DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL OF
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851

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UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF AVISTA CORPORATION FOR THE AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC AND NATURAL GAS SERVICE TO ELECTRIC AND NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO	CASE NO. AVU-E-10-01 CASE NO. AVU-G-10-01 DIRECT TESTIMONY OF RICHARD L. STORRO

FOR AVISTA CORPORATION

(ELECTRIC & NATURAL GAS)

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Richard L. Storro. I am employed as the Vice President of Energy Resources by Avista Corporation located at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational and professional background?

A. I received a Bachelor of Science degree in physics from the College of Idaho and a Bachelor of Science degree in electrical engineering from the University of Idaho, both in 1973. I began working for Avista in 1973 as a distribution engineer and have held several other engineering positions with the Company. I have held management positions in line and gas operations, system operations, hydro production and construction, and transmission. I joined the Energy Resources Department as a Power Marketer in 1997, became Director of Power Supply in 2001, became President of Avista Ventures in 2007, and became Vice President of Energy Resources in January 2009.

Q. What is the scope of your testimony in this proceeding?

A. My testimony provides an overview of Avista's resource planning and power supply operations. This includes summaries of the Company's generation resources, the current and future load and resource position, future resource plans, and an update on the Company's plans regarding the acquisition of new renewable resources. I will address hydroelectric and thermal project upgrades, followed by an update on recent developments regarding hydro licensing.

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Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit No. 4, Schedule 1C, which includes a Confidential copy of Avista's Energy Resources Risk Policy and Schedule 2 includes Avista's 2009 Electric Integrated Resource Plan.

<u>II. AVISTA'S RESOURCE PLANNING AND POWER OPERATIONS</u>

Q. Would you please provide a brief overview of Avista's generating resources?

A. Yes. Avista's resource portfolio consists of hydroelectric generation projects, base-load coal and natural gas-fired thermal generation facilities, wood waste-fired renewable generation, natural gas-fired peaking generation projects, long-term contracts including wind and Mid-Columbia hydroelectric generation, and market power purchases and exchanges. Avista-owned generation facilities have a total capability of 1,777 MW, which includes 56% hydroelectric and 44% thermal resources.

Illustration No. 1 below summarizes the present net capability of Avista's owned generation resources:

Illustration No. 1: Avista Generation

Company-Owned Projects	MW
Noxon Rapids	557
Cabinet Gorge	255
Post Falls	18
Upper Falls	10
Monroe Street	15
Nine Mile	18
Long Lake	83
Little Falls	35
Total Hydroelectric Generation	**991**
Colstrip Units 3 and 4	222
Coyote Springs 2	278
Kettle Falls	50
Total Base-Load Thermal Generation	**550**
Northeast CT	56
Kettle Falls CT	7
Boulder Park	24
Rathdrum CT	149
Total Natural Gas Peaking Generation	**236**
Total Avista-Owned Generation	**1,777**

The Company currently has long-term contractual rights for 128 MW of capability from Mid-Columbia hydroelectric projects, owned and operated by the Public Utility Districts of Chelan, Douglas and Grant Counties. The Company has a contract for 35 MW of wind generation capability from the Stateline Wind Project through March 2012, and also receives 100 aMW of energy from other firm contracts through 2010. Avista has a long-term power purchase agreement (PPA) in place entitling the Company to dispatch, purchase fuel for and receive the power output from the 275 MW Lancaster combined-cycle combustion turbine project located in Rathdrum, Idaho.

Q. Would you please provide a summary of Avista's resource planning and power supply operations?

A. Yes. Avista uses owned and contracted-for resources to serve its load requirements. The Power Supply section of the Energy Resources Department is responsible for dispatch decisions related to those resources with dispatch rights. The Department monitors and routinely studies capacity and energy resource needs. Short and medium-term wholesale transactions are used to economically balance resources with load requirements. Longer-term resource decisions such as new generation resources, upgrades to existing resources, demand-side management (DSM), and long-term contract purchases are generally made in conjunction with the Integrated Resource Plan (IRP) and Request for Proposals (RFP) processes.

