drilling wells to explore for oil and gas can be a costly and risky endeavor.

31. Leases must be acquired to obtain the rights to explore for oil and natural gas. Usually the party acquiring leases (acquiring party) performs a preliminary investigation of prospective areas, which may entail regional geologic study, offset well log analysis, and seismic analysis.

32. Once the acquiring party identifies an area where it intends to pursue activity, it must obtain the rights to explore for oil and gas, typically accomplished by leasing the subsurface exploration and development rights from mineral owners.

33. The operator is generally the party who acquires the lease and who initially holds all of the working interest.

34. The lessor typically retains a royalty interest in the potential well, generally in the range of 12.5% to 25%. The lessor may also receive a "lease bonus" that can range from $100.00 to over $10,000.00 per acre. Prospect generators may also receive an overriding royalty interest as compensation, which can increase total lease burdens to as high as 40%.

35. As new development areas become active, operators become very competitive in acquiring significant, strategic acreage blocks, resulting in significant capital investment long

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the record as Exhibit C-2, and identified it as, "the amended answer with regard to the 2001 tax year." The Division's proposed findings of fact in its post-hearing brief asserts that the amended answer is for 2002 and petitioner did not object. The body of the amended answer denies the petition's paragraphs one through eight. The petition for 2001 only has five paragraphs, while the petition for 2002 has eight paragraphs. The amended answer does not reference any notice number and the body of the answer does not state the tax year or the amount assessed, but does reference fraud. Upon review of the Order of Administrative Law Judge Bray in ***Matter of the Estate of Richard Siegal***, Division of Tax Appeals, February 18, 2016, it is noted that the Division requested leave to amend its answer for tax year 2002, and that on November 20, 2015, the Division of Tax Appeals granted the Division's request. As contained in the files of the Division of Tax Appeals, attached to the Division's request to file an amended answer for 2002, is the Division's amended answer for DTA # 826661, dated February 24, 2015, as described above. Based on the complete record, it is determined that the amended answer pertains to tax year 2002, that the reference to tax year 2001 in the caption of the answer is a typographical error, and the date of the answer is likewise a typographical error. Pursuant to Judge Bray's order, the amended answer was filed on December 12, 2015 (***see Matter of the Estate of Richard Siegal***, Division of Tax Appeals, February 18, 2016).

before an area believed to contain well prospects can be thoroughly evaluated for its oil and gas development potential.

36. Consequently, a large amount of risk falls on the operator. To relieve some of that risk, investors in the oil and gas industry employ many types of investment strategies to raise capital for the acquisition, exploration, drilling, evaluation, and development of oil and gas ventures.

37. Once mineral leases are acquired, additional geologic evaluation may be necessary before a legitimate drilling prospect is identified.

38. Operators often engage seismic companies to conduct seismic surveys to better understand subsurface geologic formations and attributes.

39. Seismic surveys are expensive to conduct and process. Survey companies typically must: (1) pay for authorization from surface land owners for access; (2) place sensitive receiving instruments called geophones over a considerable area and generate sound waves via an explosive charge or generated vibrations; (3) measure the sound waves; and (4) process the data for geologists to interpret.

40. Other techniques to identify drilling prospects include analyzing offset activity by obtaining drilling records, mud logs, and electric logs from nearby wells, as well as using technical displays such as log cross sections and complex 3-D mapping.

41. Geologists perform a large amount of interpretive work to understand and map the subsurface attributes, utilizing multiple lines of processed seismic data in order to interpret the stratigraphy and structures thousands of feet below the surface. From this data, they attempt to determine whether there appears to be potential hydrocarbon reservoirs that warrant further investigation.

42. Interpreting and mapping seismic data carries significant risk. Many assumptions are formulated based on the data and informed technical interpretations. However, geologists often can only identify conditions that are favorable for containing oil and gas deposits. Although a great deal of time, effort, and capital goes into developing prospects and attempting to mitigate the inherent risks in drilling, the only real way to determine whether a reservoir contains commercially recoverable quantities of hydrocarbons is by drilling a well.

43. Some operators choose to accept the risk of retaining 100% of the cost of developing the well. However, as a result of the great risks and capital required for drilling wells, operators typically attempt to reduce their exposure by taking on partners in a project.

44. By sharing the risks and costs with partners, an operator is able to diversify its portfolio and participate in a range of drilling activities from high risk exploration to lower risk drilling in areas offsetting existing oil and gas development. Cost sharing also allows an operator to invest in a greater number of opportunities.

45. Partners receive a share of the working interest as part of the participation, and are referred to as working interest owners.

46. A working interest is an ownership interest in the well, with the responsibility for paying a share of expenses of a well, including drilling costs and lease operating expenses. For example, a partner with a working interest of 10% in a well is obligated to pay for 10% of the costs.

47. In the oil and gas industry, well drillers and operators allocate and distribute revenue to investors in accordance with the investors' percentage of the well's "net revenue interest." Net revenue interest is not synonymous with working interest because net revenue interest expresses

the percentage of a well's revenues that a person receives, while working interest expresses the portion of the well's costs that a person must pay.

48. Certain individuals, such as those who hold an overriding royalty interest, may receive a percentage of revenues but are not responsible for expenses. Such parties commonly include property lessors, but may also be any other party as specified by contract (e.g., a prospect generator; ***see*** Finding of Fact 34).

49. There is a wide variety of participants in the oil and gas industry that fund their operations in diverse ways, such as larger oil and gas companies that finance drilling activities from cash flow, and small or individual investors, private equity and other investment funds and drilling partnerships. Operators may choose to join with other industry partners, joint venture partnerships, individual outside investors, or drilling partnerships composed of non-industry investors.

50. It is not uncommon for non-industry investors who have no experience or knowledge to participate in oil and gas drilling ventures.

51. Non-industry investors would not necessarily have the expertise to evaluate potential prospects or understand the investment opportunity and technical risks.

52. Non-industry investors typically rely on the expertise of others to evaluate potential drilling projects, review well data and cost estimates from operators, review the bills issued to working interest owners by operators showing the calculation of the amount owed by a particular working interest owner for a variety of expenses related to the drilling, maintenance, and operation of a well (joint interest billing statements or JIB), ensure that the bills are paid and revenues are received and accounted for correctly.

53. When a well project is being prepared, a large number of service providers are assembled in order to perform all of the tasks necessary for successfully drilling the well. The operator is the party that acquires the lease and assumes the working, or cost, interest, and also determines whether to add partners, in which case those partners would receive a proportionate share of the working interest. The operator provides an estimate of the costs of drilling and completing the well, also known as the authority for expenditure or authorization for expenditure (AFE), often gleaned from price quotations from providers of specific drilling activities, including line item detail of all the intangible drilling costs (IDC) and tangible drilling costs (TCD), based on the operator's best estimate of costs, which could have been adversely affected by unexpected complexities and other drilling risks.

54. Actual drilling costs may, and frequently do, exceed the AFE estimate, including any contingency, due to the complexities and risks involved in the drilling. Cost overruns can occur as much as 80% of the time and can be as high as 200%.

55. Oil and gas exploration routinely involves subcontracting. Expertise is valuable and hard to find, and operators are willing to contract for it.

Drilling Contract Types

56. Typically, the primary service that must be engaged is the drilling contractor. This contractor is responsible for providing the drilling rig and personnel for performing the drilling operations.

57. Well operators typically hire drilling contractors on a day rate basis, footage basis, or turnkey basis.

58. A footage contract is based on a specified rate per foot drilled. A day rate contract specifies that the operator pays for services based on the drilling contractor's daily billing rate for the rig and its crew. In this scenario, all risks of drilling operation are borne by the operator. If

the well-drilling process takes additional days beyond the estimate, the operator must pay the drilling contractor its daily billing rate for those additional days.

59. The day rate contract method of drilling is the least expensive on a daily basis for working interest owners. However, because all risks of cost overruns falls on the working interest owners, they must have the necessary experience and wherewithal to manage the drilling operation effectively and assume the risks. The majority of wells drilled in the United States are drilled on a day rate basis.

60. Turnkey drilling arrangements are also common in the oil and gas industry. Under this arrangement, a turnkey driller accepts a fixed fee for developing oil and gas wells up to the "turnkey point," which in this case was when the completed wells entered production and were connected to the tanks. In return, a turnkey driller is generally obligated to cover all costs, including cost overruns, incurred in the drilling process prior to the commencement of production.

61. A turnkey drilling agreement eliminates much of the operational risk of drilling a well for oil and gas investors and caps costs. The turnkey arrangement provides "insurance" that risks and uncertainties are borne by the drilling contractor, not the working interest owner. A turnkey contract offers cost inflation insurance to investors.

62. In the case of drilling investment partnerships, the fixed price guarantee of a turnkey drilling contract may be attractive to partners who would prefer to pay costs for participation in a drilling project at a fixed rate before the commencement of the project, without having to weather a wide range of risks and fluctuations in drilling costs for a diversified portfolio of prospects.

63. Turnkey drilling arrangements impose significant risks to the turnkey driller, as the costs of drilling can vary widely, and accidents and environmental damage during drilling can

cost many millions of dollars to resolve. In exchange for taking higher risk, drillers can charge a higher rate with turnkey contracts.

Drilling Risks

64. After a well is underway, it may encounter any of a variety of operational risks, such as high-pressure intervals that create an uncontrolled flow of fluids to the surface known as a blowout, low-pressure intervals that cause the operator to lose circulation of drilling fluids, weather issues, and equipment malfunction. For example, the blowout in British Petroleum PLC's (BP's) Macondo Prospect resulted in the death of 11 oil workers, injuries to 17 other personnel, the complete loss of the Deepwater Horizon drilling rig, several lawsuits, and severe environmental and economic damage to the Gulf Coast region.

65. If these risks materialize, liability for the costs of the consequences can increase drilling costs to hundreds of times the original AFE estimates. For example, the total financial burden to BP for the Macondo Prospect is approximately $44 billion, over 700 times (i.e., 70,000%) greater than its 65% working-interest share of the original AFE estimate to participate in the Macondo Prospect.

66. Without a turnkey contract, general partners in oil and gas drilling partnerships would be exposed to unlimited liability for cost overruns by virtue of their working interests.

67. Once the well reaches total depth, there are additional reservoir risks, including the risks that the target formation is not present, subsurface faulting has modified the geologic assumptions resulting in a reduction of the target, or the target formation is present but the pore space is full of water and not hydrocarbons.

68. Many wells that are drilled do not get completed as the evaluation conducted at the "casing point" (the point at which drilling ceases and pipe casing can be run and cemented in the drilled hole) suggests that commerciality cannot be achieved.

69. Wells may also be completed based on the casing point evaluation, only to find out that post-completion production rates do not measure up to expectations.

70. In cases where oil and gas are not present or recoverable in commercial quantities, the well is commonly described as a "dry hole." The process for concluding work at a dry hole, plugging and cementing the well in accordance with regulations, and returning the land to its prior condition is called "plugging and abandonment."

71. There can be a wide range in drilling and completion costs, even when wells are drilled in close proximity to each other. Wells that are close in distance and drilled to similar depths may encounter different geological impediments such as subterranean pressures, fault blocks, and different drilling protocols of different operators. Additionally, drilling and completion activities offshore carry more risk and the potential for excessive costs.

Industry Practices Regarding Turnkey Drilling Pricing

72. In exchange for the turnkey driller assuming the risks of the operations, turnkey drilling contracts are more costly to investors than a day rate basis for drilling.

73. Specifically, when determining the price of a turnkey drilling contract, a reasonable drilling contractor would take into account the following factors:

a) estimated costs of the drilling rig and crew;

b) project management and supervision;

c) required drilling and support services;

d) the depth of the well;

e) the complexity of the operations;

f) anticipated reservoir pressures to be encountered;

g) potential technical risks and opportunities for unexpected cost overruns;

h) potential environmental and other liability;

i) overhead requirements; and

j) desired profit margins.

74. The price of a turnkey drilling contract for a diversified portfolio of prospects is not a "one size fits all" formula; each project must be considered separately. In the case of the partnerships at issue herein, many different wells were drilled to a variety of formations and depths, and in a wide variety of locations.

75. Petitioner's oil and gas expert, Michael Krehel, Jr., P.E., opined that a reasonable driller would separately evaluate the anticipated costs and risks to drill each well to ensure that the total turnkey contract price would be sufficient to at least cover the driller's anticipated costs. A reasonable driller would also develop a cost estimate with the expectation that each well would be completed to the tank as the turnkey point. Once the driller accounted for the costs of the services it was providing, the final price would incorporate the driller's insurance needs, its view on the potential profitability of the wells, its desired profit, and the state of the market.

Mr. Siegal's Background

76. Mr. Siegal had participated in the oil and gas industry since the 1970s. His business was engaged in the exploration and drilling of oil wells and partnering with others in the oil and gas industry. He was experienced in selecting potential oil and gas properties for development and negotiating drilling contracts and other related financial arrangements, and created partnerships to participate in oil and gas drilling ventures. These partnerships were designed to be eligible to deduct IDCs in the first year of operation.

77. Mr. Siegal died on February 9, 2010.

78. Mr. Siegal owned and controlled Palace, Bistate Oil Distribution Corp. (Bistate Distribution), and Bistate Oil Management Corp. (Bistate Oil Management) during the years at issue.

79. Palace is an Oklahoma corporation.

80. Bistate Distribution is a New York corporation and Palace affiliate.

81. At all relevant times, Bistate Distribution was engaged in the business of receiving proceeds and paying expenses associated with the sale of oil and gas on behalf of the drilling partnerships at issue herein and distributing revenue among the various stakeholders of the drilling partnerships in accordance with their respective interests.

82. Bistate Oil Management is a New York corporation and Palace affiliate.

83. Bistate Oil Management provided general administrative services for Palace, Bistate Distribution and the drilling partnerships at issue herein, including maintaining a financial database on behalf of Palace-related companies and the drilling partnerships.

84. Bistate Distribution and Bistate Oil Management maintained an electronic database referred to as the "Bistate System" which tracked financial information related to the oil and gas drilling and exploration projects.

85. Brian Grosser, Assistant Comptroller of Bistate Oil Management, employed there since 1984, testified that the Bistate System accurately allocated and distributed revenue due to, and expenses incurred by, the drilling partnerships at issue in accordance with the partnerships' working interest and net revenue interest in their wells.

