

# HARVESTING THE SACRAMENTO

Long after the Sacramento Basin's natural gas reserves were believed exhausted, seismic-savvy operators are still tapping overlooked multiple pay zones.

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The nearly 250-mile-long and 75-mile-wide Sacramento Basin, cradled between the easterly Sierra Nevada Mountains and the westward Coastal Range, boasts a lush alphabet soup of crops, from asparagus to zucchini, as well as world-class wine vineyards.

But hidden beneath this flat, verdant lobe of northern California is also a structural and stratigraphic wonderland of highly folded, faulted and fractured Cretaceous and Eocene-age rocks that would make a geologic Alice do flips. The big subsurface harvest: natural gas.

Due to the play's complex geology and often tricky-to-target fault blocks, however, early operators—armed with only 2-D seismic or no seismic—often had to rely on serendipity for success. “I’d rather be lucky than smart” wasn’t an uncommon expression as a producer approached the moment of drilling.

But later on, the application of 3-D seismic technology greatly shifted the odds of success in favor of the basin’s producers. At the same time, the major oils began exiting the region in search of bigger hydrocarbon targets. Their belief was that by the late 1980s the Sacramento, which had already given up 8- to 9 trillion cubic feet (Tcf) of gas production, was on its last legs.

Some smaller independents working the basin took a much different view. In fact, one of their number, the head of Capital Oil Corp., contended at the time that there might be as much as 6 Tcf of remaining gas reserves in the Sacramento—in deeper, over-

looked and undrilled horizons such as the Forbes formation.

Several seismic-savvy operators outside the basin also shared this assessment. More importantly, they, too, came to the conclusion that the careful processing and analysis of 3-D seismic data gave independents a high statistical edge in economically drilling up the basin’s remaining potential—even at then-low gas prices. Two such independents were Aspen Exploration Corp. and Royale Energy Inc.

## Orphan finds home

Founded in 1980, Aspen Exploration Corp. (OTC BB: ASPN), with offices in Bakersfield, California, and Denver, entered the basin in 1996.

“We were attracted to the Sacramento because it has multiple pay horizons, from the Eocene at 2,000 feet to the Winters at 12,000 feet,” says Robert A. Cohan, Aspen’s president, chief executive officer and chief financial officer. “We also liked the fact that 3-D seismic works very well in identifying natural gas reserves in the basin.”

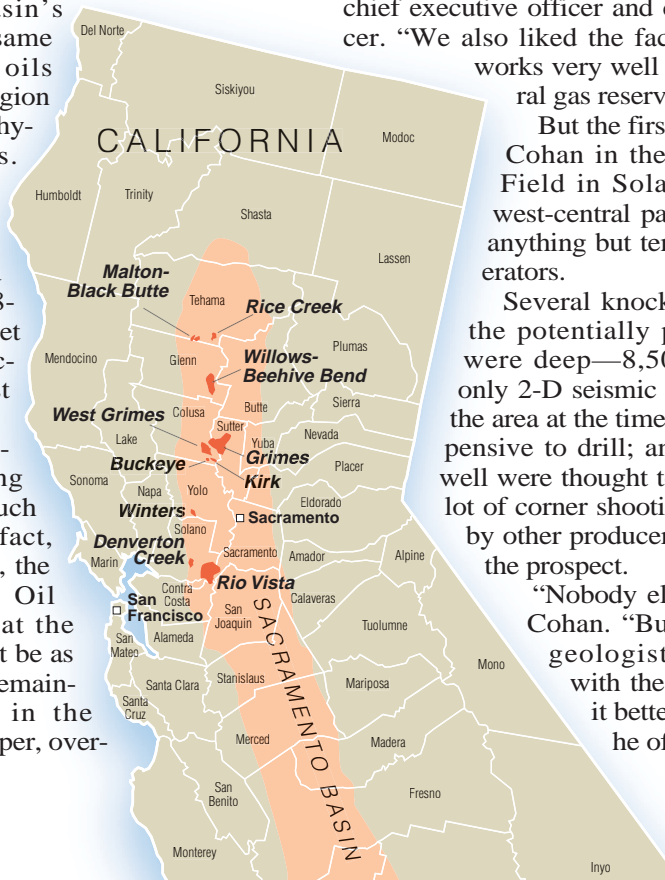
But the first prospect shown to Cohan in the Denverton Creek Field in Solano County in the west-central part of the basin was anything but tempting to some operators.

Several knocks on the prospect: the potentially productive targets were deep—8,500 to 12,000 feet; only 2-D seismic had been shot over the area at the time, the wells were expensive to drill; and the reserves per well were thought to be small due to a lot of corner shooting then being done by other producers near the edges of the prospect.

“Nobody else wanted it,” says Cohan. “But I believed in the geologist who came to us with the prospect and liked it better than the 20 others he offered to us.”