Q. Please summarize the current load and resource position for the Company.

A. With the recent addition of the 275 MW Lancaster PPA to the Company's resource mix, Avista's 2009 electric

Integrated Resource Plan (IRP) shows forecasted annual energy deficits beginning in 2018, and sustained annual capacity deficits beginning in 2019.[1]

These capacity and energy load/resource positions are shown on pages 2-27 and 2-28, respectively of Exhibit No. 4, Schedule 2. However, our most recent energy load and resource projection, which is attached as Exhibit No. 5, Schedule 1 to Mr. Kalich's testimony, has pushed the annual deficits out another year. Therefore, Avista's current projection shows an annual energy deficit in 2019 of about 40 aMW, and the deficiency increases to 481 aMW in 2029. The Company's capacity resource position is currently projected to be surplus through 2019. Sustained annual capacity deficiencies begin at 110 MW in 2020 and increase to 732 MW in 2029.

Q. How does the Company plan to meet future energy and capacity needs beginning in 2019 and 2020, respectively?

A. The Company will pursue the Preferred Resource Strategy described in the 2009 Electric IRP, which is attached as Exhibit No. 4, Schedule 2. The IRP provides

[1] The Company has a 150 MW capacity exchange agreement with Portland General Electric that ends in December 2016 which results in short-term annual capacity deficits in 2015 and 2016. Sustained annual capacity deficits begin in 2019.

details about resource needs, specific cost and operating characteristics of the resources evaluated for the Preferred Resource Strategy, and the scenarios used for resource evaluations.

The Company's 2009 Electric IRP was submitted to the Commission in August 2009 following the completion of a public process involving six Technical Advisory Committee meetings. The IRP represents the preferred plan at a point in time, however the Company will continue evaluating resource options to meet future load requirements, including medium-term market purchases, generation ownership, hydroelectric upgrades, renewable resources, distribution efficiencies, conservation measures, long-term contracts, and generation lease or tolling arrangements. As stated earlier, longer-term resource decisions are generally made in conjunction with the Company's IRP and RFP processes, although the Company may acquire some resources outside of formal RFP processes.

Avista's 2009 Preferred Resource Strategy includes 5 MWs of distribution efficiencies, 339 MWs of DSM, 5 MW of upgrades to existing hydroelectric plants, 750 MWs of gas-fired CCCT, and 350 MWs of wind located in the Pacific

Northwest. The timing of these resources as published in the 2009 IRP is shown in Illustration No. 2 below. The Company has recently decided to postpone the acquisition of Northwest Wind included in Illustration 2. I will explain this decision later in my testimony.

Illustration No. 2:

2009 Electric IRP Preferred Resource Strategy

Resource Type	By the End of	Nameplate (MW)	Energy (aMW)
Northwest Wind	2012	150.0	48.0
Distribution Efficiencies	2010 – 2015	5.0	2.7
Little Falls Upgrades	2013 – 2016	3.0	0.9
Northwest Wind	2019	150.0	50.0
CCCT	2019	250.0	225.0
Upper Falls Upgrade	2020	2.0	1.0
Northwest Wind	2022	50.0	17.0
CCCT	2024	250.0	225.0
CCCT	2027	250.0	225.0
Conservation	All Years	339.0	226.0
Total		1,449.0	1,020.6

Q. What is the status of Avista's plans to meet the renewable portfolio standard (RPS) in Washington beginning in 2012?

A. The Energy Independence Act, RCW Chapter 19.285, resulting from Initiative 937 in the State of Washington, requires utilities with more than 25,000 customers to adhere to a renewable portfolio standard by meeting 3% of their load by 2012, 9% by 2016, and 15% by 2020 with qualified renewable energy.

Avista plans to meet its RPS obligations in the near-term through a combination of qualified hydroelectric upgrades, and the purchase of renewable energy credits (RECs). In March 2009 Avista purchased 5.7 aMW of credits (RECs) per year from 2012 through 2015 to satisfy the RPS requirement through 2015.