86. The Division does not dispute the accuracy of the Bistate System.

87. Mr. Siegal and Palace had extensive experience and expertise in the oil and gas industry.

88. Palace partnered with various entities engaged in the drilling and development of oil and gas prospects in the United States and Canada, and acquired interests and farmout rights in various drilling prospects located in oil and gas producing regions of Louisiana, Texas, North Dakota, Oklahoma, Wyoming, the Gulf of Mexico, and Canada.

89. Mr. Siegal and Palace worked with other industry participants, such as Crest Resources, an oil and gas operator based in Tulsa, Oklahoma, to generate potential prospects and participate in drilling projects.

90. When Palace received a prospect proposal, it (or a third-party consultant) would conduct an evaluation of its merits. If the well presented an opportunity to make money, Palace would select the well for inclusion in a portfolio of wells.

91. Palace and its affiliated entities have been involved in drilling approximately 3,000 wells which produced over 1 trillion cubic feet of gas and 125 million barrels of oil.

92. At all relevant times, Palace was engaged in the business of acquiring interests in oil and gas properties and assigning portions of those interests to partnerships, including the drilling partnerships at issue herein (the Drilling Partnerships).[13]

93. The Drilling Partnerships are general partnerships, each formed in accordance with the Partnership Law of the State of New York, pursuant to an Agreement and Certificate of Partnership ("Partnership Agreement").

94. Mr. Siegal established the Drilling Partnerships, which enabled non-industry participants to invest in a portfolio of wells. Mr. Siegal and Palace assembled portfolios of wells and allocated fractional working interests in the wells to the Drilling Partnerships. Mr. Siegal selected the wells to be drilled for the portfolios.

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[13] The Drilling Partnerships at issue herein for 2001 are: Redfish Bay Drilling Company (Redfish Bay), Impact Drilling Company (Impact), PW&F-S-01 Drilling Company (PW&F-S-01), Belle Isle Drilling Company (Belle Isle), Bayou Drilling Company (Bayou), Cottonwood Drilling Company (Cottonwood), PW&F-W-01 Drilling Company (PW&F-W-01), Sanoroc Drilling Company (Sanoroc), and Challenger Drilling Company (Challenger). The Drilling Partnerships at issue herein for 2002 are: Bateman Lake Drilling Company (Bateman), Black Creek Drilling Company (Black Creek), Centrahoma Drilling Company (Centrahoma), Mayfield Drilling Company (Mayfield), PW&F-W-02 Drilling Company (PW&F-W-02), RCCP-02 Associates (RCCP-02), Red River Drilling Company (Red River), and Silver Spike Drilling Company (Silver Spike).

95. Mr. Siegal was a general partner in the Drilling Partnerships and invested in the Drilling Partnerships along with unrelated investors during the years at issue.

96. When Palace was operating, Mr. Siegal was on the phone with his operators on a daily basis. He worked with a network of different operators, engineers, geologists, and prospect evaluators, using his own grading system to determine whether he should invest.

97. In areas where Mr. Siegal lacked technical expertise, especially seismic interpretation, he and Palace engaged geophysicists to evaluate the prospects and double check the work of prospect generators, drillers, and operators with other industry experts.

98. The stated purpose of the Drilling Partnerships, pursuant to the partnership agreements, was to invest in the acquisition, development and drilling of oil and gas leases, and to produce and sell hydrocarbons.[14]

99. The Drilling Partnerships entered into Prospect Agreements with Palace, under which they were conveyed percentage working interests in portfolios of prospective oil and gas drill sites, giving them the right to explore, drill and produce oil and gas from the well prospects and obligating the partnerships to pay a corresponding share of the cost of drilling, producing and operating the wells.[15]

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[14] The partnership agreements for Belle Isle, Cottonwood, Bateman, Black Creek, Centrahoma, Mayfield, RCCP-02, Red River, and Silver Spike were entered into the record. While the majority of these agreements were unsigned, the parties do not dispute their authenticity. The partnership agreements for the other Drilling Partnerships were not entered into the record. The parties agree that the Belle Isle partnership agreement is generally representative of the other partnership agreements, with exceptions indicated herein, including differing prices to purchase an interest in the varying partnerships and the division between cash and notes, differing duties of the managing partner and management fees, differing managing partners and turnkey drillers, differing maximum units per partnership offered, and differing terms of the notes used to fund some of the partnerships. Petitioner's expert witness, David Plastino, reviewed the partnership agreements for all of the Drilling Partnerships in preparation of his expert report.

[15] For example, pursuant to the Prospect Agreement between Palace, Belle Isle, Bistate Distribution, and Oil & Gas Title Holding Corp., Palace assigned to Belle Isle a portion of its rights in and to the prospect wells in the Belle Isle portfolio, in return for consideration of $135,000.00. The agreement appoints a designated distributor "for all net cash receipts earned pursuant to the production and sale of oil and from the wells drilled on the Prospects herein conveyed less all operating expenses incurred in the production and sale of such oil and gas." The designated distributor is to charge $2,500.00 per year for these services. The Prospect Agreement further provides that Palace

Three of the Drilling Partnerships did not have Prospect Agreements, and instead had Participation Agreements, which provided that well interests would be transferred to the partnerships and that the partnerships would pay a turnkey drilling company to drill the wells.

100. With respect to the portfolios in which the Drilling Partnerships invested, many different wells were drilled to a variety of formations and depths, and in a wide variety of locations. The portfolios consisted of the Early 2001 Well Portfolio, which was composed of 38 wells; the Late 2001 Well Portfolio, which was composed of 37 wells; and the Late 2002 Well Portfolio, which was composed of 69 wells.

101. The type or number of prospects in the Drilling Partnerships' well portfolios was not unusual. Based on Palace's prospect lists, a person familiar with the oil and gas industry would be able to discern the following information:

a) The prospects were all located in states and areas known to produce oil and gas;

b) The formations that were the target zones covered by the prospect wells were also in zones from which oil and gas had been known to be produced;

c) A diverse set of wells was contemplated, including some offshore wells providing different risk profiles. The names of the wells also indicated that wells would be drilled in Louisiana, Oklahoma, and along the Gulf Coast. The Belle Isle prospect list also showed fractional working interests, ranging from less than 1% to 3.8%, which diversified the portfolio.

102. In some cases, the prospects were developmental wells, adjacent to and intended to offset existing oil and gas wells drilled by other industry operators; other prospects were exploratory.

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will deliver to Belle Isle a net revenue interest of 60% on every lease, reserving to itself as an overriding royalty the difference between the actual net revenue interest purchased by Belle Isle and the 60% net revenue interest delivered to Belle Isle. The Prospect Agreement calls for Richard Siegal's signature as president of Palace and as president of Bistate Distribution. It calls for Paul Howard's signature as president of Oil and Gas Title Holding Corp., and for George Coleman's signature as Managing Partner of Belle Isle. The Prospect Agreement entered into the record is unsigned by any of the named individuals.

103. Mr. Siegal contributed cash of $3,175,518.00 and $5,791,500.00 in total to the 2001 and 2002 Drilling Partnerships, respectively, and executed Subscription Notes totaling $5,243,000.00 and $9,957,000.00 in favor of the 2001 and 2002 Drilling Partnerships, respectively. The table below describes the breakdown and totals of petitioner's investments in the 2001 and 2002 Drilling Partnerships:

Partnership	Well Portfolio	Cash Invested	Notes Invested	Total Invested
Redfish Bay Drilling Co.	Early 2001	$150,000.00	$270,000.00	$420,000.00
Impact Drilling Co.	Early 2001	$17,427.00	-	$17,427.00
PW&F-S-01 Drilling Co.	Early 2001	$440,000.00	$800,000.00	$1,240,000.00
Belle Isle Drilling Co.	Late 2001	$460,000.00	$828,000.00	$1,288,000.00
Bayou Drilling Co.	Late 2001	$510,000.00	$765,000.00	$1,275,000.00
Cottonwood Drilling Co.	Late 2001	$3,091.00	-	$3,091.00
PW&F-W-01 Drilling Co.	Late 2001	$495,000.00	$900,000.00	$1,395,000.00
Sanoroc Drilling Co.	Late 2001	$600,000.00	$1,080,000.00	$1,680,000.00
Challenger Drilling Co.	Late 2001	$500,000.00	$600,000.00	$1,100,000.00
2001 Partnerships Total		**$3,175,518.00**	**$5,243,000.00**	**$8,418,518.00**
Bateman Lake Drilling Co.	Late 2002	$400,000.00	$600,000.00	$1,000,000.00
Black Creek Drilling Co.	Late 2002	$330,000.00	$594,000.00	$924,000.00
Centrahoma Drilling Co.	Late 2002	$480,000.00	$864,000.00	$1,344,000.00
Mayfield Drilling Co.	Late 2002	$710,000.00	$1,278,000.00	$1,988,000.00
PW&F-W-02 Drilling Co.	Late 2002	$594,000.00	$1,080,000.00	$1,674,000.00
RCCP-02 Associates	Late 2002	$1,320,000.00	$2,400,000.00	$3,720,000.00
Red River Drilling Co.	Late 2002	$1,320,000.00	$2,376,000.00	$3,696,000.00
Silver Spike Drilling Co.	Late 2002	$637,500.00	$765,000.00	$1,402,500.00
2002 Partnerships Total		**$5,791,500.00**	**$9,957,000.00**	**$15,748,500.00**
All Partnerships Total		**$8,967,018.00**	**$15,200,000.00**	**$24,167,018.00**

104. Each Drilling Partnership invested in the drilling of a distinct group of several wells (Portfolio Wells) (***see*** Finding of Fact 100) by paying a percentage of the costs of acquiring and evaluating the well prospects (Prospect Wells), and if commercially viable, of drilling and producing the wells.

105. Multiple Drilling Partnerships invested in the same Portfolio Wells, as follows:

Partnership	**Well Portfolio**	**Total Cash Invested**	**Total Notes Invested**	**Total Capital Invested**
Redfish Bay Drilling Co.	Early 2001	$2,879,192.00	$5,040,000.00	$7,919,192.00
Impact Drilling Co.	Early 2001	$2,045,454.00	-	$2,045,454.00
PW&F-S-01 Drilling Co.	Early 2001	$6,149,000.00	$11,180,000.00	$17,329,000.00
Belle Isle Drilling Co.	Late 2001	$4,034,468.00	$7,062,300.00	$11,096,768.00
Bayou Drilling Co.	Late 2001	$2,255,556.00	$3,300,000.00	$5,555,556.00
Cottonwood Drilling Co.	Late 2001	$618,182.00	-	$618,182.00
PW&F-W-01 Drilling Co.	Late 2001	$8,096,000.00	$14,720,000.00	$22,816,000.00
Sanoroc Drilling Co.	Late 2001	$3,768,657.00	$6,597,000.00	$10,365,657.00
Challenger Drilling Co.	Late 2001	$6,00,000.00	$7,200,000.00	$13,200,000.00
2001 Partnerships Total		**$35,846,509.00**	**$55,099,300.00**	**$90,975,809.00**
Bateman Lake Drilling Co.	Late 2002	$2,563,131.00	$3,750,000.00	$6,313,131.00
Black Creek Drilling Co.	Late 2002	$6,246,818.00	$10,935,000.00	$17,181,818.00
Centrahoma Drilling Co.	Late 2002	$5,475,948.00	$9,585,600.00	$15,061,548.00
Mayfield Drilling Co.	Late 2002	$4,850,000.00	$8,730,000.00	$13,580,000.00
PW&F-W-02 Drilling Co.	Late 2002	$8,140,000.00	$14,800,000.00	$22,940,000.00
RCCP-02 Associates	Late 2002	$10,780,000.00	$19,600,000.00	$30,380,000.00
Red River Drilling Co.	Late 2002	$11,821,139.00	$20,692,800.00	$32,513,939.00
Silver Spike Drilling Co.	Late 2002	$4,574,444.00	$5,370,000.00	$9,944,444.00
2002 Partnerships Total		**$54,451,480.00**	**$93,463,400.00**	**$147,914,880.00**
All Partnerships Total		**$90,297,898.00**	**$148,562,700.00**	**$238,860,689.00**

106. Each Drilling Partnership received a share of the revenues from the sale of oil and gas from its Portfolio Wells, in proportion to the net revenue interest they owned in each well.

107. The partnership agreement for each Drilling Partnership established the partnership, stated the purposes of the partnership, described certain operational details of the partnership, and established the price of an interest in each partnership. The partnership agreements also name a managing partner, which varied for each partnership.[16]

108. The partnership agreements for 15 of the 17 Drilling Partnerships at issue specified that the price of an interest would be paid in part with cash and in part by a full recourse promissory note made by the partner to the Drilling Partnership (the Subscription Note or Subscription Note Agreement). Partners invested in the Drilling Partnerships by executing Subscription Agreements, which outlined the price to be paid for each partnership unit, the total amount subscribed by the investor, and the division of the contribution between cash and note. As part of the Subscription Agreement, each partner was required to declare that his or her income and net worth were above certain benchmarks. For the partnerships funded in part by cash and in part by a note, the partner entered into a Subscription Note Agreement, establishing the terms of the note, including maturity date and interest rate. For example, the Belle Isle partnership agreement sets forth the purchase price for each unit in the partnership at \$280,000.00, with \$100,000.00 to be paid in cash and the remaining \$180,000.00 in the form of a promissory note. The Subscription Agreement between Belle Isle and the individual partners provides that the signatory partner subscribes for and agrees to purchase partnership units in

[16] George Coleman was the managing partner for Belle Isle, Bateman, Black Creek, Centrahoma, Red River, Redfish Bay, and Sanoroc. Mr. Coleman delegated certain responsibilities for Belle Isle to persons capable of executing them, including petitioner and Palace. Richard Siegal and Brad Reiss were managing partners for Cottonwood. Curtis Granet was managing partner for RCCP-02. Bippy Siegal was managing partner for Mayfield and Silver Spike. Rob Schoenahut was managing partner for PW&F-S-01 and PW&F-W-01. There is no information in the record as to the managing partners for the other Drilling Partnerships.

Belle Isle, at $280,000.00 per unit. The Belle Isle Subscription Note provides that the signatory partner will pay the non-cash portion of the subscription price on or before December 31, 2009, with interest at the rate of one percent through the end of the first year (2001), and at a rate of eight percent per annum thereafter.[17] Fifty percent of the signatory partner's share of partnership net operating revenues after payment of interest is to be applied in payment of the outstanding principal balance of the note. The Belle Isle Subscription Note provides that it is to be assigned to SS&T Oil Co., Inc., the turnkey driller.

Two of the partnerships at issue, Impact and Cottonwood, did not have a note component and were cash only.