**Aspen Exploration was attracted to the Sacramento Basin because of its multiple pay horizon, says Robert A. Cohan, president, chief executive and chief financial officer. The basin stretches some 250 miles east of the Sierra Nevadas.**





**Royale Energy has begun using horizontal, underbalanced drilling technology in the Sacramento, tapping more gas content, according to Don Hosmer, president and chief executive.**

The Aspen head was by no means relying on serendipity to carry the day. Cohan had previously been with Western Geophysical, several Rockies producers and H.K. van Poolen & Associates, a Denver oil and gas reservoir engineering and geological consulting firm. So he knew his way around the patch.

Not long after this initial Denver Creek acquisition, the company drilled its first well on the prospect—the Emigh 34-1. The result: a successful Bunker formation discovery with initial daily gas output of 3 million cubic feet. This led to the drilling of 15 additional Denver Creek wells, 12 of which were successful.

Today, the company's cumulative gas output from the field has risen to 10 billion cubic feet (Bcf) from eight productive horizons ranging from the 9,000-foot Martinez formation to the 11,500-foot Peterson.

That's not all. Several years ago, in the West Grimes Field in Colusa County in the northern part of the basin, Aspen acquired existing production from Vintage Petroleum and subsequently more than 5,000 lease acres, on which it shot a 10.5-square-mile 3-D seismic survey that identified 10 to 15 drilling locations.

Focusing on the 6,000- to 8,000-foot Forbes formation at West Grimes, the producer last year drilled four gas wells, successfully completing all four. Initial daily production rates on the wells were as high as 4.8 million cubic feet with estimated reserves per well ranging from 500 million cubic feet to 3 Bcf.

Up north, Aspen has also become active in the Malton Black Butte Field in Glenn and Tehama counties. Targeting the Eocene, Kione and Forbes formations at depths ranging from 1,700 to 5,000 feet, it has successfully completed six wells out of eight attempts, generating cumulative production of more than 4 Bcf of gas.

In addition, Aspen is drilling in the Winters Gas Field in Yolo County in the central part of basin, appropriately targeting the Winters formation, and in the Kirk-Buckeye Field in Colusa County where its objective is the Forbes formation.

Successful, too, has been the producer's Momentum farm-out project in the Grimes, Winters and Buckeye gas fields where last year it drilled four of four wells successfully at depths ranging from 3,800 to 8,800 feet. Initial daily flow-rate tests on the wells were as high as 2.5 million cubic feet with estimated reserves per well ranging from 500 million cubic feet to 1.1 Bcf.

Since its initial Emigh well in 1996, Aspen has drilled a total of 52 wells on its 18,000 gross acres in the basin, successfully completing 42 of them. "More notably, our drilling success rate during the past four years rose to 85% as we completed 22 gas wells out of 26 attempts—and got to 100% last year when we drilled 10-for-10 wells successfully," Cohan

says.

The reason for these success rates? "It's a combination of having good deal flow—we see at any one point as many as 25 drilling prospects being offered; having solid 3-D seismic data on which to base our drilling; having plenty of well control in the areas we operate; and just becoming more experienced in the basin."

With such a track record, Aspen—with operated and nonoperated interests in an overall 62 producing wells in the basin—has managed to grow gross production from zero in 1996 to nearly 10 million cubic feet per day as of March 2005. Gross reserves have climbed to about 16 Bcf, meanwhile; net reserves, to 2.5 Bcf, as of June 30, 2004.

In no small part due to its perfect 2004 drilling batting average, the producer has also seen meteoric gains in its financial performance and market value.

During the nine-month period ending March 2005, its reported revenues were \$3.1 million, a 149% gain compared with revenues for the prior nine-month period. Concurrently, its EBITDA (earnings before taxes, depreciation and amortization) per share for the corresponding periods rose to 35 cents from 10 cents while earnings per diluted share grew to 21 cents from four cents.

"...We are today drilling twice as many wells as we were a few years ago."

Robert A. Cohan,  
Aspen Exploration Corp.

Even more noteworthy, the Street has apparently taken note of Aspen's recent financial and operating performance. This July, the stock reached a record high of \$7.75 per share; in April, 2004, it was trading at only 62 cents per share.

For all of 2005, the company plans to drill 10 wells throughout the Sacramento Basin, with a gross capex budget of \$9 million, up from \$8 million last year.

The outlook for gas prices in the Sacramento? "It's strong—the supply of gas is limited and the demand for it in California is voracious." Currently, Aspen is getting an average \$6 to \$6.75 per million Btu for its gas while it has hedged for the November 2005-March 2006 period 25% of output at \$8.40 to \$8.43.

Says Cohan, "It's funny. Five or 10 years ago, people were saying this basin was pretty much done. Yet here we are today, drilling twice as many wells as we were a few years ago."

#### **Technology-focused**

Starting out in 1986 as a privately held producer, San Diego-based Royale Energy Inc. entered the Sacramento Basin in 1992 through a

farm-out from Pacific Gas & Electric Resources in the Rice Creek Field in Tehama County in the northern tip of the basin.