Q. You mentioned earlier that Avista has postponed the acquisition of wind generation in 2012. Why did the Company choose to delay the addition of wind generation?

A. The Company will need to add approximately 50 aMW of additional qualifying renewable resources to meet the nine percent (9%) RPS requirement at the beginning of 2016. As Mr. Morris explained in his testimony, while there were reasons to acquire additional renewable resources now, we concluded that the near-term cost impacts to our customers did not outweigh the uncertain long-term benefits of acquiring it now.

If we were to acquire additional renewable resources prior to the end of 2012 we could take advantage of a 30% investment tax credit under the Federal Stimulus Package, and also benefit from a Washington State sales tax credit of

7.7%. We issued a request for proposals on September 23, 2009 for up to 35 aMW of Washington RPS qualified renewable energy. The RFP was intended to assess the opportunity to take advantage of these state and federal tax incentives that are currently available in the 2010 - 2012 timeframe.

Avista's proposed Reardan wind project is very attractive compared with the proposals received through the RFP process. The Company purchased the rights to develop the wind project located near Reardan, Washington from Energy Northwest in May 2008, and has added additional leases with local landowners since that time. The Reardan project site has permits and leases in place and has been verified as a viable wind site through several studies based on wind data collected at the site. Current design plans call for a project capability of approximately 90 MW.

On the other hand, as the law in Washington State stands now, we do not need additional renewable energy credits until 2016, and we do not need new energy resources until 2019. And even with the tax credits, the cost of power from the Reardan project would be 9 to 10 cents per kWh, which would have resulted in a rate increase for our customers. The cost of the Project would be over $200 million, which is sizable in relation to our current electric rate base of approximately $1.6 billion. So even though the Project is "on sale" now because of the available tax credits, we concluded that the Company and our customers simply cannot afford it at this time.

Q. Will the Reardan Project still be available for development after 2012?

A. Yes. The Reardan site, including permits and leases, is available and positioned to be constructed and on line in the 2014 - 2015 timeframe. In addition, the Company continues to place met towers at other locations within its service territory to collect wind data and explore other sites for potential development. The Company anticipates that renewable resources necessary to meet 2016 RPS requirements may come from a variety of alternatives including those projects described above, and/or from qualifying renewable third-party projects. Other renewable energy options, including qualified plant upgrades and REC purchases will also be considered.

Q. Can you provide a high level summary of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses several techniques to manage the risks associated with serving load and managing Company-owned and controlled resources. The Company's risk management approach uses price diversification using a layering strategy for forward purchases and sales. The Energy Resources Risk Policy provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long term (more than 36 months), the short term (monthly and quarterly periods out to 36 months), and the immediate term (present month). The period up to 18 months focuses on mechanically layering-in purchases, as well as making advantageous purchases due to declines in energy prices. The 18 to 36 month period primarily looks for advantageous declines in price movements based on models utilizing historic price variability.

The Risk Policy is not a specific procurement plan for buying or selling power or natural gas for generation at any particular time, but is a guideline used by management when making procurement decisions for electric power and natural gas for generation. Several factors, including the variability associated with loads, hydroelectric generation, and electric power and natural gas prices, are considered in the decision-making process regarding procurement of electric power and natural gas for generation. A copy of the current Energy Resources Risk Policy is in Confidential Exhibit No. 4, Schedule 1C.

The use of the hedge scheduler approach, as outlined in an appendix in the Risk Policy, describes what is essentially a layering strategy aimed to average-in purchases or sales of electric power and natural gas generation fuel over a period of time. This approach aims to smooth the impacts of price volatility in the energy markets.

III. GENERATION CAPITAL PROJECTS

Q. Please describe the upgrade projects for the Noxon Rapids generating units.

A. The Company is in the middle of a multi-year program to upgrade the Noxon Rapids generating units which are currently using 1950's era technology. The upgrades on these four units are expected to improve efficiency by adding an additional 30 MW of capacity and approximately 6 aMW of energy to the Noxon Rapids project, as well as improve reliability. Illustration No. 4 below summarizes the timing and additional capacity and efficiency gains of these upgrades.