The Subscription Note Agreements for the other Drilling Partnerships varied in some respects from that of Belle Isle's. These differences include, but are not limited to, the following: the Drilling Partnerships established in 2001 had an initial Subscription Note term of 8 years while those founded in 2002 had an initial 15-year term; the percentage of Drilling Partnership net operating revenues after the payment of interest to be applied to principal was 25% for several partnerships, rather than the 50% specified in the Belle Isle Subscription Note; and for some of the Drilling Partnerships, the interest charged on the Subscription Note principal between its issuance date and the end of the first year was 0.5% rather than 1%.

109. The Subscription Notes further referred to an Assumption Agreement delivered with the note, and provided that the Assumption Agreement would be delivered by the Drilling Partnership in connection with a promissory note drawn by the partnership as "maker" payable to the turnkey drilling company, and that the Subscription Note would be assigned by the partnership to the turnkey drilling company. Under the Assumption Agreement, investors in the

[17] The Subscription Notes contributed by the non-managing partners to the various Drilling Partnerships were recourse notes which generally bore interest at 8%, with the exception of the Subscription Note for RCCP-02, in which the note component bore interest at 5.3%.

partnerships funded with both cash and note agreed to assume liability for their pro rata share of the liabilities owed by the partnership to the turnkey drilling company, up to the amount of their Subscription Note obligations.

110. The Drilling Partnerships entered into turnkey drilling contracts with turnkey drilling companies, including SS&T Oil Co., Inc. (SS&T), Vail Drilling Company (Vail), TAQ, and THO, among others (the Turnkey Drilling Companies or Turnkey Driller) pursuant to which the Turnkey Drilling Companies agreed to facilitate the drilling of the Portfolio Wells and, if the wells were believed to be potentially productive, complete the oil and gas wells on prospective well sites and connect them to tanks or batteries for a fixed payment. Broadly, the Drilling Partnerships' turnkey contracts provided that the Turnkey Driller would commence or cause to be commenced actual drilling, which would continue until the turnkey point, defined as completion to the tank or plugging and abandonment, either occurring after the well reached the objective depth specified in the contract.[18]

111. The key terms of the Drilling Partnerships' turnkey drilling contracts were generally as follows:

a) Drilling Partnerships agreed to pay the turnkey price via cash and a recourse promissory note (the Turnkey Note) to drill the wells;[19]

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[18] The turnkey drilling contracts for the following partnerships were entered into the record: PW&F-S-01, PW&F-W-01, Redfish Bay, Sanoroc, Black Creek, and Belle Isle. The turnkey drilling contracts for the remaining Drilling Partnerships were not entered into the record. However, the parties agree that the Belle Isle turnkey contract is generally representative of the other turnkey contracts, with exceptions indicated herein, including differing turnkey drillers and prices, along with different breakdowns of cash and promissory note for each partnership. For example, the turnkey drilling contract between Belle Isle and SS&T provides, in part, that SS&T will commence or cause to be commenced the drilling of one well on each drill site for the consideration of $10,836,000.00. The turnkey drilling contract between PW&F-S-01 and Vail provides, in part, that Vail will commence or cause to be commenced the drilling of one well on each drill site for the consideration of $17,055,000.00. The turnkey contracts provide that the driller may sublet or assign any work required under the contract. Mr. Plastino reviewed all of the turnkey drilling contracts in preparation of his expert report.

[19] Cottonwood and Impact did not have a note component.

b) As collateral for the Turnkey Note, the Drilling Partnerships pledged their right, title, and interest in the production, wells, partners' Subscription Notes and all collateral securing the Subscription Notes;

c) The driller agreed to provide, at its sole cost, risk and expense, curative work on titles; staking of well locations, well access roads, and complete drilling rig and accessories to drill to total depth; cement and cementing services; drilling mud, weighting materials and chemicals; electric induction log of hole to desired depth; plug and abandonment per applicable regulatory requirements; all labor and third party services; and necessary liability and property insurance;

d) The turnkey point is defined as the point where the well has been drilled to desired depth and completed to the tank, battery or meter (for a successful well) or has been plugged and abandoned (for an unsuccessful well). After the turnkey point is reached, all costs would be borne by the Drilling Partnerships;

e) The Drilling Partnerships would not be responsible for any drilling cost overruns except those caused by extraordinary circumstances in the well (including an act of God, war, force majeure, or strike; an operational hazard that requires redrilling the well after the well has been drilled to more than 75% of the total required footage; or a decision by other third-party participants not to proceed to completion with the well);

f) The driller had the right to subcontract or assign any of the work required without the consent of the Drilling Partnerships; and

g) The driller agreed to indemnify and hold the Drilling Partnership harmless for losses resulting from a subcontractor's failure to satisfactorily perform required services.

112. The terms of the turnkey drilling contracts did not require the Turnkey Driller to drill the wells with its own rigs or with its own employees. Rather, it required that the Turnkey Drillers commence or cause to be commenced the drilling of each well, and permitted the Turnkey Drillers to subcontract any portion of the work, which was a common practice in the oil and gas drilling industry.

113. For the partnerships funded, in part, by Subscription Notes, the terms of the Turnkey Note mirrored the Subscription Note. Generally, the Turnkey Notes included terms establishing the amount of principal due, a maturity date, and an interest rate. The Turnkey Notes for each

partnership at issue were not entered into the record.[20] However, the parties agree that the terms of the Turnkey Notes were generally similar to the turnkey note between Belle Isle and the Turnkey Driller, SS&T, with certain differences, including the following: SS&T was not the sole turnkey drilling company; other entities were contracted to drill wells for other partnerships; the total turnkey drilling price, along with the breakdown of cash and promissory note, was different for each partnership; Turnkey Notes for the 2001 Drilling Partnerships had an initial 8-year term, while those for the 2002 Drilling Partnerships had an initial 15-year term; the percentage of net operating revenues diverted to pay down principal, after interest, was 25% for certain Drilling Partnerships, rather than the 50% diversion specified in the Belle Isle Turnkey Note; and three Drilling Partnerships did not charge interest from the time the Turnkey Note was signed to the end of the first year.

114. In the case of Belle Isle, the Turnkey Note provided that Belle Isle would pay SS&T $7,062,300.00 on December 31, 2009. Interest at a rate of 8% was payable from partnership net operating revenues. After interest was paid, 50% of remaining partnership net operating revenues would be available to repay principal.

115. The Turnkey Notes for the other partnerships at issue varied from Belle Isle, in part, as follows:

a) The principal amount of the Turnkey Notes varied by Drilling Partnership;

b) Most Turnkey Notes charged a lower interest rate through the end of the first year, and three charged no interest through the end of the first year;

c) For some partnerships, 25% of net operating revenues after interest went to pay principal on the Turnkey Notes. For others, 50% went to pay principal; and

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[20] The Turnkey Drilling Contracts and Turnkey Notes for the following partnerships were entered into the record: PW&F-S-01, PW&F-W-01, Redfish Bay, Sanoroc Drilling, Black Creek Drilling, and Belle Isle Drilling. Mr. Plastino reviewed the turnkey drilling contracts and turnkey notes for all of the Drilling Partnerships in preparation of his expert report.

d) Turnkey Notes for the 2001 Drilling Partnerships had an initial 8-year term, and Turnkey Notes for the 2002 Drilling Partnerships had an initial 15-year term.[21]

116. An interest rate of 8% is generally consistent with prevailing interest rates for debt instruments in 2001 and 2002.

117. The terms of the Turnkey Notes provide, in part, that:

> "No delay or omission on the part of the holder in exercising any right hereunder shall operate as a waiver of such right or of any other right of such holder, nor shall any delay, omission or waiver on any one occasion be deemed a bar to or waiver of the same or any other right on any future occasion. The Partnership and every endorser or grantor of this Note, regardless of the time order or place of signing, waive presentment, demand, protest and notices of every kind and assent to any extension or postponement of the time of payment or any other indulgence, to any substitution, exchange or release of collateral, and to the addition or release of any other party or person primarily or secondarily liable."

118. Petitioner's financial expert, David Plastino, CPA, opined that the terms of the Turnkey Notes are consistent with common practices for secured lending.

119. The Drilling Partnerships accurately allocated to Mr. Siegal the share of the partnerships' Turnkey Note liability for which he was responsible.

120. Members of Mr. Siegal's family, other than petitioner, owned the Turnkey Drilling Companies, but Mr. Siegal controlled them. Mr. Siegal determined the turnkey contract prices, and by extension, the face value of the turnkey notes.

121. As a result of the turnkey drilling contracts, the Turnkey Drilling Companies assumed the risk of the general partners in the Drilling Partnerships for the extreme cost overruns that can result from liability if operational risks materialize.

122. The price of the turnkey drilling contracts accounted for both the costs invoiced by and paid to third parties by Palace and the costs of the services provided by Palace related to sourcing and developing the drilling prospects. Those services included: evaluating well

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[21] The managing partners of the Drilling Partnerships could extend the maturity of the Turnkey Notes.

proposals, striking deals with other operators, forming and capitalizing the Drilling Partnerships, assuming all financial risks of cost overruns, insuring the Drilling Partnerships against all potential liabilities in connection with operations, and providing general administrative services with respect to the Drilling Partnerships. Palace spent millions of dollars per year on these expenses.

123. Palace fully paid all drilling-related costs for the Portfolio Wells. The total expenses paid by Palace to third parties alone to acquire, drill, and operate the Portfolio Wells in which Mr. Siegal invested in the years at issue was approximately $249,108,153.00.

124. Pursuant to the terms of the Drilling Partnerships' partnership agreements, cash flows would first be used to pay operating and partnership expenses.

125. Partners would then receive a preferred return for a specified period of time. Specifically, the investment proposals for the partnerships provided that the turnkey drilling companies would subordinate their rights to interest payments on the turnkey notes to priority cash distributions to partnership investors. The amount of that diversion varied from 8% to 10% per year and was for a period of 5 years.[22]

126. Once the preferred return was paid out or the preferred return period had passed, the remaining partnership funds would be used to pay any current or accrued interest on the notes.

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[22] Some of the preferred return could be diverted to purchase municipal bonds as collateral for the Subscription Notes, pursuant to the Additional Collateral for Subscription Note agreement (collateral agreement). The collateral agreement provided that as additional collateral for the payment of the Subscription Note, upon demand by the Drilling Partnership, the individual partner promises to assign to the Drilling Partnership state or municipal bonds registered in the name of the turnkey drilling company, having a rating of "A" or better, a maturity date of not less than 25 years, and a face value at maturity of not less than the original principal amount of the Subscription Note. The bonds were to be used as collateral for the partnership's turnkey note. The collateral agreement further provided that in lieu of delivering the bonds, the partner may pay the partnership a sum of money equal to 15% of the face value of the Subscription Note. The turnkey drilling company would then guarantee to invest the money at 7.88% compounded so that at the end of 25 years the sum would be equal to the principal amount of the note. Mr. Siegal did not exercise this option during the years at issue.

127. Finally, any remaining partnership funds at that point were split, half towards paying principal on the Turnkey Notes[23] and half distributed to the partners.[24]

128. Although some partners elected to collateralize the Subscription Note portion of their investment by using a portion of their partnership distributions to purchase municipal bonds or pay 15% of the face value of the Subscription Note for the turnkey driller to purchase such bonds, Mr. Siegal did not do so during the years at issue.[25]

Turnkey Note Interest Payments

129. A review of the documentation of the Drilling Partnerships demonstrates that some partnerships, such as Redfish Bay and Belle Isle, paid a portion of their Turnkey Note obligations. For example, in 2003, Belle Isle paid $129,000.00 toward interest on the note and Redfish Bay paid all of the $382,647.00 current and accrued interest that was outstanding, and paid a portion of the note principal.

130. Redfish Bay made payments of interest on its Turnkey Note in every year from 2003 through 2015, totaling $1,641,226.00.

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[23] Reduction in partners' proportionate share of the Drilling Partnerships' Turnkey Note liability would be credited against the partners' Subscription Note liability to the Drilling Partnership.

[24] Some of this payment could be diverted to purchase municipal bonds as collateral for the Subscription Notes (***see*** Footnote 22).

[25] In an email dated December 11, 2003 regarding a Siegal oil drilling venture not at issue herein, Mr. Siegal stated, "Since 1981 when we began structuring these ventures, no one has ever been required to pay any portion of their notes. If . . . the investor assigns part of his income from the venture to the driller to be used to purchase securities to secure the note, there is no event other than the failure of the issuer of the securities to pay the securities at maturity, that would require the investor to pay any part of the note." When questioned about this email during a deposition taken on February 20, 2009 in the ***Matter of RODA Drilling Company, et al v. Siegal, et al***, US District Court for the Northern District of Oklahoma, Mr. Siegal described the collateralization option, explaining that a partner assigns a portion of their income from the venture to purchase securities to act as collateral for the subscription note. The bonds are of long maturity, so that they will equal the face value of the note upon maturity. When the note becomes due, the cash from the matured bonds is used to pay off the notes. The partner is not released from their obligation on the note by the bond purchase. If the issuer of the bond defaulted, the partner would be liable for the outstanding amount of the note. Additionally, the record herein shows that the partners remained obligated to pay interest and principal from the well revenue (***see*** Findings of Fact 126, 127, 129 - 135).

131. By 2004, Belle Isle had paid interest of $129,000.00 on its Turnkey Note liability. Belle Isle made payments of interest on its Turnkey Note in 2003, 2004, 2006, 2010-2012, and 2015, totaling $274,508.00.

132. Bateman made payments of interest on its Turnkey Note in 2010 through 2015, totaling $81,533.00.

Turnkey Note Principal Payments

133. In 2002, Redfish Bay made a principal payment of $245,185.00 on its Turnkey Note liability.

134. In 2003, Redfish Bay made a principal payment of $11,725.00.

135. In 2003, Belle Isle repaid an advance of $25,000.00.

136. Repayments of principal reduced Mr. Siegal's portion of the outstanding turnkey notes with respect to his interests in the Drilling Partnerships.

Distributions to Drilling Partnership Partners

137. The Drilling Partnerships made distributions to investors that comprised a priority return during certain years (less, for electing partners, an amount withheld for the purchase of collateral for their Subscription Note liabilities), and cash available after the payment of interest and a portion of principal (half of any remaining funds would be paid towards principal, and half distributed to the partners) (***see*** Findings of Fact 125 - 128).

138. Mr. Siegal received $75,049.00 in checks from Redfish Bay through April 2007, $244,882.00 in checks from Belle Isle through October 2010, and $191,259.00 in checks from Bateman through July 2010.