“We liked the basin because it has good gas prospects that are identifiable with ‘bright spot’ or amplitude-versus-offset (AVO) seismic technology. And we liked the high production rates associated with the 5,000- to 6,000-foot Forbes formation,” says Don Hosmer, Royale president and chief executive officer.

The first Forbes gas well drilled by the operator in the Rice Creek Field in 1992 was the Victor Ranch #12. It came online in December 2003 at an initial flow rate of 2 million cubic feet per day. Since then, the well has cumulatively produced more than 2.5 Bcf of gas, with current daily output around 300,000 cubic feet. Royale followed that with the successful drilling of the Victor Ranch #13, which is still producing 100,000 cubic feet daily.

“At the time, these wells cost only \$300,000 to \$350,000 to complete, so they were very attractive economically, even at \$1.20 per thousand cubic feet—the price we were then getting for our gas,” explains Hosmer. “With average reserves per well about 1 Bcf and \$1.20 gas, an operator could get back \$1.2 million on a \$300,000 to \$350,000 investment.”

The year it went public, 1994, Royale Energy (Nasdaq: ROYL) also teamed up with a Bakkersfield-based producer and participated in drilling, on the basis of AVO seismic, the highly successful Pinheiro gas well near the Willows Beehive Bend Field in Glenn County. The well initially flowed 5 million cubic feet per day from the Forbes.

On the heels of this success, the company purchased all the assets of Arkoma Production Co. of California, then run by Jerry Jones, owner of the Dallas Cowboys football franchise. The transaction: 2 million cubic feet of daily gas production throughout the basin for just north of \$2 million.

The next big step in Royale’s growth came in 1997. After purchasing all of PG&E Resources’ 3 million cubic feet of daily Rice Creek Field production for \$3 million, the operator shot 3-D seismic over its McCormack lease in Solano County’s Rio Vista Field. The Rio Vista is the largest gas field in the Sacramento; its cumulative gas production is more than 1 Tcf.

As a result of its aggressive use of 3-D seismic, the company drilled three successful wells consecutively, each with 500,000 to 1 million cubic feet of daily gas output from the 6,000-foot Hamilton formation.

Since its success at Rio Vista, Royale has expanded its footprint and its use of 3-D to other parts of the basin, including the Denverton Creek and West Grimes fields. Today it has 30,000 gross acres in the Sacramento and 20,000 net.

On that acreage, it has to date drilled 115 wells, 71% of them successfully. Daily output from those wells is 500,000 to 1 million cubic

SYSTEM	SERIES	STRATIGRAPHIC UNIT
TERTIARY	EOCENE	Markley Formation
		Nortonville Shale
		Domengin Formation
		Capay Formation/ Princeton Canyon Fill (Hamilton Sand)
		Meganos Shale/Meganos Canyon Fill
	PALEOCENE	Martinez Formation
CRETACEOUS	UPPER	Mokelumne River sands (Bunker Sand)
		Starkey Sands
		Sawtooth Shale
		Winters Sands
		Sacramento Shale
		Kione sand
		Forbes Formation

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feet, with initial flow rates at the top end of that range; reserves in the basin, meanwhile, currently stand at 12- to 13 Bcf.

In tandem with this growth, the company’s recent operating cash flow has risen from \$2.8 million in 2002 to \$9.9 million in 2003, with a decline to \$8 million in 2004. Similarly, earnings per share went from a loss of 3 cents in 2002 to 71 cents in 2003, before retreating to 31 cents in 2004.

“Last year, we had some high drilling and seismic expenses due to the deeper wells we’re drilling in the basin, and that definitely had a negative impact on our 2004 financial results,” says Hosmer. “However, we look forward to becoming more profitable over the next five years, given our outlook for strong California gas prices during that period.”

He notes that although it now costs the company an average \$600,000 to \$700,000 to drill and complete a Sacramento well, versus \$300,000 to \$350,000 in 1993, gas prices in the interim have risen six-fold, to north of \$7.

To ensure profitable growth in the basin in the future, Royale—through its joint venture with Stafford, Texas-based Output Exploration LLC—has recently introduced horizontal, underbalanced drilling to the Sacramento.

“Horizontal drilling exposes a larger portion of a formation to the wellbore, allowing more drainage of a reservoir,” explains Hosmer. “Meanwhile, drilling underbalanced causes less potential damage to a reservoir. We think this technology could open a whole new era of reserve recovery in the basin.”

Recently, the independent has seen its stock move to a high of \$11.95 per share from a 52-week low of \$4.55. Currently receiving \$6 to \$7 for its gas, Royale plans to drill upwards of 10 Sacramento wells this year, roughly the same number as last year.

Says the technology-driven Hosmer, “Today, by properly shooting and analyzing our seismic data, we’re able to drill most of our dry holes on computer, not in the field.” □