Illustration No. 4: Noxon Rapids Upgrades

Noxon Rapids Unit #	Schedule of Completion	Additional Capacity	Additional Efficiency
1	April 2009	7.5 MW	4.16%
3	April 2010	7.5 MW	4.15%
2	April 2011	7.5 MW	2.42%
4	April 2012	7.5 MW	1.49%

The Unit #1 work consisted of the replacement of the stator core, rewinding the stator, installing a new turbine and performing a complete mechanical overhaul. This upgrade increased the Unit's energy efficiency by 4.16%, and increased the unit rating by 7.5 MW. The upgrade also fixed several reliability concerns for the Unit including mechanical vibration and stator age. This work was completed in 2009. The costs and additional generation of this project were pro formed, and approved for recovery, in Case No.AVU-09-01.

The upgrade work on Units 3, 2 and 4 began in 2009 and will continue into 2012. The Unit #3 upgrade, planned for completion in April 2010, is planned to increase energy efficiency by 4.15%, and boost the unit rating 7.5 MW.

Unit #2 is scheduled to have a new turbine and complete mechanical overhaul between August 2010 and April

2011. This upgrade is planned to increase Unit #2 efficiency 2.42% and boost the unit rating by 7.5 MW.

The upgrade work at Unit #4 involves the installation of a new turbine and a complete mechanical overhaul from August 2011 through April 2012. The Unit #4 upgrade is planned to increase efficiency 1.49% and increase the unit rating by 7.5 MW.

The costs associated with Unit #3, which will be completed in April 2010, will total approximately $9.3 million (system), and Unit #2, planned for completion in April 2011, will cost approximately $9.2 million (system), as further described in Company witness Mr. DeFelice's testimony. Company witness Ms. Andrews incorporates the Idaho share of these costs in her adjustments. The costs for the upgrade for Noxon Rapids Unit #4 has not been included in this case, but will be included in future rate proceedings.

Q. Can you please provide a brief description of the other generation-related capital projects that are included in this case?

A. Yes. The 2010 generation projects included in the Company's case, as discussed by Mr. DeFelice, total $33.4 million (system). The 2010 Noxon Unit #3 upgrade project discussed above makes up $9.3 million of this total. In addition, there are ten other areas of generation capital projects totaling $24.1 million as discussed further below.

Thermal - Kettle Falls Capital Projects - $1,817,000

The primary project at the Kettle Falls Generating Station is replacement of the Air Heater. This will recover some of the capacity that has been lost over the past several years because of corrosion of air heater tubes and it will reduce the overall load of the ID Fan Motor. Other smaller projects at Kettle Falls include replacement of the wood screw conveyors which feed wood into the hopper and replacement of ash screws in the ash removal system.

Thermal - Colstrip Capital Additions- $2,275,000

Colstrip capital additions in 2010 include a major waste water treatment plant project for Units 3 and 4. This project is an environmental requirement to reduce excess water inventory in order to help reduce the water level in the ponds, which will in turn help reduce the potential for seepage and improve groundwater protection. A number of other smaller capital projects will be performed, including mercury control for Units 3 and 4 and the replacement of an existing boiler retract with a new model that has a more effective soot blower.

Thermal - Other Small Projects - $78,000

Please refer to the workpapers of Mr. DeFelice for a detailed listing of the projects included in this category.

Hydro - Nine Mile Upgrade - $3,954,000

This capital project entails the installation of a new pneumatically operated spill gate on the Nine Mile spillway section. This will improve operational performance of the project by not requiring extended operation at lower head as well as eliminate the annual downstream risk associated with tripping wooden flashboards. This project is a FERC license requirement. This project will eliminate the need to install/remove the flashboards on an annual basis, which creates savings of approximately $75,000 of O&M costs; these savings have been reflected in the proposed revenue requirement.