139. Total proceeds allocated to petitioner from Redfish Bay, Belle Isle, and Bateman for the same period were $146,870.00, $264,741.00, and $191,259.00, respectively. Of these

amounts, $58,058.00 was allocated to interest and $13,763.00 was allocated to principal repayment for Redfish Bay, and $19,859.00 was allocated to interest for Belle Isle.

Well Production, Revenue, and Expenses

140. Of the 38 wells in the Early 2001 Portfolio, 24 produced oil and gas in commercial quantities. These wells generated over 2.2 million barrels of oil and almost 80 billion cubic feet of natural gas, which sold for over $521,000,000.00.

141. Of the 37 wells in the Late 2001 Portfolio, 22 produced oil and gas in commercial quantities. These wells generated over 2.8 million barrels of oil and almost 67 billion cubic feet of natural gas, which sold for over $547,000,000.00.

142. Of the 69 wells in the Late 2002 Portfolio, 36 produced oil and gas in commercial quantities. These wells generated almost 1.7 million barrels of oils and 82.5 billion cubic feet of natural gas, which sold for $610,000,000.00.

143. The share of net revenues (gross revenue less share of lease operating expenses and severance taxes) allocable to each Drilling Partnership's working interest, is as follows:

a) Early 2001 Portfolio
1. Redfish Bay: $3,263,828.00
2. Impact: $2,691,670.00
3. PW&F-S-01: $6,793,031.00

b) Late 2001 Portfolio
1. Belle Isle: $2,360,430.00
2. Bayou: $1,343,663.00
3. Cottonwood: $443,443.00
4. PW&F-W-01: $4,821,530.00
5. Sanoroc: $2,253,064.00
6. Challenger: $4,775,954.00

c) Late 2002 Portfolio
1. Bateman Lake: $911,478.00
2. Black Creek: $2,091,627.00
3. Centrahoma: $1,186,645.00
4. Mayfield: $1,695,048.00
5. PW&F-W-02: $2,810,359.00

6. RCCP-02: $2,949,324.00
7. Red River: $3,360,128.00
8. Silver Spike: $1,517,049.00

144. Palace fully paid all the drilling-related costs associated with the Partnerships' portfolios.

145. The Drilling Partnerships' wells were drilled by well-known, reputable, and in several cases, publicly traded industry operators, including Plains Exploration and Production (PXP); Carrizo Oil and Gas, Inc. (CRZO); Cabot Oil and Gas Corporation (COG); Linn Operating Inc.; Hilcorp Energy Company; Petro-Hunt LLC; and others.

146. The portion of direct, third-party, drilling expenses that Palace paid, which were allocable to each Drilling Partnership's working interest, is as follows:

a) Early 2001 Portfolio (Total: $35,298,82.00)
1. Redfish Bay: $2,163,372.00
2. Impact: $1,410,937.00
3. PW&F-S-01: $4,504,135.00

b) Late 2001 Portfolio (Total: $50,507,195.00)
1. Belle Isle: $173,353.00
2. Bayou: $1,239,338.00
3. Cottonwood: $332,814.00
4. PW&F-W-01: $4,448,734.00
5. Sanoroc: $2,081,029.00
6. Challenger: $4,869,110.00

c) Late 2002 Portfolio (Total: $99,244,131.00)
1. Bateman: $1,163,172.00
2. Black Creek: $3,496,809.00
3. Centrahoma: $1,513,520.00
4. Mayfield: $2,162,274.00
5. PW&F-W-02: $544,794.00
6. RCCP-02: $4,752,265.00
7. Red River: $4,286,085.00
8. Silver Spike: $2,153,603.00

147. These amounts do not include costs incurred by Palace that were attributable to portfolio selection, monitoring, and decision-making regarding drilling operations.

148. Palace maintained substantial and typical well file data for its Prospect wells, including AFEs, well logs, drilling and completion reports, well test data, joint operating agreements, plugging and abandonment reports, third party reports, and other documents.

149. Palace, through Bistate Oil Management, received drilling reports directly from drillers and operators on a daily basis. Either Mr. Siegal or other Palace executives reviewed these drilling reports.

150. Bistate Oil Management received the invoices for drilling and production expenses, paid them, and input the detail into the Bistate System.

151. The Bistate System allocated revenue due to and expense incurred by the Drilling Partnerships in accordance with the partnerships' working interest and net revenue interest in their wells.

Hearing Testimony and Expert Reports

152. Petitioner's financial expert, David Plastino, CPA, is a finance and valuation expert, lecturer at Boston University's Questrom School of Business, accredited in business valuation by the American Institute of CPAs (AICPA), and a Certified Public Accountant licensed in Massachusetts.

153. Mr. Plastino credibly opined that:

- the debt instruments with which certain of the partnerships were funded were subject to standard creditor protections;
- the terms of the Turnkey Notes are consistent with common practices for secured lending;
- partnerships, including leveraged partnerships, have been used as an investment vehicle in the oil and gas industry since the 1970s;
- the Drilling Partnerships are structured in a way that is consistent with customary economic arrangements in the oil and gas industry;

- Bistate's bookkeeping and recording systems accurately allocated revenue earned and expenses incurred by the partnerships' wells to the partnerships in accordance with their net revenue interests and working interests in those wells;

- an economic analysis of the partnerships in which Mr. Siegal invested indicates that some had positive returns (ie., made money) and others had negative returns (i.e., lost money);

- given what was known about the partnerships' well portfolios at the time that the partnerships were formed, there was a reasonable expectation that the partners, including petitioner, could make money on their investments and a reasonable possibility that they could lose money, even if all tax benefits were excluded from the economic analysis;

- based on his examination of the files, documents, and financial records, there is no evidence of fraudulent economic activity in the partnerships' creation, funding and administration;

- the prices charged to the Drilling Partnerships in the Turnkey Drilling Contracts for the suite of services provided by the Turnkey Drilling Companies working with both third-party subcontractors and with Palace, and the insurance against cost overruns, were reasonable.

154. Mr. Plastino identified three purposes for making an investment in oil and gas assets: profit potential, diversifying a broader portfolio, and achieving tax benefits. Mr. Plastino opined that Mr. Siegal's investments in the Drilling Partnerships exhibited all three components.

155. Historically, oil and gas prices have fallen when the S&P 500 rises, and vice versa. Because of this inverse relationship, investments in oil and gas assets are defensive or countercyclical.

156. It is common for organizers of oil and gas investments to include discussions about tax benefits in marketing materials. The Belle Isle Drilling Company Investment Proposal states, in part:

> "While the tax rates have become confiscatory, it is still possible for an investor to redeploy his upper bracket tax dollars into certain investments and create income and cash flow rather than pay these dollars to the federal, state and municipal governments. By participating in the proposed oil and gas drilling partnership, Belle Isle Drilling Company ('Partnership'), we can accomplish these financial

> results. . . . Due to the nature of oil and gas drilling, the Partnership and each of the partners will be afforded a substantial tax loss (active, Not passive) under Section 263 C of the Internal Revenue Code which allows electing taxpayers to expense the intangible drilling costs incurred drilling oil and gas wells which otherwise would be capitalized under normal accounting principles. By investing in this Partnership, an investor will achieve the highly sophisticated result of creating a cash flow profit center without the use of pre-existing after tax capital. The reality is that an investor in the Partnership can expect an average annual cash flow of approximately 10-15% of the cash funds invested in the Partnership . . . ."

157. It is not uncommon for the founder or organizers of investment opportunities to place their own capital at risk alongside that of outside investors, and Mr. Plastino opined that such investment may signal to outside investors that the founder believed in the strength of the investments.

158. Petitioner's oil and gas expert, Michael Krehel, Jr., P.E., is a registered professional engineer in the State of Texas, with over 30 years of oil and gas engineering and operations experience.

159. Mr. Krehel credibly opined that:

- based on his personal review of a large volume of data related to the 2001 and 2002 Drilling Partnerships, the terms of the agreements and contracts are consistent with standard oil and gas practices;
- based on his review of the physical well files maintained by Palace for the wells in which the 2001 and 2002 Drilling Partnerships invested, he determined that they included the types of engineering and geologic technical documents that would ordinarily be maintained by a non-operating working interest owner;
- the data and information maintained by Palace was sufficient for Palace to conduct a thorough technical analysis of the proposed wells;
- Palace's well files demonstrate that Palace evaluated the merits of Prospect Wells, either by Palace employees or by third-party consultants, to determine if the prospect had the opportunity to make money;
- the Palace well files maintained by Bistate contain evidence of projects that Palace rejected and the reasons why Palace rejected them;
- he did not identify any evidence of questionable documentation;

- the prospect agreements conveyed working interests to the partnerships;
- a turnkey drilling contract is a standard agreement in the industry for drilling oil and gas wells;
- using multiples or a percentage of the estimates of drilling costs contained in AFEs (i.e., marking-up the AFEs) is not an appropriate methodology for determining whether the prices of the turnkey drilling contracts were reasonable;
- any retrospective analysis of Palace's reasonably anticipated drilling costs would require a comprehensive evaluation of the technical risks involved in drilling each well which would be cost prohibitive in this case due to the analysis required and the passage of time (13 years after the fact).

160. Mr. Krehel prepared detailed projections of the potential flowstreams for each well prospect in order to provide Mr. Plastino with data necessary for his financial analysis.

161. According to Mr. Plastino and Mr. Krehel, there is no "industry-standard" markup for turnkey drilling contracts, and the prices charged to the Drilling Partnerships in the Turnkey Drilling Contracts for the suite of services provided by the Turnkey Drilling Companies working with both third-party subcontractors and with Palace were reasonable. Both Mr. Plastino and Mr. Krehel concurred that the terms of the Turnkey Drilling Contracts were reasonable relative to industry standard.

162. During the hearing, Mr. Krehel described his review of a prospect package from Palace, which included a well drilled for the Chapman 34-2 Well. First, Mr. Krehel explained that the isopic map of the Anderson Reservoir prospect area indicates a "very faulted, very complex geologic picture" with some fault blocks that may have been produced and others that may be untested. He then explained the seismic line. This type of information combined with other geologic data allows an analyst to make assumptions regarding the location and size of potential hydrocarbon deposits. Mr. Krehel testified that creating and interpreting such a report is highly technical and requires specialized expertise. Mr. Krehel testified that the volumetric

reserve analysis in the packet indicated uncovered reserves of 20 billion cubic feet of natural gas, which represents what might be recoverable from a well in that part of the prospect area. Mr. Krehel explained that estimating the uncovered reserves uses the seismic and geological mapping of the prospect area to determine parameters like the fault block surface, the aerial extent, the average thickness of the zone, and the ultimate reservoir volume calculated from that thickness and area. He further testified that the Chapman 34-2 well file also included economic output runs using an engineering software package called "Power Tools," which showed production profile estimates on an annual basis, the ultimate production recovery, and revenue estimates on a gross and net basis based on ownership interest, and a cash flow analysis at various discount rates. According to Mr. Krehel, geological, engineering and economic information for a technical expert to analyze in deciding whether to participate in the Chapman 34-2 well were included in the well files maintained by Palace. Based on that information, the base case estimated that the Chapman 34-2 prospect would have an economic life of 19 years and generate $12.5 million in cumulative cash flow ($8.7 million discounted). Mr. Krehel testified that based on Crest Resources' technical analysis, done by qualified people using the best information available, Chapman 34-2 appeared to be a good prospect.

He estimated that generating the kind of prospect analysis that Crest Resources did for Chapman 34-2 would cost at least hundreds of thousands of dollars. Finally, Mr. Krehel explained that in spite of all the analytical expertise applied to evaluate the Chapman 34-2 prospect, when the well was actually drilled, it contained salt water in a greater proportion than hydrocarbon, and completion was not commercially viable.

163. The Division's expert petroleum engineer, Mikel Morris, opined that the industry-standard markup for turnkey drilling contracts in 2001 and 2002 was 10 - 25% above drilling costs. Mr. Morris testified that the basis for his opinion regarding the industry-standard markup

came from having audited major drilling contractors that had offices in Houston during his employment with the IRS. He testified that the drillers he audited were drilling on a day-rate, rather than a turnkey, basis. When further pressed for the basis of his opinion regarding markups of turnkey contracts, Mr. Morris stated that his testimony was based on his "experience in the industry." When asked to identify what companies he used to support his opinion that the industry-norm markup on turnkey drilling contracts was 10 - 25% in 2001 and 2002, Mr. Morris could name only ADT. Mr. Morris could not identify any companies other than ADT, and admitted that in his prior work with drilling contractors to drill and complete wells, "I never asked them to do the [sic] turnkey drilling contract."

164. Mr. Morris further opined that he thinks drilling contractors would consider a markup theory in pricing a turnkey contract, but that the price is "not going to be totally based upon mark-up." He also opined that a drilling contractor would quote a turnkey price substantially higher than the day rate or footage prices, and testified that day-rate contracts have no markup over drilling costs.

165. Mr. Morris could not identify how many turnkey drilling contracts he examined. When asked for an approximation or general description of the quantity, Mr. Morris stated, "I can't tell you anymore. It's been too long." Mr. Morris also testified that his opinion was based on the pricing that his current employer uses now, and, when reminded that the issue was pricing in 2001 and 2002, Mr. Morris admitted that he was not working in oil and gas exploration and production then. Mr. Morris conceded that he performed no research about turnkey drilling services or the market for them in 2001 and 2002.

166. Mr. Morris opined that if drilling contractors want to stay in business, they would not enter into turnkey drilling contracts unless they absolutely had to, because of the prohibitive financial risks, and that during 2001 and 2002, companies never drilled a significant number of

wells on a turnkey basis. When questioned regarding Grey Wolf, a publicly traded company that from 1997 to 2003 drilled 728 wells on a turnkey basis in the same region as Palace's Portfolio Wells, which represented as much as nearly one-fifth of Grey Wolf's drilling activity in a single year during that time period, Mr. Morris stated that he had never heard of Grey Wolf. Mr. Morris conceded that Grey Wolf's 2003 annual report shows that its turnkey drilling was profitable: Grey Wolf reported operating margins on its turnkey drilling contracts were over five times its operating margins on day-rate contracts. Mr. Morris also testified that he did not recall Grey Wolf having drilled any of the Palace wells. However, according to an exhibit prepared by Mr. Morris, Grey Wolf drilled at least five of the Portfolio Wells.