Hydro - Noxon Capital Project - $7,551,000

Replacements of the Generator Step up Transformers (GSU) are needed to accommodate the additional capacity from the turbine upgrades. These transformers are 50 years old and were reaching the end of their useful life, without the additional capacity requirements. The new GSU's will be roughly 50% more efficient than the existing transformer, saving a potential $125,000 a year in loss reductions; these savings have been reflected in the proposed revenue requirement.

Hydro - Clark Fork/Spokane Implement PM&E Agreements - $4,053,000

Multiple projects on both river systems are planned for 2010 as part of the protection, mitigation and enhancement (PM&E) plans. These projects were agreed to as part of the Clark Fork settlement agreement and FERC license received in 2001 and the Spokane settlement agreement and FERC license received in 2009.

Hydro - Other Small Projects - $2,296,000

There are a number of other small hydro project capital improvements planned for 2010, including:

(1) Completing a system station sump control and monitoring systems to facilitate anticipated license conditions, and other small projects;

(2) Replacing a major component of the Cabinet Unit 1 Turbine (discharge ring);

(3) Replacing the roof at our Long Lake HED; and

(4) Completing the project to replace the old plant controls and locate all new equipment from the Post Street Substation to the Upper Falls plant. New equipment will be installed to modernize the unit, enhance the protection schemes, and to automate the plant from the Generation Control Center. This will improve the ability to control the plant and assist with river flow requirements of the new Spokane FERC license. Please refer to the workpapers of Mr. DeFelice for detailed listing of these projects.

Other - Coyote Springs 2 (CS2) Capital Projects - $1,197,000

There are a number of project improvements planned for 2010, including the upgrade of the Attemperator valve, which is part of the heat recovery steam generator, to enhance steam temperature control and system reliability. Other smaller projects planned for 2010 include the replacement of heat exchangers, installation of ammonia dilution heating equipment, battery replacement, and several smaller PGE/Avista shared projects to improve safety and reliability.

Other - Boulder Park - $410,000

Generation capital projects at Boulder Park include the replacement of the control network. The existing system is obsolete and replacement parts are no longer available.

Other Small Projects - $493,000

There are a number of project improvements planned for 2010. These projects include the upgrade of the control system at the Northeast Combustion Turbine for standby reserve. This project includes the construction of a new building to house the control room and provide better battery capacity for back up purposes. This project is expected to improve the starting and running reliability of this asset to better service our reserve requirements. Please refer to the workpapers of Mr. DeFelice for detailed listing of other projects in this category.

Ms. Andrews incorporates Idaho's share of these capital project additions in her adjustments.

IV. HYDRO RELICENSING

Q. Would you please provide an update on work being done under the existing FERC operating license for the Company's Clark Fork River generation projects?

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on March 1, 2001. The Company has continued to work with the 27 signatories to the Clark Fork Settlement Agreement to meet the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. The implementation program, in coordination with the Management Committee which oversees the collaborative effort, has resulted in the protection of approximately 2,620 acres of bull trout, wetlands, uplands, and riparian habitat. The fish passage program, using electrofishing and trapping with over 150 adults radio tagged and their movements studied, has reestablished bull trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries above Cabinet Gorge Dam. Avista has worked with the U.S. Fish and

Wildlife Service to develop two experimental fish passage facilities, and to develop plans to move forward with designs for permanent fish passage facilities.

Recreation facility improvements have been made to over 20 sites along the reservoirs. Finally, tribal members continue to monitor known cultural and historic resources located within the project boundary to ensure that these sites are appropriately protected. The earlier costs associated with the PM&E measures were reviewed and were included in prior cases. Ms. Andrews has included a pro forma adjustment to reflect the planned PM&E expenditures for 2010.

Q. Would you please provide an update on the current status of the Cabinet Gorge Bypass Tunnels Project?

A. Yes. Total dissolved gas (TDG) levels occurring during spill periods at Cabinet Gorge Dam was an unresolved issue when the current Clark Fork license was received. The license provided time to study the actual biological impacts of dissolved gas and for the subsequent development of a dissolved gas mitigation plan. Stakeholders, through the Management Committee, ultimately have concluded that dissolved gas levels should be mitigated, in accordance with federal and state laws. A plan to reduce dissolved gas levels was developed with all stakeholders, including the Idaho Department of Environmental Quality. The original plan called for the modification of two existing diversion tunnels which could redirect streamflows exceeding turbine capacity away from the spillway.

The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass Tunnels Project indicated that the preferred tunnel configuration did not meet the performance, cost and schedule criteria established in the approved Gas Supersaturation Control Plan (GSCP). This led the Gas Supersaturation Subcommittee to determine that the Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The subcommittee then developed an addendum to the original GSCP to evaluate alternative approaches to the Tunnel Project. In September 2009, the Management Committee agreed with the proposed addendum, which rejects the Tunnel Project. The addendum envisions implementation of a series of smaller TDG reduction efforts, combined with mitigation efforts while design and construction of abatement efforts occur. FERC approved the GSCP addendum in February 2010.

Implementation of the addendum is expected to be significantly less costly than the Tunnels Project plan.

Q. Would you please give a brief update on the status of the work being done under the new Spokane River Hydroelectric Projects license?

A. Yes. The Company filed applications with FERC in July 2005 to relicense five of its six hydroelectric generation projects located on the Spokane River. The Spokane River Project, which is currently under a single FERC license, includes Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls. Little Falls, the Company's sixth project on the Spokane River, is not under FERC jurisdiction, but operates under separate Congressional authority. In June 2009, FERC issued a new 50-year license for the Spokane River Project, incorporating key agreements with the Department of Interior and other key parties. Implementation of the new license began immediately. Approximately 20 work plans or reports were prepared and are under review by agencies and FERC. These pertain not only to license requirements, but also to meeting requirements under Clean Water Act 401 certifications by both Idaho and Washington and other mandatory agency conditions. In 2010, we will be implementing a number of water quality, fisheries, recreation, cultural, wetland, weed management, operational and related conditions (PM&E projects) across all five hydro developments.

The Spokane River Relicensing costs include actual life-to-date expenditures from April 2001 through June 30, 2009. These charges were reviewed and approved in Case No. AVU-09-01. The Company was allowed to defer the amortization of these charges, including a carrying charge on the deferrals and unamortized balance, until rates went into effect August 1, 2009. Idaho's share of these costs, and additional pro forma amounts included to reflect the planned PM&E expenditures for 2010, have been reflected by Ms. Andrews in her adjustments filed in this case.

Q. Does this conclude your pre-filed direct testimony?

A. Yes it does.

DAVID J. MEYER
VICE PRESIDENT AND CHIEF COUNSEL OF
REGULATORY & GOVERNMENTAL AFFAIRS
AVISTA CORPORATION
P.O. BOX 3727
1411 EAST MISSION AVENUE
SPOKANE, WASHINGTON 99220-3727
TELEPHONE: (509) 495-4316
FACSIMILE: (509) 495-8851
DAVID.MEYER@AVISTACORP.COM

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NATURAL GAS SERVICE TO ELECTRIC	)	EXHIBIT NO. 4
AND NATURAL GAS CUSTOMERS IN THE	)	
STATE OF IDAHO	)	RICHARD L. STORRO
	)	

FOR AVISTA CORPORATION

(ELECTRIC ONLY)

CONFIDENTIAL

Avista Utilities Energy Resources Risk Policy

THESE PAGES ALLEGEDLY CONTAIN TRADE SECRETS OR CONFIDENTIAL MATERIALS AND ARE SEPARATELY FILED.

Electric Integrated Resource Plan (IRP)

Compact Disc Exhibit

Also Available At

http://www.avistautilities.com/inside/resources/irp/electric/Pages/default.aspx

Exhibit No. 4
Case Nos. AVU-E-08-01 and AVU-G-08-01
R. Storro, Avista
Schedule 2, P. 1 of 1