167. Without referencing a particular time period, Mr. Morris opined that multiple wells would never be drilled on a single turnkey contract. However, during cross-examination, Mr. Morris was presented with exhibits showing that in 2009, Halliburton, a recognized name in the oil and gas industry, was awarded a single, integrated turnkey drilling contract for between 153 and 185 wells, and that in 2012, Halliburton was awarded a $648 million contract to drill 58 wells on a turnkey basis. Mr. Morris conceded that he was unaware of the existence of either of these contracts.

168. While working for the IRS in 2007 and auditing certain Palace related oil and gas partnerships, Mr. Morris presented multiple examination "mission statements" advocating the disallowance of all prepaid IDC deductions or the disallowance of direct costs for turnkey drilling companies. However, Mr. Morris admitted that his theories were disregarded by IRS's legal counsel.

169. Mr. Morris testified that he was "under the impression" that Palace's wells were mainly developmental and not exploratory, and that the producing wells were all developmental. The basis of this impression was Mr. Morris's assumption that "being Palace Explorations, I

would assume they were looking for low risk drilling ventures." When shown AFEs for Palace's Portfolio Wells, which contain a designation of well classification as development or exploratory, Mr. Morris did not recognize the particular documents, but testified that he may have seen them before. After reviewing the well classifications documents on the AFEs, Mr. Morris did not dispute the analysis of petitioner's oil and gas expert, Mr. Krehel, which concluded that 53% of the Late 2001 Portfolio Wells were exploration or exploratory, only 12% were development or developmental, and 35% were unknown. Mr. Morris admitted this his review of the AFEs for the late 2001 Well Portfolio at the hearing calls into question the level of certainty he has with respect to his own opinions in this case.

170. Mr. Morris conceded he never performed an economic analysis of any of Palace's productive Portfolio Wells.

171. Mr. Morris opined that arrangements in which related entities contract for drilling do not exist in the oil and gas industry. However, on cross-examination, Mr. Morris conceded that a public filing made to the Securities and Exchange Commission (SEC) by Atlas Resources in 1999 contains a drilling and operating agreement between related entities. Mr. Morris stated that he was familiar with the kind of arrangement described in the SEC filing and that it was the same type of arrangement used by Palace.

172. Mr. Morris also opined that the use of debt or leverage does not occur in oil and gas exploration. However, Mr. Morris conceded he performed no research into reports from any company describing investment structures or contractual arrangements used in oil and gas exploration and production. Mr. Morris testified that he could not tell whether debt-financed oil and gas exploration, including borrowing from affiliates, was common, "because I never did any financial analysis or audits on these type [sic] of structures."

173. Petitioner submitted 263 proposed findings of fact. In accordance with State Administrative Procedure Act (SAPA) § 307 (1), proposed findings of fact 5, 7, 8, 10, 11, 13 - 15, 17, 18, 20, 23, 26 - 29, 32, 33, 35 - 37, 39, 42 - 46, 48, 50 - 52, 56 - 61, 66 - 78, 81, 84 - 87, 90, 91, 96, 99, 102, 104, 106, 107, 110, 112 - 116, 118 - 143, 149, 150, 153 - 166, 168 - 187, 189, 192 - 195, 199, 200, 208 - 213, 217, 218, 229 - 234, 236, 237, 240, 244, 245, 247 - 251, 253 - 259, and 261 are supported by the record and have been substantially incorporated in the foregoing Findings of Fact.[26] Proposed findings of fact 1 - 4, 9, 40, 109, and 204, have been rejected as conclusions of law. Proposed findings of fact 6, 16, 25, 34, 38, 47, 53, 54, 62, 82, 83, 92 - 94, 98, 100, 101, 111, 117, 147, 148, 151, 152, 167, 191, 196, 201 - 203, 206, 207, 223, 226, 228, 235, 238, 239, 246, 252, 260, 262 and 263 have been modified to more accurately reflect the record. Proposed findings of fact 12, 19, 21, 22, 24, 30, 31, 41, 63 - 65, 79, 80, 88, 89, 95, 97, 144 - 146, 188, 197, 198, 214 - 216, 219 - 222, 225, 227, and 241 - 243 are repetitive of other proposed findings of fact and have been combined therein. Proposed findings of fact 49 and 55 set forth undisputed procedural matters whose recitation is unnecessary for purposes of resolving the issues presented. Proposed finding of fact 103 is rejected as argument and not a proper finding of fact. Proposed findings of fact 105 and 205 have been modified to remove the portions constituting argument. Proposed finding of fact 108 has no citation to the record and is rejected. Proposed findings of fact 190 and 224 are not supported by the record and are rejected.

The Division submitted 60 proposed findings of fact. Proposed findings of fact 1 - 3, 5, 9, 11, 13, 15, 17 - 20, 22, 24 - 26, 29 - 32, 36, 37, 40, 42 - 44, 46 - 50, 52, and 57 are supported by the record and have been substantially incorporated in the foregoing Findings of Fact.[27] Proposed

[26] The proposed facts as presented by petitioner have been condensed and renumbered as incorporated in the Findings of Fact set forth above.

[27] The proposed facts as presented by the Division have been condensed and renumbered as incorporated in the Findings of Fact set forth above.

findings of fact 4, 8, 10, 12, 16, 23, 27, 28, 38, 39, 41, 45, 51, and 56 have been modified to more accurately reflect the record. Proposed findings of fact 6 and 7 are rejected as irrelevant. Proposed findings of fact 14 and 21 set forth undisputed procedural matters whose recitation is unnecessary for purposes of resolving the issues presented. Proposed findings of fact 33, 34, 58 - 60 are not supported by the record and are rejected. Proposed finding of fact 35 has no citation to the record and is rejected. Proposed finding of fact 53 is repetitive of other proposed findings of fact incorporated herein. Proposed finding of fact 54 is rejected as irrelevant to the years at issue herein. Proposed finding of fact 55 is not supported by the citation given.

CONCLUSIONS OF LAW

A. The income tax deficiencies at issue purportedly result from the Division's denial of petitioner's distributive share of the Drilling Partnerships' claimed 2001 and 2002 losses, as reported on petitioner's Schedule E.[28] Such losses consists almost entirely of the Drilling Partnerships' claimed IDC expense deductions.[29] IDCs are payments for non-salvageable capital expenditures incurred in connection with oil and gas drilling (***see*** Treas Reg [26 CFR] 1.612-4 [a]). Examples of IDCs include expenditures for labor, fuel, repairs, hauling, and supplies "incident to and necessary for the drilling of wells and the preparation of wells for the production of oil or gas" (***id.***). Generally, a capital expenditure may not be deducted as an expense (Internal Revenue Code [IRC] [26 USCA] § 263 [a]), but may be recovered through depreciation, amortization or depletion (***see e.g.***, IRC [26 USCA] §§ 167, 195, 611). In apparent recognition

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[28] However, as noted in Footnote 8, the losses disallowed by the Division for 2002, in the amount of $15,748,500.00, exceed the amount of deductions actually claimed by petitioner for his share of the Drilling Partnerships' 2002 losses. Similarly, the losses disallowed for 2001 exceed deductions claimed by petitioner for the 2001 Drilling Partnerships (***see*** Findings of Fact 11 and 25 and Appendices A and B).

[29] The amount of losses disallowed by the Division for 2001 and 2002 exceed petitioner's share of the 2001 and 2002 Drilling Partnerships' reported IDCs. See Findings of Fact 11 and 25, and Appendices A and B. The Division provided no explanation for the discrepancy.

of the risks inherent in oil and gas exploration, and in order to encourage investment in such activities, the IRC allows operators of oil or gas wells to elect to treat IDCs as expenses, and thereby deduct such costs in the year incurred (***Matter of Sznajderman***, Tax Appeals Tribunal, July 11, 2016, citing ***Exxon Corp. v United States***, 547 F2d 548, 554, 555 [1976]); IRC [26 USCA] § 263 [c]; Treas Reg [26 CFR] § 1.612-4 [a]). An operator of a well includes a working interest owner for purposes of the IDC expense election (Treas Reg [26 CFR] § 1.612-4 [a]).

The record establishes that the Drilling Partnerships acquired a share of the working interest in various well sites pursuant to the prospect agreements. The Drilling Partnerships invested in the Early 2001 well portfolio acquired a share of the working interest in 38 wells sites; the Drilling Partnerships invested in the Late 2001 well portfolio acquired a share of the working interest in 37 wells sites; and the Drilling Partnerships invested in the Late 2002 well portfolio acquired a share of the working interest in 69 wells sites (***see*** Findings of Fact 100, 104, and 105). Accordingly, the Drilling Partnerships were operators eligible to claim their share of the IDCs associated with the drilling of those wells, and Mr. Siegal, as a partner in the Drilling Partnerships, was eligible to claim his proportionate share of their IDC expenses (***see Matter of Sznajderman***). The Division disallowed Mr. Siegal's claimed IDC deductions in full for tax years 2001 and 2002.[30]

B. A notice of deficiency of personal income tax generally must be issued within three years after the filing of the return (Tax Law § 683 [a]). Two exceptions to this rule, upon which the Division's assessments herein rely, are Tax Lax § 685 (c) (1) (B), which provides that the tax may be assessed at any time if a false or fraudulent return is filed with the intent to evade tax, and

[30] ***See*** Footnote 29.

Tax Law former § 683 (c) (11) (B),[31] which extends the general limitations period to six years "if the deficiency is attributable to an abusive tax avoidance transaction."

With respect to tax year 2002, Mr. Siegal's tax return was timely filed, with extension, on October 15, 2003. There is no dispute that the notice of deficiency for tax year 2002 was not issued until December 18, 2013, beyond both the three-year statute of limitations set forth in Tax Law § 683 (a) and the six-year statute of limitations set forth in Tax Law former § 683 (c) (11) (B). As such, in order for the notice of deficiency for tax year 2002 to be timely, the Division bears the burden of proving that petitioner filed a false or fraudulent return with the intent to evade tax (Tax Law §§ 685 [c] [1] [B], 689 [e] [1]).

For tax year 2001, Mr. Siegal's tax return was timely filed, with extension, on October 15, 2002. The notice of deficiency for tax year 2001 asserting tax, penalty and interest was issued on August 25, 2008, and the notice of deficiency asserting an additional penalty for 2001 for alleged failure to participate in a voluntary compliance initiative was issued on September 15, 2008. Both dates fall beyond the three-year statute of limitations set forth in Tax Law § 683 (a), but would fall within the six-year statute of limitations set forth in Tax Law former § 683 (c) (11) (B). The Division contends that Mr. Siegal's investment in the Drilling Partnerships was an abusive tax avoidance transaction, and accordingly, asserts that the six-year period under Tax Law former § 683 (c) (11) (B) is applicable herein. As the notices of deficiency for 2001 were issued within six years after the relevant return was filed, but later than three years, the notices would be time-barred unless the exception applies. Petitioner has the burden of proof to show that the notices of deficiency for tax year 2001 were not subject to the six-year limitations period (Tax Law § 689 [e]; ***Matter of Sznajderman***; ***Matter of Sholly***, Tax Appeals Tribunal, January

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[31] Tax Law former § 683 (c) (11) was effective until July 1, 2015 (***see*** L 2005 c 61, pt N. § 12 [iii]).

11, 1990 [burden on petitioner to show that the six-year statute of limitations for an omission from New York adjusted gross income of an amount in excess of 25% of the amount reported on the return was not applicable]).

In the Division's answer for 2001, the Division asserts, as an alternative to its assertion of a deficiency based on abusive tax avoidance transactions, "that petitioner engaged in willful, knowledgeable and intentional wrongful course of conduct that resulted in deliberate nonpayment or underpayment of taxes due and owing and that fraud penalties are therefore applicable." The Division bears the burden of proof with respect to the assertion of the alternative fraud penalties (Tax Law § 689 [e] [1]).

C. Addressing first the Division's assertion of fraud, the Division must establish that petitioner filed a false or fraudulent return with the intent to evade tax for the years 2001 and 2002 (Tax Law § 689 [e] [1]). While fraud is not defined in the statute, a finding of fraud requires the Division to show:

> '"clear, definite and unmistakable evidence of every element of fraud, including willful, knowledgeable and intentional wrongful acts or omissions constituting false representation, resulting in deliberate nonpayment or underpayment of taxes due and owing' (***Matter of Ilter Sener***, Tax Appeals Tribunal, May 6, 1988; ***see also***, ***Schaffer v. Commissioner***, 779 F2d 849, 86-1 USTC ¶ 9132; ***Matter of Cousins Serv. Sta.***, Tax Appeals Tribunal, August 11, 1988).
>
> The Division need not establish fraud by direct evidence, but can establish it by circumstantial evidence by surveying the taxpayer's entire course of conduct in the context of the events in question and drawing reasonable inferences therefrom (***Plunkett v. Commissioner***, 465 F2d 299, 72-2 USTC ¶ 9541; ***Biggs v. Commissioner***, 440 F2d 1, 71-1 USTC ¶ 9306; ***Matter of Cinelli***, Tax Appeals Tribunal, September 14, 1989, citing ***Korecky v. Commissioner***, 781 F2d 1566, 86-1 USTC ¶ 9232)" (***Matter of Ellett***, Tax Appeals Tribunal, December 18, 2003).

In order to establish fraudulent intent, it must be shown that Mr. Siegal acted deliberately, knowingly and with the specific intent to violate the Tax Law (***see Matter of Cousins Serv. Sta.***, Tax Appeals Tribunal, August 11, 1988), and the burden rests with the Division to prove by clear and convincing evidence that Mr. Siegal, with willful intent, was in violation of the tax laws (***see Matter of Sona Appliances; Matter of Cardinal Motors***, State Tax Commn., July 8, 1983, ***confirmed Matter of Cardinale v Chu***, 111 AD2d 458 [3d Dept 1985]). Fraud must be established with affirmative evidence and may not be presumed (***see Matter of Jay's Distributors, Inc.***, Tax Appeals Tribunal, April 15, 2015, citing ***Intersimone v Commissioner***, TC Memo 1987-290, 53 TCM 1073 [1987]). Therefore, mere suspicion of fraud from the surrounding circumstances is not enough (***see Goldberg v Commissioner***, 239 F2d 316 [5th Cir 1956]; ***Matter of What a Difference Cleaning***, Tax Appeals Tribunal, May 15, 2008). The Division has failed to present clear, definite and unmistakable evidence of every element of fraud, and as such has not met its burden of proving that Mr. Siegal filed a false or fraudulent return with the intent to evade tax for the years 2001 and 2002. The Division's asserted basis for finding fraud has been fluid and inconsistent throughout the proceedings herein.

The notice of deficiency issued for 2002 does not state a basis for fraud, but merely states that the Division disallowed $15,748,500.00 of Schedule E deductions related to the 2002 Drilling Partnerships and asserts fraud penalties, in addition to other penalties. As noted above, the amount of deductions disallowed according to the 2002 notice of deficiency exceeds the amount of deductions actually claimed by Mr. Siegal for the 2002 Drilling Partnerships (***see*** Footnote 8). The Division has offered no explanation as to why it disallowed $15,748,500.00 of purported Schedule E deductions for the 2002 Drilling Partnerships in its calculation of the 2002 deficiency, rather than the actual reported deduction of $12,682,099.00 related to the 2002 Drilling Partnerships (***Id.***). When questioned regarding the Division's disallowance of the IDC deductions, Mr. Fahrenkopf's testimony was often vague and contradictory, initially replying that the basis for the disallowance was "at the direction of Office of Counsel." The Division provided no audit workpapers explaining its calculation of the 2002 deficiency or how it arrived at the disallowed loss.

A review of Mr. Siegal's and the partnerships' returns, as well as the exhibits contained in the expert report of Mr. Plastino, reveal that the number the Division used in its calculation of the 2002 notice ($15,748,500.00) is actually the amount of Mr. Siegal's total capital invested in the 2002 Drilling Partnerships, which consisted of $5,791,500.00 in cash and $9,957,000.00 in notes, totaling $15,748,500.00 (***see*** Finding of Fact 103), rather than the $12,682,099.00 actual deduction reported on Mr. Siegal's 2002 return as his share of the 2002 Drilling Partnerships' IDCs. There is no explanation as to why the Division used $15,748,500.00 as the amount of loss disallowed, and the Division did not present any workpapers for its calculation of the 2002 deficiency into the record. Indeed, the propriety of the Division's use of Mr. Siegal's capital contributions in its calculation of the deficiency is belied by Mr. Fahrenkopf's testimony. When questioned as to what number the Division considered fraudulent on the Schedule K-1 for one of the Drilling Partnerships, Mr. Fahrenkopf responded that it was the amount of IDCs reported, not the capital contributions. Yet the Division used the amount of Mr. Siegal's capital contributions when calculating the 2002 notice. The Division has failed to provide any rational basis for its use of capital contributions in its calculation of the 2002 notice, resulting in a disallowance of an amount greater than the deduction actually claimed (***see Matter of Fortunato***, Tax Appeals Tribunal, February 22, 1990), and has failed to establish fraud as a result of its conflicting basis of what amount constitutes false representation resulting in deliberate non-payment or underpayment of tax.

The Division's asserted basis for fraud as stated in its amended answer for 2002 is likewise contradicted by Mr. Fahrenkopf's testimony. The Division's amended answer alleges, in part, that "Siegal purchased interests in oil and gas wells through his wholly controlled company, Palace Exploration, at a fixed price, and then fragmented such interests and sold them to 'investors' in his partnerships, including himself, at a profit in excess of 500 percent." This allegation is contradicted by Mr. Fahrenkopf's testimony that, "I am not saying that Palace's profit was in excess of 500%. I am saying that the markup of the capital in each partnership to the actual costs of drilling the wells was in excess of 500%."

Mr. Fahrenkopf's testimony regarding the calculation of a purported 500% markup is inconsistent and the Division contention that the Drilling Partnerships' IDC deductions were inflated to over 500% of the purported "actual" drilling costs is not supported by the record. Mr. Fahrenkopf first testified that his mark-up calculations were based on a ratio of the costs to the partners via the turnkey drilling contract to the actual drilling costs. However, he later testified that he calculated the purported mark-up by dividing the partners' capital contributions (i.e., the partners' initial cash and subscription note contributions) by the amount Palace paid to third-parties to drill the wells. Mr. Fahrenkopf admitted that in calculating the alleged mark-up, he used numbers from petitioner's expert witness, David Plastino's report. It must first be noted that although the Division asserts the auditor's mark-up theory as a basis for its assertion of fraud, Mr. Plastino's report, dated June 2, 2017, was written subsequent to the issuance of the Division's 2002 notice of deficiency, subsequent to the Division's amended answer for 2002, and subsequent to the Division's answer for 2001 asserting additional penalties for fraud. Thus, the assertion that the Division's initial determination of fraud was based on this calculation is untenable.

Furthermore, the Division's mark-up calculation is flawed. The amount of drilling expenses Mr. Fahrenkopf used in his calculation did not reflect all of the actual costs to drill the wells, such as the cost of evaluating well prospects, as well as various other administrative costs. Additionally, Mr. Fahrenkopf's numerator (partners' capital contributions) exceeded the amount of IDCs actually deducted, thereby improperly inflating the numerator. As such, Mr. Fahrenkopf's ratio is flawed with both an over-inflated numerator and a denominator that fails to include all costs associated with the wells. The Division's mark-up theory as grounds for fraud is accordingly rejected.

Additionally, the Division's argument that the amount of IDC deductions were evidence of fraud based on a contention that the turnkey contracts were marked-up excessively above the "industry standard" is rejected. The Division's expert's testimony that the industry standard markup for turnkey contracts was 10 to 25% is unpersuasive. Specifically, although the Division's expert, Mr. Morris, opined that the industry-standard markup for turnkey contracts in 2001 and 2002 was between 10 to 25% above drilling costs, Mr. Morris's opinion was based on his prior work with the IRS auditing drilling contractors who worked on a day-rate, rather than a turnkey, basis. Mr. Morris conceded that he did not perform any research about turnkey drilling services or the market for them in 2001 and 2002. Mr. Morris further testified that his opinion was based on his "experience in the industry," but when asked to identify what companies he used to support his opinion that the industry-norm markup on turnkey drilling contracts was 10 to 25%, he could only identify one. He admitted that in his prior experience with drilling contractors he "never asked them to do the turnkey drilling contract," and could not identify how many drilling contracts he had examined, testifying that "it's been too long." Mr. Morris admitted that he was unfamiliar with a number of industry-recognized and publically traded companies that drilled on a turnkey basis during the years at issue, including Grey Wolf, which had drilled some of Palace's portfolio wells.[32]

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[32] Mr. Morris's testimony that he is unfamiliar with Grey Wolf, despite having included it in an exhibit he prepared, listing it as a driller of some of the Drilling Partnerships' wells, calls into question his credibility.

Mr. Morris further incorrectly testified that wells in the Drilling Partnerships' portfolios were mainly developmental wells. After being shown AFEs for the Drilling Partnerships' portfolio wells and a breakdown of well classifications showing that 54% of the late 2001 Portfolio Wells were exploratory, only 12% were developmental, and 35% were unknown, Mr. Morris conceded that his level of certainty with regard to his opinions was questionable.

Based on a thorough review of the record, it is determined that Mr. Morris's credibility regarding an industry standard markup was compromised by his admitted lack of experience with turnkey contracts in general and his lack of familiarity with the specific wells and drilling contracts related to the Drilling Partnerships at issue (***see Matter of 677 New Loudon Corp. d/b/a Nite Moves***, Tax Appeals Tribunal, April 14, 2010). For the above reasons, I do not find Mr. Morris's testimony compelling.

The gravamen of the Division's argument for fraud as ultimately set forth in its post-hearing brief distills to two further points: the first being the Division's contention that Mr. Siegal promoted abusive tax shelters, and that his participation in such transactions rises to the level of fraud; and second, that Mr. Siegal has been creating and participating in leveraged partnerships that artificially inflate IDC deductions for the partners since at least 1992, by means of subscription notes, turnkey drilling notes, and collateral agreements.

The Division's first argument, with regard to the promotion of abusive tax shelters, is fatally flawed because the notice, dated April 14, 2014, upon which the Division relies for this argument, is not at issue in this proceeding and was previously canceled (***see*** footnote 6). The Division initially put the wrong notice into the record, and then contended in its brief that the assertion of a penalty for promoting abusive tax shelters under Tax Law § 685 (bb), as asserted in that notice, rises to the level of fraud. The promotion of abusive tax shelters as asserted in this notice was not at issue in this proceeding and cannot now be used to support the Division's assertion of fraud. Indeed, during the hearing, the Division asserted that the notice of deficiency was for the voluntary compliance penalty, not for promoting abusive tax shelters, and subsequently, upon the reopening of the record, introduced the correct notice (***see Id.***). The Division further incorrectly conflates the promotion of abusive tax shelters under Tax Law § 685 (bb) with fraud under Tax Law § 683 (c) (1) (B). The tax shelter penalty and the fraud penalty are separate and distinct (***compare*** Tax Law § 685[e] and § 685 [bb]), and the exception to the three-year statute of limitations for issuance an assessment under Tax Law § 683 (c) (1) (B) applies only to the filing of a false or fraudulent return with the intent to evade tax. As petitioner correctly notes, there is no relationship between the question of whether Mr. Siegal's personal income tax returns for the years at issue are fraudulent, and the Division's allegation, not even at issue in this proceeding, that Mr. Siegal promoted abusive tax shelters.

The Division's second argument is likewise unpersuasive. The Division contends that,

> "for decades petitioner has been orchestrating transactions that overstate deductions by up to 85% by means of the collateral agreement. Since at least 1992 he has been participating in these transactions himself, pledging subscription notes to partnerships he controls, which then pledge turnkey drilling notes to turnkey drilling companies he controls."

While fraud by a taxpayer may be established "by surveying the taxpayer's entire course of conduct in the context of events in question and drawing reasonable inferences therefrom" (***Plunkett v Commissioner***, 465 F2d 299 [1972]; ***Matter of Cinelli***, Tax Appeals Tribunal, September 14, 1989, citing ***Korecky v Commissioner***, 781 F2d 1566 [1986]), and consistent and substantial understatement of income may properly be found to constitute strong evidence of fraud (***see Matter of Bennett***, Tax Appeals Tribunal, December 16, 2004), the Division must affirmatively prove such understatement (***see Matter of Jay's Distributors, Inc.***; ***Matter of Cousins Serv. Sta.***), and understatement of income by itself is insufficient to prove fraud; other factors indicating fraudulent intent must be present for the Division to meet its burden (***Matter of Ellett*** citing ***Foster v Commissioner***, 391 F2d 727, 733 [1968]). The Division has failed to prove its allegation that Mr. Siegal has been participating in tax avoidance transactions "for decades." For purposes of the fraud allegation, the Division has the burden of proving both that Mr. Siegal participated in abusive tax avoidance transactions, and that such participation has been continuous and substantial with willful intent. The Division has failed to meet its burden on both fronts.

The Division relies on the Tax Appeals Tribunal's holding in ***Matter of Sznajderman*** (Tax Appeals Tribunal, July 11, 2016) for its argument that petitioner participated in tax avoidance transactions in 2001 and 2002. However, ***Sznajderman*** is distinguishable from the matter here. The lynchpin of the Tribunal's holding in ***Sznajderman*** was the taxpayer's use of a collateral agreement, by which the Tribunal found that Mr. Sznajderman satisfied his obligation on the principal of his subscription note upon payment of a sum of money equal to 15% of the face value of the note, to be used for the purchase of bonds. The Tribunal found that due to the use of the collateral agreement, the subscription note obligation was overstated by 85% and was therefore lacking in economic reality. Unlike the taxpayer in ***Sznajderman***, petitioner here did not use a collateral agreement for any of the Drilling Partnerships in the years at issue. There is also no evidence to support the Division's argument that petitioner used collateral agreements for multiple other years. Additionally, the record differs here from ***Sznajderman*** in that petitioner has introduced evidence that both interest and principal repayments were made for Redfish Bay, Belle Isle, and Bateman. This evidence shows that, regardless of the possible use of collateral agreements by some other partners (which the Division has not presented into this record), the partnerships' debt was not reduced by 85%, as distinguished from the findings in ***Sznajderman***. Indeed, Mr. Fahrenkopf admitted that the Division did not look through the financial records petitioner provided to determine whether interest or principal payments were made on the turnkey notes, nor did he review all of the records provided in response to information document requests he sent: "I did not compare all - - again, I got about 3 boxes, full boxes of responses. I did not review every single response that was given to me." Thus, the Division's reliance on ***Sznajderman*** to support its allegation of fraud is misplaced.

Even assuming that Mr. Siegal's IDC deductions for the years at issue resulted from tax avoidance transactions due to the use of subscription notes, turnkey drilling notes, and collateral agreements by other partners, there is no evidence in the record that the financing arrangements for other years not at issue herein were improper tax avoidance transactions. Indeed, while the Division's auditor, Mr. Fahrenkopf stated that the basis for the assertion of fraud was a purported 500% markup of the turnkey contracts, and contended that petitioner created partnerships with similar markups in other years, he testified that, "*I have no reason to believe* the other years . . . weren't equally marked up" (emphasis added). Clearly, Mr. Fahrenkopf's assumption regarding an alleged markup for other years, without any evidence in the record, is insufficient to establish a pattern of conduct. This claim amounts to a suspicion of fraud, which does not prove fraudulent intent (***Matter of Jay's Distributors, Inc.***, Tax Appeals Tribunal, April 15, 2015, citing ***Goldberg v Commissioner*** 239 F2d 316 [1956]).

The Division's unsubstantiated contention that Mr. Siegal participated in abusive tax avoidance transactions for decades is further belied by the no-change letters petitioner introduced into the record. Mr. Siegal's personal income tax returns, including his Schedule E, for 1999, 2000, and 2001, were previously examined by the Division, resulting in no change. Two of the Drilling Partnerships currently included in the Division's assertion of fraud (PW&F-W-01 and PW&F-S-01) were previously examined by the Division for tax year 2001, as well as other oil and gas partnerships for 2000, and such audits resulted in no further inquiry. The IRS issued a number of no-change letters for various Siegal-related partnerships and entities for multiple years. Indeed, the court in ***Zeluck v Commissioner*** (TC Memo 2012-98 [2012]) made a point of noting that Mr. Siegal's tax returns and the returns of various entities he owned and operated had been audited by taxing authorities (including the Division) "many times over his career with no material changes made to the returns." In fact, the partnership in ***Zeluck***, for which the court found that the subscription note/assumption agreement of the taxpayer was genuine debt for 2001 and 2002, is one of the Drilling Partnerships at issue here. Based on the foregoing, there is no evidence of a consistent and substantial understatement of taxes (***see Merritt v Commissioner***, 301 F2d 484 [5th Cir 1962]). The Division has therefore failed to prove that Mr. Siegal's entire course of conduct demonstrates the clear, definite and unmistakable standard required to sustain a fraud penalty (***see Matter of Sona Appliances***, Tax Appeals Tribunal, March 16, 2000).

Additionally, the Division offered no evidence of other common indicators of fraud, such as a failure by Mr. Siegal to maintain accurate records of his business (***see Niedringhaus v Commissioner***, 99 TC 202 [1992]); a failure to include all of his income in his records (***see Gromacki v Commisioner***, 361 F2d 727 [1966]); or a refusal to cooperate and to make records available (***see Estate of Granat v Commisioner***, 298 F2d 397 [1962]).

Based on the foregoing, the Division has failed to meet its burden of proving that Mr. Siegal filed a false or fraudulent return with the intent to evade tax for the years 2001 and 2002. As such, the issuance of the notice of deficiency for 2002 was untimely. Accordingly, the notice of deficiency for 2002 is hereby canceled, and the assertion of additional penalties for fraud for 2001 is denied.

D. While the Division bears the burden of proof for its fraud allegations, petitioner bears the burden of proof to show that the notice of deficiency at issue for tax year 2001 was not subject to the six-year limitations period for abusive tax avoidance transactions (Tax Law § 689[e]). In order to meet his burden to show that the notice of deficiency for 2001 was untimely, petitioner must establish that Mr. Siegal's investment in the Drilling Partnerships was not an abusive tax avoidance transaction.

Tax Law former § 683 (c) (11) (C) defines such a transaction for purposes of Tax Law former § 683 (c) (11) (B) as "a plan or arrangement devised for the principal purpose of avoiding tax." As used in Tax Law former § 683 (c) (11), "principal" means first in importance (***see*** Random House Webster's College Dictionary 1035 [1997]; see also ***Matter of Automatique, Inc. v Bouchard***, 97 AD2d 183, 186 [3d Dept 1983] [where a statute does not define a term it is appropriate to interpret it in its ordinary everyday sense]). This definition is in accord with the definition of principal purpose as used in IRC [26 USCA] § 269, involving corporate acquisitions made to evade or avoid income tax (***see e.g., Love v Commissioner***, TC Memo 2012-166 ["'principal purpose' means that the evasion or avoidance purpose must exceed in importance any other purpose"]), as well as in Treasury regulations detailing the proper application of penalties for substantial understatement of income tax under IRC [26 USCA] § 6662 (d) (***see*** Treas Reg [26 CFR] 1.6662-4 [g] [2] [C] [i] ["The principal purpose of an entity, plan or arrangement is to avoid or evade Federal income tax if that purpose exceeds any other purpose."]). Accordingly, in order to prevail for tax year 2001, petitioner must prove that tax avoidance was not the most important purpose of Mr. Siegal's Drilling Partnership investments.

For purposes of Tax Law former § 683 (c) (11) (B) and (C), "the term transaction includes all of the factual elements relevant to the expected tax treatment of any investment, entity, plan, or arrangement, and includes any series of steps carried out as part of a plan" (20 NYCRR 2500.3 [a] [definition of transaction for purposes of defining "New York reportable transaction," a tax avoidance transaction substantially similar to an abusive tax avoidance transaction under Tax Law former § 683 [c] [11] [B] and [C]).

Tax Law former § 683 (c) (11) (C) offers further guidance as to the meaning of an abusive tax avoidance transaction by noting that such transactions "include, but are not limited to, listed transactions described in [Tax Law former § 685 (p-1) (5)]." In turn, Tax Law former § 685 (p-1) (5) defines a listed transaction as including "any transaction designated as a tax avoidance transaction pursuant to [Tax Law § 25]." Regulations promulgated under Tax Law § 25 define a New York listed transaction as follows:

> "A New York listed transaction is a transaction that is the same as or substantially similar to one of the types of transactions that the commissioner has determined to be a tax avoidance transaction and identified by notice or other form of published guidance as a New York listed transaction. For purposes of identifying a New York listed transaction, the determination that a type of transaction is a tax avoidance transaction shall be based upon a finding by the commissioner that:
>
> (1) the transaction is not done for a valid business purpose, that is, one or more business purposes, other than obtaining tax benefits, that alone or in combination constitute the primary motivation for the transaction;
>
> (2) the transaction does not have economic substance apart from its tax benefits; or
>
> (3) the tax treatment of the transaction is based upon an elevation of form over substance" (20 NYCRR 2500.3 [b]).

Treasury regulations promulgated under IRC [26 USCA] § 6662 (d) define "tax shelter" in a manner similar to the definition of an abusive tax avoidance transaction in Tax Law former § 683 (c) (11) (C); that is, a plan or arrangement with the principal purpose of avoiding or evading tax (***see*** Treas Reg [26 CFR] 1.6662-4 [g] [2] [i]). Such regulations further explain the meaning of "tax shelter" as follows:[33]

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[33] Given the similarity between the State law and the federal regulation, it is appropriate to look to the regulation for additional guidance as to the meaning of this term (***see e.g. Matter of Great Neck-Port Washington, New York Lodge No. 1543 BPO Elks***, Tax Appeals Tribunal, September 5, 1991).

> "Typical of tax shelters are transactions structured with little or no motive for the realization of economic gain, and transactions that utilize the mismatching of income and deductions, overvalued assets or assets with values subject to substantial uncertainty, certain nonrecourse financing, financing techniques that do not conform to standard commercial business practices, or the mischaracterization of the substance of the transaction. The existence of economic substance does not of itself establish that a transaction is not a tax shelter if the transaction includes other characteristics that indicate it is a tax shelter" (Treas Reg [26 CFR] 1.6662-4 [g] [2] [i]).

Whether a transaction is an abusive tax avoidance transaction, that is, a plan or arrangement devised for the principal purpose of avoiding tax, is a question of fact. While the question of purpose is subjective, greater weight is given to objective facts than to a taxpayer's stated intent (***see Lee v Commisioner***, 155 F3d 584, 586 [1998] citing Treasury regulation for determining whether an activity is engaged in for profit [26 CFR 1.183-2 [a]). It is also appropriate to look to the substance, and not the form, of the transaction (***see Gregory v Helvering***, 293 US 465, 469 [1935]).

Upon review of the record, and pursuant to the following discussion, I find that petitioner has met its burden of proving that Mr. Siegal's investments in the 2001 Drilling Partnerships Red Fish, Belle Isle, Cottonwood, and Impact were not abusive tax avoidance transactions as defined in Tax Law former § 683 (c) (11) (C) and that, accordingly, the 2001 notice of deficiency with regard to those investments was not subject to the exception listed under Tax Law former § 683 (c) (11) (B). In contrast, for the remainder of the 2001 Drilling Partnerships (PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger) petitioner has not met its burden of proving that those investments were not abusive tax avoidance transactions as defined in Tax Law former § 683 (c) (11) (C) and accordingly, the 2001 notice of deficiency with regard to those investments was timely.[34]

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[34] The determination herein thus finds the same evidence insufficient to affirmatively prove the Division's fraud allegation, but sufficient to sustain the six-year statute of limitations for the 2001 notice as pertains to the disallowance of the claimed IDC deductions for PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger. This

As noted above, this matter is distinguishable from ***Sznajderman***, in that there was no use of a collateral agreement by Mr. Siegal here. In ***Sznajderman***, the Tribunal found that the taxpayer employed a financing structure designed to artificially inflate his actual capital contributions by the use of the subscription note with a stated principal amount and the concurrent execution of the additional collateral agreement that, according to the Tribunal, effectively reduced the principal debt to 15% of the stated amount. Based on the evidence presented in ***Sznajderman***, the Tribunal found that the taxpayer and the partnership he invested in (Belle Isle) did not have an intent to create a debtor-creditor relationship with respect to 85% of the face value of the subscription note on the date the parties entered into the transaction (***Sznajderman***, citing ***Calloway v Commissioner***, 135 TC 26, 37 [2010]).

The deciding factor of the Tribunal's holding in ***Sznajderman*** was the taxpayer's use of the collateral agreement. The Tribunal found that the collateral agreement entered into by Mr. Sznajderman provided that his obligation on the principal would be satisfied upon payment of a sum of money equal to 15% of the face value of the note to be used for the purchase of bonds. The Tribunal noted that the collateral agreement Mr. Sznajderman entered provided that, if he chose to pay such sum to the partnership and agreed to extend the subscription note for a total of 25 years, the drilling company would guarantee to invest this money at 7.88% compounded so that at the end of 25 years the sum would be equal to the principal amount of the note. The Tribunal concluded that the taxpayer's cash payment of 15% of the stated principal for the purchase of bonds pursuant to the additional collateral agreement effectively protected him from any realistic possibility of liability with respect to the remaining 85% of the principal amount of the note (***Matter of Sznajderman***).

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is not an inconsistency, but simply a shifting of the burden of proof (***see Matter of Jay's Distributors, Inc.,*** citing ***Matter of Cousins Service Station***, Tax Appeals Tribunal, August 11, 1988).

In reaching this conclusion, the Tribunal found that ***Zeluck v Commissioner*** was distinguishable solely on the basis that the Tax Court's decision in ***Zeluck*** made no reference to any option for the taxpayer in that case to fulfill his subscription note principal obligation through the purchase of bonds. The Tribunal found that the terms of the bond purchase option in ***Sznajderman*** did provide such an opportunity and effectively reduced the principal amount of the Mr. Sznajderman's subscription debt to 15% of the face value of the subscription note. Other than the sole distinguishing factor of Mr. Sznajderman's use of the collateral agreement, the Tribunal otherwise found the facts in ***Zeluck*** analogous. ***Zeluck*** involved a Siegal oil and gas partnership similar to the one at issue in ***Sznajderman*** and similar to, and in fact one of, the Drilling Partnerships at issue here.[35] Like the partners in the Drilling Partnerships, the partner in ***Zeluck*** acquired his partnership interest by a combination of cash and a subscription note. Following a review of the various indicia of indebtedness, the ***Zeluck*** court determined that the taxpayer's liability under the subscription note and assumption agreement were genuine at the time they were entered.

As the sole factor relied upon by the Tribunal to distinguish ***Zeluck*** from its holding in ***Sznajderman***, the collateral agreement, is not present here, I find that ***Zeluck***, rather than ***Sznajderman*** is controlling. Accordingly, it is necessary to review and apply the factors analyzed in ***Zeluck*** to the facts of this case. The court considered the following factors in determining whether a genuine indebtedness exists: (1) whether the promise to repay is evidenced by a note or other instrument; (2) whether interest was charged; (3) whether a fixed schedule for repayments was established; (4) whether collateral was given to secure payment; (5) whether repayments were made; (6) whether the borrower had a reasonable prospect of repaying

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[35] ***Zeluck*** involved a taxpayer's investment in PW&F-W-01.

the debt; and (7) whether the parties conducted themselves as if the debt was genuine (***Zeluck v Commissioner***). The court noted that not one factor is necessarily determinative, that the factors are not exclusive, and that it is appropriate to take into account the substance and realities of the financing arrangements at issue (***Id.*** citing ***Calloway v Commissioner***, 135 TC 26, 37 [2010]; ***Melvin v Commissioner***, 88 TC 63, 76 [1987] ***aff'd*** 894 F2d 1072 [9th Cir 1990]).

Evaluating the facts before it with the first factor, the court found the existence of the subscription note and assumption agreement evidence of genuine debt for the years at issue (***Zeluck v Commissioner***). Here, analogous facts are present with regard to the subscription note and assumption agreement. Although the notes and agreements that Mr. Siegal entered into with respect to all of the Drilling Partnerships were not entered into the record, the parties agree that the subscription note and assumption agreement for Belle Isle was representative of the documents Mr. Siegal entered with the other Drilling Partnerships, and do not dispute the existence of such documents (with the exception of Cottonwood and Impact, which did not have a note component, and will be addressed separately below). The partnership agreements for the 2001 Drilling Partnerships with the note component (Redfish Bay, PW&F-S-01, Belle Isle, Bayou, PW&F-W-01, Sanoroc, and Challenger) (the 2001 note component DPs) specified that the price of an interest would be paid in part with cash and in part by a full recourse Subscription Note made by the partner to the Drilling Partnership. The parties do not dispute that Mr. Siegal invested in the 2001 note component DPs by executing Subscription Agreements and Subscription Notes, which outlined the price to be paid for each partnership, the total amount subscribed, and the division of the contribution between cash and note (***see*** Finding of Fact 103, detailing the amount of cash and note Mr. Siegal invested in each Drilling Partnership). As found by the court in ***Zeluck***, the existence of the notes and agreements are evidence of genuine debt for 2001.

Addressing the second factor, the court found that the charge of annual interest of 8% on the subscription note in both 2002 and 2003 was evidence of genuine debt existing in both years (***Zeluck v Commissioner***). Similarly, here, the Subscription Note Agreements for the 2001 note component DPs establish the terms of the note, including maturity date and interest rate. The Subscription Notes for the 2001 note component DPs were recourse notes which bore an interest rate of 8% (after an initial lower rate for the first year). As found by the court in ***Zeluck***, the charge of annual interest is evidence of genuine debt.

The court found that the third factor, whether a fixed schedule for repayments was established, was met in that the partner was required to make quarterly interest payments in 2002, and in 2003 interest payments were to be made out of the withholdings from the partnership's net operating revenue distributions (***Id.***). The court further found that the provision that 25% of the partner's share of net operating revenues (after the payment of interest) was to be used to pay down the outstanding principal balance on the subscription note (and the related turnkey note) was evidence of genuine debt for the years at issue (***Id.***). Here, too, the subscription notes and turnkey notes provided repayment schedules for interest and principal: the 2001 note component DPs had an initial note term of 8 years and provided for interest payments to be made out of the net operating revenue distributions; 25% of Mr. Siegal's share of net operating revenue (after the payment of interest) was to be used to pay towards the outstanding principal in the notes (for Belle Isle, the subscription note agreement provided for a payment of 50% of the partner's share of revenue). This schedule for repayments is evidence of the existence of genuine debt.

The fourth factor analyzed by the court in ***Zeluck*** to determine whether the debt was genuine was whether collateral was pledged to secure payment. The court found that payment was secured by the partner's grant to the partnership of a security interest in his interest in the partnership and his rights to the production and proceeds from the wells. These same security interests were granted to the turnkey driller as collateral for the turnkey note. In addition, the turnkey note was secured by the subscription notes payable to the partnership, any collateral securing the subscription notes, and the contract between the turnkey driller and the partnership (***Id.***). The court concluded that the existence of such collateral was evidence of the existence of genuine debt. The same security provisions are present for the subscription notes and turnkey notes at issue here (***see*** Findings of Fact 109 and 111) and are evidence of the existence of genuine debt.

The fifth factor to be reviewed is whether repayments were made. The court found that the taxpayer made the required interest payments in 2002, but did not pay down principal in 2002 even though a net operating revenue distribution was made to him. The court concluded that this reflected mixed evidence of whether genuine debt exited in 2002 (***Zeluck v Commissioner***). For 2003, the court found a failure to properly repay the required interest and principal on the subscription note and assumption agreement through withholding on distributions to the taxpayer, as well as a failure by the partnership to pay down the turnkey note upon termination of the partnership, were strong evidence that no genuine debt existed in 2003 (***Id.***).

In the present matter, the only evidence in the record regarding interest and principal repayments for the 2001 note component DPs are with regard to Redfish Bay and Belle Isle. Mr. Siegal made payments of interest to Redfish Bay through April 2007 totaling $58,058.00, and made principal repayments to Redfish Bay totaling $13,763.00 for that same period. For Belle Isle, Mr. Siegal made interest payments of $19,859.00 through October 2010. Portions of the turnkey notes obligations for Redfish Bay and Belle Isle were paid as well: in 2003 Belle Isle paid $129,000.00 toward interest on the note and Redfish Bay paid all of the $382,647.00 current and accrued interest that was outstanding. Redfish Bay made payments of interest on its Turnkey Notes in every year from 2003 through 2015, totaling $1,641,226.00. Belle Isle made payments of interest on its Turnkey Note from 2003 through 2015, totaling $274,508.00. In 2002, Redfish Bay made a principal payment of $245,185.00 on its Turnkey Note liability, and in 2003, made a principal payment of $11,725.00. These repayments are evidence of genuine debt for the obligations of Mr. Siegal with Belle Isle and Redfish Bay.

As for the remaining 2001 note component DPs (PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger) there is no evidence in the record regarding any repayments of interest or principal. The lack of evidence weighs against petitioner meeting its burden of proving genuine debt with regard to these partnerships.

The sixth factor, whether the borrower had a reasonable prospect of repaying the loan, is difficult to ascertain, because, similar to the circumstances in ***Zeluck***, no evidence was specifically presented detailing Mr. Siegal's ability to pay the liabilities as they existed during the year at issue. However, the court in ***Zeluck*** noted that the taxpayer was able to obtain $110,000.00 in cash to invest in the partnership and was able to make the required interest payments in 2002. The court further considered that had proper withholdings been made from the taxpayer's net operating revenue distributions, a small principal payment would have been made in 2002 and approximately 80% of the interest would have been paid in 2003, which could have had a great effect on the taxpayer's ability to pay off the debt upon maturity in 2009 (***Id.***). The court concluded that such facts were neutral evidence of the existence of genuine debt for the years at issue.

It is noted in the present matter that at the time Mr. Siegal made the 2001 investments, he likely had a reasonable prospect of repaying the loan, as evidenced by his ability to invest an additional $5,791,500.00 the following year in other drilling partnerships. Further, as noted above, the record establishes that Mr. Siegal did repay portions of the loan with respect to Redfish Bay and Belle Isle. However, as noted, there is no evidence of repayments for the other

2001 note component DPs. Similar to ***Zeluck***, here too the facts are neutral evidence of the existence of genuine debt.

The last factor to be addressed, whether the parties conducted themselves as if the debt was genuine, is again limited by the evidence that was presented in the record. The evidence shows that for Redfish Bay, both interest and principal payments were made from the net operating revenue distributions to Mr. Siegal, evidencing that the parties conducted themselves in accordance with the subscription note and thus supporting the existence of genuine debt of Mr. Siegal. For Belle Isle, the record shows payments of interest, but not principal, from the net operating revenue distributions to Mr. Siegal. Although Mr. Siegal received check distributions from Belle Isle totaling $244,882.00 through October 2010, no portion of Mr. Siegal's distributions went towards principal, despite Belle Isle's subscription note provision that 50% of the net operating revenue, after interest payment, was to be applied to principal. The parties conduct of treating the debt as genuine with regard to interest, but failing to make the required principal payments, reflects mixed evidence of whether the debt with Belle Isle was genuine.

Again, for the remaining 2001 note component DPs (PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger), there is no evidence in the record as to whether the parties conducted themselves as if the debt was genuine. The lack of evidence weighs against petitioner meeting its burden of proving genuine debt with regard to these partnerships.

E. After considering each of the seven factors set forth in ***Zeluck*** in relation to the evidence presented in this matter, it is determined that the subscription note debt between Mr. Siegal and Redfish Bay and the subscription note debt between Mr. Siegal and Belle Isle were genuine debt. Having concluded that the actual indebtedness given by Mr. Siegal in exchange for his partnership interests in Redfish Bay and Belle Isle was genuine, it follows that Redfish Bay's and Belle Isle's turnkey notes with the turnkey drilling companies were likewise genuine debt. It is further concluded, based on the credible testimony presented from Mr. Plastino and Mr. Krehel, that the prices charged to the Drilling Partnerships in the turnkey drilling contracts were reasonable, and the Division's mark-up theory was erroneous (***see*** Conclusion of Law C). Accordingly, it is concluded that petitioner has established that Mr. Siegal's primary purpose in entering into the investments with Redfish Bay and Belle Isle was not tax avoidance. As such, the six-year statute of limitations does not apply with regard to those transactions. However, for the other 2001 note component DPs (PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger), petitioner has failed to present evidence of genuine debt and as such has not established that Mr. Siegal's primary purpose of entering into those transactions was not tax avoidance. Accordingly, the six-year statute of limitations applies solely to the IDC deductions Mr. Siegal claimed for PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger in 2001, totaling $5,476,066.00. The Division is ordered to recalculate the 2001 notice of deficiency accordingly.

F. As noted in Conclusion of Law D and Finding of Fact 11, Mr. Siegal's investment in Cottonwood and Impact did not have a note component and were cash only. Nevertheless, the Division included the intangible drilling costs claimed by Mr. Siegal for his proportionate share in these unleveraged, cash only partnerships in the amount of losses it disallowed for 2001. The Division's current auditor, Mr. Fahrenkopf, testified that he does not know the basis for that disallowance.

The Division concedes that Mr. Siegal's investment in Cottonwood and Impact was by cash only. Thus its argument that "petitioner artificially inflated available deductions by inflating the Subscription Notes, which were non-genuine to the extent of the amounts allocated pursuant to the collateral agreement" is baseless with regard to these investments.

Although a determination of tax must have a rational basis in order to be sustained upon review (***see Matter of Grecian Sq. v New York State Tax Commn.***, 119 AD2d 948 [3d Dept 1986]), the presumption of correctness raised by the issuance of the assessment, in itself, provides the rational basis, so long as no evidence is introduced challenging the assessment (***see Matter of Tavolacci v State Tax Commn.***, 77 AD2d 759 [3d Dept 1980]; ***Matter of Leogrande***, Tax Appeals Tribunal, July 18, 1991). Evidence that both rebuts the presumption of correctness and indicates the irrationality of the audit may appear on the face of the audit as described by the Division through testimony or documentation (***see Matter of Snyder v State Tax Commn.***, 114 AD2d 567 [3d Dept 1985]; ***Matter of Fortunato***, Tax Appeals Tribunal, February 22, 1990); from factors underlying the audit that are developed by the petitioner at hearing (***see Matter of Ristorante Puglia, Ltd. v Chu***, 102 AD2d 348 [3d Dept 1984]; or in the inability of the Division to identify the basis of the audit methodology in response to questions posed at the hearing (***see Matter of Basileo***, Tax Appeals Tribunal, May 9, 1991; ***Matter of Shop Rite Wines & Liqs.***, Tax Appeals Tribunal, February 22, 1991; ***Matter of Fashana***, Tax Appeals Tribunal, September 21, 1989). There is no dispute that Cottonwood and Impact were cash-only investments and the Division has been unable to explain the basis of its inclusion of the losses from those partnerships in its disallowance. As such, the Division lacked a rational basis for disallowing Mr. Siegal's losses derived from these cash-only partnerships, and the six-year statute of limitations does not apply with regard to these transactions.

G. The Division asserted penalties for negligence under Tax Law § 685 (b) (1) and (2), and substantial understatement of liability under Tax Law § 685 former (p)[36] in the notice of deficiency for tax year 2001, dated August 25, 2008. On September 15, 2008, the Division

[36] Tax Law § 685 former (p) was effective until July 1, 2015 (***see*** L 2005 c 61, pt N, § 12 [iii]).

issued an additional notice of deficiency for 2001, asserting penalties in the amount of $272,576.17 for failure to participate in the Voluntary Compliance Initiative under Chapter 61 of the Laws of 2005, Part N, § 11 (l).

Tax Law § 685 (b) (1) and (2) provide for the imposition of penalties if any part of the deficiency is due to negligence or intentional disregard of Article 22 of the Tax Law or the regulations thereunder. Tax Law § 685 former (p) provides for the imposition of penalty where there is substantial understatement of the amount of income tax required to be shown on the return. Under this provision, a substantial understatement means that the difference between the tax required to be reported and the tax actually reported is greater than 10% of the tax required to be reported. Substantial understatement excludes any portion of the understatement attributable to the tax treatment of an item for which there is substantial authority for such treatment. Tax Law § 685 former (p) allows abatement of penalty under that section upon a showing of reasonable cause and good faith.

Petitioner has not met its burden of proving that the deficiency with regard to the deductions claimed for his share of the IDCs from PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger in 2001 was not due to negligence or intentional disregard of the Tax Law and has not made a showing of reasonable cause or good faith. Petitioner failed to put any transactional documents specific to these partnerships into the record and did not provide any evidence showing whether repayments of either interest or principal from the subscription notes between Mr. Siegal and these partnerships were made or whether the parties conducted themselves as if the debt was genuine. Due to the lack of evidence presented with regard to these partnerships, petitioner has not met its burden of proof for the abatement of penalties. However, as found in Conclusion of Law E and F, the Division is directed to recalculate the 2001 notice of deficiency, as it has been determined herein that the six-year statute of limitations is only applicable to the deficiencies attributable to the IDC deductions petitioner claimed for PW&F-S-01, Bayou, PW&F-W-01, Sanoroc, and Challenger in 2001, and the penalties must be recomputed accordingly.

A voluntary compliance initiative (VCI) was established in 2005 which applied to tax liabilities attributable to the use of tax avoidance transactions for taxable years beginning before January 1, 2005 (Chapter 61 of the Laws of 2005, Part N, § 11 [b]). The VCI provided that if an eligible taxpayer entitled to participate failed to do so and has a deficiency with respect to one or more designated taxes for a taxable year beginning before January 1, 2005 that is attributable to the use of a tax avoidance transaction for such taxable year, "there shall be added to the tax an amount equal to one hundred percent of the interest payable for the period beginning on the last date prescribed by law for the payment of the tax (determined without regard to extensions) and ending on the date the notice of deficiency is mailed to the taxpayer" (Chapter 61 of the Laws of 2005, Part N, § 11 [l]). There are no provisions for abatement of a penalty assessed for failure to participate in the VCI. However, as with the penalties assessed under §§ 685 (b) (1) and (2), and (p), the penalty for failure to participate in the VCI must be recalculated in accordance with Conclusions of Law E and F.

H. The petition of Richard Siegal (Estate of), Gail Siegal, Administrator, is granted to the extent indicated in Conclusions of Law C, E, F, and G, but is in all other respects denied; the notice of deficiency for 2002, dated December 18, 2013, is canceled; the Division is directed to recompute the notices of deficiency for 2001, dated August 25, 2008 and September 15, 2008, in accordance with Conclusions of Law E, F, and G, and as so modified, the notices for 2001 are sustained.

DATED: Albany, New York
February 15, 2018

/s/ Barbara J. Russo
ADMINISTRATIVE LAW JUDGE

Reported Schedule E Deductions and IDC Amounts for Petitioner's 2001 Partnerships

	Reported on 2001 K-1 and Reconciliation Worksheet				1040 Statement 5 - Schedule E
Partnership	Ordinary Income	IDCs	Total Schedule E	Tax Return	Nonpassive Loss
Redfish Bay	-2,021	-373,095	-375,116	-375,116	375,115
Impact	-171	-14,629	-14,800	-14,800	14,800
PW&F-S-01	-4,369	-1,096,082	-1,100,451	-1,100,451	1,100,451
Belle Isle	-1,778	-1,149,870	-1,151,648	-1,151,648	1,151,648
Bayou	-2,781	-1,145,675	-1,148,456	-1,148,456	1,148,456
Cottonwood	-5	-2,637	-2,642	-2,642	2,642
PW&F-W-01	-220	-1,237,480	-1,237,700	-1,237,700	1,237,700
Sanoroc	-2,405	-1,497,661	-1,500,066	-1,500,066	1,500,066
Challenger	-894	-499,168	-500,062	-500,062	500,062
TOTALS	**14,644**	**7,016,297**	**7,030,941**	**7,030,941**	**7,030,941**
Total Nonpassive Losses for 2001 Partnerships Reported on Schedule E					**7,030,941**

Appendix A

Reported Schedule E Deductions and IDC Amounts for Petitioner's 2002 Partnerships

	Reported on 2002 K-1 Reconciliation Worksheet					1040 Statement 4 - Schedule E	
Partnership	Ordinary Income	IDCs	Total Schedule E	PAL Disallowed	Tax Return	Passive Loss	Nonpassive Loss
Bateman	-2,030	-898,123	-900,153		-900,153		900,153
Black Creek	-641	-824,710	-825,351		-825,351		825,351
Centrahoma	-776	-1,199,342	-1,200,118		-1,200,118		1,200,118
PWF-W-02	-121	-1,485,267	-1,485,388		-1,485,388		1,485,388
Mayfield	-148	-1,776,034	-1,776,182	1,748,047	-28,135	28,135	
RCCP-02	-272	-3,665,910	-3,666,182		-3,666,182		3,666,182
Red River	-1,836	-3,298,784	-3,300,620		-3,300,620		3,300,620
Silver Spike	-506	-1,275,646	-1,276,152		-1,276,152		1,276,152
TOTALS	**-6,330**	**-14,423,816**	**-14,430,146**	**1,748,047**	**-12,682,099**	**28,135**	**12,653,964**
Total Passive and Nonpassive Losses for 2002 Partnerships Reported on Schedule E						**12,682,099**	

Appendix B